Cost and Benefits of Embedded Generation in Ireland

September 2004

Report prepared for Sustainable Energy Ireland by:

PB Power

CONTENTS

1. Executive Summary

To achieve Ireland's commitment of supplying 13.2 percent[1] of its electricity from energy based on renewable sources by 2010 will present significant challenges to the whole industry. The fundamental technical differences in the characteristics and sizes of typical embedded generation power plants when compared to conventional central power stations will present specific challenges for the design and operation of existing medium voltage distribution networks. Connecting significant amounts of embedded generation to passive electricity distribution networks will require the distribution utility to adapt in order that a continued safe, reliable and efficient source of electricity is ensured.

In addition to the technical issues, the EC Renewables Directive (2001/77/EC) and the Electricity Market Directive (2003/54/EC) place obligations on Member States and their network operators in terms of their treatment of embedded generation. This extends to the dispatch, energy pricing and accounting for the contribution that embedded generation makes to distribution network security and reliability.

To assist with the formulation and implementation of future Irish Government policy for the period after the proposed market liberalisation in 2005, Sustainable Energy Ireland (SEI) commissioned PB Power to undertake a detailed study on the costs and benefits associated with the connection of embedded generation in the Irish electricity distribution network.

The principal objectives of the study[2] have been to:

a. Perform a detailed assessment of the costs and benefits to all parties involved in the connection of embedded generation to the electricity networks, including analysis of generic sections of the Irish electricity distribution network;

b. Propose procedures that can be used to identify the costs and benefits of connecting specific types and sizes of embedded generation to the Irish electricity distribution network;

c. Review and analyse the commercial considerations put in place by other jurisdictions to facilitate the connection and the technical and commercial operation of increased levels of embedded generation;

d. Poll the views and opinions of the key Irish market participants with interests in the development of embedded generation. The participants approached included the CER, ESB National Grid, ESB Networks and a representative sample of prospective generation developers and independent supply companies. Issues explored ranged from the treatment of embedded generation, the implementation of EC directive 2001/77/EC in Ireland and the implications of the proposed move to market liberalisation through the adoption of a centralised wholesale market.

e. Propose options for allocating the costs of connecting embedded generation fairly and equitably between all of the parties involved.

[1] Target from EU Directive 2001/77/EC

[2] The Terms of Reference for the Study are included within Appendix A to this report.

1.1 Representative Networks

The bulk of the ESB distribution network is located in rural areas and is likely to remain so for the foreseeable future, even with continued growth of the Irish economy and the resulting expansion of the area of urban and semi-urban development, particularly in areas within reasonable commuting distance (i.e. 100 km) of Dublin.

The rural distribution network is characterised by long, single circuit overhead lines, configured as a radial network at either 10 kV or 20 kV, to supply an area of low load density, with densities typically in the range 20 kW/km^2 to 50 kW/km^2. At the other extreme, in central Dublin, electricity distribution is via 38 kV and 10 kV underground cable networks that supply customers in high load density areas, with densities typically in the range 5,000 kW/km^2 to 10,000 kW/km^2. In the larger towns and on the outskirts of Dublin and the other cities where there is a mix of domestic, commercial and light industrial loads the load density is typically in the range 1,000 kW/km^2 to 4,000 kW/km^2.

Following a review of ESB Networks' rural, semi-urban and dense urban networks in Ireland, five principal network types are considered to capture the characteristics that typify the electricity distribution network in Ireland. These five representative network types are:

Type 1 - 38/10 kV rural,

Type 2 – 38/20 kV rural,

Type 3 – 110/20 kV rural[3],

Type 4 – 38/10 kV semi-urban,

Type 5 – 38/10 kV dense urban.

To determine principal physical characteristics for each of the representative network types, topographical analysis was undertaken on fifteen high voltage and sixty medium voltage network circuits. These networks were selected from areas where there is a reasonable expectation of future development of embedded generation based on the availability of sustainable energy resources. Raw data for the analysis was in the form of the ESB Networks single line diagrams for the 38kV network, geographic layouts of the medium voltage distribution network, substation and feeder loads, transformers, overhead line and cable data. The principal characteristics reviewed in the analysis were:

- Primary substation and feeder voltages
- Type of network (i.e. overhead or underground)
- Installed primary substation and distribution transformer capacity
- Load supplied (or load density)
- Area of supply
- Feeder physical characteristics (i.e. numbers and lengths of trunk, spurs and stub circuits)[4]
- Voltage control facilities.

---

[3] The analysis presented in this report has been limited to determining the effects of embedded generation specifically on the distribution network. Consequently power system studies of the 110/20 kV network type have not been undertaken. Although the principles for system modelling and power system studies presented in this report can be similarly adopted to examine the effects of embedded generation with respect to the 110 kV system, the model of the transmission system would have to take account of load and generation despatch.

[4] ESB Networks, in common with utilities elsewhere, use standard conductor sizes for their overhead line and underground cable networks. Consequently there is a degree of commonality with regard to conductor types and sizes across the various network types.

The sample networks analysed were located in the counties of Donegal, Leitrim, Kerry and Kildare[5]. The analysis included one of the Midlands networks to determine whether there is a significant difference between rural networks in the west of Ireland and networks in the Midlands. The analysis of semi-urban networks was based on data for an area outside central Dublin. The analysis of dense urban networks was based on data for a part of the 10 kV distribution network in Central Dublin.

The power system studies have been undertaken using industry recognised load flow software incorporating the physical characteristics determined for the representative networks. These studies have concentrated on determining the impact the embedded generation has upon the steady state operation of the distribution system with a range of generator capacities and connection points with the distribution network[6]. The representative network single line diagram for the semi-urban 38/10kV network is shown below to illustrate the various connection points used for the embedded generation in the power system studies.

In particular, load flow and short circuit analysis has examined the effect that increasing levels of embedded generation in the high voltage and medium voltage networks will have on the following:

a) Circuit and equipment loading - to identify when connection of embedded generation influences the requirements for reinforcement of the network compared with base case conditions;

b) Technical losses – to identify the effect that connection of embedded generation has upon the distribution system technical losses. Specifically whether they increase or reduce as a result of the connection of the generator;

c) Voltage and voltage control requirements - to determine the effect that connecting embedded generation will have on the representative network voltage profile;

d) Short circuit levels – to determine the effect that connection of embedded generation to the network will have on system fault level and the likelihood of the local distribution network switchgear rating being exceeded.

[5] The number of networks in our sample was necessarily limited. There are obviously other counties and areas of rural Ireland that have similar potential for sustainable energy type developments that could equally have been included in the sample.

[6] There are other concerns associated with the dynamic performance of the generator and the network that are not addressed here. The study of the dynamic performance would require specific modelling of frequency and voltage control devices of generation and is therefore considered at this time a site-specific issue.

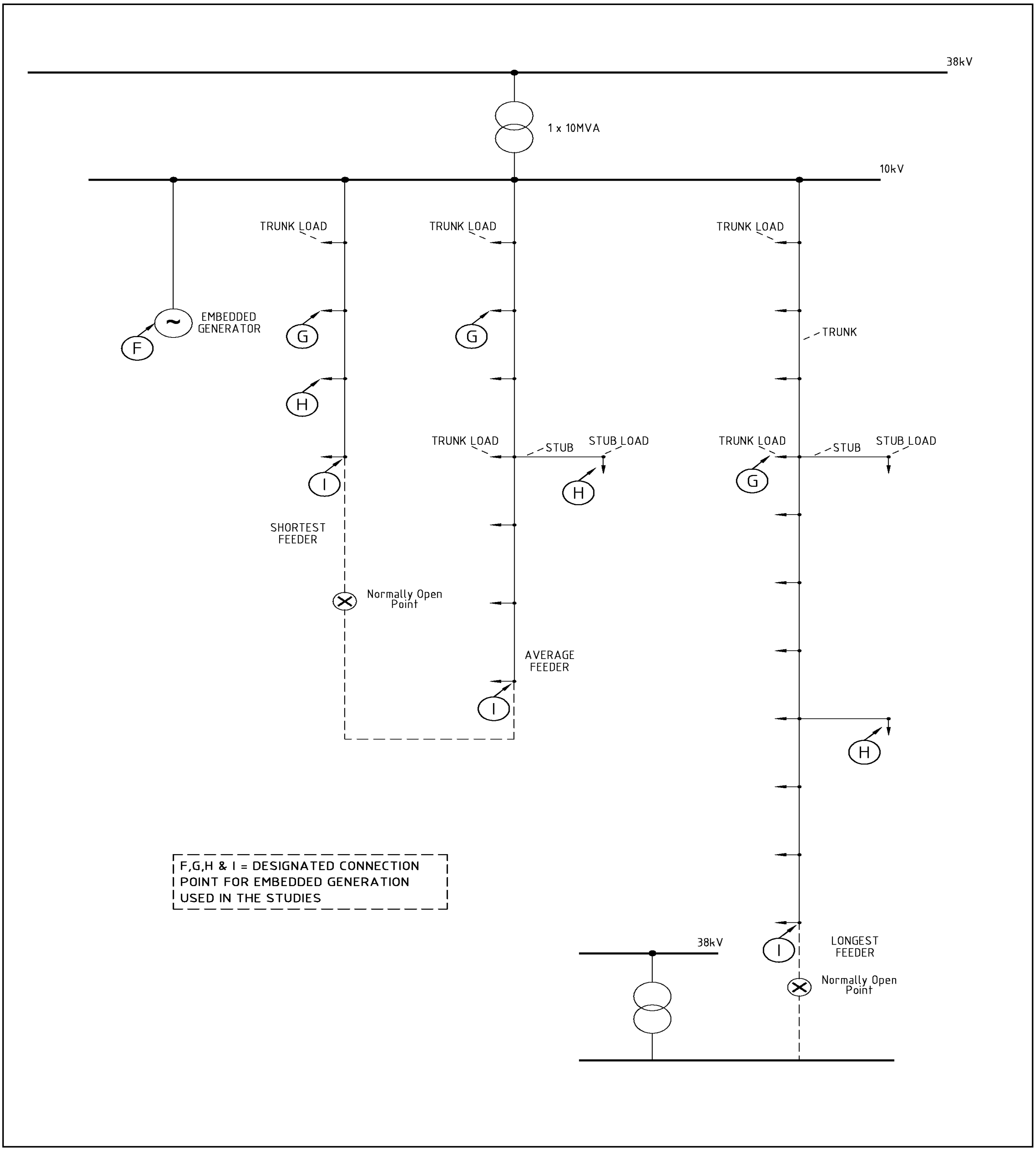


Figure 1-1 Representative Network used Semi-Urban 38/10kV Analysis

The key findings of the power system studies showed that :

Connection of embedded generation directly onto the MV substation bus bar effectively reduces the 110kV power import by the same amount;

Significant loss savings can be realised by connecting the generation near to the mid point of the outgoing MV trunk feeder. In the case of the 100/38/10kV rural representative network there was an optimum generator size of between 3 to 3.5MW, above which the embedded generation begins to increase system losses;

For voltage benefits to be realised on the MV network the embedded generation should ideally be connected at, or close to, the mid point of the MV trunk. In the case of the 110/38/10kV representative network this removed the need for voltage booster transformers;

In the longer term embedded generation provides an offset to technical losses, voltage support requirements and potential overloads that would otherwise be evident due to system load growth. This will effectively allow offset of capital expenditure on voltage support and system reinforcement;

1.2 Costs and Benefits Methodology

The intent behind the calculation methodology is to propose a mechanism that accounts for the full range of costs and benefits from connection of embedded generation to the Irish electricity distribution network. The methodology has taken a holistic approach to the calculation of the costs and benefits and incorporates benefits that have a more country-wide impact. Further, the calculations are projected over a 15-year period in order to capture longer term benefits from the embedded generation operation. The proposed method is split into elements to aid visibility of the assumptions, input data sources and calculation formulae. The elements[7] considered are:

Energy Price Benefit - The connection and operation of embedded generation plant within the distribution network will affect the operation of transmission system connected generation plant due to system demand being reduced through the embedded generation offsetting local system demand. The purpose is to assess the extent of any differential in the cost of generation between the embedded generation and the cost of providing the energy from a system generation plant;

Energy Loss Benefit – This determines the value of the embedded generation impact on the distribution system losses. It is likely that there will be a positive benefit through the reduction in peak system capacity required to service the distribution network demand and reduced cost in terms of annual energy loss as the load is being supplied locally;

Voltage Benefit (including Reactive Power provision) - This determines the value of the embedded generators impact on the distribution system power factor and voltage support. It calculates a benefit value arising from any avoided / deferred capital expenditure due to improved power factor and any saving in the cost of reactive energy required by the distribution system.

[7] Note that in the context of this list, "benefits" incorporates negative benefits i.e. costs.

Customer Minutes Lost (CML) Benefit - This determines the value attributable to the impact of the embedded generation on the distribution system reliability and security of supply through increased DUoS charge revenue to ESB Networks and improved service levels to customers;

Asset Benefit - This determines the benefit on the basis that the embedded generation defers the need to replace assets either as a result of reduced thermal loading or releasing network capacity that can be used to support load growth in future years. The asset benefit related to reduced system peak losses is accounted for within the Losses calculation process.

Transmission Benefit - This determines the value of the embedded generators impact on the transmission system through from reduced losses and capital expenditure deferment due to changes in the timing of system reinforcement;

Emissions Benefit - This determines a value for any benefit from reduced environmental emissions due to displaced system generation plant. The emissions considered are CO_2 (EU ETS costs), NO_X and SO_X.

Social Benefit – The determines the value of any social benefits that will derive from the installation of the embedded generation. This is driven by the impact of the embedded generation on local jobs and other sources of income.

Fuel Benefit - This determines the quantity of fuel that is saved / displaced as a result of the embedded generation operation. This will be derived from the avoided system plant and the embedded generation operation profile. This is represented in terms of kWh pa of fossil fuel input avoided.

The example calculations undertaken use the power system study results for a 2.5MW embedded generator connected into various points on the 38kV section of the 110/38/10kV rural reference network. The assumed LCTAS connection cost for both plant was €250,000 which was used to offset the benefits calculated. The impact of the generator reliability has been 'flexed' by running the calculation for a Wind generator and a CHP generator, as shown in Table 1-1 below.

Table 1-1 Benefits for Embedded Generation - Example Calculations

Connection Point	Wind Generation		CHP Generation	
	Total Benefit	Fuel Benefit	Total Benefit	Fuel Benefit
Mid Trunk	€4,941,887	21,900,000kWh	€5,903,976	8,591,539kWh
End Mid Trunk Spur	€2,918,553	21,900,000kWh	€2,774,174	8,591,539kWh
End Trunk	€3,052,487	21,900,000kWh	€2,921,776	8,591,539kWh
5km 38kV Feeder	€2,788,545	21,900,000kWh	€2,592,548	8,591,539kWh

(totals over 15 years)

The results of these example calculations[8] have shown that:-

The value of the loss benefits is very sensitive to generator location on the network due to the contribution from the avoided energy losses with connection at the mid point along the trunk being the best location ;

The value of the displaced energy is dependent on having access to a suitable long term operational profile for the generation plant and the resultant load factor on the system;

The elements contributing most value all include energy related components (Displaced Energy, Loss Benefit and the Transmission Benefit) ;

Asset based benefits will require access to auditable capital expenditure plans for the distribution network and the ability to discriminate between load related and voltage related capital expenditure;

The value of the CML benefit is marginal;

The scale of the benefits is significant as they have been projected across a fifteen year time horizon;

The recognition of the various benefits will need to be made either on a cash basis through offsetting connection costs or on a societal basis similar to the arrangements under the Public Service Obligation that support the social generation plant.

1.3 Stakeholder Views

The views of key stakeholders in the Irish electricity market were polled using a structured questionnaire. Unsurprisingly, a wide range of differing views was expressed. These are analysed briefly below.

There was a general acknowledgment of the need to reduce commercial uncertainty in order to encourage increased deployment of embedded generation. Developers' underlying concern was the bankability of projects, rather than on what the market mechanisms are *per se*. Compensation or protection from the variations in a large market pool was a key theme. Other respondents were more concerned with ensuring market mechanisms provide a level playing field for all generators. A separate, predictable support mechanism outside the market might best meet the range of needs expressed.

Costs of connection and reinforcement associated with new embedded generation connections clearly need to be allocated in some manner, although existing deep connection charges are viewed as a discouragement to

[8] Refer to detail provided in Section 6.16.

embedded generation by most generators. Repayment of costs over a number of years might mitigate this, effectively converting the upfront capital cost into a form of DUoS charge. Allocation of part of the costs to other beneficiaries of the reinforcement would also encourage embedded generation.

There were differing views on flexibility of generation. While the proposed market arrangements would encourage generators to be more flexible, it was pointed out by some that wind is inherently inflexible – due to resource intermittency, it cannot always choose when to generate (although it can choose when not to). There is therefore a concern that wind may be disadvantaged as thermal plant makes itself more flexible.

On the treatment of losses, there was a general desire for a more transparent means of calculation and allocation. An underlying theme was to avoid general limits or definitions that would result in some embedded generation causing losses and not being charged, and vice versa.

The question of location pricing divided respondents between those who believe that it would discriminate against wind generation (where the best resource is often in remote areas where Location Marginal Price is low), and those who believe that all generators should receive price signals related to location. However, there was general acceptance that only generators above a certain capacity should receive Location Marginal Price, while those below would receive the wholesale system price. Since the survey of opinion was conducted, CER has set this limit.[9].

1.4 Recommendations for the Irish Market

A number of international markets have been reviewed to identify any novel approaches implemented to provide support to embedded generation through recognition of the benefits that it is able to provide to the electricity distribution system (and to a lesser degree the transmission network). The general situation appears to be that tariffs and connection policies are focused on minimising the impact of embedded generation and large demand customers on the distribution network due to the need to maintain security of supply and standards of supply quality.

In general there does not appear to be any strong evidence for pro-active support for renewable and CHP generation within the charging structures for connection and use of the distribution and transmission systems[10]. Germany appears to provide the most pro-active support through the provision of feed-in tariffs at the transmission level which filter through to the generation users in the form of offset payments made to them by the distribution companies.

Within the Irish market the benefits could be treated in the following way:

- **Loss Benefit** - Recognition of this could be through applying an uplift to the generator distribution loss factor that represents a share (say 85%) of the avoided system loss. This uplift could be applied for a defined period of time, say 5 years, after which the uplift is incorporated into the embedded generators loss factor and is removed from ESB Networks' allowable revenues. This calculation is best undertaken by ESB Networks;

[9] Limit is at a maximum export capacity of 5 MVA. See CER/04/214, "Implementation of the Market Arrangements for Electricity (MAE) in relation to CHP, Renewable and Small-scale Generation", 9th June 2004

[10] Most support schemes focus on providing support on an electricity generated basis, i.e. per kWh

- **Asset Benefit** - The deep connection charging could be replaced with shallow charging (dedicated connection assets only) and a generator DUoS charge levied on the exported energy from the embedded generation site. These DUoS charges could then provide locational signals related to the potential to avoid capital costs. This calculation is best undertaken by ESB Networks and would benefit from provision of a regular distribution network planning statement;

- **Voltage Benefit** - The reactive energy production from the embedded generation plant should be assigned a value and payments should be made on the basis of metered reactive power production or consumption. Any payments made by the distribution company to embedded generators would be on the basis of the reactive power charge within the published DUoS tariff for the connection voltage level. This calculation is best undertaken by ESB Networks or the metering and settlement agent in the MAE;

  ESB Networks should be encouraged to make best use of the capability of embedded generators to provide voltage support 'on-demand' to the distribution network. This will need to be taken into account during the connection process;

- **Transmission Benefit** - this benefit should be paid by the DNO on an annual basis as an offset against ongoing connection charges levied on the embedded generator. The amount would be directly proportional to the embedded generators contribution to the reduced capacity requirement at the transmission-distribution interface. This calculation is best undertaken by ESB Networks;

- **Energy Benefit** - To the extent that there is a positive benefit arising from the displacement of energy (i.e. the cost of the displaced system plant energy is greater than the cost of the embedded plant energy), the benefit should be passed through to the end customer as a reduction in the energy tariff applied by ESB PES to the customer energy sales. This calculation could sit within ESB Supply or ESB NG;

- **Emissions Benefit** - the emissions benefit can be seen as a mechanism by which the PSO support for the alternative energy requirements is reduced as the embedded renewable generation plant will be able to source revenue to support their business from emission trading. This would prevent a windfall crystallising in favour of the embedded generation plant and serve to reduce the overall cost to the end customers;

- **Fuel Benefit** – this benefit will be seen within the long term Irish economy. It is not seen as being a benefit that feeds through directly to the embedded generator;

- **Social Benefit** – this benefit is realised within the community local to the generator through construction and operation and maintenance.

- **Micro and Small Scale Embedded Generation** - standardised connection terms could be applicable for micro- and small-generation plant below a de-minimis level[11]. These standardised connection terms might provide a sliding scale of standard connection charges for such generation linked to the generator capacity and incorporating the costs and benefits associated with typical import/export profiles for this class of customer.

[11] For example, 100kVA, which has been set by CER as the limit for exemption from MAE rules (CER/04/214).

NEXT STEPS

Following the above analysis and suggestions for the Irish market, it is suggested that a number of areas be explored further.

- Examine the potential benefits of establishing 'Active Network Areas' to provide incentive on the DNO to partner with embedded generation and/or responsive demand connections to investigate the potential for alternative distribution network control mechanisms;
- Determine the level of system security support that can be attributed to embedded generation, the process to determine this and the value of the avoided / deferred cost of network capital expenditure;
- Determine the impact and value of introducing an element of 'Non-firm' capacity to the connections for embedded generators and the operational controls that would need to be implemented to control the capacity used;
- Investigate the present costs for islanding schemes and the validity of the ESB Networks prohibition on establishing islanded portions of the distribution network;
- Seek to have ESB Networks publish a distribution network statement to provide detailed information on the development plans for the distribution network and the opportunity areas for generation and/or demand location. Such a statement would have information relating to network fault statistics, CMLs, in addition to the capacity available and fault levels on the network;
- Study the possibility of establishing an incentive within the ESB Networks regulatory formulae to incentivise investment in technology and mechanisms that reduce the overall system losses. This should provide a notional allowable value to losses such that benefit can be derived by ESB where they manage the network with losses below the target amount.
- Determine the process to ensure that any deferred capital expenditure or loss benefits are recycled to the appropriate party and accounted for within the LCTAS connection process or under regular payments;
- Determine the appropriate capacity cut-off level for standard connection terms and costs to facilitate connection of micro- and small-scale embedded generation to the distribution network;
- Undertake independent assessment of the impact on ESB Networks' operational costs were elements of the embedded generation calculation methodology to be adopted within the LCTAS connection process;

Examine the potential for utilising embedded generation to provide local Ancillary Services within the distribution system. This would include provision of Black Start, Reactive Compensation Services etc and would need to determine the technical capability of the technology and the cost of any specific control equipment necessary to enable the service (both within the DNO and the generator).

2. INTRODUCTION

The connection of a significant amount of embedded generation to existing electricity distribution networks poses a series of challenges that need to be overcome to ensure a safe, reliable and efficient source of energy. In addition to the technical issues, the EC Renewables Directive 2001/77/EC places obligations on Member States and their network operators in terms of:

- open access to networks for energy from renewable sources
- preferential despatch from renewable sources; and
- a non-discriminatory charging policy with respect to energy from renewable sources.

Further the EC Electricity Market Directive 96/92/EC (as repealed by Directive 2003/54/EC) requires that:

- Despatching of generating installations be determined on the basis of criteria that must be "objective, published and applied in a non-discriminatory manner" (Article 8.2);
- "Distribution system operators shall procure the energy they use to cover energy losses and reserve capacity in their system according to transparent, non-discriminatory and market based procedures" (Article 14.5);
- "When planning the development of the distribution network, energy efficiency/demand side management and / or distributed generation that might supplant the need to upgrade or replace electricity capacity shall be considered by the distribution system operator" (Article 14.7).

The Irish electricity sector is also in a period of transition as the market moves away from its previous monopolistic state and works towards full liberalisation through the introduction of a centralised wholesale power pool. This change in trading arrangements imposes an extra layer of complexity on the resolution of technical, commercial and economic issues surrounding the connection of embedded generation. However, the introduction of the changed trading arrangements will provide smaller generators ready access to the market to obtain prices equal to that which other generators will receive.

To achieve Ireland's commitment of supplying 13.2 percent of its electricity from energy based on renewable sources by 2010 will present significant challenges to the whole industry. Additional to the fundamental technical differences in the characteristics and sizes of typical embedded generation power plants, compared to conventional central power stations, challenges will arise because the majority of this new capacity will be connected to existing medium voltage distribution networks. To further exacerbate the problems associated with the connection of embedded generation, it is likely that wind turbine generators will provide most of the embedded generating capacity. Wind turbines provide an intermittent source of generation that can present new challenges to which conventional distribution system operational practices will have to adapt.

To assist with the formulation and implementation of future Irish Government policy for the period after the proposed market liberalisation in 2005, Sustainable Energy Ireland (SEI) commissioned PB Power in September 2003 to undertake a detailed study on the costs and benefits associated with the connection of embedded generation in the Irish electricity distribution network.

The principal objectives of the study are to:

a. Perform a detailed assessment of the costs and benefits to all parties involved in the connection of embedded generation to the electricity networks, including analysis of generic sections of the Irish Network. This aspect of the study is presented in sections 5, 6 and 7 of the report.

b. Propose procedures that can be used to identify the costs and benefits of connecting specific types and sizes of embedded generation to actual sections of the Irish electricity network. These proposals are discussed and presented in Section 8 of the report.

c. Review and analyse the commercial considerations put in place by other jurisdictions to facilitate the connection and the technical and commercial operation of increased levels of embedded generation. This analysis in Section 9 of the report.

d. Ascertain the latest opinions of CER, ESB National Grid, ESB Networks and a representative sample of prospective generation developers and independent supply companies in relation to the treatment of embedded generation, the implementation of EC directive 2001/77/EC in Ireland and the implications of the proposed move to market liberalisation through the adoption of a centralised wholesale market. The discussion and presentation of views on the issues is presented in Sections 3 and 4 of the report.

e. Establish the options for allocating the costs of connecting embedded generation fairly and equitably between all of the parties involved. The options are identified in Section 9 of the report.

A copy of the Terms of Reference for the study is presented in Appendix A.

3. Review of Perceived Costs and Benefits of Embedded Generation

In this section we identify the potential costs and benefits that can be obtained from the connection of embedded generation to the distribution network. A qualitative analysis is undertaken to identify where this results in a cost or a benefit to the Developer, to ESB Networks (the Distribution Network Operator or DNO), to ESB National Grid (the Transmission System Operator or TSO), or to some other third party.

We have examined the impact of connecting embedded generation to the distribution system in relation to what we view as the critical issues, embracing the technical, economic and financial sectors. The areas covered are listed in Table 3.1 overleaf. The qualitative review of the associated costs and benefits for each of the items in Table 3.1 is presented below – split into between those items that are regarded as 'Technical' (Part A) and those regarded as 'Commercial / Financial' (Part B).

It should be noted that certain costs and benefits associated with embedded generation can be difficult to ascertain and it is noted that efforts are underway to clarify these. Where this is the case the issues have nevertheless been identified, albeit without any firm indication of the associated costs or benefits.

Table 3-1 Costs and Benefits of Embedded Generation

Issue	Contributory Elements
Utilisation of Network Assets	Asset Life and Utilisation Effect on System Planning
System Losses and Overall System Efficiency	Treatment / Allocation of Losses System Operation Costs
Security and Quality of Supply	Voltage Regulation Availability and Quality of Supply Voltage Waveform Quality Security of Supply System Operation Costs
System Reinforcement Costs	Effect on Fault Levels Network Planning Cost and Resources
Avoidance / Deferred Reinforcement	Possible delay in reinforcement Impact of Generation location on Load Flows
System Control, Load Balance and Safety	Islanding Reactive Power Flows Displaced Loads Network Constraint and Load Management
Commercial Arrangements	Avoidance of TUoS Charges Displaced Load Capital Cost of Plant Connection Costs System Operation Costs Wind Power forecasting
Financial Implications	Reduction in fuel consumption Reduction in emissions Avoidance of Carbon Trading Costs Indigenous Fuel Supply Security Social Benefit of Green Energy sales

Part A – Technical Issues

3.1 Utilisation of Network Assets

The life of a distribution system asset is determined by a number of factors, notably; the duty it has performed, the standard of maintenance it has received and the number of major faults on neighbouring assets that it has endured during the course of its operational life. It is well known that the life of assets that have a thermal rating, such as transformers, cables and overhead lines[12] is related to the temperature at which they operate and the operating temperature is related directly to the current flowing through the asset's conductors, i.e. its utilisation.

The nominal life of an asset is determined by its normal operating regime. However, on occasions when an asset is overloaded for one reason or another, this may cause the insulation material to age prematurely in cables and transformers such that the asset life is reduced.. However, when the same asset is operated below its normal loading this tends to reduce the ageing process and may extend its life.

One of the results of operation with embedded generation connected to the network is that it can reduce demand on cables and transformers connected upstream of the generator and so prolong the life of the upstream assets.

The distribution system owned and operated by ESB Networks operates at the following voltage levels:

a) 110kV[13] and 38 kV High Voltage (HV) distribution,

b) 20 kV and 10 kV Medium Voltage (MV) distribution,

c) 380/220 V Low Voltage (LV) distribution.

The capacity of embedded generation that can be connected at each voltage level is limited by factors such as short circuit level[14], allowable voltage change that would result from the sudden disconnection of the embedded generation and the thermal loading and rating of existing circuits and equipment. As a general guide for a typical rural network an indicative capacity for the connection of embedded generation at the HV, MV and LV voltage levels is 10 MW, 2 MW and 200 kW respectively. On the other hand a typical urban network can accept about double the capacity of the typical rural network with 20 MW, 5 MW and 400 kW indicative capacities for embedded generation at the corresponding voltage levels[15].

Examination of a number of typical rural MV networks in the west of Ireland revealed that the majority of renewable energy schemes (involving wind farms and small hydro plants) are connected directly to the local HV/MV primary substation at 10 kV or 20 kV via a dedicated circuit. This type of connection for embedded generation will have minimal effect on utilisation of the downstream network, but in the more remote rural areas, where voltage regulation is a problem, the embedded generation will provide some voltage support to the local area. The upstream network will, however, generally benefit from the connection of embedded generation through lower

[12] With the exception of switchgear these are the main current carrying elements of a distribution network.

[13] The 110kV distribution network is within the area of the Dublin.

[14] In particular the amount of headroom available between the existing short circuit level and the switchgear rating (or more realistically a 5 percent margin below the switchgear rating).

[15] This is referenced to PB Power's report to ETSU on the "Costs and Benefits of Embedded Generation", dated February 2000.

network utilisation. The new generation will, depending on its capacity, be able to supply part, or all of the local load and, if of sufficient capacity, even part of the upstream load.

The effect on system utilisation of an alternative connection arrangement, based on "teeing-in" the embedded generator to an existing network circuit, is more difficult to assess, it being very much site specific and dependent on factors such as the existing network arrangement, the location and capacity of the embedded generator and the location and size of the load. In this type of connection arrangement the effect of the embedded generator on the utilisation of the network will be variable and it is conceivable that, whilst utilisation on some parts of the network at the connection voltage level may fall, utilisation on other parts of the network may well rise. Our analysis in Section 5 will demonstrate this effect, but as with a dedicated connection the utilisation level upstream will again be reduced and to this extent it is conceivable that some element of cost offsetting could be incorporated into the connection charging methodology.

Lower utilisation levels on circuits and equipment will be beneficial in the long-term as it will place less stress on the network components and consequently result in an extension of the useful life of that equipment, i.e. the asset life.

The operation of embedded generation on the network can significantly reduce the utilisation levels on circuits and equipment at times of peak load, both local to the generator and on the network upstream. This can prove of real benefit to the DNO in that it can allow network reinforcement to be delayed or even avoided[16]. Conversely, where embedded generation can result in higher network utilisation the effect could be to advance the timing of network reinforcement. In either case the impact of embedded generation on network reinforcement requirements is very site specific and depends on a range of factors, such as the loading of the existing network, the projected growth rate, the location, capacity and characteristics of the embedded generation.

In order to establish the costs and benefits of embedded generation on network utilisation, a simplified computer based model of each representative network segment has been developed to facilitate the load flow and short circuit analysis (Section 5). The output from this model demonstrates the effect on network utilisation of different levels of embedded generation on the network, with the embedded generation connected at various locations, i.e. at the source substation, at a remote location and at some points in-between.

3.2 System Losses And Overall System Efficiency

3.2.1 Treatment and allocation of losses

Although technical losses on the distribution network[17] vary continuously as the load on the network changes it is usual practice to confine analysis of network technical losses to an assessment of the peak load power loss and the total annual energy loss[18]. Indicative loss levels in the Irish electricity system are detailed in Table 3.2 below:

16 It is noted that the DNO is obliged to provide security of supply to users connected to its distribution network and that this security level also needs to consider the possibility of the loss of output from any embedded generation. Network reinforcement would only be avoided where the DNO regards the embedded generator as being as secure as its own distribution network.

17 Technical losses are losses associated with the passage of current through the network and the losses that are generated by transformers when unloaded.

18 To convert the peak power loss to an annual energy loss requires knowledge of the system load duration characteristics, from which the loss load factor can be derived and applied to the peak power loss to determine the annual energy loss.

Table 3-2 Indicative Losses in Irish Electricity System[19]

Network	Loss
Transmission	4.0%
110 kV stations	0.6%
38kV Network	1.6%
38kV Stations	0.8%
MV Network	2.5%
MV Subs	1.6%
LV Network	3.4%
Total	14.5%

This indicates that a high proportion of the total system losses arise on the distribution networks. Embedding generation into the distribution networks would tend to reduce the power losses on those networks. The extent of this reduction would be dependent on the precise location of the generation, the capacity of the generation, the load in the network and the reduction in circuit utilisation. This would also tend to result in a reduction in transmission system losses on account of the resulting reduction in power flows on those networks.

Further, the above indicates the significant contribution that micro- and small scale embedded generation could make in offsetting the system losses, given that ~35% of the overall losses are incurred at the MV transformer and LV network levels.

Power losses. In the analysis in Section 5 we quantify the change in peak load power loss that results from the connection of embedded generation on each representative network segment. In particular we determine the effect on network losses of the connection of embedded generation for a range of generator capacities when installed at various points on the network. The savings, or otherwise, in system losses are converted into equivalent monetary values based on information on the current cost of losses.

The connection of embedded generation, assuming it is operational, reduces the demand on the upstream network at times of peak load whilst leaving the downstream network relatively unaffected and this is seen as a benefit to all users.

Energy losses. Although running embedded generation at times of peak load will reduce network power losses at peak load, the reverse may be true at times of light load where operation of embedded generation may actually increase the losses if exporting power to the grid. Since peak load conditions only exist for a short period during the day and the period of light load covers a much longer period (i.e. through the night) when electricity demand is low, the overall effect of running embedded generation throughout any 24-hour period may actually be to increase the overall energy loss.

With the present commercial arrangements developers of embedded generation are encouraged to optimise their generation profile against expectations of market price or in response to pricing signals built into the SToD type AER tariffs[20]. However, this assumes that the tariffs or market pricing accurately represent the cost of distribution system losses at different time of day and time of year. If not then it may lead to an increase in the distribution system

[19] Marginal Cost of Electricity Service Study; CER 04/240; 1 July 2004

[20] Seasonal Time of Day tariffs offer under the Alternative Energy Requirements scheme

energy losses, which is in contrast to an energy saving policy, and may require the distribution network operator to adapt its use of system charges.

3.2.2 System operation costs

Whilst embedded generation will in some applications reduce both peak power losses and annual energy losses and thereby improve system efficiency, there are other aspects of system operation that will also benefit from the connection of embedded generation.

The obvious benefit to be gained from the widespread use of wind energy and other indigenous sources of sustainable energy in the future is that it will reduce the demand for conventional fuel, whether indigenous or imported, to well below what would be required to keep pace with the current rate of growth in demand with the present mix of generation plant. This will benefit the country as a whole from a reduction in the cost of imported fuel and by increasing fuel diversity. Increasing the use of indigenous energy sources will also improve overall security of supply. Further, reducing the reliance on imported fuels should also reduce the exposure of the Irish market to the impact of fuel prices spikes and the reduced requirement for conventional fuels will also assist in extending the projected available life of the indigenous conventional fuel sources.

Another feature of embedded generation is that it can produce reactive power for voltage support that might normally be met from more remote generators. This can be regarded as an opportunity for the DNO to utilise a 'point of use' ancillary service capability of the embedded generation which should reduce the price the DNO has to pay at the distribution / transmission system interface. The generator can therefore enter the market for supplying ancillary services and conceivably develop an income from this.

In line with ESBNG ancillary services agreements, it is envisaged that the income would be realised by payments for producing or consuming reactive power and also being available to produce or consume reactive power. The present form of agreement to facilitate this service is through a bilateral agreement with ESBNG who, by means of dispatch instructions, instructs the unit to adjust reactive power output. The Grid Code obliges generators to ensure that their plant has the physical capabilities to supply ancillary services in each category appropriate to the plant technology. Generator licences mandate them to offer their ancillary services to the market, under reasonable terms.

Developing the use of embedded generation to supply ancillary services should benefit the general customer by increasing the competition for these contracts, with a consequent downward pressure on contract pricing.

Conversely, with embedded generation connected to the distribution network it is anticipated that the DNO will need to adapt its operations to take a more active role in managing voltage control on the distribution network. This would be through increased use of automatic control devices and other frequent low-level interventions not currently incorporated into the present distribution network operation[21]. This is likely to involve additional switching operations of the control circuit breakers and associated equipment that will effectively increase the Operation and Maintenance (O&M) costs. The additional O&M cost is difficult to estimate at this stage.

[21] This process of active distribution network management is akin to the practices adopted for the management of the Transmission system.

3.3 Security And Quality Of Supply

3.3.1 Security of supply

The various types of embedded generation that can be connected to the distribution network depend, with the exception of wind energy, on a reliable and steady supply of fuel (or water in the case of hydro stations) to ensure that embedded generation can operate on a fairly continuous basis.

Wind, on the other hand, is a more intermittent source of energy so that its contribution to the security of the network is less apparent. A single wind turbine will not generate electricity when the wind speed falls below a certain level and, although Ireland has the greatest potential for development of wind power in Europe, there are significant periods when the wind speed is insufficient to operate wind turbines. This implies a 'firm' wind generating capacity of 20% of installed capacity - consistent with recent analysis[22] undertaken for wind farms in the UK advising that the overall 'firm capacity' would lie in the range 20-35% of installed capacity. This overall capacity takes into account aggregation and diversity of the total system wind generation capacity.

The distribution of wind farms and other embedded generation across the network will allow their contribution to be aggregated. To the extent that wind power can contribute to Ireland's energy requirements on most days of the year, and even on those days when there is no wind in some areas, wind and other embedded generation plant in other areas will generate power that can be injected into the network elsewhere. The contribution from power available from such aggregated embedded generation resources will impact most on the higher voltage networks, specifically the transmission system where the effective aggregated power available from embedded generation on the distribution network makes a positive contribution to the security of the transmission network. This issue is recognised in the TSO Generator Adequacy Report (GAR) 2004[23] which indicates a capacity credit of about 200 MW for 1000 MW of installed wind power allowing for the geographical diversity of the embedded wind generation. Additionally, it may be argued that the impact of the aggregated contribution from all embedded generation reduces the ratio of the largest generating unit to total generating system size, hence improving the security of a system inherently reliant on a few large generation plants.

The presence of embedded generation on the distribution network will, where the generation is available on a continuous and predictable basis, improve the security of supply to the local area load and supplement the power available from the grid. For example, in the event of the loss of a 38/10 kV transformer at the primary substation that supplies local load, secure and reliable embedded generation will be able to continue supplying power to that load. The extent of this, of course, depends on the magnitude of the generation and the load and the retention of a suitable link with the main grid or the installation of suitable "island" operation systems.

The availability of secure quantities of embedded generation will therefore be of benefit to the DNO by improving the security of supply. Where there are significant amounts of reliable embedded generation connected to the network this can reduce the amount of security-related network investment. However, the benefit is location dependent and with wind farms likely to be the largest type of renewable generation on the network their overall contribution to system security will be dependent on an aggregation of their effective output.

[22] 'Quantifying the system costs of additional renewables in 2020', UK DTI, October 2002.

[23] Referenced in "Transmission System Operator, Ireland Generation Adequacy Report 2004 – 2010", page 33

3.3.2 Availability and quality of supply

The existing distribution network has only limited amounts of embedded generation connected to it, but with the Government's energy targets this is likely to increase substantially over the next few years. It is accepted that, providing the connection of new generation to the distribution network has been properly designed, the effect will be to improve both the quality of supply and its availability to the customer. The actual benefit obtained is, like some other benefits and costs, difficult to quantify and dependent on a number of factors such as the existing availability and quality of supply, the magnitude of the embedded generation and how it is connected to the existing network and the existing network configuration.

However, with connection of embedded generation to the network, an obligation is placed on the developer to ensure that the new generation will perform to the required technical standard when operating in parallel with the distribution network by complying with specific requirements for protection against over and under voltage, over and under frequency, and loss of mains. Other requirements that the generator has to comply with include the frequency of paralleling with the network (to limit the number of step voltage changes as the generation is switched on and off the network); the maximum limit for the step change in voltage when switching the generation; and maintaining a satisfactory power factor. The outcome of this is to maintain the quality of supply on the local electricity distribution network within statutory limits.

These requirements are specified by the DNO following a worst case (maximum generation and minimum load) system analysis to determine the voltage impact of the new connection and then placing constraints on the voltage fluctuation at the point of connection which it deems to be appropriate to satisfy its statutory obligations. The DNO analysis does not consider any measures that the developer may offer to implement that mitigate system voltage issues on the local network which may negate the need for a direct connection to the network. To the extent that the new connection provides an improvement in the supply quality[24] this may be regarded as a benefit to all users connected to that local network.

3.3.3 Voltage regulation

The major portion of ESB's distribution network is characterised by a typical rural network, based on overhead distribution with long radial MV feeders supplying power to remote loads in sparsely populated areas.

This type of network is therefore very susceptible to poor voltage regulation under peak load conditions[25] with significant voltage drops being experienced between the source substation and the remote end of the MV feeder.

The connection of embedded generation to the network will tend to improve the situation by providing voltage support, although the extent of any improvement depends largely on where the generation is connected and its capacity. Depending on the extent and effectiveness of the voltage support provided by the embedded generation it is possible that the DNO may avoid the need to provide additional means of voltage support.

The operational practices for voltage control in areas where embedded generation are connected will require agreement between the DNO and the generation developer. Depending on the location of the embedded generation it may be beneficial for the generator to provide voltage control e.g. in areas where the source

---

[24] This is due to increased fault capacity on the local network following connection of the generation plant and when the plant is operational. However, this is tempered by the introduction of a voltage transient when the generator connects/disconnects from the local network.

[25] It is standard practice for ESB Networks to install a booster transformer at intervals along the trunk of very long medium voltage feeders to control the voltage profile along the length of the feeder such that limits on voltage regulation are not exceeded.

impedance is high hence benefiting from a local source of voltage control. Alternatively, if the generator is operated in power factor control mode then voltage control will be the responsibility of the DNO. Under these operating conditions, particularly during light load, there is the possibility that local system voltages could rise above statutory limits. It would therefore be advantageous under these circumstances to change the generator from power factor control to voltage control mode. This operational flexibility suggests that it may be beneficial to link the generator and network control schemes such that optimum control is maintained.

Overall, the DNO and electricity users will benefit from improved voltage regulation, although the extent of improvement will be site specific. In Section 5 we examine this in some detail for each representative network segment.

On the cost side, limitations are likely to be imposed on the generator through restrictions on power factor to avoid further deterioration in the supply voltage. This can be viewed as a cost for the generation developer.

A further consideration with regard to voltage regulation is the requirement imposed on generators that their sudden connection to or disconnection from the network should not cause an excessive step change in voltage on the network. Whilst in some cases this may not prove to be a problem, it is possible that the generator will be unable to be connected at the developer's preferred location because of a weakness of the distribution system at that point. In those circumstances it will often be necessary to connect the generator to a stronger part of the network (i.e. where the short circuit level is higher) and this will involve the developer financing the additional cost of connection[26].

3.3.4 Voltage waveform quality

The technical requirements imposed on embedded generation, as a condition of its connection to the distribution network, will ensure that the generation will not adversely affect the quality of the supply voltage waveform. In fact, where the shape of the voltage waveform is less than ideal due to the presence of harmonics on the network, the embedded generation will generally tend to improve the quality of the waveform by acting as a partial sink for such distortions.

Limitations imposed on the parallel operation of the embedded generator will minimise the frequency of switching operations to connect or disconnect the generator from the network, as will limits imposed on the extent of the allowable step change in voltage. Additionally, the presence of embedded generation will raise the fault level at the connection point and thereby strengthen the system, so that the magnitude of voltage flicker is reduced. Whilst reduced voltage flicker is a benefit, the improvement will vary across the network and it is therefore difficult to quantify this on a generic basis.

Offset against these benefits is the portion of the connection cost that has to be carried by the developer in meeting voltage waveform quality requirements.

[26] This applies equally to all new connections irrespective of whether it is a generation or demand connection.

3.4 System Reinforcement Costs

3.4.1 Effect on network fault levels

The strength of the network, or any part thereof, is directly related to its short circuit level. The higher the short circuit level, the stronger the network becomes, and the more capable it is of accommodating disturbances to the network such as those caused by the switching of major items of equipment like generators, capacitors and reactors.

Any embedded generation connected to the distribution network will provide a contribution to the system fault level. In some respects this will strengthen the network and thereby make more capacity available.

In some instances[27] where the existing fault level is approaching the ceiling imposed by the switchgear rating, the connection of generation to the distribution network may be constrained. The result is either that the generation must be connected elsewhere on the network, which in itself will involve extra cost for the developer[28], or that its connection arrangement is designed specifically to keep fault levels to within rating. This again will involve the developer in additional costs, though the extent of these will be very site specific.

Similarly, it is possible that the connection of embedded generation may provide a degree of flexibility to the DNO that can result in the avoidance of reinforcement or replacement of existing plant[29]. In such cases the "betterment" needs to be recognised as a benefit attributed to the generation.

3.4.2 Network planning costs and resources

The connection of embedded generation imposes an extra degree of complexity on the system planning process. Each connection application requires the DNO to examine the impact of the new generation in order to confirm that the network and other customers connected to it will not be adversely affected.

In addition to the system planning studies that the DNO would normally perform, such as base case load flow, contingency load flow and short circuit analysis, the DNO has to be satisfied that the step change voltage limits are not exceeded when the embedded generation is suddenly switched on or off the network. Other technical aspects that are examined at this stage include harmonics, system losses and network protection.

Each new application for a generator connection that the DNO receives requires it to undertake this process of evaluation before approval is given for the scheme to proceed. The cost of this additional planning work, i.e. the connection studies, is passed on by the DNO to the developer of the new generation project.

The cost of the additional system planning requirements is not identified in this study.

3.5 Impact of embedded generation on reinforcement plans

The connection of embedded generation to the distribution network introduces a new source of power on to the network that in many cases is located much closer to the demand than the existing power source, i.e. the local bulk supply point. Consequently, when the generation delivering power to the network it will affect the power flow

[27] This generally will not apply in rural areas where the fault level on the MV system is relatively low.

[28] As discussed in Section 3.3.3 Voltage Regulation.

[29] This is likely to require the connection of a number of generators at a single point on the DNO network to provide the necessary continuity in output to enable avoidance of reinforcement expenditure.

between the existing source and the embedded generator. The extent to which the power flow is affected will depend largely on the magnitude of the connected generation, the configuration of the network and the location of the generation itself.

In general the effect of the embedded generation will be to reduce power flows on the distribution network when the generation is in service, although where the generation is teed into the existing network the power flow in the network in the vicinity of the generator connection may well be increased.

In cases where the change in power flow on the local network is significant, and the output from the generation is considered a secure and reliable supply[30], the embedded generation can have a positive impact as far as the DNO is concerned in that it may allow the DNO to defer or even avoid altogether the reinforcement of the network in a particular area.

Similarly, embedded generation on the distribution network will reduce power flow down through the transmission network to the local area bulk supply point. This can conceivably allow the TSO (i.e. ESB National Grid) to delay system reinforcement, particularly at the local bulk supply point, providing the generation is of sufficient magnitude and is available on secure and reliable basis. In the longer term, the overall contribution from a much higher concentration of embedded generation on the network will be to reduce the power that would be transported across the transmission system to well below the level resulting from continued use of large conventional power stations connected to the transmission system. The load-related capital expenditure requirements of the TSO under this "embedded generation" scenario would also be correspondingly lower.

In order to provide the necessary information to embedded generation developers, there may be a need to provide transparent and objective rules by which the contribution of embedded generation to system security is calculated and accounted for within the LCTAS connection design process.

Although the effect of embedded generation on system reinforcement is seen as a real benefit, in that it can allow network reinforcement to be delayed or avoided altogether, there may be an "up-front" cost to the DNO and the developer. This is the cost associated with strengthening the local network near to where the generator is connected, to allow the generation to deliver its contracted power to the network without any constraints.

3.6 System Control, Load Balance And Safety

3.6.1 Control of reactive power flow

The typical rural distribution network in Ireland is characterised by a long radial overhead line with spur feeders tapped off at various points along the trunk of the feeder between the source and the remote end of the line. Large voltage drops are an inherent problem with networks of this type and it is the DNO's practice to strategically locate boosting transformers at one or more locations en route to keep the voltage profile within the statutory voltage limits. As voltage drop is directly related to reactive power flow, any action that will minimise the reactive power flow down the overhead line will reduce the voltage drop down the line. Improved voltage regulation benefits the consumer through improved quality of supply and benefits the DNO by meeting its obligations with regard to supply voltage whilst at the same time reducing system losses.

[30] This will depend on the generation technology and its output profile. It is unlikely that intermittent generation would be regarded as providing a "reliable" alternative to the DNO network.

The availability of embedded generation can provide the DNO with a localised source of controllable reactive power that can reduce the reactive power flow through the distribution network. The output from the generator can be used to reduce the reactive power flow upstream of its connection point and thereby improve system voltage along the whole feeder length. The extent of the improvement in voltage control is clearly site specific, but the contribution from embedded generation can be important. This is also recognised by the DNO who have set down specific requirements for the power factor of the generator output[31].

Whilst the control of reactive power flow can bring real benefits to the DNO through an improved voltage profile, the benefits have an associated cost. To control reactive power[32] additional hardware and software is being developed for large wind farms to meet the requirements of the TSO. It is very likely that the same technology (and requirements) will soon be applicable for smaller wind farms. However, a more sophisticated control facility will have an additional cost. It would seem reasonable that where the DNO sees the reactive power availability from embedded generation as a benefit, the developer should be recompensed for the supply of reactive power.

A further cost to the DNO would arise if the generator absorbed reactive power, in which case reactive power flow through the transmission system and distribution network would be increased. Although the increase could be fairly small, it nevertheless would increase the voltage regulation and the losses, and effectively impose a cost on the TSO and the DNO. For that reason strict control of the power factor is necessary to prevent the embedded generator operating at leading power factor, i.e. under-excited and thereby absorbing reactive power.

3.6.2 Network constraints and load management

The electricity demand in Dublin is increasing annually at a rate of over 6 percent, whilst in the rest of Ireland the annual growth rate is between 3 and 4 percent[33]. Continued growth at these rates will see the demand for electricity increase by over 60 percent in 10 years. To keep pace with this rate of growth the TSO (National Grid) and DNO (ESB Networks) will be faced with a significant increase in their load-related capital expenditure budgets.

However, network reinforcement may not be the best option in all cases for various technical and/or economic reasons, and a more viable solution could be for load to be constrained off the network. This approach has been adopted on many developed systems around the world and a substantial amount of work on demand-side management techniques has been pioneered in Northern Ireland by the local electricity utility, Northern Ireland Electricity.

Whilst there are well-established techniques available for demand management to constrain-off load at peak times, embedded generation is an ideal tool for the system operator to use to reduce the demand on the distribution network at peak times. Demand management on other networks in the UK and abroad currently attracts premium payments from system operators and the provision of a similar facility from embedded generators may also provide some income to the developer. It will also benefit the TSO and the DNO through a reduction in the amount of system reinforcement required in their respective load-related capital expenditure budgets.

Continued growth in the number of generators connected to the distribution networks will ultimately have implications for the operational control of those networks and the control interface with the transmission network. For example, it may be that clusters of embedded generation could be scheduled to effectively reduce demand such

---

[31] As specified in the Distribution Code

[32] Sophisticated hardware and software is being developed to control other parameters, such as peak power output and ramp rate.

[33] References from ESB (www.esb.ie) and within the National Allocation Plan (www.epa.ie).

that distribution and or transmission system constraints are removed. This is clearly a scenario where the control of load management would require effective interfacing between the DNO and TSO.

Against the benefits identified above, there would be an the increased cost of communications, both in terms of equipment and manpower effort. This is necessary to ensure efficient and timely management of the constraints with the increased number of parties that are involved in the process.

A further cost associated with the operation of network constraints and demand management is the increase in operation and maintenance (O & M) costs necessary to apply the constraint. Although it is probable that the embedded generation will operate for long periods between "down-times" the additional control and switching that is likely to be required to control the generator output to manage demand at peak times is likely to result in increased O&M costs.

3.6.3 Islanding

In the event of a supply failure to an area of the distribution network in which generation is embedded, protection equipment can be set to operate (on the basis of the rate of change of frequency) to "island" the embedded generation and part of the affected network in order to ensure that at least part of the affected load remains supplied[34].

The obvious benefit of this "islanding" capability is that it reduces the amount of lost load. In remote areas that suffer regular interruptions in supply, the savings in respect of lost load could be relatively high. The economic savings are dependent on the Value of Lost Load (VoLL) and the outage duration. The DNO will benefit from reductions in the number of Customer Minutes Lost (CML's) and Customer Interruptions (CI's) that are used to measure supply availability and impact on the allowed DUoS revenue, whilst the customer will benefit from an improvement in the availability of supply.

To facilitate "islanding" of the network the DNO will be required to pick up the cost of interface protection, such as that used to detect an excessive rate of change of frequency that will occur in the event of a supply failure. An additional cost that also has to be borne is for a secure communications channel from the generator to the DNO's control centre.

3.6.4 Displaced load

The question of displaced load is closely associated with security of supply and whether embedded generation is considered as a secure and reliable power source. In cases where the DNO considers the embedded generation this to be the case, it will allow the generator to contribute to security of supply. In that case the output from the generator will effectively displace load on the distribution network so that the displaced load can be discounted from the demand taken from the TSO. This can result in a reduction in the required capacity of the connection assets between the TSO and the DNO.

---

[34] It is worth noting here that ESB presently forbids islanding due to safety hazard and potential user equipment damage. Provided that these safety and damage concerns can be addressed through design of the "islanding" system, the costs and benefits can be calculated.

Part B – Commercial / Financial Issues

3.7 Commercial Implications

In the context of the connection and operation of embedded generation within an interconnected / meshed electricity distribution network, other considerations come into play over and above those technical items required for the embedded generation may be physically connected to the system.

These mainly apply at a commercial level within the cost structure of the proposed embedded generation and the distribution / transmission system asset owner and operator[35]. These items are discussed in more detail in the sub-sections below.

3.7.1 Avoided TUoS Charges

In liberalised / liberalising markets the costs of providing the transmission and distribution systems are controlled within licence condition constraints and the expenditure is typically capped through an agreed regulatory price control mechanism. The intention is to prevent abuse of monopoly power and to extract business efficiency from any over-performance in order to benefit the end customer.

The costs of providing the transmission and distribution systems comprise capital expenditure (asset replacement etc.) and revenue expenditure (system operation, losses) and are recovered through the Use of System (UoS) charges levied by the DNO / TSO. These UoS charges recover the costs associated with the provision of the electricity distribution / transmission system assets and their operation such that the charges at each voltage level and for each customer type reflect the costs incurred to provide service at that point of supply. Such an approach drives out any potential for cross-subsidy between customer groups.

The UoS charges provide an incentive to customers to make efficient use of their network connection capacity. This ensures that the peak demand on the system is limited within the capacity installed in the system to ensure reliability and security of supply. Peak demand charging is employed both by the DNO within their customer UoS charges (Maximum Demand charges), and TSO in their entry / exit charges for transmission system connections. These entry / exit charges are recovered from system generation plant (entry) and DNO and transmission connected demand (exit). The exact split between the entry and exit charge revenues in recovering the costs of the TSO depends on the connection charging methodology (shallow or deep) and the allocation of system cost recovery to generation and demand.

The application of transmission exit charges on the DNOs means that a proportion of the distribution UoS charge levied on distribution-connected customers is used to recover those transmission exit charges. Therefore, to the extent that a demand customer commits to reduce their peak demand requirement at times of system peak loading the DNO receives a direct benefit through a reduction[36] in the transmission exit charges payable to the TSO.

---

[35] Dependent on the market status and structure the Asset Owner (AO) may be a separate commercial entity to the System Operator (SO) with appropriate Asset Use agreements in place between the AO and SO that establish the relationship between these parties and ensure the security and reliability of the network.

[36] The avoided transmission exit charges benefit will include any additional uplift accrued through the associated reduction in the DNO system losses that come with a reduction in demand. Therefore the kW benefit seen by the DNO at the Transmission system boundary is the demand reduction uplifted by the applicable site DLAF.

This mechanism is equally applicable for embedded generation to the extent that such plant is operating during times of system peak demand. The local embedded generation output will offset local customer demand giving a net reduction[37] in the DNO peak transmission system exit capacity. Therefore the embedded generation can provide benefits to the end customer as its operation offsets (fully or partially dependent on the plant reliability) some of the costs of operating the systems at times of peak demand.

3.7.2 Displaced Load

As with the UoS charges benefit that can be derived from embedded generation operation, the generator may be regarded as being sufficiently reliable to permanently displace load on the DNO system and contribute to the security of supply. In this case the displaced load can be discounted from the transmission capacity required by the DNO. This may allow the DNO to reduce the capacity of the connection assets at the TSO / DNO boundary.

The question of displaced load is closely associated with security of supply and whether embedded generation is considered as a secure and reliable power source. Examples of embedded generation plant that may be regarded as being sufficiently reliable to allow permanent load displacement – and the associated accrued benefits to the DNO – would be Peat, Biomass or gas fired CHP. Other renewable generation technologies such as wind and hydro are unlikely to provide the necessary reliability.

3.7.3 Capital Cost of Plant

The connection of embedded generation to the distribution network introduces a new source of power on to the network that in many cases is located much closer to the demand than the existing power source, i.e. the local bulk supply point. Consequently, when the generation is delivering power to the network it will affect the power flow between the existing source and the generator, and between the generator and the local customers.

As described in Section 3.5 above, this provides a number of potential benefits. These include allowing the DNO to defer or avoid reinforcement of the network in a particular area[38], and reducing the load-related capital expenditure required from the TSO

3.7.4 Connection Costs

As described in Section 3.4.2, the connection of embedded generation imposes an extra degree of complexity on the system planning process. The costs associated with these additional planning activities will be recovered from the developer by the DNO as part of the overall connection costs.

As described in Section 3.4.1, embedded generation can contribute to system strength by increasing its short circuit level at the point of connection, and to a lesser degree, further out within the distribution network. Depending on the identified connection point and its electrical proximity to the transmission system, there may also be some implications for the transmission system (this is only expected to be the case where a large embedded generator is proposed). In some respects this can strengthen the network and make more capacity available to enable the DNO to connect more demand customers.

---

[37] This reduction will also need to account for the losses uplift effect.

[38] Deferred of avoided reinforcement capital expenditure will require the embedded generation to have a consistent operating profile. It is unlikely that 'intermittent' generation would be regarded as being a reliable alternative to the DNO network reinforcement.

However, where the existing fault level is approaching the ceiling imposed by the switchgear rating, the LCTAS assessment of the connection application could identify that it is more cost effective to connect the proposed generator to a point on the distribution network that is physically further away. Such a decision will involve extra connection cost for the generator, or a modified connection arrangement designed specifically to keep fault levels to within rating.

3.7.5 System Operation Costs

As described in Section 3.2.2, embedded generation will impact on the costs to the DNO of operating the network. These may be benefits in the form of reactive power supply and reduced losses, or costs through the need for more active management.

3.7.6 Wind Power Forecasting

The inherent variability in wind means that with significant levels of embedded wind generation, extra system operating costs are incurred to maintain the ability to respond to this variation. These extra operating costs may come from:

- maintaining other system plant at part output (reduced efficiency, increased fuel costs and lost opportunity costs) to allow for a rapid ramp-up in the event that the wind stops blowing; or
- the installation of costly rapid-start plant; or
- curtailing wind generation.

While variability in output is an inherent property of wind generators, significant efforts have been made in providing improved forecasting methodologies for wind generation. These can reduce the uncertainty over the variation in output that will actually occur. Significantly when combined with a short market 'gate closure' period, these forecasting techniques can remove the majority of the output uncertainty. Through increasing the confidence in the output from wind generation and the communication with the TSO, more effective planning can take place and any additional system costs may be significantly mitigated.

While any improved forecasting will have an associated cost, it is likely that this will be justified by the reduced costs in a system with high levels of wind generation.

3.8 Financial Implications

3.8.1 Unit Costs of Generation

Many embedded generation technologies have a unit cost of generation that is driven by their high initial capital cost, while large fossil fuel plant generation cost is more closely linked to fuel costs. This currently results in higher unit generation costs for embedded generation. Capital costs for many embedded generation plants are expected to fall through economies of scale in manufacturing and advances in the emerging technologies on which they may be based. This reduced capital cost will be directly reflected in the delivered energy unit cost from embedded generation plant.

Comparison of the unit costs of the embedded generation and the system plant needs to be done carefully, as the cost of generation is only the cost associated with putting the energy into the system, not the cost to the customer.

As a result items related to energy loss benefit, avoided use of system charges, and potentially deferred capital expenditure need to be accounted for to obtain a complete picture. However, these items are included within the other cost / benefit items mentioned in earlier Sections and their inclusion here would result in double counting.

3.8.2 Environmental Mitigation Costs

Large fossil fuel power plants are coming under increasingly stringent regulation through measures such as the Large Combustion Plant Directive (LCPD)[39]. This may require flue gas desulphurisation, low NOx burners or low sulphur fuel sources to be utilised, dependent on the generation plant. Each of these items has an associated capital or revenue cost that will be passed through to the end customers as an increased cost of energy. The impact of the sulphur emission constraints and forthcoming carbon emissions limits have already seen price movement within the UK electricity market as system plant operators seek to ensure compliance with emission limits by restricting their operation.

Embedded generation plants falling below the threshold thermal input criteria will avoid these environmental mitigation costs, although the level of benefit achieved will depend on the marginal cost of the avoided emission and the final National Allocation Plan level of carbon emissions allowed for each polluter.

Any benefit that arises will derive from differentials in thermal efficiency of the plant (in terms of total heat use) and the fuel source (whether it is fossil or renewable). The prices attaching to the respective emissions will need to be those that are seen in the market for medium to long-term emissions.

3.9 Other Issues

Many embedded generation technologies, such as wind, solar and hydro, use renewable energy sources that are not "consumed" (i.e. they are constantly replenished whether or not their energy is extracted). Increasing use of embedded generation can thus reduce the consumption of non-renewable fuels. Generation from biomass sources essentially replaces one form of fuel with another, but provided that more biomass is grown or produced, it can also be considered to be "non-consuming".

A reduction in fuel consumption also implies a reduction in transportation, and the fuel consumed in doing so. Fuel-based embedded generation such as biomass or Energy-from-Waste will require transportation, although this will typically be local and may occur anyway as part of existing waste disposal systems. The fuel consumption involved in the local transportation of the fuel to the embedded generation plant will be difficult to quantify for this study and is regarded as being insignificant in terms of the plant input energy.

3.9.1 Reduction in Emissions

The use of renewable fuels for embedded generation will reduce greenhouse gas emissions. The level of reduction actually achieved will depend on factors such as:

- the fossil-fuelled generation that is replaced or avoided. For example, the replacement of existing coal-fired plant by renewable embedded generation would give a greater emissions reduction than if it is used to avoid new gas-fired plant.
- the strategy adopted to manage wind power variability. For example, operating thermal plants at part load to increase responsiveness will reduce their efficiency, resulting in lower emissions reductions per unit of wind energy generated.

---

[39] Directive 2001/80/EC

- the specific mix of embedded generation technologies adopted, remembering that not all embedded generation is renewable.

The emission reduction calculation will need to take into account the expected operating profile of the embedded generation (base load, mid merit, peaking / intermittent), its fuel source and thermal efficiency in order to calculate and value emission savings that reflect actuality. This value is captured within the environmental mitigation costs assessment.

3.9.2 Avoidance of Carbon Trading Costs

The recently adopted Emissions Trading Directive[40] obliges member states of the EU to allocate greenhouse gas emissions allowances to major emitters, including large thermal power stations.

The total number of allowances must be consistent with each state's Kyoto commitments, but the allowance distribution is to be determined by national governments within the National Allocation Plan (NAP)[41]. A reduction in generation emissions through an increase in embedded generation could therefore make more allowances available for other Irish industries. This would reduce the number that would need to be purchased from other member states, or even provide income from sales of surplus allowances.

This is a macro economic benefit that will accrue as a result of the combined effect of numerous renewable generation project implementations. As this study is considering a range of discrete embedded generation projects we have restricted the scope to quantifying the impact of the discrete projects and not provided any study into the wider, macro economic effect of multiple plants on the Irish economy.

3.9.3 Indigenous Fuel Supply Security

Many embedded generation technologies will not require imported fuels; the wind, water and biomass they rely on being indigenous. Increased levels of embedded generation can thus contribute to fuel supply security. The actual increase in security gained will depend on the fuels that embedded generation replaces, and the relative security of imported oil, coal and gas. However, embedded generation such as gas-fired CHP that relies on imported fuel will not, of course, contribute to supply security. It may even reduce security if it displaces more secure fuels.

High levels of embedded generation are likely to mean high levels of wind generation. While wind is an indigenous resource, and is predictable over the longer term, it is variable over the short term, as discussed earlier. It can therefore be argued that supply security in the short-term (of the order of days or weeks) is actually reduced, requiring back-up capacity in the form of other fuels.

An obvious benefit from the widespread use of wind energy and other sources of indigenous sustainable energy is that it offset future demand for conventional fuels, whether they are indigenous or imported. This could even offset any increase in conventional fuel use to well below what would be required to keep pace with the current rate of growth in demand with the present mix of generation plant.

This will benefit the country as a whole from a reduction in the cost of imported fuel and by increasing fuel diversity.

---

[40] Directive 2003/87/EC

[41] Irish NAP was approved by the European Commission on 7 July 2004.

3.9.4 Social Benefit of Green Energy Sales

Renewable energy sources are likely to power a significant part of future embedded generation plants. Such "green" energy sources can have a number of social benefits, including:

- Embedded generation using a local fuel supply, principally biomass, can provide income and employment in growing and handling the fuel, particularly in rural areas. This may represent an alternative or extra income stream for the agricultural industry;

- While wind generation provides few permanent local jobs, it can bring income in the form of land rents and short-term construction work;

- The strengthening of weak distribution grids by the installation of embedded generation can improve reliability of supply to local commercial and domestic customers and increase the overall efficiency of local business through improved quality of supply and / or reduce UoS charges;

- Reductions in noxious emissions may have positive local health and environmental benefits.

A reduction in fossil fuel use, through expanding embedded generation, does imply a reduction in income in the fossil fuel supply chain and as such this may have an offsetting effect through reduced employment in the longer term within the fossil fuel supply sector. The scale of this impact is regarded as being outside the scope of this study due to its macro economic nature.

3.10 Considerations for Micro- and Small Scale Embedded Generation (SSEG)

The contribution from SSEG units will be effected at the point of use of electricity for LV consumers. This means that these units will be able to offset the LV system losses to a greater or lesser extent. As identified in Table 3.2 above, the losses in the MV/LV transformation and LV network amount to some 35% of the overall transmission / distribution system losses and almost 50% of the typical distribution system loss. Therefore there is significant value from SSEG both in terms of its potential to avoid load related capital expenditure and to offset energy loss costs.

The connection of significant quantities of SSEG to a particular LV distribution network will present itself on the MV or HV network in a similar way to a direct connected larger embedded generator and the costs and benefits discussed in Sections 3.2 through 3.9 will be evident. The discussion below considers some of these items further in relation to SSEG connections;

Voltage Regulation - The units will provide voltage support to the LV network through the displacement of demand at the point of use. The voltage profile for the LV Network and the tap setting on the local MV/LV distribution transformer will determine the extent to which the voltage rise may exceed accepted distribution network ' design' limits. However, there is the potential to adjust the transformer tap to take into account the changed voltage profile;

Voltage Unbalance – There is a 'background' level of voltage imbalance on LV networks due to the random connection of users to particular phases along a feeder. This effect is more pronounced the further away from the distribution transformer. The voltage imbalance at the distribution transformer LV terminals is lower since they are not affected by the feeder cable voltage drops and this will mitigate the impact of multiple SSEG on voltage unbalance at the MV and HV levels;

Power Flow – Whilst the SSEG penetration remains below the level of demand on an LV network it is unlikely that there will be issues related to reverse power flow through the distribution transformer. However, should there be reverse flow (real power or reactive power) through the distribution transformer there may be issues related to the protection systems and tap changer equipment associated with the transformer, and there could well be cost issues for the connection of the SSEG beyond this level.

The distribution company may need to consider providing statements on the allowable penetration of SSEG on their LV networks and certainly should consider a mechanism for treatment of connections that require capital expenditure on the LV network;

Fault Levels – The introduction of multiple SSEG units onto an LV network will increase the fault level. However, recent studies[41] have shown that the impact is not significant due to the impedance of the LV network. Further, the contribution to the fault level at higher voltage levels has also been shown to be minimal;

Voltage Step Changes – the SSEG units may be sensitive to the voltage transients that can be seen on LV networks, say from the disconnection of an adjacent distribution transformer. If this is the case it is likely that the action of circuit breakers or fuses local to the fault will not cause loss of supply to the unfaulted transformer. However, protection equipment on the SSEG units may operate and trip the generation and this secondary effect will result in voltage step change. This may lead to a standard range of protection setting for SSEG plant on a given LV network, or possibly a generic 'fault ride through' capability.

Generation Location – the location of the SSEG units on the LV network will influence the extent of their effect on the LV network. The location on the MV/HV network of those LV networks with significant SSEG penetration will have a similar influence on the MV/HV networks as does the location of a larger directly connected embedded generator;

The detailed calculation of the costs and benefits of SSEG is included within an Addendum to this report.

4. Representative Network Identification and Modelling

4.1 Electricity distribution in Ireland

4.1.1 General

The population of Ireland is concentrated in the cities of Dublin, Cork, Limerick and Galway, in towns along the east coastal strip and the south east corner, and inland within commuting distance Dublin, the main urban development. The remainder of the population is distributed across the country in small county towns, villages, on farms and on individual plots of land. About two-thirds of Ireland's population is concentrated in probably less than one-quarter of its surface area.

ESB Networks has over the years developed its distribution network to supply electricity to customers across the length and breadth of the country, such that 38 kV high voltage primary substations are located in every county[42], with 20 kV or 10 kV medium voltage networks distributed from these substations or from 110 kV substations on the transmission system of ESB National Grid. Consequently the bulk of ESB's distribution network is located in rural areas and is likely to remain so for the foreseeable future, even with continued growth of the Irish economy and the resulting expansion of the area of urban and semi-urban development, particularly in areas within reasonable commuting distance (i.e. 100 km) of Dublin.

The rural distribution network is characterised by long, single circuit overhead lines, configured as a radial network at either 10 kV or 20 kV, to supply an area of low load density, with densities typically in the range 20 kW/km^2 to 50 kW/km^2. These medium voltage networks are either supplied from the 38 kV high voltage distribution system at 38/10 kV and 38/20 kV primary substations or directly from the 110 kV transmission system via 110/20 kV substations.

At the other extreme, in central Dublin, electricity distribution is via 38 kV and 10 kV underground cable networks that supply customers in high load density areas, with densities typically in the range 5,000 kW/km^2 to 10,000 kW/km^2. The transmission system injects power into Dublin at various locations at 110 kV[43]. From these grid substations a 38 kV high voltage cable network is distributed across the city, with 38/10 kV primary substations located at various points on route. The 38 kV network in central Dublin is interconnected to an extent, with closed ring circuits between bulk supply points linking a number of primary substations on route. A 10 kV cable network interconnects primary substations, but this network is operated as a radial network with open points at strategic points along its length. The cable lengths are relatively short with 38 kV and 10 kV substations located much closer together than in the rural areas. The 10 kV cable network supplies 10 kV/LV secondary distribution substations across the city from which domestic customers and the bulk of ESB's commercial and light industrial customers receive their supply. The 10 kV distribution network also provides supplies directly at 10 kV to some large customers.

In the larger towns and on the outskirts of Dublin and the other cities where there is a mix of domestic, commercial and light industrial load the load density is typically in the range 1,000 kW/km^2 to 4,000 kW/km^2 and the network is a combination of underground cable and overhead line with circuits generally of a more moderate length.

---

[42] The ESB Networks distribution system includes 110kV system voltages within the Dublin area distribution network.

[43] At a number of number of grid substations power is injected initially at 220 kV, but stepped down immediately to 110 kV, and then supplied to the 38 kV distribution network from the 110 kV grid substations through 110/38 kV transformers.

ESB has been implementing a voltage conversion programme for some time now in which new developments are, where appropriate, being supplied at 20 kV, instead of 10 kV. ESB is also converting parts of its 10 kV network to 20 kV, as circuits and equipment are upgraded or replaced under ESB's programme of asset replacement. Therefore, depending on the location, the medium voltage network in these areas can be either a 10 kV network or a 20 kV network supplied from either the 38 kV high voltage distribution network or the 110 kV transmission system. To enable network conversion to continue in the future it is ESB practice to install dual voltage transformers (i.e. 38/20/10 kV with two secondary windings) at many primary substations, particularly in rural areas.

4.1.2 Rural networks

The bulk of rural distribution networks are similar in construction and in basic design configuration. The high voltage (38 kV) and medium voltage (10 and 20 kV) distribution networks in rural areas are characterised by radial networks that supply power to sparsely distributed loads over long, single circuit overhead lines. Consequently under extreme conditions many rural networks are regularly subject to problems with voltage quality and availability of supply.

In an analysis of the range of representative network types the obvious feature that distinguishes one network type from another is the combination of voltage levels used to deliver power from the transmission system to the customer. In common with other distribution companies the vast majority of ESB Networks' customers receive their electricity supply at low voltage, i.e. 400/230 V, and as such the low voltage distribution system is common to all voltage combinations.

The most common combinations of distribution voltage levels in use in rural areas of Ireland are:

a) 38/10 kV distribution

b) 38/20 kV distribution.

c) However, there are also a number of cases where the 110 kV transmission system has been used directly to feed the distribution system and this has produced a third representative rural network type:

d) 110/20 kV distribution.

The principal characteristics of each of the three rural network types are summarised below.

38/10 kV networks. The 38 kV network receives its supply from the 38 kV bus bars of the local 110/38 kV transmission substation of ESB National Grid. In the rural areas the 110/38 kV substation capacity is generally based on one or two 31.5 MVA transformers.

From the bulk supply point typically two outgoing feeders supply power for up to four other 38/10 kV primary substations. The network is configured radially and open points isolate the 38 kV network from its neighbour, which is sourced from another transmission substation. The 38 kV circuits that connect the 38/10 kV primary substations are all single circuit overhead lines in the rural areas.

At the primary substations, the most common arrangement is for two 38/10 kV, 5 MVA transformers to supply the 10 kV switchboard, although there are examples of single transformer primaries, with 2 MVA and 5 MVA transformer capacities the most commonplace. Examination of a sample of rural networks has shown that typically between three and five 10 kV radial feeders are supplied from the primary substation and the 10 kV feeder is configured such that from the main "trunk" of the feeder are routed a number of lengthy "spur" circuits to supply loads located some distance from the main route taken by the trunk. Also it is usual for a number of much shorter "stub" circuits to be teed off the trunk to supply customers that are located just off the main route. The trunk of the network is generally a 3-phase circuit. However, the spur circuits can be either 3-phase or single-phase depending on the size of the load and the length of the spur. ESB Networks use standard conductor sizes for the 38 kV and 10 kV overhead lines. In cases where the primary substation is located in a town the outgoing feeder may be run underground, over the initial part of the route, and for these relatively small lengths ESB Networks again use standard cable sizes.

The longer circuits also incorporate voltage-regulating transformers (i.e. "boosters") at strategic points along the main trunk of the feeder, and in some exceptional cases booster transformers are connected in the spur, to boost the voltage downstream.

From the sample of networks analysed in our study it would seem that current practice for the connection of wind farms and small hydro sets (typically less than 4 MW) to the 10 kV network is through a single dedicated circuit to the 10 kV bus bars of the nearest 38/10 kV primary substation, bypassing any existing 10 kV network infrastructure that may be in the vicinity. This type of connection for the embedded generation will have little effect on the 10 kV distribution system, though it will effect the performance of the 38 kV network upstream.

Figure 4.1 shows a typical 38/10 kV rural network including a connection arrangement commonly used by developers to connect an embedded generator to the distribution system at the local primary substation.

38/20 kV networks. In a similar way to that used to supply the 38/10 kV distribution network, the typical 38/20 kV rural network is supplied from the 110/38 kV grid substation via one or two 110/38 kV, 31.5 MVA transformers. In many rural areas, the 20 kV network runs alongside the 10 kV network, as part of the voltage conversion programme, and consequently it is common practice for the 20 kV network to take its supply from the same 38 kV primary substation as a neighbouring 10 kV network. In those instances, at least in the sample we examined, one 38/10 kV, 5 MVA transformer supplied the local 10 kV network and one 38/20 kV, 5 MVA transformer supplied the local 20 kV network. In time as voltage conversion continues the logical process would be for the 10 kV network to be upgraded to 20 kV. The key aspect is that the same 38 kV network is often used to supply the 10 kV and / or the 20 kV network, i.e. it is typically common to both.

Analysis of a small sample of 20 kV circuits showed that typically two 20 kV outgoing feeders distributed power from the 20 kV bus bars of the 38/20 kV primary substation. The 20 kV feeders are in the main, like the 10 kV rural feeders, single circuit overhead lines configured as radial networks to sparsely distributed loads. The advantage of 20 kV distribution over 10 kV distribution is that the same power can be distributed much further at 20 kV, nominally by up to four times, so that the supply area of a 20 kV network should extend well beyond that of the 10 kV network. Alternatively, the 20 kV network can cover a similar supply area, but handle a much greater load, effectively providing capacity to handle significant projections in load growth. As with 10 kV feeders, a number of lengthy spur circuits and shorter stub circuits are teed off the trunk of the 20 kV feeder. The trunk of the network is again essentially a 3-phase circuit, with the spurs either 3-phase or single-phase depending on the size of the load and the length of the spur. ESB Networks use standard conductor sizes for the 20 kV overhead lines and cables.

The current practice for the connection of wind farms and small hydro sets to the 20 kV network (typically less than 10 MW) is, like that at 10 kV, through a single dedicated circuit to the 20 kV bus bars of the nearest 38/20 kV primary substation, bypassing any existing 20 kV network infrastructure that may be in the vicinity. This type of connection for the embedded generation will have little effect on the 20 kV distribution system, though it will effect the performance of the 38 kV network upstream.

Figure 4.2 shows a typical 38/20 kV rural network with connection arrangement.

110/20 kV. The number of networks with direct transformation from transmission voltage to medium voltage is fairly limited. In most cases it has been the practice to step down from 110 kV to 38 kV for onward distribution to other 38 kV primary substations, which would increase the potential supply area from the 110 kV transmission substation compared with 20 kV distribution. However, in exceptional cases, such as the Arigna network in Leitrim, where there was an existing 110 kV grid substation in place (following the closure of the local power station) and no 38 kV network within 25 km there was an economic case for direct transformation from 110 kV to 20 kV.

The installed capacity at the 110/20 kV grid substations will be higher than that installed on the 38/20 kV or 38/10 kV primary substations, but for Arigna, the case in our sample, the 110/20 kV substation provides supplies through a single 15 MVA transformer.

The 20 kV outgoing feeders are similar in design to those employed in the 38/20 kV network, although given the potential for increased installed capacity at the 110/20 kV substation the number of outgoing 20 kV feeders could be higher than for a typical 38/20 kV network.

Figure 4.3 shows a typical 110/20 kV rural network.

4.1.3 Semi-urban networks

On the outskirts of the major cities and towns the electricity demand comes basically from a mix of domestic, commercial and light industrial customers. The outskirts are essentially semi-urban areas with power injected into the area from 110 kV transmission substations. At the main bulk supply points it is standard practice to operate with two, or possibly three 110/38 kV, 63 MVA transformers in service to supply the 38 kV network. From the bulk supply points, typically three or more 38 kV feeders connect with other 38/10 kV primary substations through a combination of radial and closed loop circuits. In the sample network provided for semi-urban areas, up to four primary substations were connected, with open points segregating it from an adjacent network. The 38/10 kV primary substations on the outskirts of Dublin are based, typically, on two 10 MVA transformers with up to five outgoing 10 kV feeders routed from each primary substation, supplying power to 10 kV/LV secondary distribution substations on route. The load density in semi-urban areas is much higher than in rural areas, so that circuit lengths are generally much shorter. The 10 kV feeders run between primary substations, with open points located strategically along the route, and in a typical network there are no spur circuits tapped off to supply distant loads and only a few short stubs to customers just off the main route.

The 38 kV and 10 kV circuits are predominantly run underground, although there may be examples, depending on the specific location, where a combination of overhead lines and underground cables carry power to the primary substations.

Figure 4.4 shows a typical semi-urban 38/10 kV network on the outskirts of Dublin. At the present time ESB Networks voltage conversion programme is understandably focused on the rural areas as a means of improving system voltage, reducing losses and improving overall network efficiency. There is some 20 kV network near each of the main cities, but as yet this does not extend much to semi-urban areas and for the purpose of this study the semi-urban network is considered exclusively as a 38/10 kV network.

Embedded generation in semi-urban areas can take a number of forms with wind energy, CHP, landfill gas and biomass a particular possibility. Brownfield sites are the likeliest location for new embedded generation in semi-urban areas and these could conceivably be connected directly to the main 38/10 kV primary substations at either voltage, depending on the magnitude of the generation, or else teed into the 10 kV network at some point near to where the generation is situated.

4.1.4 Dense urban networks

In central Dublin there is a prime example of how embedded generation is located and operates on the distribution network. A large processing company has its own generating facilities on its factory site, for economic and security of supply reasons, and a contract to both export to and import power from the grid depending on its operating circumstances.

The electrical system on the site is connected by a 10 kV cable circuit that is routed in and out of the site between two 38/10 kV primary substations (i.e. A and B) . These substations are themselves connected into two separate 38 kV circuits run over different supply routes between two 110/38 kV grid substations (i.e. X and Y). The cable circuit between the A and B substations is dedicated entirely to the connection of the factory supply to the 10 kV network. Under normal operation the 10 kV feeder between A and B substations is open at either A or B, so that the supply to the factory site is connected to either A or B substations, but not both simultaneously.

Figure 4.5 shows the supply arrangement for connection of the embedded generation to the 38/10 kV network in central Dublin. The rest of the supply arrangement shown in Figure 6.5 is reasonably representative of the supply arrangement in a dense urban area in the larger cities.

The 38 kV network interconnects a number of 38/10 kV primary substations either in a closed ring from a single bulk supply point, or in one or more 38 kV circuits laid over different routes between the two bulk supply points. Typically each 38/10 kV primary substation on the 38 kV network has an installed capacity of one or two 10 MVA transformers, although there are cases where 15 MVA transformers have been used. In order to limit short circuit levels, it is standard practice to configure the network so that for each group of primaries, a maximum of two 110/38 kV transformers (whether located at the same bulk supply point or at different ones) is used to supply the demand.

Typically from the main bulk supply points several 10 kV feeders are routed to other primaries and bulk supply points across the city. A significant level of interconnection exists, but strategically placed open points ensure the 10 kV network is operated as a radial network.

4.1.5 Identification of representative network types

The review of rural, semi-urban and dense urban networks in Ireland, has identified five principal network types that are considered further in this section in a more quantitative manner. The five representative network types are:

- Type 1 - 38/10 kV rural,
- Type 2 – 38/20 kV rural,
- Type 3 – 110/20 kV rural[44],
- Type 4 – 38/10 kV semi-urban,
- Type 5 – 38/10 kV dense urban.

---

[44] The analysis presented in this report has been limited to determining the effects of embedded generation specifically on the distribution network. Consequently power system studies of the 110/20 kV network type have not been undertaken. Although, the principles for system modelling and power system studies presented in this report can be similarly adopted to examine the effects of embedded generation with respect to the 110 kV system, the model of the transmission system would have to take account of load and generation despatch.

At an early stage in the study PB Power held discussions with ESB Networks to identify a reasonable sample of distribution networks that could be analysed to determine their principal characteristics with a view to placing each network in one of the above categories. From this representative sample it was intended to define the principal physical attributes of each network with a view to producing representative system models for each network type that can be used in power system studies to determine the impact on system performance of embedded generation.

4.2 Topographical analysis

In undertaking topographical analysis of a sample of distribution networks it is recognised that the size of the sample has unavoidably been limited, because of the extent of work involved in analysing the networks in the first instance and the limited timescale and budget available to cover all aspects of the Scope of Work. Nevertheless we have sampled, either in whole or in part, a minimum of fifteen high voltage networks, and sixty medium voltage circuits. The sampled networks were taken from areas where there is a reasonable expectation of future development of embedded generation based on sustainable energy resources.

The purpose of undertaking topographical analysis of the sampled networks was basically to determine the principal physical characteristics of each of the five representative network types defined in Section 4.1.5 above.

4.2.1 Principal network characteristics

There are a number of distinctive features of any distribution circuit, or group of circuits that form a network[45] and which can be used to characterise it for analytical purposes. These are:

- Primary substation and feeder voltages
- Type of network (i.e. overhead or underground)
- Installed primary substation and distribution transformer capacity
- Load supplied (or load density)
- Area of supply
- Feeder physical characteristics (i.e. numbers and lengths of trunk, spurs and stub circuits)[46]
- Voltage control facilities.

In order to characterise the network types by their physical parameters, raw data provided by ESB Networks for each circuit in the sample was analysed to establish data for each of the above characteristics. The raw data consisted of single line diagrams of the 38 kV network, geographic layouts of the medium voltage distribution network, substation and feeder loads, transformers, overhead line and cable data.

[45] In our discussions with ESB Networks at which a number of sample networks were provided, it was understood that they use the term "network" to refer to a grouping of up to four primary substations, i.e. from one to four primaries.

[46] ESB Networks, in common with other utilities, use standard conductor sizes for their overhead line and underground cable networks. Consequently there is a degree of commonality with regard to conductor types and sizes across the various network types.

4.2.2 Rural networks

The sample of rural networks analysed topographically covered areas in which there was considered to be significant potential for the connection of generation based on sustainable energy type resources. The sample networks analysed were located in the counties of Donegal, Leitrim, Kerry and Kildare[47]. The analysis included one of the Midlands networks to determine whether there is a significant difference between rural networks in the west of Ireland, where the networks are acknowledged as "weak" and networks in the Midlands where some reinforcement to the higher voltage networks had been made in the past to accommodate local power stations that have only recently been retired. Subsequent analysis showed that whilst the Midlands network was more heavily loaded than most of the rural networks in the sample, the difference was not significant and therefore the Midlands network was included as part of the rural network sample.

In the assessment of the rural networks we have considered first the analysis of the medium voltage networks.

The analysis of medium voltage feeder circuits routed from a single primary substation showed a significant difference in the lengths of individual feeders. This reflects on the amount of installed transformer capacity and the connected load and can also affect the requirements for voltage control. Consequently in our topographical analysis we have specifically determined the characteristics of the shortest feeder, an average length feeder and the longest feeder[48] so that the three are represented in our system model used to analyse the effects of embedded generation on the network.

10 kV feeder circuits. Table 4.1 summarises the principal characteristics of the 10 kV rural networks. It is evident from the table that there is a significant difference between the shortest and longest feeder lengths and the respective loads on these feeders. There is also a corresponding difference in the total load on each feeder, although the average distribution transformer utilisation is fairly comparable (i.e. between 36 and 42 percent). The difference in circuit length and circuit loads will significantly impact on the voltage, utilisation and losses associated with the respective feeder. This is demonstrated later in section 5, in which the results of power system studies are presented, but there is evidence of this in the fact that the longest feeder has typically two voltage boosters installed along its trunk.

The data presented in Table 4.1 is used directly in the development of the system model of the representative rural 38/10 kV network. The topographical analysis of the 10 kV feeders is presented fully in Appendix D.

---

[47] The number of networks in our sample was necessarily limited. There are obviously other counties and areas of rural Ireland that have similar potential for sustainable energy type developments that could equally have been included in the sample.

[48] The data presented in Table 6.1 for the shortest, average length and longest feeder was derived from a review of the medium voltage feeders supplied from seven 38/10 kV primary substations, for which the shortest and longest feeders were identified and an average taken. The average length feeder was derived from the full sample.

Table 4.1: Principal physical and load characteristics of medium voltage feeders on 10 kV rural networks

	Shortest feeder	Average feeder	Longest feeder
Installed transformer capacity (kVA)	**3357**	**4853**	**6733**
Average transformer utilisation (%)	36	38	42
Feeder trunk length (km)	**5.6**	**11.2**	**18.5**
Number of spur circuits	1	2	3
Average spur length (km)	2.4	3.0	3.7
Number of stub circuits (km)	3	6	10
Average stub length (km)	0.3	0.3	0.4
Total circuit length (km)	**9.0**	**19.2**	**33.1**
Number of booster transformers	**0**	**0**	**2**
Load connected to trunk (kW)	432	664	1014
Load connected to spur circuits (kW)	417	640	984
Load connected to stub circuits (kW)	297	456	700
Total connected load (kW)	**1146**	**1760**	**2698**

20 kV feeder circuits. A similar treatment was applied to a smaller sample of 20 kV networks and the results of this analysis are presented in Table 4.2.

From the table it is evident that whilst there is still a significant difference in the length and the total load associated with the shortest and longest feeders, the differential is not as large as with the 10 kV feeder circuits and this is reflected to some extent in the fact that the longest feeder in this case does not require booster transformers to support the voltage.

It is also of note that although the 20 kV feeders in the sample were longer than the 10 kV feeders in Table 4.1 the 20 kV feeder loads were lower and the average distribution transformer utilisation was roughly half that of the transformers connected to the 10 kV feeder. The 20 kV feeders sampled were located in North Donegal and Leitrim and it is possible that 20 kV feeders in other areas could be more heavily loaded. However, the principal objective of the analysis is to demonstrate where the costs and benefits lie and in that respect we consider the data obtained adequate for the purpose of this study.

The data presented in Table 4.2 is used directly in the development of the system model of the representative rural 38/20 kV network. The topographical analysis of the 20 kV feeders is presented fully in Appendix B.

Table 4.2: Principal physical and load characteristics of medium voltage feeders on 20 kV rural networks

	Shortest feeder	Average feeder	Longest feeder
Installed transformer capacity (kVA)	**5415**	**6202**	**10393**
Average transformer utilisation (%)	21	27	16
Feeder trunk length (km)	**12.0**	**16.8**	**18.4**
Number of spur circuits	2	3	4
Average spur length (km)	1.8	3.0	6.0
Number of stub circuits (km)	6	7	7
Average stub length (km)	0.5	0.6	0.6
Total circuit length (km)	**18.6**	**30.2**	**46.9**
Number of booster transformers	**0**	**0**	**0**
Load connected to trunk (kW)	560	820	935
Load connected to spur circuits (kW)	310	453	516
Load connected to stub circuits (kW)	216	315	357
Total connected load (kW)	**1086**	**1588**	**1808**

38 kV networks. The analysis of rural high voltage networks was based on a sample of four, supplying a total of seventeen 38/10 kV and 38/20 kV primary substations. The 38 kV networks that supply the primary substations generally are configured as radial circuits from a single source 110/38 kV grid station to outlying primary substations, from which the medium voltage network is distributed. Alternatively, the supply from the source 110/38 kV grid station can be connected as a closed ring circuit connecting up to two primary substations on route. For the purpose of the analysis presented in section 7 of this report we have modelled the 38 kV network as a radial connection to two outlying primary substations.

Table 4.3: Principal physical characteristics of 38 kV high voltage networks

Installed grid station 110/38 kV transformer capacity	1 (or 2) x 31.5 MVA
Number of 38 kV primaries supplied from grid station	2 to 4
Number of outgoing 38 kV feeders from grid station	2 to 3
Average length of 38 kV feeders between primaries	10 km

Table 4.3 summarises the principal characteristics of the 38 kV network and Figure 4.4 shows a typical 38 kV network in the rural areas.

4.2.3 Semi-urban networks

The analysis of semi-urban networks was based on data for an area outside central Dublin. A typical high voltage distribution network that supplies semi-urban areas on the outskirts of Ireland's largest cities was described in sub-section 4.1.3 and is not repeated here. However, although the 38 kV network configuration may be similar to that shown in Figure 4.4 for a typical rural network, there are some significant differences. In particular the semi-urban networks are predominantly underground cable networks, the grid station capacities are higher (typically 2 x 63 MVA) transformers and the primary substations are closer together.

The results of topographical analysis of a sample of twenty-four 10 kV feeder circuits from four primary substations that supply the semi-urban areas are presented in Table 4.4. Again we have identified the characteristics for the shortest, average length and longest feeders.

Table 4.4: Principal physical and load characteristics of medium voltage feeders on 10 kV semi-urban networks

	Shortest feeder	Average feeder	Longest feeder
Installed transformer capacity (kVA)	**2038**	**4726**	**6926**
Average transformer utilisation (%)	62	37	30
Feeder trunk length (km)	**1.7**	**3.0**	**4.6**
Number of spur circuits	-	-	-
Average spur length (km)	-	-	-
Number of stub circuits (km)	-	1	2
Average stub length (km)	-	1.0	1.1
Total circuit length (km)	**1.7**	**4.0**	**6.7**
Number of booster transformers	**-**	**-**	**-**
Load connected to trunk (kW)	1192	1232	1441
Load connected to spur circuits (kW)	-	-	-
Load connected to stub circuits (kW)	-	448	522
Total connected load (kW)	**1192**	**1680**	**1963**

The data presented in Table 4.4 is used directly in the development of the system model of the representative semi-urban 38/10 kV network. The topographical analysis of the 10 kV feeders is presented fully in Appendix B.

4.2.4 Dense urban networks

The analysis of dense urban networks was based on data for a part of 10 kV distribution network in Central Dublin supplied from Inchicore and Francis Street 110/38 kV grid stations. The high voltage network in this area was described previously in sub-section 4.1.4 and is therefore not described here.

The results of topographical analysis of a sample of nine 10 kV feeder circuits from two primary substations that supply this dense urban area are presented in Table 4.5. Again we have identified the characteristics for the shortest, average length and longest feeders.

Table 4.5: Principal physical and load characteristics of medium voltage feeders on 10 kV dense urban networks

	Shortest feeder	Average feeder	Longest feeder
Installed transformer capacity (kVA)	**3260**	**6288**	**6425**
Average transformer utilisation (%)	36	22	55
Feeder trunk length (km)	**1.2**	**1.7**	**2.2**
Number of spur circuits	-	-	-
Average spur length (km)	-	-	-
Number of stub circuits (km)	-	-	1
Average stub length (km)	-	-	0.1
Total circuit length (km)	**1.2**	**1.7**	**2.3**
Number of booster transformers	**-**	**-**	**-**
Load connected to trunk (kW)	1110	1290	3204
Load connected to spur circuits (kW)	-	-	-
Load connected to stub circuits (kW)	-	-	157
Total connected load (kW)	**1110**	**1290**	**3361**

It is acknowledged that the sample size is small and as a result the load on the longest feeder, in particular, may be unrepresentatively high, as denoted by the 55% average transformer utilisation. We will comment further on this in Section 5, if it is seen to significantly effect the results of the analysis on this type of network.

The data presented in Table 4.5 is used directly in the development of the system model of the representative dense urban 38/10 kV network. The topographical analysis of the 10 kV feeders is presented fully in Appendix B.

4.3 Power system modelling

The summarised results of the topographical analysis presented in Tables 4.1 to 4.5 for each network type have been used as the basis of the power system models used in our analysis of the effects of embedded generation on the performance of the distribution networks.

Steady state models of each network type have been developed using PSS/E power system analysis software that is used extensively by system planners in ESB and in major utilities in Britain and elsewhere.

In undertaking the analysis we have developed a number of models that are summarised briefly below:

a) Rural 110/38/10 kV network

A detailed study of the 110/38/10 kV rural network was undertaken based on the results of the topographical analysis described in sub-section 4.2. The results of the study are presented in Section 5 as an example for illustrative purposes of the analysis involved in assessing the costs and benefits of embedded generation.

The model represented the 110/38/10 kV grid station with two 31.5 MVA transformers installed supplying the local 38/10 kV primary substation with two 38/10 kV, 5 MVA transformers and two remote 38/10 kV primary substations of similar installed capacity located 5 km and 10 km respectively from the grid station. The remote primary substations are each supplied radially via a single 38 kV feeder circuit from the grid station. Figure 4.6 shows the system model used in studies of the 110/38/10 kV network.

Three outgoing radial 10 kV feeders representing typically the shortest, average length and longest feeder supply the load from each primary substation. The load on each circuit was consistent with that determined in the analysis presented in sub-section 4.2.2, representing ESB Network's estimate of current peak demand.

Load flow and short circuit analysis was undertaken on the model for the base case (i.e. no embedded generation), and for increasing levels of embedded generation (up to 5 MW) connected to each 10 kV feeder in turn at the most remote primary substation, directly to the 10 kV bus bars at this primary substation and at various points on the 38 kV network. The location and amount of embedded generation was varied to identify the impact this had on the system power flows, circuit utilisation, voltages, losses and short circuit levels.

The same model was then modified to take account of a 4 percent annual growth rate projected over a 5-year and 10-year period to investigate the costs and benefits over a longer term.

b) Rural 38/20 kV network

The full model used in the study of the 110/38/10 kV network demonstrated the effect of the placement of embedded generation on the 38 kV network. The location of embedded generation on the 38 kV network has only a second order effect on the performance of the medium voltage (i.e. 10 kV or 20 kV) network and similar results for the 110/38/20 kV network can be expected for the 110/38/20 kV network, for those cases where generation is connected on the 38 kV network.

Consequently a reduced model was used to study the impact of embedded generation on the 20 kV network. The model represented the 38/20 kV primary substation with two 10 MVA installed supplying three outgoing 20 kV feeders representing the shortest, average length and longest feeder circuits as identified in the topographical analysis and each loaded as defined in sub-section 4.2.2.

The analysis undertaken with this model has studied the effect on the system power flows, circuit utilisation, voltages, losses and short circuit levels of increasing levels of embedded generation (up to 5 MW) connected to each 20 kV feeder in turn and directly to the 20 kV bus bars at the primary substation.

c) Semi-urban 38/10 kV network

The model used to represent this network type is of similar configuration to that used to study the 38/20 kV rural network, with only the primary substation, the outgoing medium voltage feeders, load and embedded generation modelled.

In the urban areas because the medium voltage network is heavily interconnected (although essentially operated as a radial system) the 38/10 kV primary substations typically are based on a single 38/10 kV, 10 MVA transformer. The model reflects this and again three outgoing 10 kV feeders, representing the shortest, average length and longest feeders with their respective loads, according to the analysis described in sub-section 4.2.3, have been represented.

d) Dense urban 38/10 kV network

A similar model to that developed for the semi-urban 38/10 kV network was used to study the effect of embedded generation on dense urban networks, but with feeder data based on the analysis presented in sub-section 4.2.4.

Details of the models used in the analysis including figures showing the respective network configuration can be found in Appendix C.

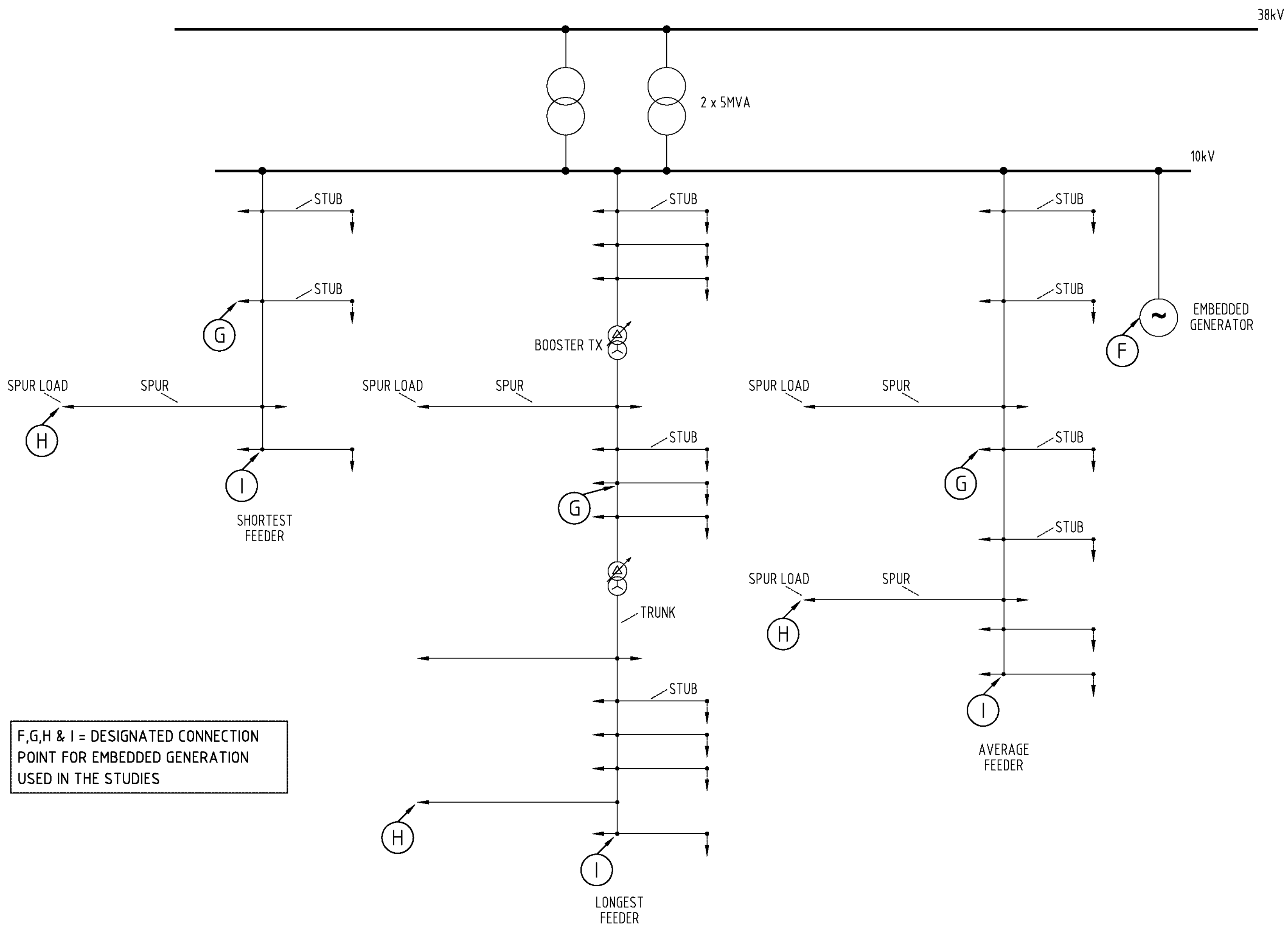


FIGURE 4.1
TYPICAL 38/10 kV RURAL NETWORK MV FEEDER SUPPLY ARRANGEMENT

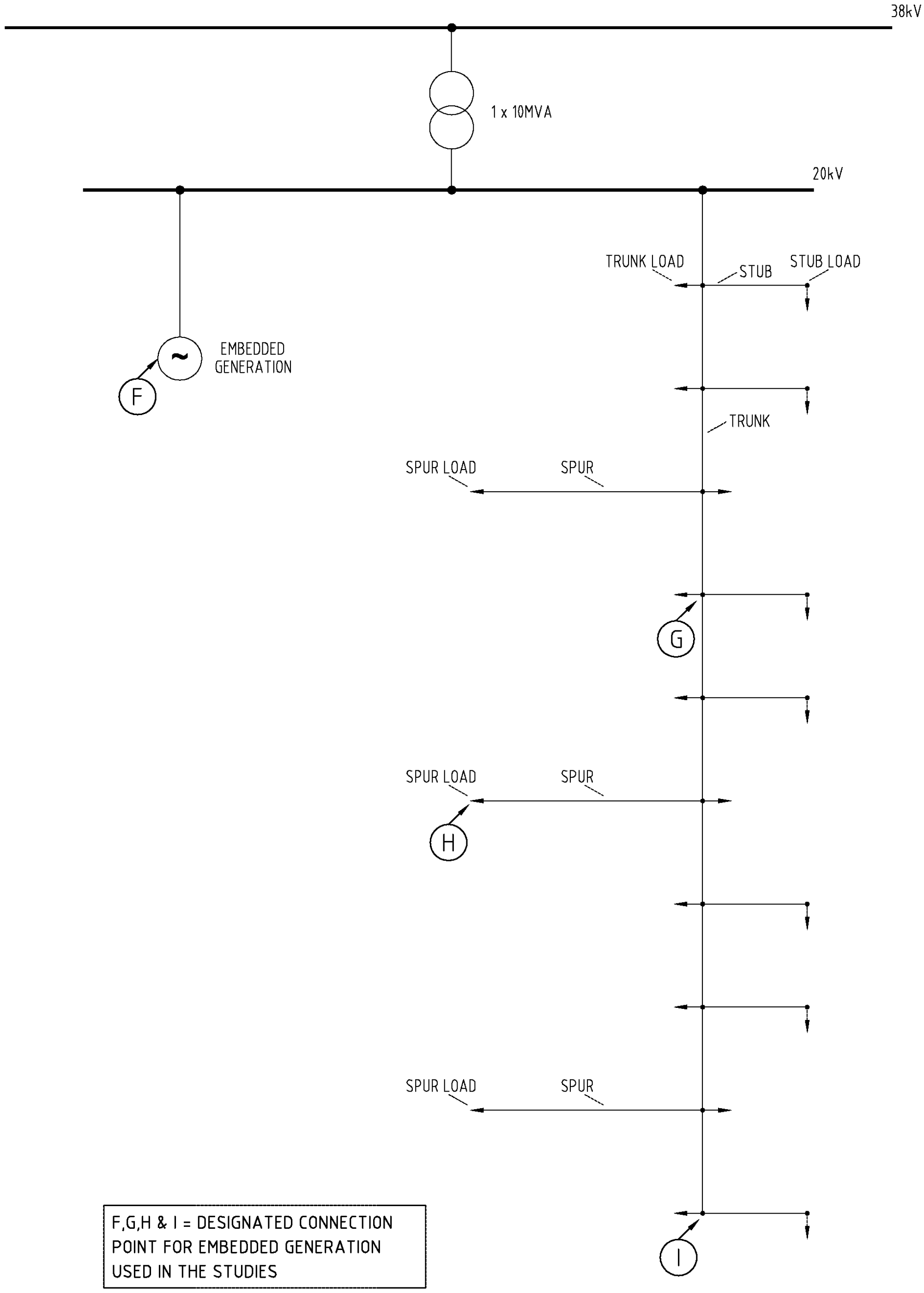


FIGURE 4.2
REPRESENTATION OF A TYPICAL RURAL 38/20 kV NETWORK WITH CONNECTION ARRANGEMENT FOR EMBEDDED GENERATION

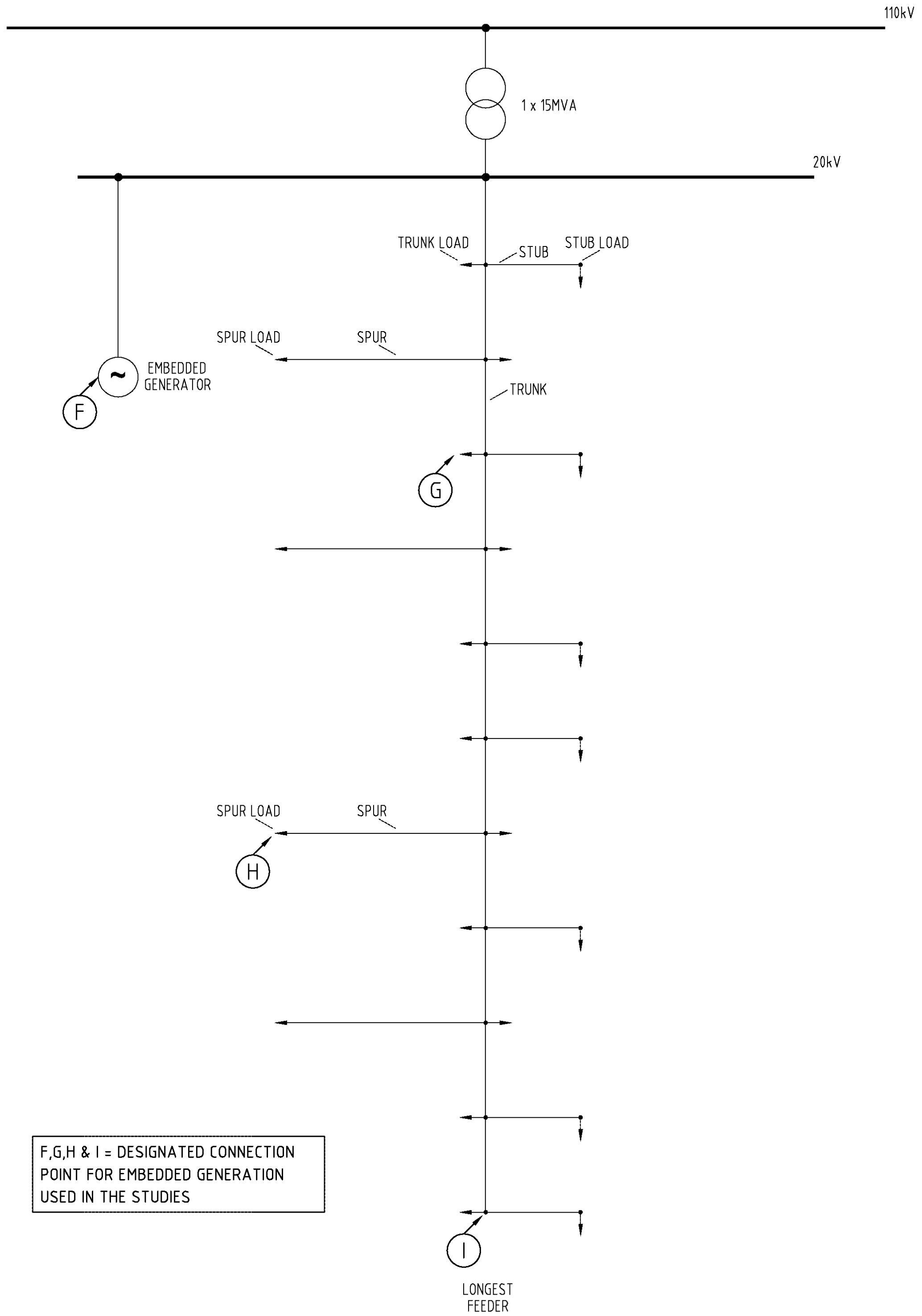


FIGURE 4.3
REPRESENTATION OF A TYPICAL 110/20 kV RURAL NETWORK

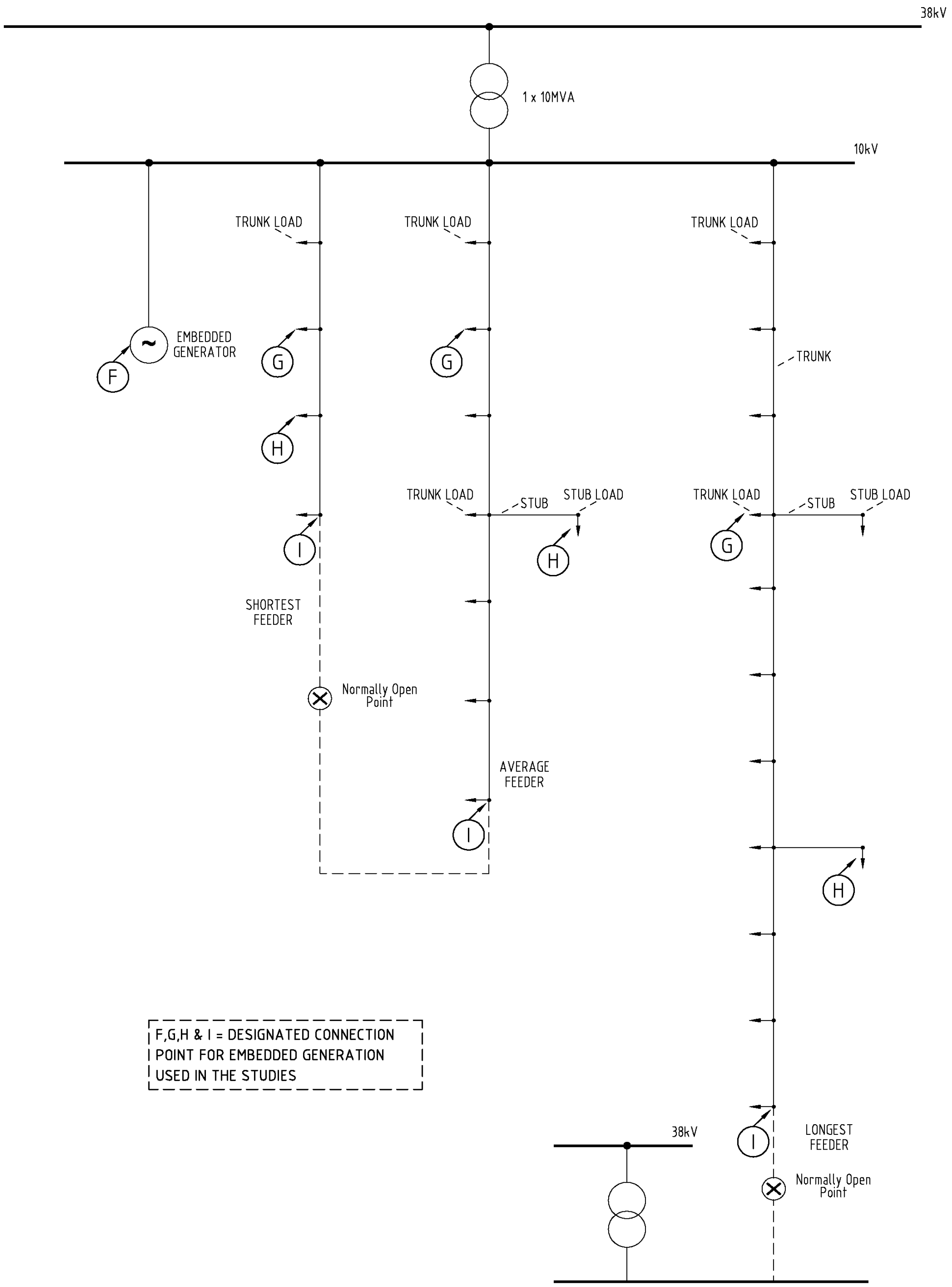


FIGURE 4.4
REPRESENTATION OF A TYPICAL SEMI - URBAN 38/10 kV NETWORK SHOWING LONGEST FEEDER

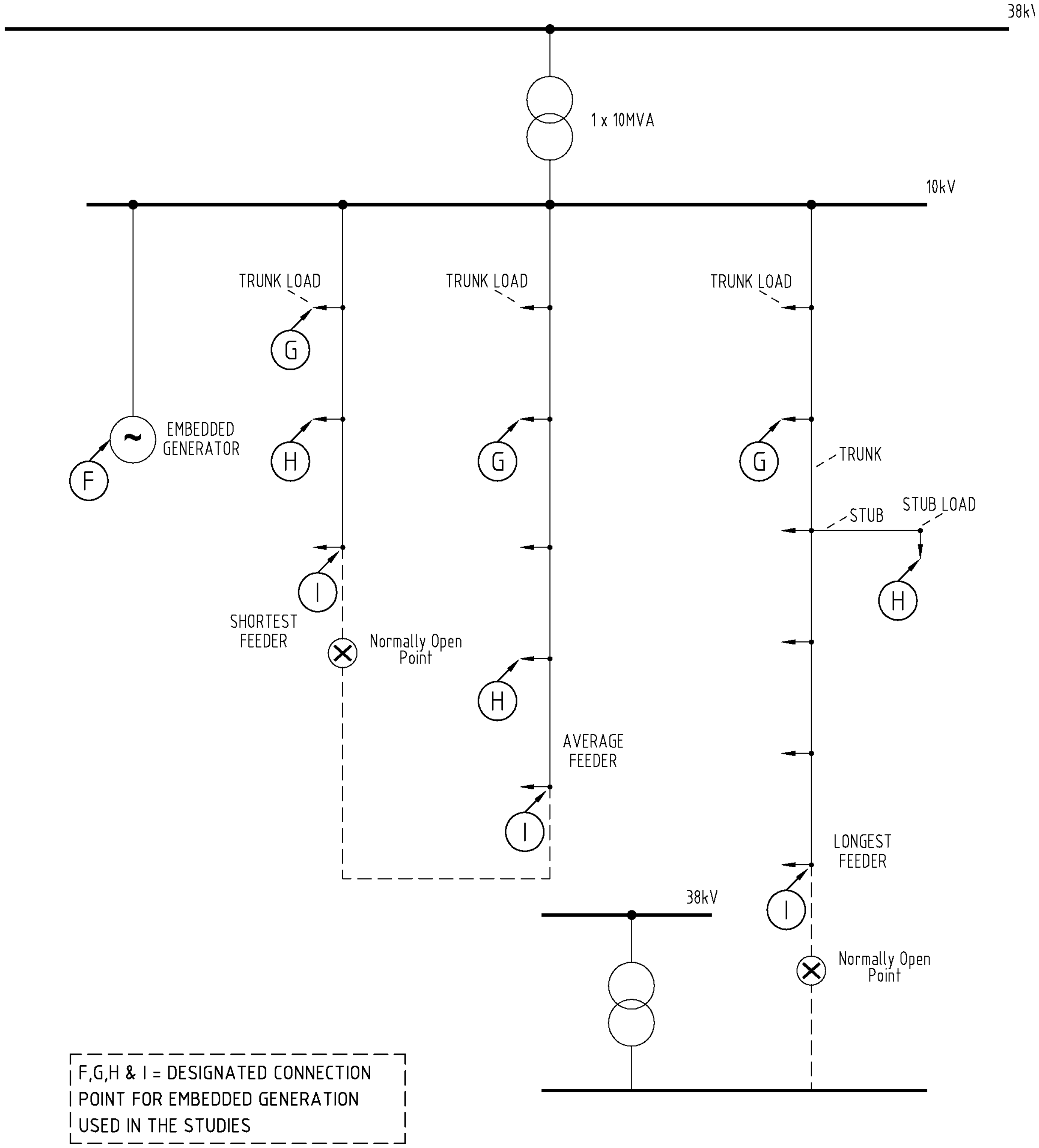


FIGURE 4.5
REPRESENTATION OF A TYPICAL 38/10 kV NETWORK IN CENTRAL DUBLIN

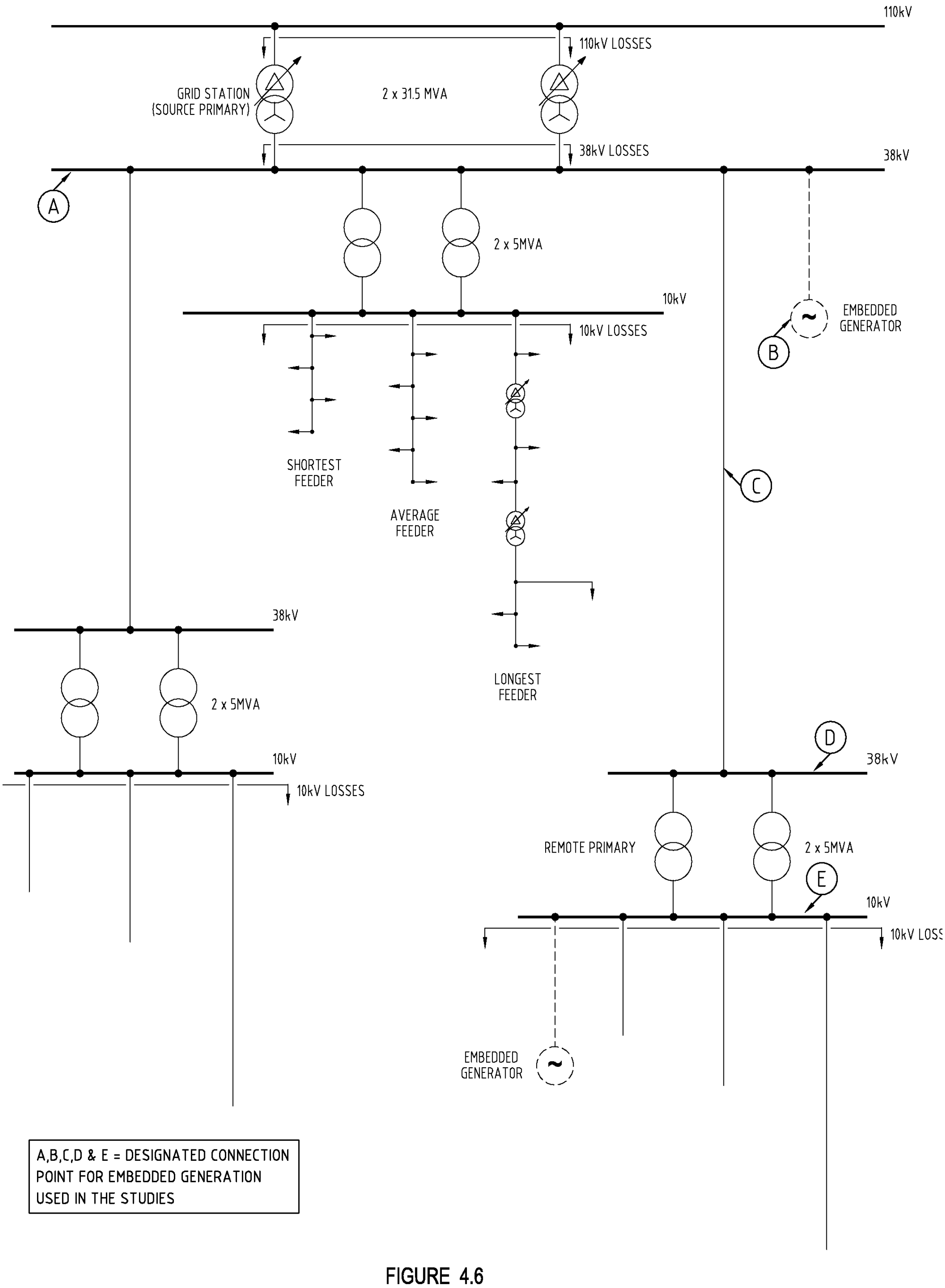


FIGURE 4.6
REPRESENTATION OF TYPICAL 110 /38 /10kV SUPPLY ARRANGEMENT IN THE RURAL AREA'S

5. Power System Studies

5.1 Purpose of studies

Power system studies were undertaken as the first stage in the process to determine the level of costs and benefits associated with embedded generation on the distribution system.

The studies have concentrated on determining the impact the embedded generation has upon the steady state operation of the distribution system[49]. In particular, load flow and short circuit analysis has examined the effect increasing levels of embedded generation the high voltage and medium voltage networks will have on the following:

a) Circuit and equipment loading

b) Technical losses

c) Voltage and voltage control requirements

d) Short circuit levels.

Load flow studies have determined the effect of embedded generation on circuit loading in order to identify when connection of embedded generation influences the requirements for reinforcement of the network compared with base case conditions, i.e. no embedded generation, either by increasing the utilisation of the circuit to the point where it needs to be reinforced, or conversely by its presence avoiding, or at least delaying, the need for reinforcement.

Load flow studies also identify the effect the generation has upon system technical losses. Depending on whether they increase or reduce as a result of the connection of the generator, these will be either viewed as a definite cost or a benefit to the DNO.

Similarly load flow studies determine the voltage at each node on the system model and as such are used to determine the effect the generation will have on the system voltage profile. In this way we can compare the voltages with generation present on the system against base case conditions, i.e. no embedded generation, to determine if the generation can reduce the need for voltage control devices, such as booster transformers and power factor correction capacitors.

Finally short circuit analysis has determined the effect the connection of embedded generation to the network will have on system fault level. In examining the fault level the critical issue here is whether existing fault levels are close to the installed switchgear rating, and whether the connection of the generator will increase the fault level to or above the switchgear rating. If that were to be the case then it would have a major impact on the economic viability of the embedded generation since it would require changes to the system design, constraints on system operation, or upgrade of switchgear; all of which would increase the connection cost for the embedded generation Developer.

[49] There are other concerns associated with the dynamic performance of the generator and the network that are not addressed here. The study of the dynamic performance would require specific modelling of frequency and voltage control devices of generation and is therefore considered at this time a site-specific issue.

In this section we present the results of the power system studies and identify the specific impact of the embedded generation in comparison with the base case for each of the four representative network types. In Section 6 the results of the studies are then processed using the methodology to convert the technical costs and benefits into actual monetary values, so that a comparative analysis can be made to put each cost and benefit into perspective.

The results of the power system studies are presented in more detail in Appendix C

5.2 Effect of embedded generation on network performance

Load flow and short circuit analysis of each representative network type was undertaken using the models established in Section 4. In determining the effect of embedded generation on network performance we have compared the performance with embedded generation connected against a base case condition with no embedded generation. The studies have determined network conditions with increasing levels of generation embedded in the network at the high voltage and medium voltage levels from 1000 kW to 5,000 kW.

The effect of the generator on network performance was also examined with respect to its location and our analysis presents the results of studies with the generator located at various points on the network. The locations considered for the connection of the generator were at:

a) The source 110/38 kV substation and connected directly to the 38 kV bus bars at that substation,

b) 5 km from the source 110/38 kV substation and connected via a dedicated feeder to the 38 kV bus bars at that substation,

c) Connected to a tee-point midway along the 10 km 38 kV feeder from the source grid station to the remote 38/10 kV or 38/20 kV primary substation,

d) At the remote primary substation and connected directly to the 38 kV bus bars at that substation,

e) At the remote primary substation and connected directly to the 10 kV or 20 kV bus bars at that substation,

f) 5 km from the remote primary substation and connected via a dedicated feeder to the 10 kV or 20 kV bus bars at that substation,

g) Connected directly to the trunk of the outgoing feeder circuit at its mid-point,

h) Connected directly at the end of a remote spur off the trunk of the outgoing feeder from the remote primary substation,

i) Connected directly to the remote end of the trunk of the outgoing feeder circuit.

With regard to locations g) to i) above, we have determined the effect of connecting the generation to the three feeder lengths identified in Section 4, i.e. shortest, average and longest length feeders.

5.3 Effect of embedded generation on low density 110/38/10 kV rural networks

In order to satisfy one of the conditions of the Terms of Reference, that requires the report to provide a detailed example of the analysis that has been undertaken to establish the level of costs and benefits associated with embedded generation, we present a detailed description of the results associated with the rural 110/38/10 kV network. A less detailed presentation of the results is provided for the other representative networks in the main text of the report, but the complete study results are available in Appendix C.

5.3.1 Analysis of 110/38/10 kV rural networks

Load flow studies have been undertaken on the basis that strict control of system voltage is observed. The results of the analysis are presented fully in Appendix C of the report, which summarises the assumptions made for voltage control.

The results presented in this section of the report concentrate on the effect of the generation on the following parameters in comparison with the base case study with no embedded generation present:

a) Real and reactive power import at the grid and primary substations

b) Real and reactive power losses at the grid and primary substations

c) Voltage profile along the medium voltage feeders

d) Circuit utilisation.

It is these figures that are used in Section 6 to determine the actual costs and benefits associated with the generation.

Table 5.1 shows the effect of increasing amounts of embedded generation on the real and reactive power imported by the network on the HV side of the 110/38 kV transformers at the source substation with the generation at different locations on the 38 kV and 10 kV networks in comparison with the base case. Table 5.2 converts the power import values in Table 5.1 into the respective reductions (or savings) in imported power that result from the connection of embedded generation. A sample of these results, illustrating the reductions in imported power due to embedded generation, for study cases 2, 3, 4L, 5L, 6L, 8 and 10 are presented graphically in Figures 5.1 and 5.2 respectively. The Figures show that with cases 2, 8and 10 (i.e. where the generator is connected at 38 kV or directly on to the 10 kV bus at the remote 38/10 kV primary) the connection of 5 MW of generation effectively reduces the imported power at the 110 kV bus by the same amount. Cases 4L, 5L and 6L, in which the generator is connected at some point along the outgoing 10 kV feeder from the remote substation, show a much poorer return when the generator output is greater than about 3 to 3.5 MW, although below that figure these cases provide a better return than the rest with case 4L, for example, providing a reduction in imported power of over 3 MW when the generator is delivering 2.5 MW. The significant factor in this respect is the magnitude of the system technical losses.

Transformers can be obviated. Connection of the generator the end of the trunk or a remote Tables 5.3 and 5.4 show the respective real and reactive power losses on the system as affected by the magnitude and location of the embedded generation, for a range of generator output up to 5 MW. Tables 5.5 and 5.6 respectively show the corresponding savings (or increases) in system losses. Figures 5.3 and 5.4 present in graphic form the loss savings for the same study cases as in Figures 5.1 and 5.2.

Figure 5.3 shows that there are significant loss savings to be made by connecting the generation at some point on the outgoing 10 kV feeder providing the capacity does not exceed between 2 to 3 MW, with the most benefits being achieved by connecting the generator near to mid-point along its trunk. Above 3 to 3.5 MW the advantage is lost and the embedded generation starts to increase the system losses.

Figure 5.4 shows the effect of embedded generation on reactive power losses. In most of the cases presented the generation produces savings in reactive power losses for generation up to 5 MW. However, when the generator is connected at or near the end of the outgoing feeder the reactive power loss increases when the generator output exceeds 3 MW.

Table 5.7 summarises the effect of increasing amounts of embedded generation on the network voltage. In the Base Case (study case 1) with no embedded generation the voltage profile along the average length and longest 10 kV feeders falls below 0.95 per unit with the standard DNO practice of operating with two booster transformers installed strategically along the longest feeder to give maximum voltage boost. In study cases 2 and 3 with the generator either connected directly to the 10 kV bus at the remote primary or via a dedicated feeder to the same bus the connection provides no voltage relief. In cases 4, 5 and 6 with the generator connected to the outgoing feeder there can be a significant improvement in the voltage profile. With the generator connected midway along the trunk of the feeder the under voltage condition is avoided and with a generator of 2.5 MW or above the need for booster spur will also control system voltage within the required +/-5% limit, but with a 5MW generator voltage constraints apply to prohibit the connection of this size of generator at the end of the longest feeders. In cases 7 to 10 with the generation connected at 38 kV and upstream of the remote primary it provides little or no relief to the voltage problems on the outgoing 10 kV feeders from the remote primary. The full voltage profile is presented in Appendix C.

Table 5.8 summarises the effect of increasing amounts of embedded generation on circuit loadings (i.e. utilisation). In the Base Case (study case 1 - with no embedded generation) all circuits in the model were operating within their nominal rating and therefore not overloaded. With embedded generation connected at 38 kV (cases 7 to 10) or directly (case 2) and indirectly (case 3) to the 10 kV bus at the remote primary, the network is again operating within rating. The connection of a 2.5 MW generator or a lower rated machine to the 10 kV feeders will not overload the feeders, but a 5 MW set would produce overloads particularly on the shortest and average length feeders and a marginal overload on the longest feeder. However, as stated voltage constraints prohibit the connection of such a relatively large generator to the end of the 10 kV feeders. The circuit utilisation is listed in detail in Appendix C.

Figure 5.1: Reduction in imported real power as affected by embedded generation

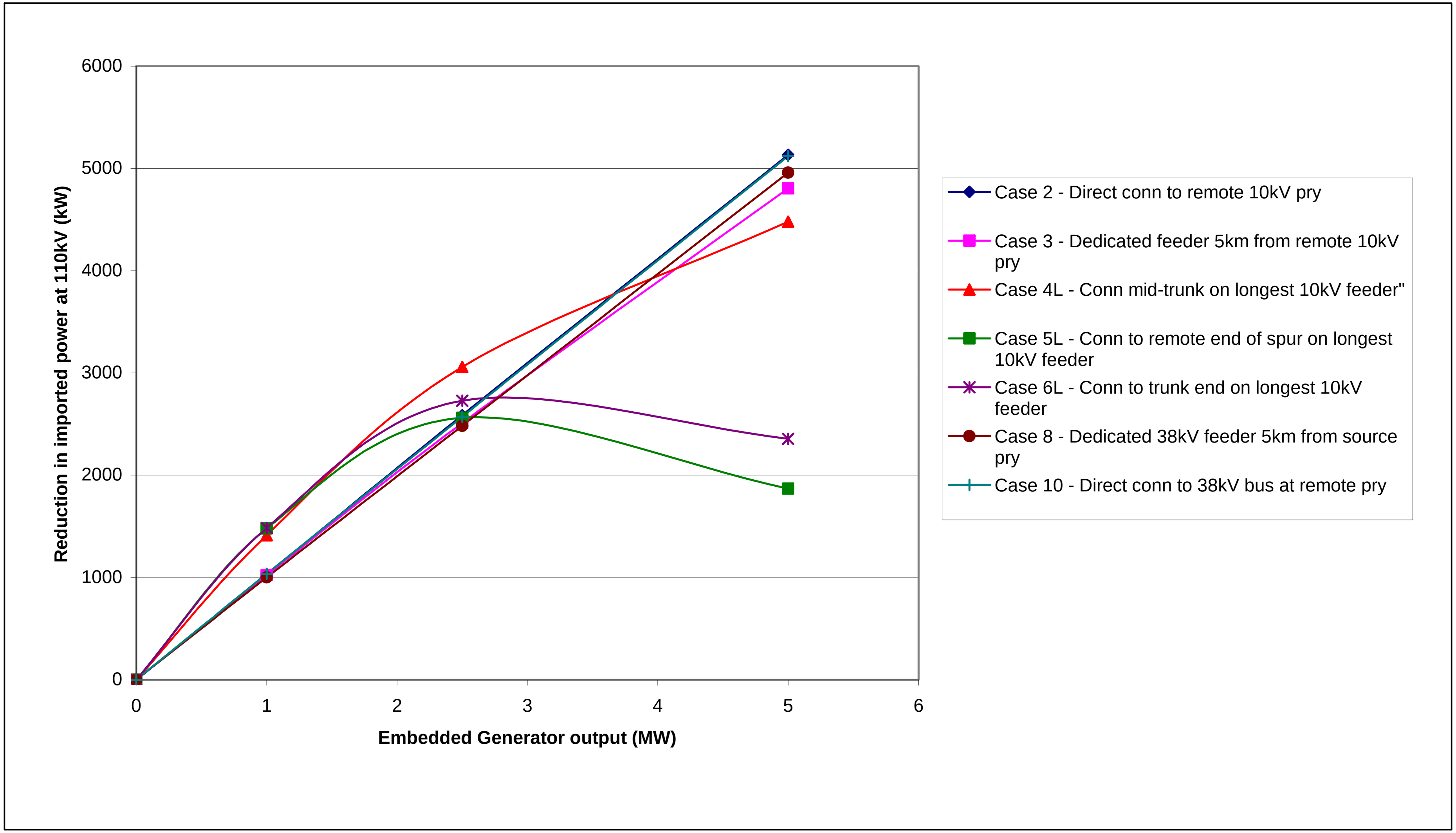


Figure 5.2: Reduction in imported reactive power as affected by embedded generation

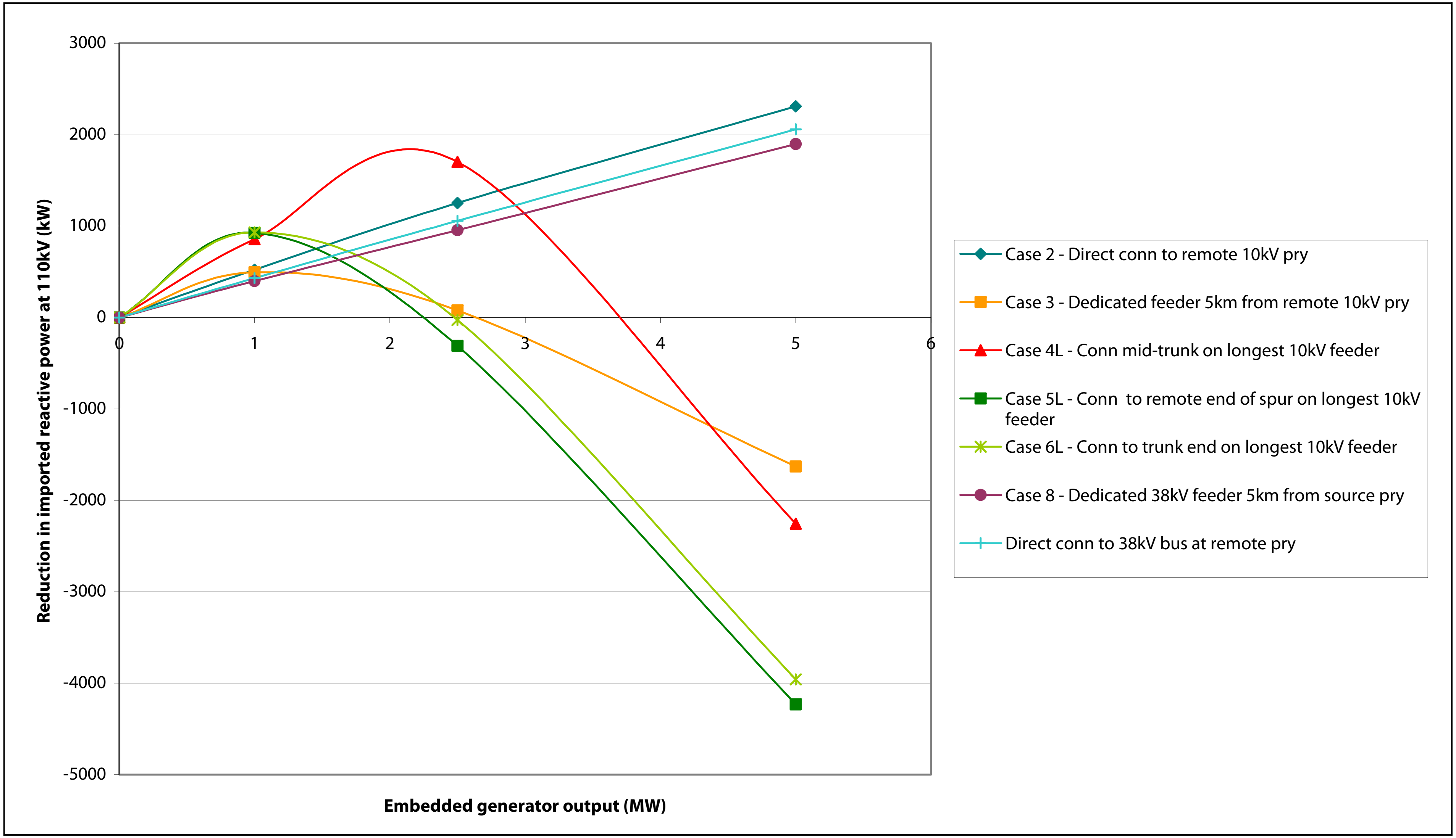


Table 5.1: Real and Reactive Power Import at 110kV bus as a function of Embedded Generation

MW gen	Real power import (kW)														
0	18300	18300	18300	18300	18300	18300	18300	18300	18300	18300	18300	18300	18300	18300	18300
1	17268	17276	17226	17170	16886	17228	17168	16820	17234	17158	16816	17296	17298	17292	17264
2.5	15714	15790	15748	15698	15240	15920	16034	15738	15950	16042	15572	15792	15816	15738	15728
5	13168	13496	13658	13908	13822	14116	14814	16432	14232	14846	15944	13286	13342	13238	13178
	Case 2	**Case 3**	**Case 4S**	**Case 4A**	**Case 4L**	**Case 5S**	**Case 5A**	**Case 5L**	**Case 6S**	**Case 6A**	**Case 6L**	**Case 7**	**Case 8**	**Case 9**	**Case 10**

MW gen	Reactive power import (kVAr)														
0	8340	8340	8340	8340	8340	8340	8340	8340	8340	8340	8340	8340	8340	8340	8340
1	7818	7846	7790	7746	7484	7794	7746	7414	7790	7748	7410	7942	7942	7906	7910
2.5	7088	8262	8264	8362	6638	9400	9484	8652	9422	9486	8366	7356	7386	7308	7284
5	6030	9970	10676	10848	10596	10990	11494	12572	11082	11514	12300	6394	6444	6344	6282
	Case 2	**Case 3**	**Case 4S**	**Case 4A**	**Case 4L**	**Case 5S**	**Case 5A**	**Case 5L**	**Case 6S**	**Case 6A**	**Case 6L**	**Case 7**	**Case 8**	**Case 9**	**Case 10**

Table 5.2: Savings in Real and Reactive Power Import at 110kV bus as a function of Embedded Generation

MW gen	Real power import savings (kW)														
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	1032	1024	1074	1130	1414	1072	1132	1480	1066	1142	1484	1004	1002	1008	1036
2.5	2586	2510	2552	2602	3060	2380	2266	2562	2350	2258	2728	2508	2484	2562	2572
5	5132	4804	4642	4392	4478	4184	3486	1868	4068	3454	2356	5014	4958	5062	5122
	Case 2	**Case 3**	**Case 4S**	**Case 4A**	**Case 4L**	**Case 5S**	**Case 5A**	**Case 5L**	**Case 6S**	**Case 6A**	**Case 6L**	**Case 7**	**Case 8**	**Case 9**	**Case 10**

MW gen	Reactive power import savings (kVAr)														
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	522	494	550	594	856	546	594	926	550	592	930	398	398	434	430
2.5	1252	78	76	-22	1702	-1060	-1144	-312	-1082	-1146	-26	984	954	1032	1056
5	2310	-1630	-2336	-2508	-2256	-2650	-3154	-4232	-2742	-3174	-3960	1946	1896	1996	2058
	Case 2	**Case 3**	**Case 4S**	**Case 4A**	**Case 4L**	**Case 5S**	**Case 5A**	**Case 5L**	**Case 6S**	**Case 6A**	**Case 6L**	**Case 7**	**Case 8**	**Case 9**	**Case 10**

Figure 5.3: Real power loss savings from embedded generation

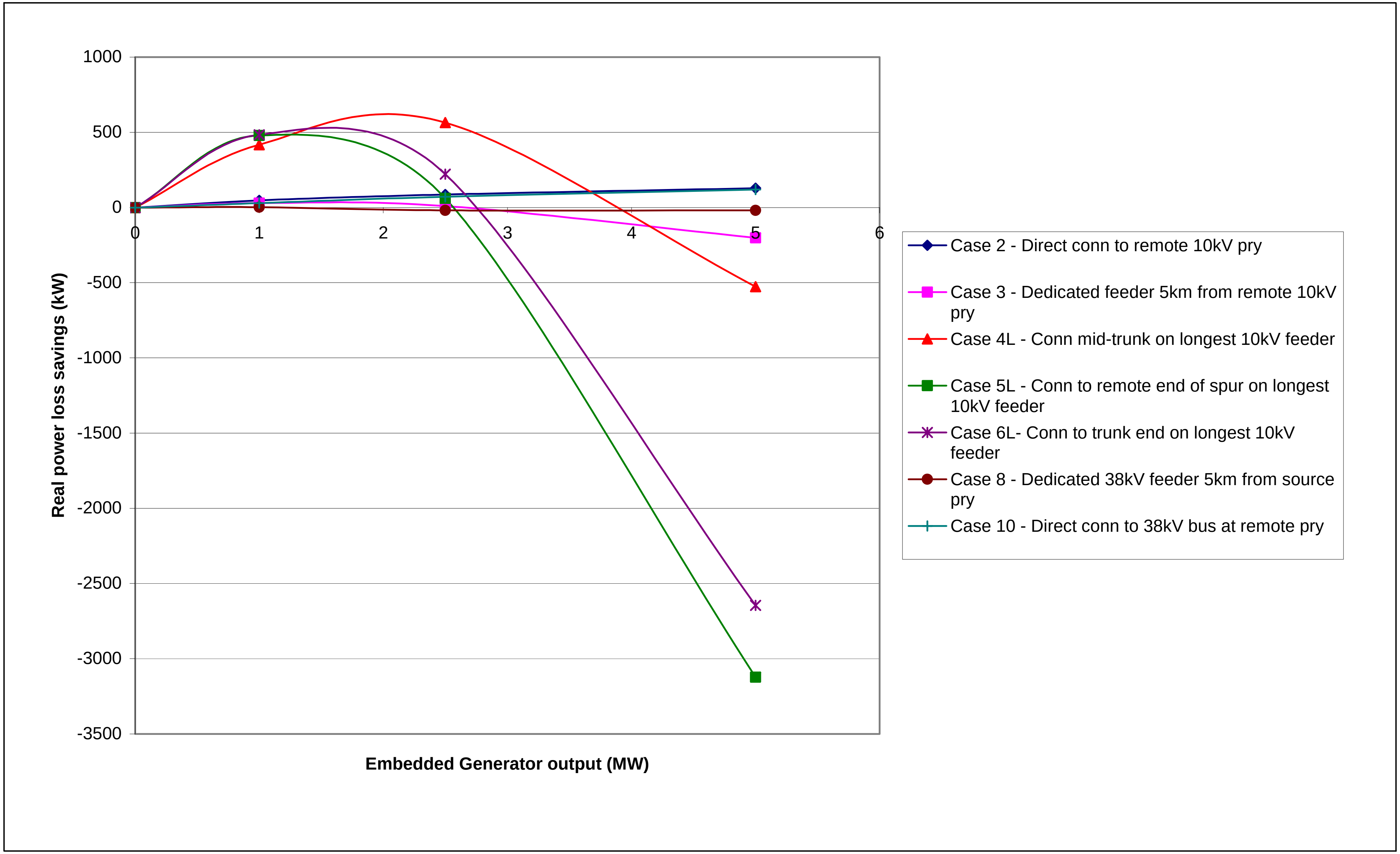


Figure 5.4: Reactive power loss savings from embedded generation

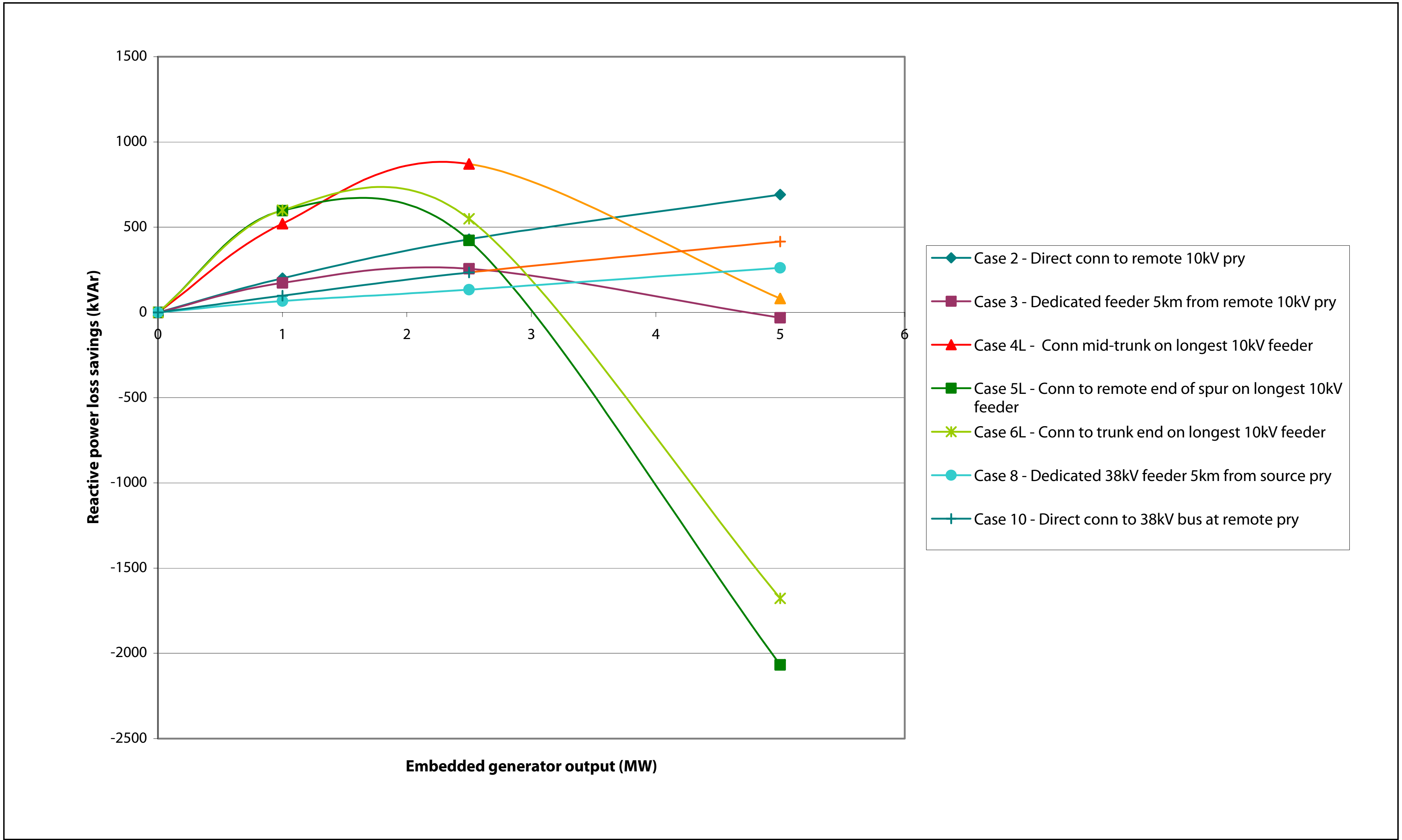


Table 5.3: Real power losses as affected by embedded generation

MW gen	Real power loss (kW)				Real power loss (kW)				Real power loss (kW)				Real power loss (kW)				Real power loss (kW)			
0	17	221	716	**954**	17	221	716	**954**	17	221	716	**954**	17	221	716	**954**	17	221	716	**954**
1	15	180	711	**906**	15	181	728	**924**	15	179	685	**879**	15	177	619	**811**	14	167	356	**537**
2.5	12	136	719	**867**	13	151	780	**944**	13	150	739	**902**	13	150	694	**857**	11	121	257	**389**
5	9	95	722	**826**	12	155	989	**1156**	12	175	1126	**1313**	13	182	1368	**1563**	13	174	1294	**1481**
	110kV loss	38kV loss	10kV loss	Total	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**
	Study 2				Study 3				Study 4S				Study 4A				Study 4L			

MW gen	Real power loss (kW)				Real power loss (kW)				Real power loss (kW)				Real power loss (kW)				Real power loss (kW)			
0	17	221	716	**954**	17	221	716	**954**	17	221	716	**954**	17	221	716	**954**	17	221	716	**954**
1	15	179	686	**880**	15	175	619	**809**	14	164	297	**475**	15	179	686	**880**	15	179	634	**828**
2.5	14	176	915	**1105**	14	179	994	**1187**	13	156	724	**893**	14	175	885	**1074**	14	179	1002	**1195**
5	13	192	1687	**1892**	15	213	2224	**2452**	17	279	3781	**4077**	13	188	1556	**1757**	15	214	2254	**2483**
	110kV loss	38kV loss	10kV loss	Total	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**
	Study 5S				Study 5A				Study 5L				Study 6S				Study 6A			

MW gen	Real power loss (kW)				Real power loss (kW)				Real power loss (kW)				Real power loss (kW)				Real power loss (kW)			
0	17	221	716	**954**	17	221	716	**954**	17	221	716	**954**	17	221	716	**954**	17	221	716	**954**
1	14	164	293	**471**	15	221	714	**950**	15	222	714	**951**	15	203	709	**927**	15	187	722	**924**
2.5	13	148	571	**732**	13	220	710	**943**	13	230	729	**972**	12	184	714	**910**	12	148	722	**882**
5	17	258	3324	**3599**	9	219	706	**934**	9	254	710	**973**	9	165	718	**892**	9	112	713	**834**
	110kV loss	38kV loss	10kV loss	Total	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**
	Study 6L				Study 7				Study 8				Study 9				Study 10			

Table 5.4: Reactive power losses as affected by embedded generation

MW gen	Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)			
0	631	1049	499	**2179**	631	1049	499	**2179**	631	1049	499	**2179**	631	1049	499	**2179**	631	1049	499	**2179**
1	560	922	497	**1979**	562	925	519	**2006**	558	918	482	**1958**	554	911	445	**1910**	539	879	240	**1658**
2.5	470	778	502	**1750**	495	828	600	**1923**	493	825	513	**1831**	493	827	488	**1808**	431	732	145	**1308**
5	331	653	504	**1488**	439	837	935	**2211**	469	895	732	**2096**	485	915	868	**2268**	473	891	733	**2097**
	110kV	38kV	10kV		110kV	38kV	10kV		110kV	38kV	10kV		110kV	38kV	10kV		110kV	38kV	10kV	
	loss	loss	loss	**Total**	loss	loss	loss	**Total**	loss	loss	loss	**Total**	loss	loss	loss	**Total**	loss	loss	loss	**Total**
	Study 2				Study 3				Study 4S				Study 4A				Study 4L			

MW gen	Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)			
0	631	1049	499	**2179**	631	1049	499	**2179**	631	1049	499	**2179**	631	1049	499	**2179**	631	1049	499	**2179**
1	558	919	483	**1960**	553	910	445	**1908**	527	870	185	**1582**	558	918	482	**1958**	553	915	454	**1922**
2.5	535	905	612	**2052**	541	915	658	**2114**	503	844	410	**1757**	533	901	595	**2029**	542	912	662	**2116**
5	508	947	1049	**2504**	548	1008	1353	**2909**	659	1209	2378	**4246**	499	934	974	**2407**	551	1012	1370	**2933**
	110kV	38kV	10kV	**Total**	110kV	38kV	10kV	**Total**	110kV	38kV	10kV	**Total**	110kV	38kV	10kV	**Total**	110kV	38kV	10kV	**Total**
	loss	loss	loss		loss	loss	loss		loss	loss	loss		loss	loss	loss		loss	loss	loss	
	Study 5S				Study 5A				Study 5L				Study 6S				Study 6A			

MW gen	Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)			
0	631	1049	499	**2179**	631	1049	499	**2179**	631	1049	499	**2179**	631	1049	499	**2179**	631	1049	499	**2179**
1	527	870	182	**1579**	565	1048	498	**2111**	565	1049	498	**2112**	564	1025	495	**2084**	563	1014	504	**2081**
2.5	487	820	323	**1630**	474	1045	496	**2015**	475	1062	509	**2046**	470	1006	497	**1973**	469	971	504	**1944**
5	625	1151	2080	**3856**	339	1042	493	**1874**	342	1079	496	**1917**	336	987	501	**1824**	333	932	498	**1763**
	110kV	38kV	10kV	**Total**	110kV	38kV	10kV	**Total**	110kV	38kV	10kV	**Total**	110kV	38kV	10kV	**Total**	110kV	38kV	10kV	**Total**
	loss	loss	loss		loss	loss	loss		loss	loss	loss		loss	loss	loss		loss	loss	loss	
	Study 6L				Study 7				Study 8				Study 9				Study 10			

Table 5.5: Savings in real power losses as affected by embedded generation

MW gen	Real power loss (kW)				Real power loss (kW)				Real power loss (kW)				Real power loss (kW)				Real power loss (kW)			
0	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**
1	2	41	5	**48**	2	40	-12	**30**	2	42	31	**75**	2	44	97	**143**	3	54	360	**417**
2.5	5	85	-3	**87**	4	70	-64	**10**	4	71	-23	**52**	4	71	22	**97**	6	100	459	**565**
5	8	126	-6	**128**	5	66	-273	**-202**	5	46	-410	**-359**	4	39	-652	**-609**	4	47	-578	**-527**
	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**
	Study 2				Study 3				Study 4S				Study 4A				Study 4L			

MW gen	Real power loss (kW)				Real power loss (kW)				Real power loss (kW)				Real power loss (kW)				Real power loss (kW)			
0	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**
1	2	42	30	**74**	2	46	97	**145**	3	57	419	**479**	2	42	30	**74**	2	42	82	**126**
2.5	3	45	-199	**-151**	3	42	-278	**-233**	4	65	-8	**61**	3	46	-169	**-120**	3	42	-286	**-241**
5	4	29	-971	**-938**	2	8	-1508	**-1498**	0	-58	-3065	**-3123**	4	33	-840	**-803**	2	7	-1538	**-1529**
	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**
	Study 5S				Study 5A				Study 5L				Study 6S				Study 6A			

MW gen	Real power loss (kW)				Real power loss (kW)				Real power loss (kW)				Real power loss (kW)				Real power loss (kW)			
0	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**
1	3	57	423	**483**	2	0	2	**4**	2	-1	2	**3**	2	18	7	**27**	2	34	-6	**30**
2.5	4	73	145	**222**	4	1	6	**11**	4	-9	-13	**-18**	5	37	2	**44**	5	73	-6	**72**
5	0	-37	-2608	**-2645**	8	2	10	**20**	8	-33	6	**-19**	8	56	-2	**62**	8	109	3	**120**
	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**
	Study 6L				Study 7				Study 8				Study 9				Study 10			

Table 5.6: Savings in reactive power losses as affected by embedded generation

MW gen	Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)			
0	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**
1	71	127	2	**200**	69	124	-20	**173**	73	131	17	**221**	77	138	54	**269**	92	170	259	**521**
2.5	161	271	-3	**429**	136	221	-101	**256**	138	224	-14	**348**	138	222	11	**371**	200	317	354	**871**
5	300	396	-5	**691**	192	212	-436	**-32**	162	154	-233	**83**	146	134	-369	**-89**	158	158	-234	**82**
	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**
	Study 2				Study 3				Study 4S				Study 4A				Study 4L			

MW gen	Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)			
0	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**
1	73	130	16	**219**	78	139	54	**271**	104	179	314	**597**	73	131	17	**221**	78	134	45	**257**
2.5	96	144	-113	**127**	90	134	-159	**65**	128	205	89	**422**	98	148	-96	**150**	89	137	-163	**63**
5	123	102	-550	**-325**	83	41	-854	**-730**	-28	-160	-1879	**-2067**	132	115	-475	**-228**	80	37	-871	**-754**
	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**
	Study 5S				Study 5A				Study 5L				Study 6S				Study 6A			

MW gen	Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)			
0	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**
1	104	179	317	**600**	66	1	1	**68**	66	0	1	**67**	67	24	4	**95**	68	35	-5	**98**
2.5	144	229	176	**549**	157	4	3	**164**	156	-13	-10	**133**	161	43	2	**206**	162	78	-5	**235**
5	6	-102	-1581	**-1677**	292	7	6	**305**	289	-30	3	**262**	295	62	-2	**355**	298	117	1	**416**
	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**	110kV loss	38kV loss	10kV loss	**Total**
	Study 6L				Study 7				Study 8				Study 9				Study 10			

Table 5.7: Summary of embedded generation effects on 110/38/10 kV rural network voltage

Study Case No.	EG location	Comment on voltage effects
1	Base case (No EG)	Under-voltages on average & longest 10 kV feeders
2	EG connected direct to 10 kV bus at remote primary	Under-voltages on average & longest 10 kV feeders
3	EG 5 km from remote with direct connection to 10 kV bus	Under-voltages on average & longest 10 kV feeders
4	EG connected mid-trunk on outgoing 10 kV feeders	Voltage controlled within limits (i.e. +/- 5% of nominal) with generation > 1 MW to 5 MW. At 2.5 MW and above no longer a requirement for booster transformers.
5	EG connected at end of spur on outgoing 10 kV feeder	Voltage controlled within limits with generation of 2.5 MW or less. Voltage constraints prohibit connection of 5MW generator at this location.
6	EG connected at end of trunk on outgoing 10 kV feeder	Voltage controlled within limits with generation of 2.5 MW or less. With the 1 MW generator only one booster is required and with the 2.5 MW generator there is no requirement for booster transformers. Voltage constraints prohibit connection of 5MW generator at this location.
7	EG direct connection to source 38 kV bus	Under-voltages on average & longest 10 kV feeders
8	EG 5 km from source with direct connection to 38 kV bus	Under-voltages on average & longest 10 kV feeders
9	EG connected midway along 38 kV feeder between source substation & remote primary	Under-voltages on average & longest 10 kV feeders
10	EG connected direct to 38 kV bus at remote primary	Under-voltages on average & longest 10 kV feeders

Table 5.8: Summary of embedded generation effects on 110/38/10 kV rural network circuit loadings (i.e. utilisation).

Study Case No.	EG location	Comment on equipment utilisation
1	Base case (No EG)	No overloads
2	EG connected direct to 10 kV bus at remote primary	No overloads
3	EG 5 km from source with direct connection to 38 kV bus	No overloads
4	EG connected mid-trunk on outgoing 10 kV feeders	Connection of a 5 MW generator produces significant overloads on the shortest and average length feeders and a marginal overload on the longest feeder. The smaller generators do not produce overloads.
5	EG connected at end of spur on outgoing 10 kV feeder	Connection of a 5 MW generator produces significant overloads on the shortest and average length feeders and a marginal overload on the longest feeder. The smaller generators do not produce overloads. However, voltage constraints prohibit connection of 5MW generator at this location in any case.
6	EG connected at end of trunk on outgoing 10 kV feeder	Connection of a 5 MW generator produces significant overloads on the shortest and average length feeders and a marginal overload on the longest feeder. The smaller generators do not produce overloads. However, voltage constraints prohibit connection of 5MW generator at this location in any case.
7	EG direct connection to source 38 kV bus	No overloads
8	EG 5 km from source with direct connection to 38 kV bus	No overloads
9	EG connected midway along 38 kV feeder between source substation & remote primary	No overloads
10	EG connected direct to 38 kV bus at remote primary	No overloads

Table 5.9 summarises the effect of increasing amounts of embedded generation on short circuit levels. The contributions were based on those from a maximum generator size of 5MW. The table shows that in rural areas the increase in fault level due to generation is relatively small, with the contribution from the generators to fault level at 110 kV, 38 kV and 10 kV estimated at 0.1 kA, 0.4 kA and 1.7 kA respectively. The additional fault current does not therefore raise the fault level above the typical rating of switchgear installed at these voltages, although there are some 12 kA rated re-closers in services against which an estimated maximum fault level of 10.6 kA is possible with the contribution from embedded generation taken into account.

Table 5.10 summarises in graphic form the results of the analysis of the 110/38/10 kV network, where those cases yielding benefits can be identified at a glance.

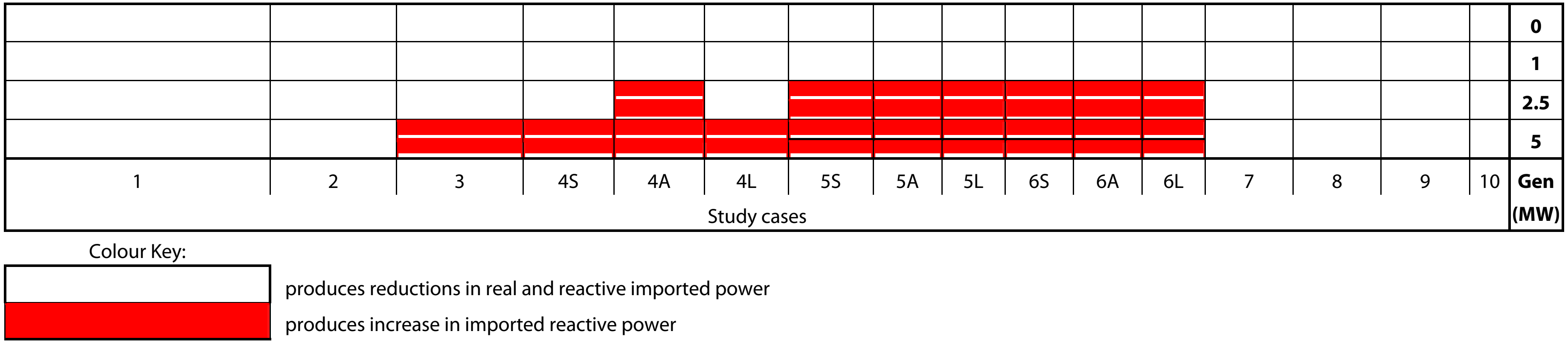
Table 5.9: Summary of effect of embedded generation on short circuit levels in rural area

Type of switchgear	Voltage (kV)	Switchgear rating (kA)	Maximum fault level (kA)	Maximum generator fault contribution (A)	Maximum fault level with gen connected (kA)	Comment
Main bus circuit breaker	110	20	10.0	127	10.1	Within rating
Main bus circuit breaker	38	20	10.1	387	10.5	Within rating
Main bus circuit breaker	20	16	6.2	845	7.0	Within rating
Re-closer	20	12.5	6.2	845	7.0	Within rating
Expulsion fuse	20	12	6.2	845	7.0	Within rating
Load break switch	20	16	6.2	845	7.0	Within rating
Main bus circuit breaker	10	16	8.9	1747	10.6	Within rating
Re-closer	10	12	8.9	1747	10.6	Within rating, but approaching marginal
Expulsion fuse	10	16	8.9	1747	10.6	Within rating
Load break switch	10	16	8.9	1747	10.6	Within rating

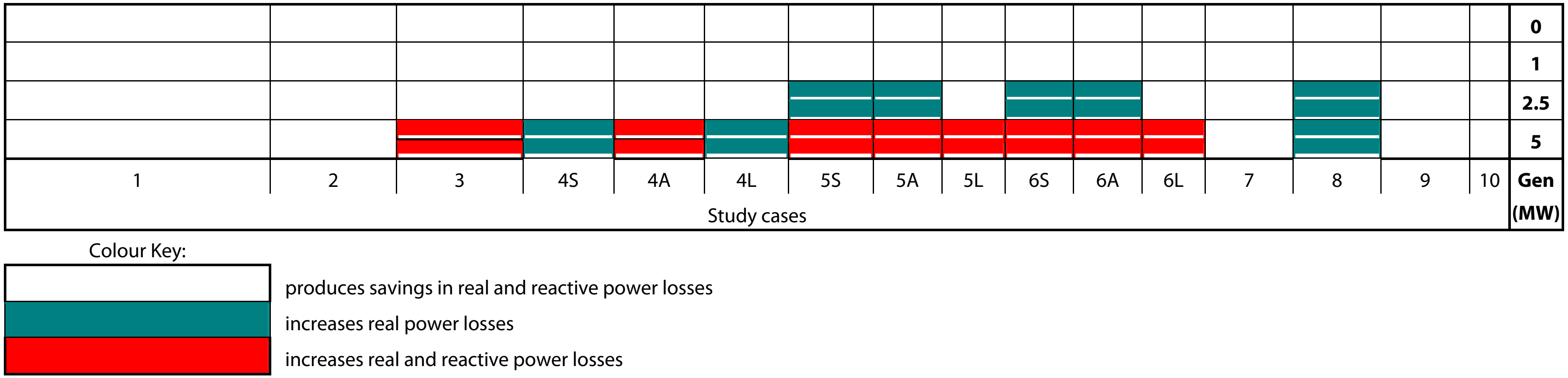
Note: The fault contribution is based on that from a 5 MW generator.

Table 5.10: Summary of costs and benefits from embedded generation on rural 10kV networks

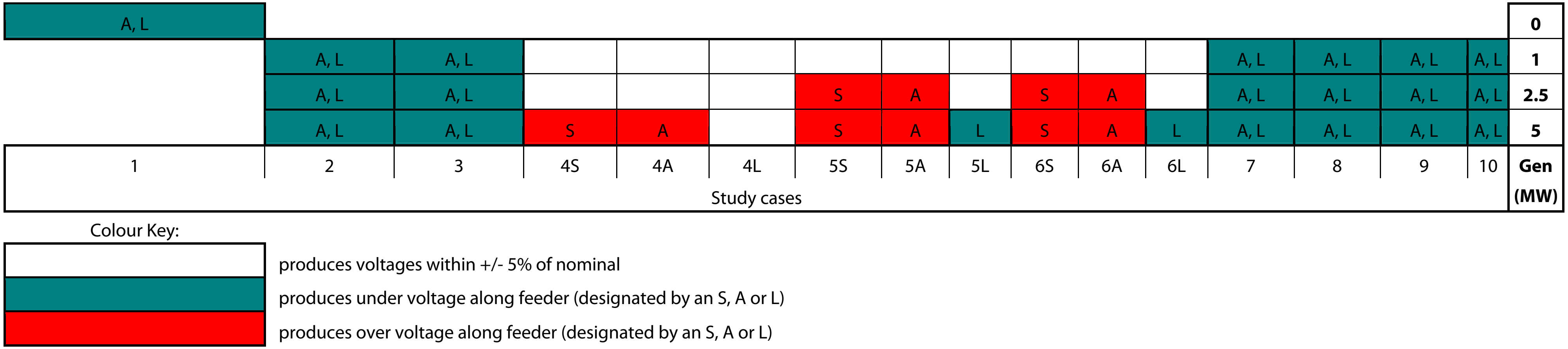
a) Cases that produce a reduction in imported power



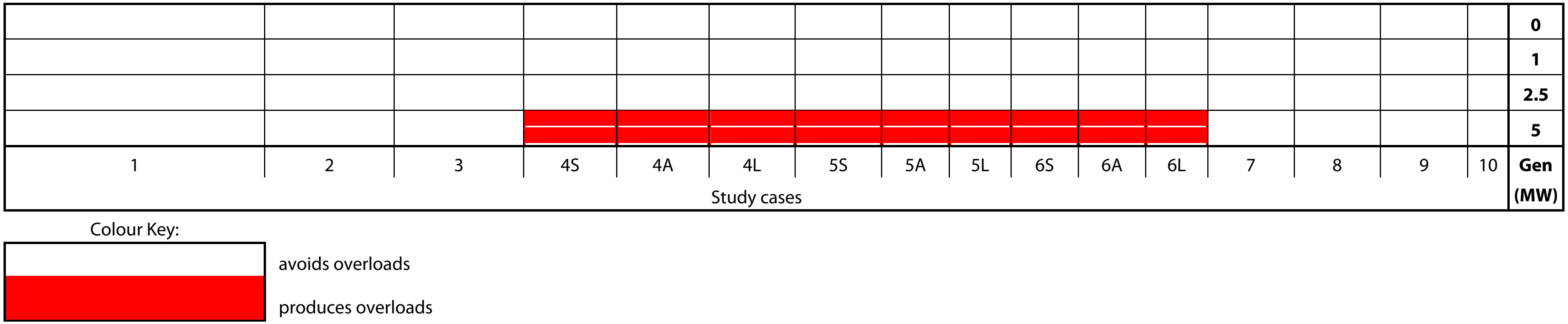
b) Cases that produce a reduction in power losses



c) Cases that produce under voltages and over voltages



d) Cases that produce overloads



e) Cases that produce fault levels in excess of switchgear rating

With the present rural area fault levels and the level of embedded generation, switchgear ratings should not be at risk due to connection of new generation.

5.3.2 Effect on costs and benefits accrued over 10 year period

In sub-section 5.3.1 we have examined in detail the technical performance of the representative rural network with embedded generation connected, whilst supplying the current levels of peak demand. In rural areas the growth in demand in forecast to average between 3 and 4 percent per annum over the next few years. In this sub-section we examine the impact on system performance of a sustained annual growth rate of 5 percent over a 10-year period through load flow studies for year '5' and year '10', having already presented the results of year '0' in sub-section 5.3.1.

To illustrate the effects of load growth on the costs and benefits associated with embedded generation, we have confined our analysis to a single generator size, i.e. 2.5 MW. Voltage constraints identified with the 5 MW generator in the previous sub-section encouraged us to study a mid-range generator size to avoid the possibility of further constraints being encountered which could limit the determination of costs and benefits.

Table 5.11 shows the effect of embedded generation on imported real and reactive power at through the 110 kV bus at the source 110/38 kV source primary at years 0, 5 and 10. In Table 5.11 for cases 4, 5 and 6 only the results for generation connected to the longest feeder are presented. Figures 5.5 and 5.6 show the results graphically in terms of the reduction in imported power in comparison with the base case (i.e. no embedded generation). It is evident from Figure 5.5 that when the generation is connected to the 10 kV feeders, there is a significant reduction in imported real power over the period. This can be attributed to the fact that as load grows along the feeder, the power delivered by the 2.5 MW generator that at full output would have been a major source of power loss, is offset and the overall effect is to significantly reduce the real power losses. This is evident later in Figure 5.7.

Table 5.12 shows the effect of embedded generation on real and reactive power losses respectively and Figures 5.7 and 5.8 show the corresponding savings in real and reactive power losses compared with the base case (i.e. no embedded generation) in years 0, 5 and 10 over the period.

The load flow studies detailed in Appendix C show a major deterioration in voltage conditions along the 10 kV feeders by year 5 in all cases except those to which generation is connected (i.e. cases 4, 5 and 6). It is evident from the studies that significant voltage support will be required on these feeders before year 5 and the studies show that this can be provided by embedded generation providing it is reliable and available to cope with higher load conditions. The benefits from embedded generation can in this case be equated to the savings in the cost of providing voltage support or a re-configuration of the network to transfer load to other circuits.

Similarly the studies show that embedded generation connected to the outgoing 10 kV feeders will avoid an overload on the longest 10 kV feeder by year 5 and marginal overloading on the shortest and average length feeders by year 10. The benefits from embedded generation can in this case be equated to the savings in the cost of system reinforcement.

Figure 5.5: Reductions in imported real power as affected by embedded generation over 10 year period

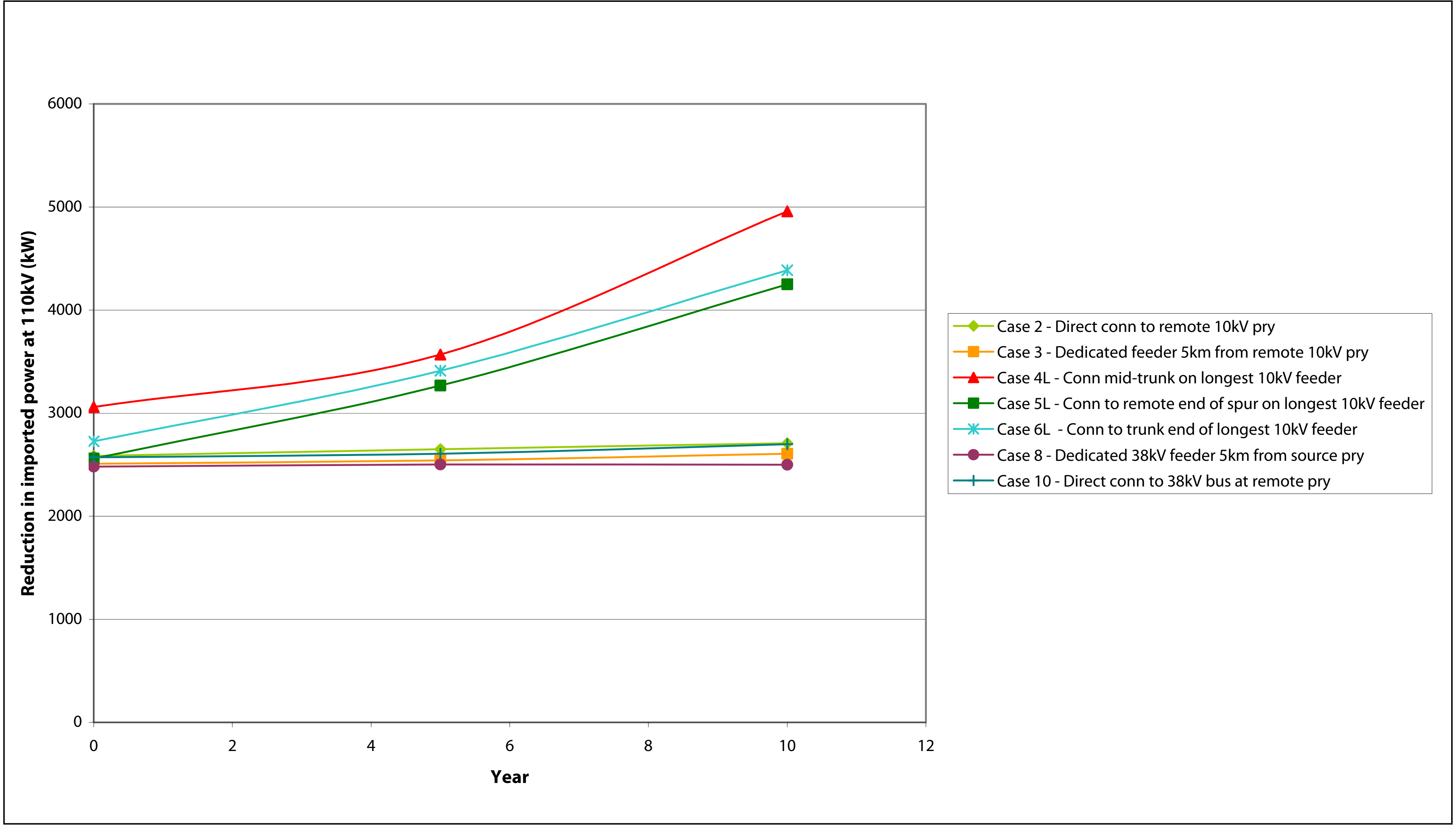


Figure 5.6: Reductions in imported reactive power as affected by embedded generation over 10 year period

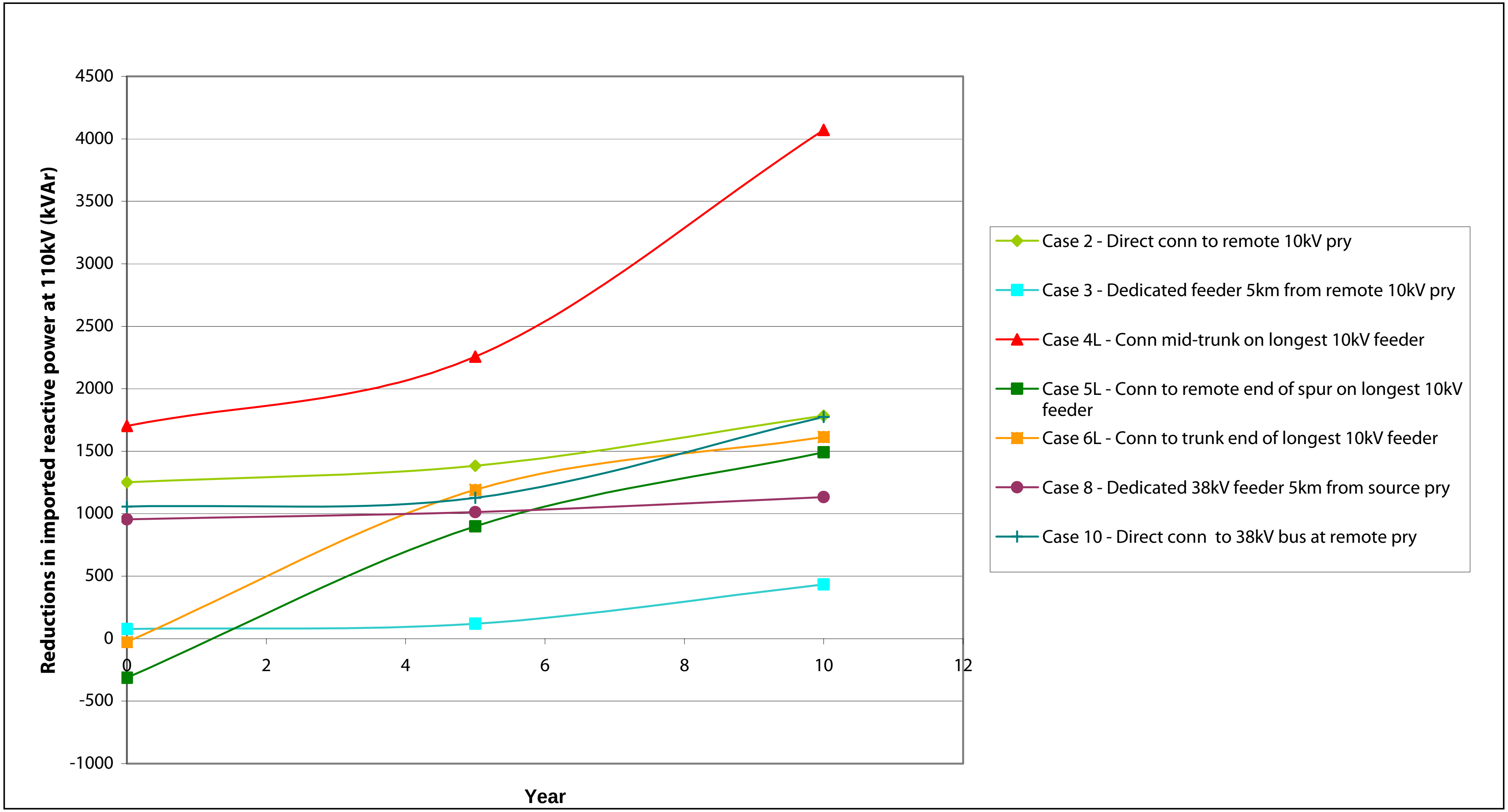


Table 5.11: Effect of Embedded Generator Location on Real and Reactive Power Import on HV Side of 110/38 KV Transformer at Grid Substation Supplying Rural 10 KV Network over 10 Year Period

Embedded generator output = 2.5 MW in all cases

Annual growth rate = 4%

	Rural 110/38/10 kV network Power flow on HV side of 110/38 kV transformer as a function of Embedded Generator location in years 0, 5 and 10														
Year	**0**	**5**	**10**	**0**	**5**	**10**	**0**	**5**	**10**	**0**	**5**	**10**	**0**	**5**	**10**
Generator node	-	-	-	200	200	200	299	299	299	266	266	266	272A	272A	272A
Power import (kW)	**18298**	**22780**	**29174**	**15714**	**20130**	**26466**	**15790**	**20240**	**26568**	**15240**	**19212**	**24216**	**15738**	**19514**	**24924**
Reactive Power import (kVAr)	**8340**	**11032**	**15722**	**7088**	**9648**	**13938**	**8262**	**10912**	**15288**	**6638**	**8776**	**11650**	**8652**	**10134**	**14230**
	Study 1 - Base case			**Study 2 - Direct connection of gen to remote 10kV Pry**			**Study 3 - Dedicated gen. feeder 5km from remote 10kV Pry**			**Study 4 - Generator connected mid-trunk**			**Study 5 - Gen. connected to remote end of mid-point spur**		

	Rural 110/38/10 kV network Power flow on HV side of 110/38 kV transformer as a function of Embedded Generator location in years 0, 5 and 10														
Year	**0**	**5**	**10**	**0**	**5**	**10**	**0**	**5**	**10**	**0**	**5**	**10**	**0**	**5**	**10**
Generator node	273	273	273	3100	3100	3100	3101	3101	3101	3102	3102	3102	100	100	100
Power import (kW)	**15572**	**19370**	**24788**	**15792**	**20270**	**26644**	**15816**	**20278**	**26674**	**15738**	**20208**	**26568**	**15728**	**20174**	**26476**
Reactive Power import (kVAr)	**8366**	**9840**	**14108**	**7356**	**10004**	**14564**	**7386**	**10020**	**14588**	**7308**	**9946**	**14438**	**7284**	**9904**	**13948**
	Study 6 - Gen. connected at remote end of trunk			**Study 7 - Direct connection of generator to 38kV bus at 110/38kV grid station**			**Study 8 - Gen connected via dedicated 38kV feeder 5km from 110/38kV source pry**			**Study 9 - Generator connected midway along 38kV circuit to remote pry**			**Study 10 - Gen. connected to 38kV bus at remote pry**		

Figure 5.7: Savings in real power losses over 10-year period due to embedded generation

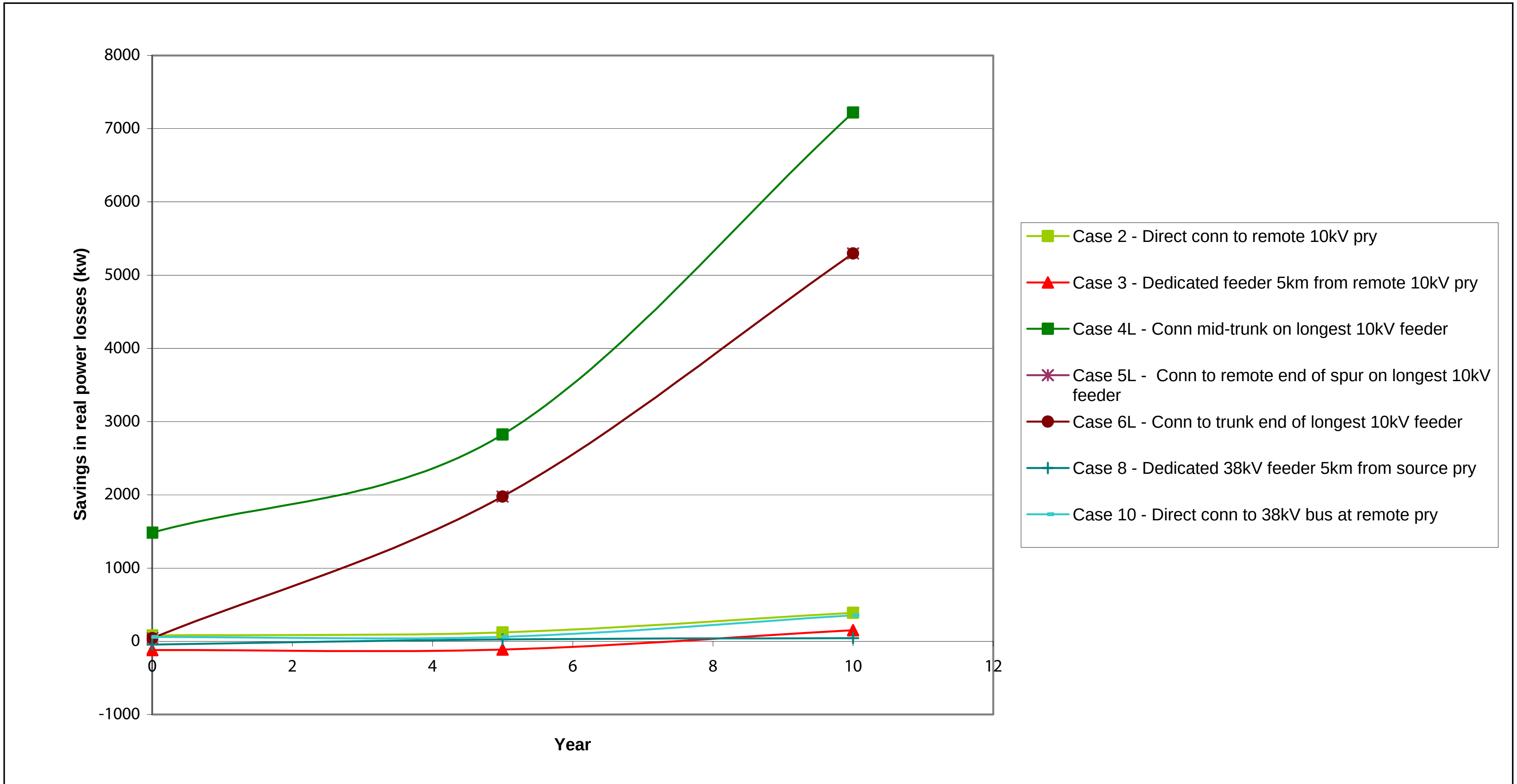


Figure 5.8: Savings in reactive power losses over 10-year period due to embedded generation

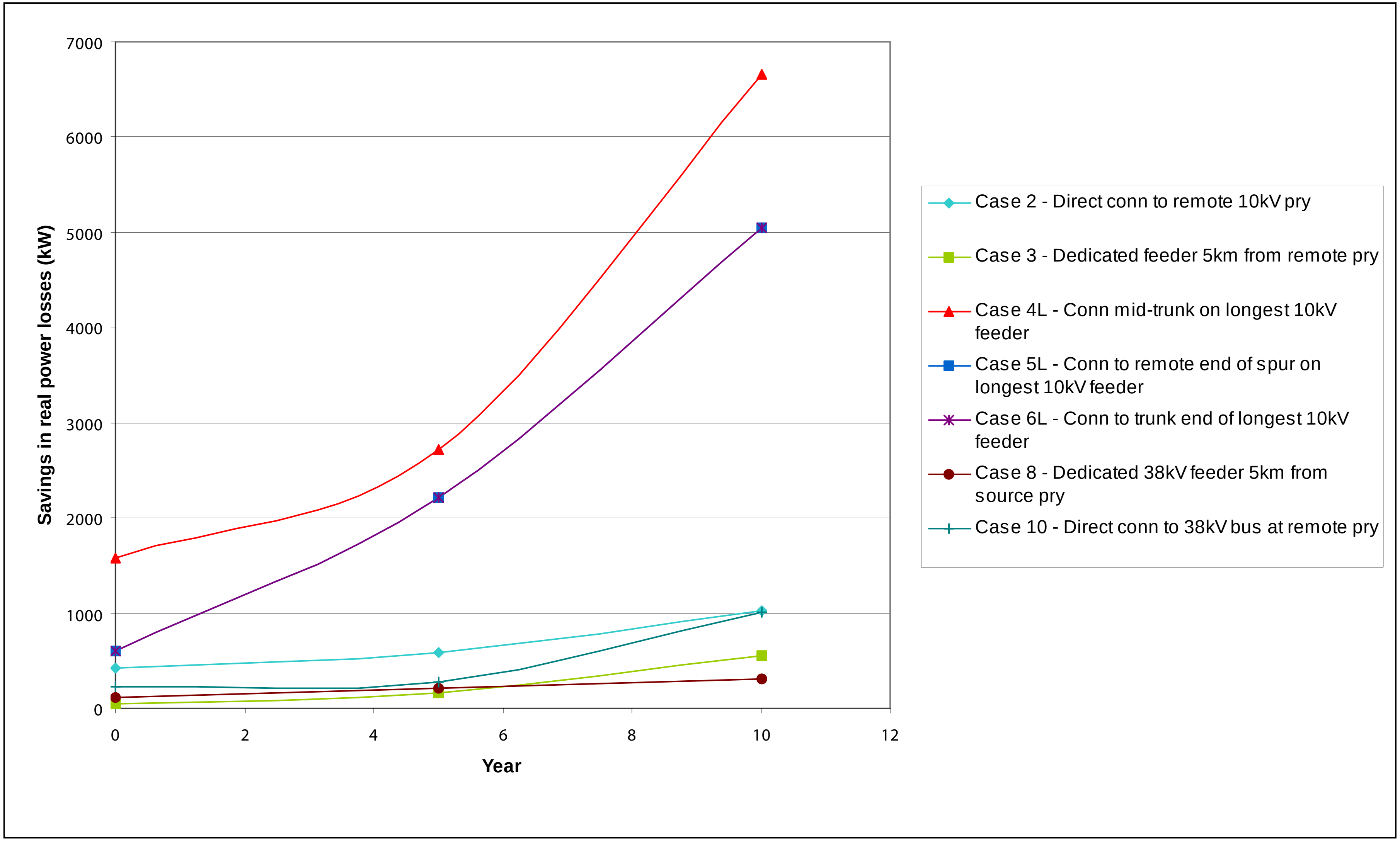


Table 5.12: Effect of Embedded Generator Location on Real Power Losses in Rural 110/38/10 KV Network over 10 Year Period

Embedded generator output = 2.5 MW in all cases

Annual growth rate = 4%

	Rural 110/38/10 kV network Power losses (kW) as a function of Embedded Generator location in years 0, 5 and 10														
Year	**0**	**5**	**10**	**0**	**5**	**10**	**0**	**5**	**10**	**0**	**5**	**10**	**0**	**5**	**10**
Generator node	-	-	-	200	200	200	299	299	299	266	266	266	272A	272A	272A
110kV power loss (kW)	**17**	**26**	**45**	**12**	**21**	**36**	**13**	**22**	**38**	**11**	**18**	**29**	**13**	**20**	**33**
38kV power loss (kW)	**221**	**360**	**669**	**136**	**239**	**468**	**151**	**264**	**514**	**121**	**201**	**332**	**148**	**219**	**403**
10kV power loss (kW)	**2146**	**3808**	**8890**	**2156**	**3813**	**8710**	**2340**	**4022**	**8899**	**770**	**1151**	**2021**	**1712**	**1583**	**3479**
Total power loss (kW)	**2384**	**4194**	**9604**	**2304**	**4072**	**9215**	**2504**	**4307**	**9452**	**903**	**1370**	**2383**	**2342**	**2217**	**4307**
	Study 1 - Base case			**Study 2 - Direct connection of gen to remote 10kV Pry**			**Study 3 - Dedicated gen. feeder 5km from remote 10kV Pry**			**Study 4 - Generator connected mid-trunk**			**Study 5 - Gen. connected to remote end of mid-point spur**		

	Rural 110/38/10 kV network Power losses (kW) as a function of Embedded Generator location in years 0, 5 and 10														
Year	**0**	**5**	**10**	**0**	**5**	**10**	**0**	**5**	**10**	**0**	**5**	**10**	**0**	**5**	**10**
Generator node	273	273	273	3100	3100	3100	3101	3101	3101	3102	3102	3102	100	100	100
110kV power loss (kW)	**13**	**20**	**34**	**13**	**21**	**38**	**13**	**21**	**38**	**12**	**21**	**37**	**12**	**21**	**37**
38kV power loss (kW)	**156**	**228**	**412**	**220**	**359**	**665**	**230**	**368**	**674**	**184**	**308**	**583**	**148**	**257**	**469**
10kV power loss (kW)	**2173**	**1969**	**3861**	**2129**	**3778**	**8889**	**2186**	**3777**	**8850**	**2141**	**3814**	**8714**	**2165**	**3857**	**8742**
Total power loss (kW)	**2342**	**2217**	**4307**	**2361**	**4158**	**9592**	**2429**	**4166**	**9562**	**2338**	**4143**	**9334**	**2325**	**4135**	**9248**
	Study 6 - Gen. connected at remote end of trunk			**Study 7 - Direct connection of generator to 38kV bus at 110/38kV grid station**			**Study 8 - Gen connected via dedicated 38kV feeder 5km from 110/38kV source pry**			**Study 9 - Generator connected midway along 38kV circuit to remote pry**			**Study 10 - Gen. connected to 38kV bus at remote pry**		

Table 5.12 (continued): Effect of Embedded Generator Location on Reactive Power Losses In Rural 110/38/10 KV Network over 10 Year Period

Embedded generator output = 2.5 MW in all cases

Annual growth rate = 4%

	Rural 110/38/10 kV network Reactive power losses (kVAr) as a function of Embedded Generator location in years 0, 5 and 10														
Year	**0**	**5**	**10**	**0**	**5**	**10**	**0**	**5**	**10**	**0**	**5**	**10**	**0**	**5**	**10**
Generator node	-	-	-	200	200	200	299	299	299	266	266	266	272A	272A	272A
110kV power loss (kVAr)	**631**	**999**	**1691**	**470**	**777**	**1378**	**495**	**825**	**1447**	**431**	**696**	**1112**	**503**	**754**	**1269**
38kV power loss (kVAr)	**1049**	**1634**	**2812**	**778**	**1272**	**2211**	**828**	**1337**	**2325**	**732**	**1154**	**1804**	**844**	**1233**	**2039**
10kV power loss (kVAr)	**1498**	**2686**	**6379**	**1506**	**2684**	**6262**	**1801**	**3001**	**6551**	**436**	**745**	**1303**	**1229**	**1113**	**2529**
Total reactive power loss (kVAr)	**3178**	**5319**	**10882**	**2754**	**4734**	**9851**	**3124**	**5163**	**10323**	**1599**	**2594**	**4219**	**2576**	**3101**	**5837**
	Study 1 - Base case			**Study 2 - Direct connection of gen to remote 10kV Pry**			**Study 3 - Dedicated gen. feeder 5km from remote 10kV Pry**			**Study 4 - Generator connected mid-trunk**			**Study 5 - Gen. connected to remote end of mid-point spur**		

	Rural 110/38/10 kV network Reactive power losses (kVAr) as a function of Embedded Generator location in years 0, 5 and 10														
Year	**0**	**5**	**10**	**0**	**5**	**10**	**0**	**5**	**10**	**0**	**5**	**10**	**0**	**5**	**10**
Generator node	273	273	273	3100	3100	3100	3101	3101	3101	3102	3102	3102	100	100	100
110kV power loss (kVAr)	**487**	**736**	**1253**	**474**	**797**	**1420**	**475**	**798**	**1424**	**470**	**791**	**1408**	**469**	**788**	**1379**
38kV power loss (kVAr)	**820**	**1210**	**2012**	**1045**	**1634**	**2781**	**1062**	**1649**	**2801**	**1006**	**1580**	**2690**	**971**	**1530**	**2213**
10kV power loss (kVAr)	**969**	**896**	**2285**	**1487**	**2666**	**6359**	**1526**	**2666**	**6350**	**1492**	**2685**	**6252**	**1511**	**2718**	**6283**
Total reactive power loss (kVAr)	**2576**	**3101**	**5837**	**3006**	**5097**	**10560**	**3063**	**5112**	**10575**	**2968**	**5056**	**10350**	**2951**	**5035**	**9875**
	Study 6 - Gen. connected at remote end of trunk			**Study 7 - Direct connection of generator to 38kV bus at 110/38kV grid station**			**Study 8 - Gen connected via dedicated 38kV feeder 5km from 110/38kV source pry**			**Study 9 - Generator connected midway along 38kV circuit to remote pry**			**Study 10 - Gen. connected to 38kV bus at remote pry**		

5.3.3 Analysis of 110/38/20 kV rural networks

Load flow and short circuit studies were undertaken for the representative 110/38/20 kV rural network similar to those presented in Section 5.3 for the representative 110/38/10 kV rural network. The studies cover the same levels of embedded generation located at similar locations addressing the same issues, such as the effect on power imports, power losses, voltage regulation, overloads and fault levels. The results of the studies are presented in the following set of tables:

Table 5.13 identifies the real and reactive power losses for the base case (i.e. with no embedded generation) and for increasing levels of embedded generation up to 5 MW, with the generation located at points on the network consistent with those studied in Section 5.3. The losses are converted into real and reactive power loss savings compared with base case losses and the results are presented in Table 5.14, from which it is evident that the benefits obtained from power loss savings resulting from embedded generation on the network are much lower with the 20 kV rural network than with the rural 10 kV network.

Table 5.15 summarises the effect of embedded generation on the network voltage profile. The table shows that in all but two cases (i.e. study cases 5 and 6) the voltage across the network is controlled within +/-5 percent of nominal. In case 5, with the generator connected at the end of a spur, voltage constraints prevent the connection of generation of 2.5 MW and above. In case 6, with the generator connected at the end of the trunk of the 10 kV feeder, voltage constraints prevent connection of the 5MW generator. The voltage constraints in each case are associated with over voltages.

Table 5.16 confirms that in the base case and in the other cases with embedded generation connected to the system there are no overloads on the representative network.

The results of short circuit analysis presented previously in Table 5.9 show that fault levels on the rural 110 kV, 38 kV and 20 kV networks are increased only marginally by the presence of embedded generation and do not impinge on the spare fault capacity.

The details of study results for the 110/38/20 kV rural network are presented in Appendix C.

Table 5.13: Real power losses on the representative 110/38/20 kV rural network as affected by embedded generation

MW gen	Study 2: Real power loss (kW)				Study 3: Real power loss (kW)				Study 4S: Real power loss (kW)				Study 4A: Real power loss (kW)				Study 4L: Real power loss (kW)			
	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total
0	12	156	243	**411**	12	156	243	**411**	12	156	243	**411**	12	156	243	**411**	12	156	243	**411**
1	11	127	243	**381**	11	128	246	**385**	11	127	237	**374**	11	125	228	**364**	10	118	225	**353**
2.5	8	96	243	**348**	9	107	261	**377**	9	106	261	**376**	9	106	235	**350**	8	86	227	**321**
5	6	67	243	**317**	8	110	313	**431**	8	124	409	**541**	9	129	314	**452**	9	123	299	**432**

MW gen	Study 5S: Real power loss (kW)				Study 5A: Real power loss (kW)				Study 5L: Real power loss (kW)				Study 6S: Real power loss (kW)				Study 6A: Real power loss (kW)			
	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total
0	12	156	243	**411**	12	156	243	**411**	12	156	243	**411**	12	156	243	**411**	12	156	243	**411**
1	11	127	241	**379**	11	124	227	**361**	10	116	227	**353**	11	127	240	**378**	11	127	221	**358**
2.5	10	124	350	**484**	10	127	359	**495**	9	110	426	**545**	10	124	330	**464**	10	127	337	**473**
5	9	136	739	**884**	11	151	827	**988**	12	197	1099	**1308**	9	133	714	**856**	11	151	842	**1004**

MW gen	Study 6L: Real power loss (kW)				Study 7: Real power loss (kW)				Study 8: Real power loss (kW)				Study 9: Real power loss (kW)				Study 10: Real power loss (kW)			
	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total
0	12	156	243	**411**	12	156	243	**411**	12	156	243	**411**	12	156	243	**411**	12	156	243	**411**
1	10	116	212	**338**	11	156	242	**409**	11	157	242	**410**	11	144	240	**395**	11	132	245	**388**
2.5	9	105	333	**447**	9	156	241	**406**	9	163	247	**419**	8	130	242	**381**	8	105	245	**358**
5	12	182	881	**1075**	6	155	239	**401**	6	180	241	**427**	6	117	244	**367**	6	79	242	**327**

Table 5.13 (continued): Reactive power losses on the representative 110/38/20 kV rural network as affected by embedded generation

MW gen	Study 2: Reactive power loss (kVAr)				Study 3: Reactive power loss (kVAr)				Study 4S: Reactive power loss (kVAr)				Study 4A: Reactive power loss (kVAr)				Study 4L: Reactive power loss (kVAr)			
	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total
0	446	742	139	**1327**	446	742	139	**1327**	446	742	139	**1327**	446	742	139	**1327**	446	742	139	**1327**
1	396	652	139	**1187**	397	654	144	**1195**	395	649	136	**1179**	392	644	132	**1168**	381	621	130	**1133**
2.5	332	550	138	**1020**	350	585	166	**1102**	349	583	148	**1080**	349	585	133	**1067**	305	518	129	**952**
5	234	462	137	**833**	310	592	249	**1151**	332	633	231	**1195**	343	647	177	**1167**	334	630	169	**1133**

MW gen	Study 5S: Reactive power loss (kVAr)				Study 5A: Reactive power loss (kVAr)				Study 5L: Reactive power loss (kVAr)				Study 6S: Reactive power loss (kVAr)				Study 6A: Reactive power loss (kVAr)			
	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total
0	446	742	139	**1327**	446	742	139	**1327**	446	742	139	**1327**	446	742	139	**1327**	446	742	139	**1327**
1	395	650	137	**1181**	391	643	128	**1163**	373	615	125	**1113**	395	649	138	**1182**	391	647	127	**1165**
2.5	378	640	185	**1203**	382	647	182	**1211**	356	597	200	**1152**	377	637	188	**1202**	383	645	192	**1220**
5	359	670	366	**1395**	387	713	384	**1484**	466	855	464	**1785**	353	660	403	**1416**	390	715	478	**1583**

MW gen	Study 6L: Reactive power loss (kVAr)				Study 7: Reactive power loss (kVAr)				Study 8: Reactive power loss (kVAr)				Study 9: Reactive power loss (kVAr)				Study 10: Reactive power loss (kVAr)			
	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total
0	446	742	139	**1327**	446	742	139	**1327**	446	742	139	**1327**	446	742	139	**1327**	446	742	139	**1327**
1	373	615	122	**1110**	399	741	139	**1279**	399	742	139	**1280**	399	725	138	**1262**	398	717	141	**1256**
2.5	344	580	190	**1114**	335	739	138	**1212**	336	751	142	**1229**	332	711	139	**1182**	332	686	141	**1159**
5	442	814	491	**1746**	240	737	138	**1114**	242	763	138	**1143**	238	698	140	**1075**	235	659	139	**1033**

Table 5.14: Saving in real power losses on representative 110/38/20 kV rural network as affected by embedded generation

MW gen	Study 2				Study 3				Study 4S				Study 4A				Study 4L			
	Real power loss (kW)				Real power loss (kW)				Real power loss (kW)				Real power loss (kW)				Real power loss (kW)			
	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total
0	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**
1	1	29	-1	**30**	1	28	-4	**26**	1	30	6	**37**	1	31	14	**47**	2	38	17	**58**
2.5	4	60	0	**63**	3	49	-18	**34**	3	50	-18	**35**	3	50	8	**61**	4	71	15	**90**
5	6	89	0	**94**	4	47	-70	**-20**	4	33	-166	**-130**	3	28	-71	**-41**	3	33	-57	**-20**

MW gen	Study 5S				Study 5A				Study 5L				Study 6S				Study 6A			
	Real power loss (kW)				Real power loss (kW)				Real power loss (kW)				Real power loss (kW)				Real power loss (kW)			
	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total
0	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**
1	1	30	1	**32**	1	33	16	**50**	2	40	15	**58**	1	30	2	**33**	1	30	22	**53**
2.5	2	32	-107	**-73**	2	30	-116	**-84**	3	46	-183	**-134**	2	33	-87	**-52**	2	30	-94	**-62**
5	3	21	-496	**-473**	1	6	-584	**-577**	0	-41	-856	**-897**	3	23	-471	**-445**	1	5	-599	**-592**

MW gen	Study 6L				Study 7				Study 8				Study 9				Study 10			
	Real power loss (kW)				Real power loss (kW)				Real power loss (kW)				Real power loss (kW)				Real power loss (kW)			
	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total	110kV loss	38kV loss	20kV loss	Total
0	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**
1	2	40	31	**73**	1	0	1	**2**	1	-1	1	**1**	1	13	2	**17**	1	24	-2	**23**
2.5	3	52	-90	**-36**	3	1	2	**6**	3	-6	-4	**-8**	4	26	1	**30**	4	52	-2	**53**
5	0	-26	-638	**-664**	6	1	3	**10**	6	-23	2	**-16**	6	40	-1	**45**	6	77	1	**84**

Table 5.14 (continued): Saving in reactive power losses on representative 110/38/20 kV rural network as affected by embedded generation

MW gen	Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)			
0	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**
1	50	90	0	**140**	49	88	-5	**132**	52	93	3	**148**	54	98	7	**159**	65	120	9	**195**
2.5	114	192	2	**307**	96	156	-27	**225**	98	158	-9	**247**	98	157	6	**261**	141	224	10	**375**
5	212	280	2	**494**	136	150	-109	**176**	115	109	-91	**132**	103	95	-38	**160**	112	112	-29	**194**
	110kV loss	**38kV loss**	**20kV loss**	**Total**	**110kV loss**	**38kV loss**	**20kV loss**	**Total**	**110kV loss**	**38kV loss**	**20kV loss**	**Total**	**110kV loss**	**38kV loss**	**20kV loss**	**Total**	**110kV loss**	**38kV loss**	**20kV loss**	**Total**
	Study 2				**Study 3**				**Study 4S**				**Study 4A**				**Study 4L**			

MW gen	Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)			
0	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**
1	52	92	2	**146**	55	98	11	**165**	74	127	14	**214**	52	93	1	**145**	55	95	12	**162**
2.5	68	102	-46	**124**	64	95	-42	**116**	90	145	-61	**175**	69	105	-48	**126**	63	97	-52	**107**
5	87	72	-227	**-68**	59	29	-244	**-157**	-20	-113	-325	**-458**	93	81	-264	**-89**	57	26	-338	**-256**
	110kV loss	**38kV loss**	**20kV loss**	**Total**	**110kV loss**	**38kV loss**	**20kV loss**	**Total**	**110kV loss**	**38kV loss**	**20kV loss**	**Total**	**110kV loss**	**38kV loss**	**20kV loss**	**Total**	**110kV loss**	**38kV loss**	**20kV loss**	**Total**
	Study 5S				**Study 5A**				**Study 5L**				**Study 6S**				**Study 6A**			

MW gen	Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)				Reactive power loss (kVAr)			
0	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**	0	0	0	**0**
1	74	127	17	**217**	47	1	0	**48**	47	0	0	**47**	47	17	1	**65**	48	25	-1	**71**
2.5	102	162	-50	**213**	111	3	1	**115**	110	-9	-3	**98**	114	30	1	**145**	115	55	-1	**168**
5	4	-72	-351	**-419**	206	5	2	**213**	204	-21	1	**184**	209	44	-1	**252**	211	83	0	**294**
	110kV loss	**38kV loss**	**20kV loss**	**Total**	**110kV loss**	**38kV loss**	**20kV loss**	**Total**	**110kV loss**	**38kV loss**	**20kV loss**	**Total**	**110kV loss**	**38kV loss**	**20kV loss**	**Total**	**110kV loss**	**38kV loss**	**20kV loss**	**Total**
	Study 6L				**Study 7**				**Study 8**				**Study 9**				**Study 10**			

Table 5.15: Summary of embedded generation effects on 110/38/20 kV rural network voltage

Study Case No.	EG location	Comment on voltage effects
1	Base case (No EG)	Voltage controlled within limits for embedded generation up to 5 MW
2	EG connected direct to 20 kV bus at remote primary	Voltage controlled within limits for embedded generation up to 5 MW
3	EG 5 km from remote with direct connection to 20 kV bus	Voltage controlled within limits for embedded generation up to 5 MW
3	EG connected mid-trunk on outgoing 20 kV feeders	Voltage controlled within limits for embedded generation up to 5 MW
5	EG connected at end of spur on outgoing 20 kV feeder	Voltage constraints prohibit connection of 2.5 MW generator (to average and longest feeders) and 5 MW generator (to shortest, average and longest feeders) at this location
6	EG connected at end of trunk on outgoing 20 kV feeder	Voltage constraints prohibit connection of 5MW generator to shortest, average and longest feeders
7	EG direct connection to source 38 kV bus	Voltage controlled within limits for embedded generation up to 5 MW
8	EG 5 km from source with direct connection to 38 kV bus	Voltage controlled within limits for embedded generation up to 5 MW
9	EG connected midway along 38 kV feeder between source substation & remote primary	Voltage controlled within limits for embedded generation up to 5 MW
10	EG connected direct to 38 kV bus at remote primary	Voltage controlled within limits for embedded generation up to 5 MW

Table 5.16: Summary of embedded generation effects on 110/38/20 kV rural network circuit loadings (i.e. utilisation).

Study Case No.	EG location	Comment on equipment utilisation
1	Base case (No EG)	No overloads
2	EG connected direct to 20 kV bus at remote primary	
3	EG 5 km from remote with direct connection to 20 kV bus	
3	EG connected mid-trunk on outgoing 20 kV feeders	
5	EG connected at end of spur on outgoing 20 kV feeder	
6	EG connected at end of trunk on outgoing 20 kV feeder	
7	EG direct connection to source 38 kV bus	
8	EG 5 km from source with direct connection to 38 kV bus	
9	EG connected midway along 38 kV feeder between source substation & remote primary	
10	EG connected direct to 38 kV bus at remote primary	

5.4 Analysis of 110/38/10 kV semi-urban networks

The corresponding results for this representative network identifying losses, loss savings, voltage constraints and circuit utilisation are presented in Tables 5.17 to 5.20 respectively. A complete set of results is presented in Appendix C.

The studies show that loss savings with this representative network are relatively small. It is also evident that the voltage profile is maintained within the +/-5 percent limits and in most cases much closer than that to the nominal voltage. Additionally, except in those cases where a 5 MW generator is connected at the end of a spur or the trunk of the 10 kV feeder, the network is not overloaded. In exceptional cases where the generator is overloaded the overload is only minimal, i.e. estimated at about 1 percent.

Table 5.17 : Real power losses as affected by embedded generation at 10 kV

MW gen	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)
0	29	29	29	29	29	29	29	29	29	29	29
1	28	34	26	24	19	26	21	16	27	22	16
2.5	28	61	30	25	18	33	33	35	37	33	38
5	28	161	59	46	56	75	115	161	95	130	178
	Study 2	Study 3	Study 4S	Study 4A	Study 4L	Study 5S	Study 5A	Study 5L	Study 6S	Study 6A	Study 6L

Table 5.17 (continued): Reactive power losses as affected by embedded generation at 10 kV

MW gen	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)
0	22	22	22	22	22	22	22	22	22	22	22
1	18	23	17	16	14	17	15	13	17	15	13
2.5	14	44	15	13	12	17	17	20	18	19	21
5	13	123	25	20	24	33	51	71	42	57	78
	Study 2	Study 3	Study 4S	Study 4A	Study 4L	Study 5S	Study 5A	Study 5L	Study 6S	Study 6A	Study 6L

Table 5.18: Savings in real power losses as affected by embedded generation at 10 kV

MW gen	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)
0	0	0	0	0	0	0	0	0	0	0	0
1	0	-5	2	5	10	3	7	13	2	7	13
2.5	1	-32	-1	4	10	-4	-5	-7	-9	-4	-9
5	1	-132	-30	-17	-27	-46	-86	-132	-66	-101	-149
	Study 2	Study 3	Study 4S	Study 4A	Study 4L	Study 5S	Study 5A	Study 5L	Study 6S	Study 6A	Study 6L

Table 5.18 (continued): Savings in reactive power losses as affected by embedded generation at 10 kV

MW gen	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)
0	0	0	0	0	0	0	0	0	0	0	0
1	4	-2	4	6	8	5	7	9	4	6	9
2.5	7	-22	7	9	10	5	5	2	3	3	1
5	9	-101	-3	2	-3	-11	-29	-49	-20	-35	-56
	Study 2	Study 3	Study 4S	Study 4A	Study 4L	Study 5S	Study 5A	Study 5L	Study 6S	Study 6A	Study 6L

Table 5.19: Summary of embedded generation effects on 110/38/10 kV semi-urban network voltage

Study Case No.	EG location	Comment on voltage effects
1	Base case (No EG)	Voltages controlled within +/- 5 percent of nominal in all cases.
2	EG connected direct to 10 kV bus at remote primary	
3	EG 5 km from remote with direct connection to 10 kV bus	
3	EG connected mid-trunk on outgoing 10 kV feeders	
5	EG connected at end of spur on outgoing 10 kV feeder	
6	EG connected at end of trunk on outgoing 10 kV feeder	
7	EG direct connection to source 38 kV bus	
8	EG 5 km from source with direct connection to 38 kV bus	
9	EG connected midway along 38 kV feeder between source substation & remote primary	
10	EG connected direct to 38 kV bus at remote primary	

Table 5.20: Summary of embedded generation effects on 110/38/10 kV semi-urban network circuit loadings (i.e. utilisation).

<table>
<tr><th>Study Case No.</th><th>EG location</th><th>Comment on equipment utilisation</th></tr>
<tr><td>1</td><td>Base case (No EG)</td><td rowspan="10">Only minor overload (1%) when 5 MW generator located at end of trunk on longest 10 kV feeder (case 6)</td></tr>
<tr><td>2</td><td>EG connected direct to 10 kV bus at remote primary</td></tr>
<tr><td>3</td><td>EG 5 km from remote with direct connection to 10 kV bus</td></tr>
<tr><td>3</td><td>EG connected mid-trunk on outgoing 10 kV feeders</td></tr>
<tr><td>5</td><td>EG connected at end of spur on outgoing 10 kV feeder</td></tr>
<tr><td>6</td><td>EG connected at end of trunk on outgoing 10 kV feeder</td></tr>
<tr><td>7</td><td>EG direct connection to source 38 kV bus</td></tr>
<tr><td>8</td><td>EG 5 km from source with direct connection to 38 kV bus</td></tr>
<tr><td>9</td><td>EG connected midway along 38 kV feeder between source substation & remote primary</td></tr>
<tr><td>10</td><td>EG connected direct to 38 kV bus at remote primary</td></tr>
</table>

5.5 Analysis of 110/38/10 kV dense urban networks

The corresponding results for this representative network that identify losses, loss savings, voltage constraints and circuit utilisation are presented in Tables 5.21 to 5.24 respectively. A complete set of results is presented in Appendix C.

The studies show that loss savings with this representative network are again relatively small. Again the voltage profile is maintained within the +/-5 percent limits and in most cases much closer than that to the nominal voltage. The network is not overloaded.

Table 5.21: Real power losses as affected by embedded generation at 10 kV

MW gen	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)
0	28	28	28	28	28	28	28	28	28	28	28
1	28	34	27	26	20	27	26	14	27	26	18
2.5	28	52	29	29	13	31	33	11	35	37	11
5	28	158	41	49	18	56	76	54	75	93	27
	Study 2	Study 3	Study 4S	Study 4A	Study 4L	Study 5S	Study 5A	Study 5L	Study 6S	Study 6A	Study 6L

Table 5.21 (continued): Reactive power losses as affected by embedded generation at 10 kV

MW gen	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)
0	12	12	12	12	12	12	12	12	12	12	12
1	18	23	18	17	20	17	17	17	18	17	19
2.5	17	44	17	17	11	18	19	10	20	21	10
5	13	121	19	22	9	26	34	25	34	42	13
	Study 2	Study 3	Study 4S	Study 4A	Study 4L	Study 5S	Study 5A	Study 5L	Study 6S	Study 6A	Study 6L

Table 5.22: Savings in real power losses as affected by embedded generation at 10 kV

MW gen	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)	Real power loss (kW)
0	0	0	0	0	0	0	0	0	0	0	0
1	0	-5	1	2	8	1	2	14	1	2	11
2.5	0	-24	-1	-1	15	-3	-5	17	-7	-9	18
5	0	-129	-13	-20	10	-28	-48	-26	-47	-65	1
	Study 2	Study 3	Study 4S	Study 4A	Study 4L	Study 5S	Study 5A	Study 5L	Study 6S	Study 6A	Study 6L

Table 5.22 (continued): Savings in reactive power losses as affected by embedded generation at 10 kV

MW gen	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)	Reactive power loss (kVAr)
0	0	0	0	0	0	0	0	0	0	0	0
1	-6	-11	-6	-5	-8	-6	-5	-6	-6	-5	-7
2.5	-5	-32	-5	-5	1	-6	-7	2	-8	-9	2
5	-1	-109	-7	-10	3	-14	-22	-13	-22	-30	-1
	Study 2	Study 3	Study 4S	Study 4A	Study 4L	Study 5S	Study 5A	Study 5L	Study 6S	Study 6A	Study 6L

Table 5.23: Summary of embedded generation effects on 110/38/10 kV dense urban network voltage

Study Case No.	EG location	Comment on voltage effects
1	Base case (No EG)	
2	EG connected direct to 10 kV bus at remote primary	
3	EG 5 km from remote with direct connection to 10 kV bus	
3	EG connected mid-trunk on outgoing 10 kV feeders	
5	EG connected at end of spur on outgoing 10 kV feeder	Voltages controlled within +/- 5 percent of nominal in all cases.
6	EG connected at end of trunk on outgoing 10 kV feeder	
7	EG direct connection to source 38 kV bus	
8	EG 5 km from source with direct connection to 38 kV bus	
9	EG connected midway along 38 kV feeder between source substation & remote primary	
10	EG connected direct to 38 kV bus at remote primary	

Table 5.24: Summary of embedded generation effects on 110/38/10 kV dense urban network circuit loadings (i.e. utilisation).

Study Case No.	EG location	Comment on equipment utilisation
1	Base case (No EG)	No overloads, although with the 5 MW generator connected to outgoing 10 kV feeders the loading on the cable where the generator is connected may be fully loaded, particularly cases 5 and 6.
2	EG connected direct to 10 kV bus at remote primary	
3	EG 5 km from remote with direct connection to 10 kV bus	
3	EG connected mid-trunk on outgoing 10 kV feeders	
5	EG connected at end of spur on outgoing 10 kV feeder	
6	EG connected at end of trunk on outgoing 10 kV feeder	
7	EG direct connection to source 38 kV bus	
8	EG 5 km from source with direct connection to 38 kV bus	
9	EG connected midway along 38 kV feeder between source substation & remote primary	
10	EG connected direct to 38 kV bus at remote primary	

6. Embedded Generation Benefit Calculation Methodology

6.1 Introduction

The previous sections have qualitatively identified the costs and benefits associated with the connection of embedded generation to the distribution network in Ireland. This qualitative assessment provided the basis for the cost / benefit and established a preliminary scope of the areas that the costs / benefit will arise. These areas can roughly be split into three categories:

- Revenue or operational;
- Capital or asset;
- Service or customer related.

The intent behind this section is to develop a methodology for the quantification of these costs and benefits within the context of the Irish electricity market. Further, examples will be calculated using the findings from the representative network modelling studies to illuminate the calculation methodology and to provide a sense of scale and gain an understanding of the relative order of importance of the respective costs / benefits.

6.2 Approach

The approach adopted to establish the calculation methodology has incorporated the various benefits within a series of logical groupings. This approach will reduce the possibility of double counting and is intended to allow visibility of the revenue, capital and service costs / benefits independently of one another.

Revenue Costs and Benefits include:

- Energy Losses
- Emissions Benefits
- Avoided Use of System charges
- Energy Price Benefits

Capital Costs and Benefits include:

- Displaced System Plant
- Asset Benefit – deferred reinforcement;
- Displaced Load
- Initial Connection Costs;

Service Costs and Benefits include:

- Customer Minutes Lost
- Voltage Support and Reactive Power Provision;
- Social benefit to local community;

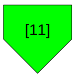
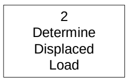
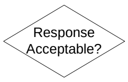
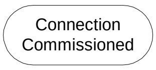
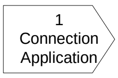
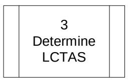
The methodology takes into account the existing Least Cost Technically Acceptable Solution approach to the derivation of the connection point and connection costs for embedded generation to connect to the ESB distribution network. The LCTAS provides the starting point for any and all of the additional calculations to determine the value of the identified benefits and a context within which the calculations can be formulated.

In order that the methodology can provide a pragmatic solution a number of simplifying assumptions have been made. These are identified and discussed within the context of the relevant part of the methodology and where it is seen that there could be differences in opinion on the approach adopted we have flagged this as a potential issue and drawn these issues out within a separate sub-section.

Wider macro economic issues are considered to be outside the scope of this study, however, where these arise we have endeavoured to quantify the impact as far as reasonably practicable. Further, it should be noted that should elements of this methodology be subsequently adopted, additional costs will be incurred in the connection design and planning process. Estimation and suggested treatment of these costs are out with the scope of this report.

6.3 Key to symbols

The methodology is presented as a process flow diagram with supporting descriptive text that outlines the functionality of each of the steps involved. The process diagrams used a series of symbols and these are identified and described below:

Symbol	Description
	This signifies a link to another process within the methodology. There are two types of link –coloured green to show a link into the process, and coloured red / orange to show a link from the process. These have been used to enable the separate elements of the calculation methodology to be self-contained within the overall process. These links are in numbered pairs to show where they come from or go to.
	This signifies data that is required to support the calculation to be made. Such data may comprise statements of policy, financial assumptions, technical specifications and market pricing / tariffs etc.
	This signifies a process step. These are numbered sequentially to signify the flow in the process with the numbering being restarted for each process. Each step involves a specific task or calculation in the process. The steps are described within the process description.
	This signifies a decision point in the process. The process routing from this step will follow either a 'Yes' or 'No' direction.
	Signifies the end of the process.
	Signifies the start of the process.
	This signifies a predefined process. This symbol is used within the overview process flow diagram to represent the various sub calculation processes that are defined within the methodology.

6.4 Connection Methodology Functional Overview

This process provides an overview of the proposed methodology, incorporating the existing connection application, offer and dispute processes. It begins with the applicant submitting their application for connection to ESB Networks – Step 1. This is the trigger for the whole process.

Prior to this present piece of work only those costs associated with the physical connection to the distribution network – specifically the connection assets / reinforcement that is required to enable such connection. However, this calculation methodology identifies those areas impacted due to the connection of the embedded generation to the distribution network. These areas will include, not only the connection asset costs, but also any benefits that may arise from system annual energy and peak loss reduction, avoided emissions from system generation plant, social benefits, improvements to the quality of supply etc.

It is recognised that the connection of embedded generation does not guarantee that benefits are created, indeed it may be the case that such an embedded generation plant may compound losses already existing on the distribution or even create additional cost in the wholesale electricity market though less efficient operation of system thermal power plant. All of these elements are individually considered within the framework of the methodology outlined within this process. It should be noted that the Transmission system costs and benefits are considered within the "Displaced System Plant Costs" and "Commercial Benefits" processes.

6.4.1 Inputs

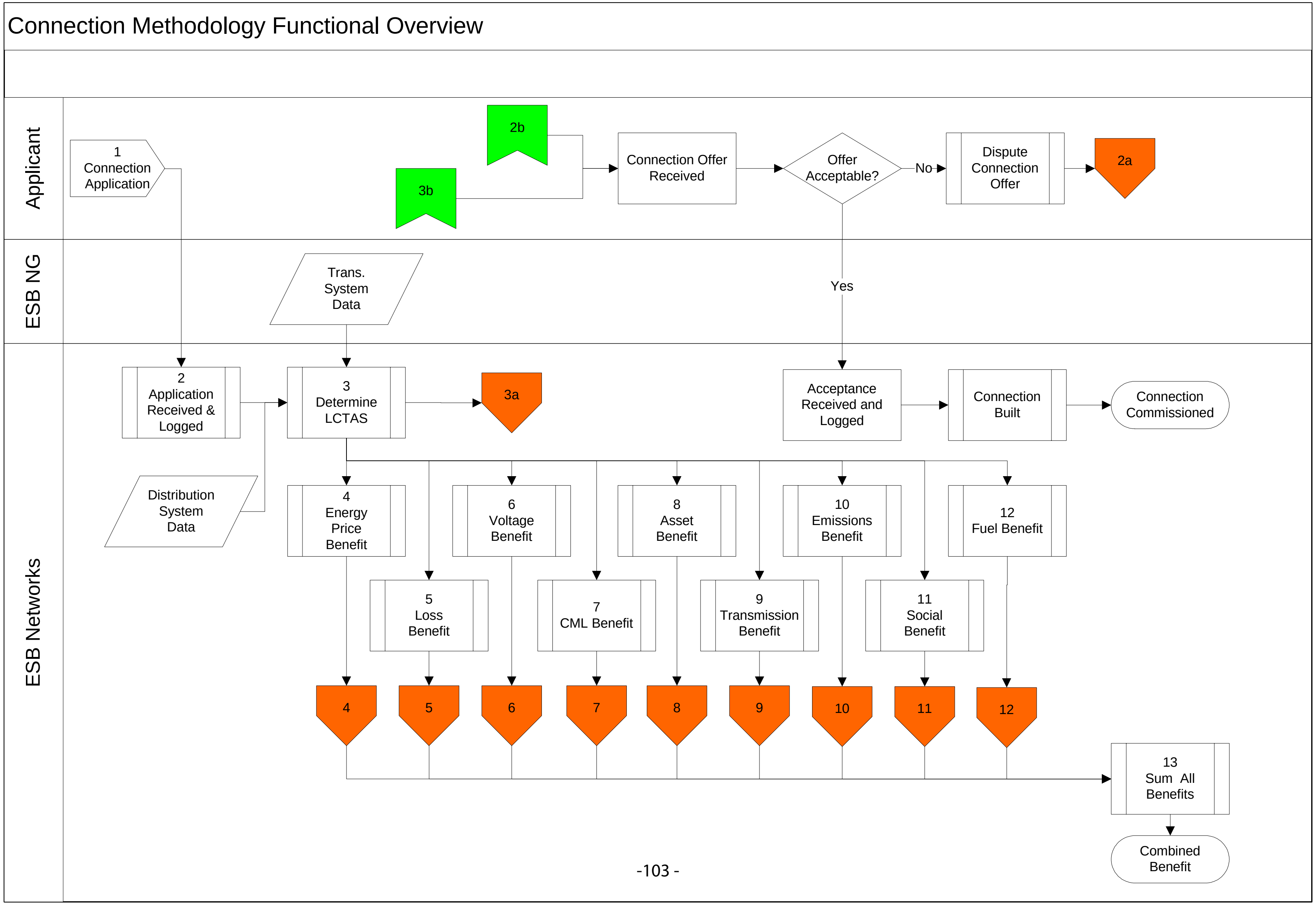
Application for connection of embedded generation plan to the ESB Networks distribution system submitted by the Applicant;

6.4.2 Outputs

Net benefit of connection of the embedded generation plant to the ESB Networks distribution system.

6.4.3 Participants

Applicant; ESB Networks / ESB National Grid



Connection Methodology Functional Overview
Applicant
ESB NG
ESB Networks
1
Connection
Application
2b
3b
Connection Offer
Received
Offer
Acceptable?
No
Dispute
Connection
Offer
2a
Trans.
System
Data
Yes
2
Application
Received &
Logged
3
Determine
LCTAS
3a
Acceptance
Received and
Logged
Connection
Built
Connection
Commissioned
Distribution
System
Data
4
Energy
Price
Benefit
5
Loss
Benefit
6
Voltage
Benefit
7
CML Benefit
8
Asset
Benefit
9
Transmission
Benefit
10
Emissions
Benefit
11
Social
Benefit
12
Fuel Benefit
4
5
6
7
8
9
10
11
12
13
Sum All
Benefits
Combined
Benefit

6.4.4 Connection Methodology: Process Description

Step	Name	From	To	Description	Data Sources
1	Connection Application	Applicant	ESB Networks	The Applicant will complete the necessary information request forms – CX51C_1[50] and provide all relevant data in relation to the proposed equipment to be connected to the distribution system to allow ESB Networks to undertake the studies and costing exercises necessary to provide a connection offer to the Applicant.	
2	Application Received and Logged	ESB Networks	ESB Networks	ESB Networks receive the formal request and provide confirmation in the form of an acknowledgement letter to the Applicant.	
3	Determine LCTAS	ESB Networks	ESB Networks	This process is undertaken by ESB Networks to determine the connection solution that is technically acceptable and which results in the least cost being incurred by the DSO. Any costs incurred by ESB Networks in providing a connection or installing infrastructure which are deemed to be over and above the LCTAS are presently borne in full by the customer or developer.	Applicant Application form and supporting information; Distribution system data; Transmission system data;
4	Displaced Energy Benefit	ESB Networks	ESB NG	The connection and operation of embedded generation plant within the distribution network will affect the operation of transmission system connected generation plant due to system demand being reduced through the embedded generation offsetting local system demand. The outcome of this is that the system plant may incur additional costs (due to reduced operating efficiency); there may be a net benefit on the transmission system losses or benefit from deferred load related capital expenditure. The purpose of this process is to assess the extent of any differential in the cost of generating the embedded generation and the cost of providing the energy from a system generation plant.	Transmission System Data; System generation plant data; Ancillary Service Contracts data;

[50] As identified in "Guide to the Process for Connection to ESB's Distribution System", Revision 1, February 2002.

6.4.4 Connection Methodology: Process Description (cont.)

Step	Name	From	To	Description	Data Sources
5	Loss Benefit Calculation	ESB Networks	ESB Networks	The purpose of this process is to determine the impact of the embedded generation on the distribution system losses. It is likely that there will be a positive benefit through the reduction in peak system capacity required to service the distribution network demand and reduced cost in terms of annual energy loss as the load is being supplied locally. The output of this process is a net value for any benefit deriving from the operation of the embedded generator.	System Generation Plant Costs Distribution System data Load duration data System loss data (energy and kW)
6	Voltage Benefit	ESB Networks	ESB Networks	This process is to determine the impact of the embedded generation on the distribution system power factor and voltage support. The connection of embedded generation may result in a net benefit of cost depending on the network configuration and its connection point into the system. The output of this process will be a benefit value arising from any avoided / deferred capital expenditure due to improved pf and any saving in the cost of reactive energy required by the system.	Reactive power costs Distribution system data Load duration data
7	CML Benefit	ESB Networks	ESB Networks	This process is to determine the impact of the embedded generation on the distribution system reliability and security of supply. Any reduction in CMLs will arise from providing an 'islanding' scheme for the embedded generator to provide alternative electricity supply during system fault conditions.	Load duration curves; Network statistical fault probabilities (SAIFI, SAIDI); Operational restoration schemes;
8	Asset Benefit	ESB Networks	ESB Networks	This will provide a benefit calculation on the basis that the embedded generation defers the need to replace assets either as a result of reduced thermal loading or releasing network capacity that can be used to support load growth. The asset benefit related to reduced system peak losses is accounted for within the Losses calculation process.	Load duration curve for network; Forecast generation profile Forecast load growth; Asset replacement costs;

6.4.4 Connection Methodology: Process Description (cont.)

Step	Name	From	To	Description	Data Sources
9	Transmission Benefit	ESB NG	ESB NG	This process will determine the impact of the embedded generation on the transmission system through reduced losses and capital expenditure deferment through changes in the timing of system reinforcement.	
10	Emissions Benefit	ESB Networks	ESB Networks	This process will provide a value for any benefit from reduced environmental emissions. Those emissions considered are CO2 (EU ETS costs), NOX and SOX.	System generation emission data; Generation plant emission data; Emission Costs;
11	Social benefit			To calculate the extent of any social benefits that will derive from the installation of the embedded generation. This is driven by the impact of the embedded generation on local jobs.	
12	Fuel Benefit			This process will calculate the quantity of fuel that is saved / displaced as a result of the embedded generation operation. This will be derived from the avoided system plant and the embedded generation operation profile.	
13	Sum All Benefits			The combined benefit calculation is a summation of the various benefits calculated within items 4 through 12. These will be summated and the cost of the connected subtracted to determine the net benefit of the embedded generation.	

6.5 Least Cost Technically Acceptable Solution (LCTAS) Process

The developer of the embedded generation (the Applicant) will need to approach the DNO in order to receive a formal quotation for the connection of their proposed generation plant to the distribution network. Typically the process would involve the request for budget connection offer followed by a formal offer when the developer is finalising the project costing. The LCTAS approach will identify the point of connection and any additional works required on the distribution network to enable the embedded generator to be connected whilst maintaining the quality of supply and network operational stability.

The strength of the distribution network is directly related to the short circuit level. Higher short circuit levels give an electrically stronger network more able to deal with disturbances arising from switching transients (e.g. generators coming on or off load, motors and other reactive elements of the network). The connection of an embedded generator to the distribution network will contribute to the short circuit level (inter alia – fault level). In some situations the existing fault level is approaching the switchgear rating on the network and the connection of the embedded generation may require this equipment to be upgraded due to the increased fault level following connection.

Each connection application demands that the DNO examines the impact the new generation will have on the network in order to confirm that the network and other customers connected to the network will not be adversely affected by the presence of the new generation. In addition to the system planning studies that the DNO would normally perform, such as base case load flow, contingency load flow and short circuit analysis, the DNO has to be satisfied that the step change voltage limits are not exceeded when the embedded generation is suddenly switched on or switched off the network. Other technical aspects that are examined include harmonics, losses and network protection.

The costs of these additional system planning requirements cannot be easily determined, however, the activity that has been undertaken in assessing the representative network segments for the SEI Study will provide an indication on the time required to complete such studies. This should enable resourcing costs to be determined. Such costs are assumed to be recovered on a case-by-case basis from the developer and therefore form part o the overall connection costs for the generation plant.

6.5.1 Inputs

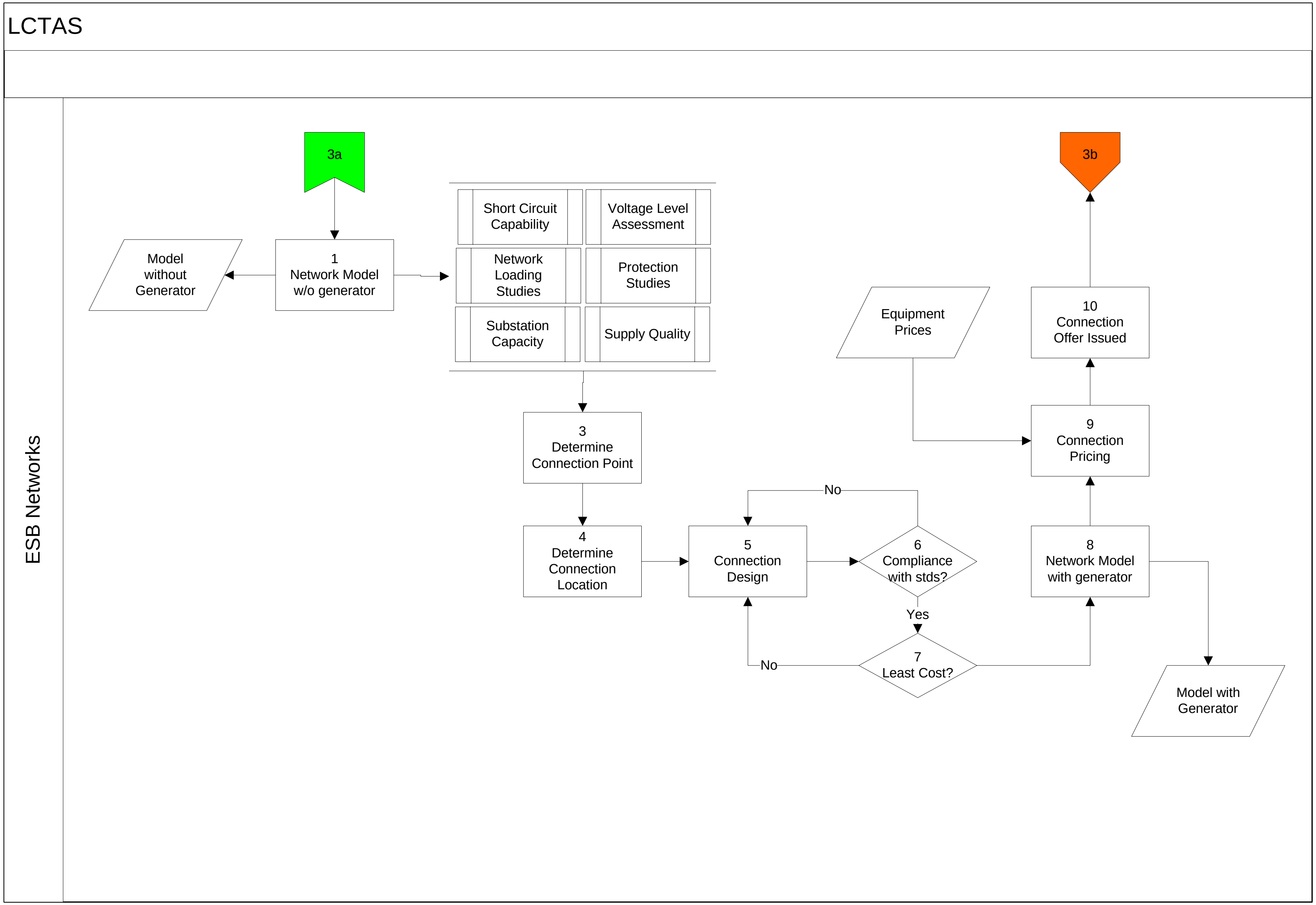
Connection Application; Machine Performance Data; DNO Network Data; Equipment Pricing

6.5.2 Outputs

Connection Offer to Applicant; Network Model without Generator; Network Model with Generator

6.5.3 Participants

ESB Networks



LCTAS
ESB Networks
3a
Model without Generator
1 Network Model w/o generator
Short Circuit Capability
Voltage Level Assessment
Network Loading Studies
Protection Studies
Substation Capacity
Supply Quality
3 Determine Connection Point
4 Determine Connection Location
5 Connection Design
No
6 Compliance with stds?
Yes
7 Least Cost?
No
Equipment Prices
8 Network Model with generator
9 Connection Pricing
10 Connection Offer Issued
3b
Model with Generator

6.5.4 LCTAS: Process Description:

Step	Name	From	To	Description	Data
1	Network Model without Generator	ESB Networks	ESB Networks	ESB will create a model of the distribution network as it is before the connection of the embedded generator. This model will subsequently be used as the baseline network model.	Distribution Network Data
2	Short Circuit Voltage Level Network Loading Protection Studies Substation Capacity Supply Quality	ESB Networks	ESB Networks	These studies all form part of the process undertaken in determining the least cost technically acceptable solution for the connection of the embedded generation. The details of these studies and their implementation will be covered within internal ESB business policy and procedural documentation. Review of this documentation is outside the scope of this study.	Demand Load Profiles Network Plan
3	Determine Connection Point			ESB will need to make a judgement as to the most appropriate point for the connection of the embedded generation to the distribution network on the basis of the results of the studies undertaken in step 2 above. Such a decision will be driven by the statutory obligations on ESB to maintain the quality and reliability of the electricity supplied from the distribution network.	ESB Statutory Obligations ESB Connection Policy
4	Determine Connection Location	ESB Networks	ESB Networks	The connection point will provide the electrical solution for the connection to the distribution system. The next step is to determine the physical location of the connection. There will be consideration required of the availability of land, local geography etc. It is likely that there will be a degree of compromise required in determining the final physical location for the connection and subsequent amendment to the network model to reflect the final electrical connection point.	Land topography; Land Ownership records;
5	Connection Design	ESB Networks	ESB Networks	The connection will now undergo detailed design to ensure that it satisfies the ESB standards for the LCTAS and that the connection provides the level of reliability that is being requested in the connection application.	ESB Construction Standards
6	Compliant with Standards?	ESB Networks	ESB Networks	The connection design needs to satisfy the relevant standards. To the extent that it does not then the connection needs to be re-designed.	

Step	Name	From	To	Description	Data
7	Least Cost?	ESB Networks	ESB Networks	Does this design comprise the least cost solution? If not then the design needs to be revisited.	
8	Network Model with Generator	ESB Networks	ESB Networks	Once the connection design has been determined to be compliant with the LCTAS policy the Network model should be updated to incorporate the embedded generator and the new connection assets and any reinforcement to be undertaken as a consequence of the new connection. This revised Network Model with the embedded generation will be used in the benefit calculations.	
9	Connection Pricing			Once the connection point has been finalised and the connection design is detailed the formal offer will be priced against a current equipment price database and a bill of quantities collated for the connection.	Current Equipment Prices
10	Offer Issued			The connection offer is issued to the Applicant	

6.6 Connection Offer Dispute

This process briefly describes the steps involved should an Applicant dispute a connection offer made by ESB Networks for the connection of an embedded generator to the ESB distribution network. This process has been incorporated for the sake of completeness. This process description does not specify particular timescales by which the various activities must be completed.

6.6.1 Inputs

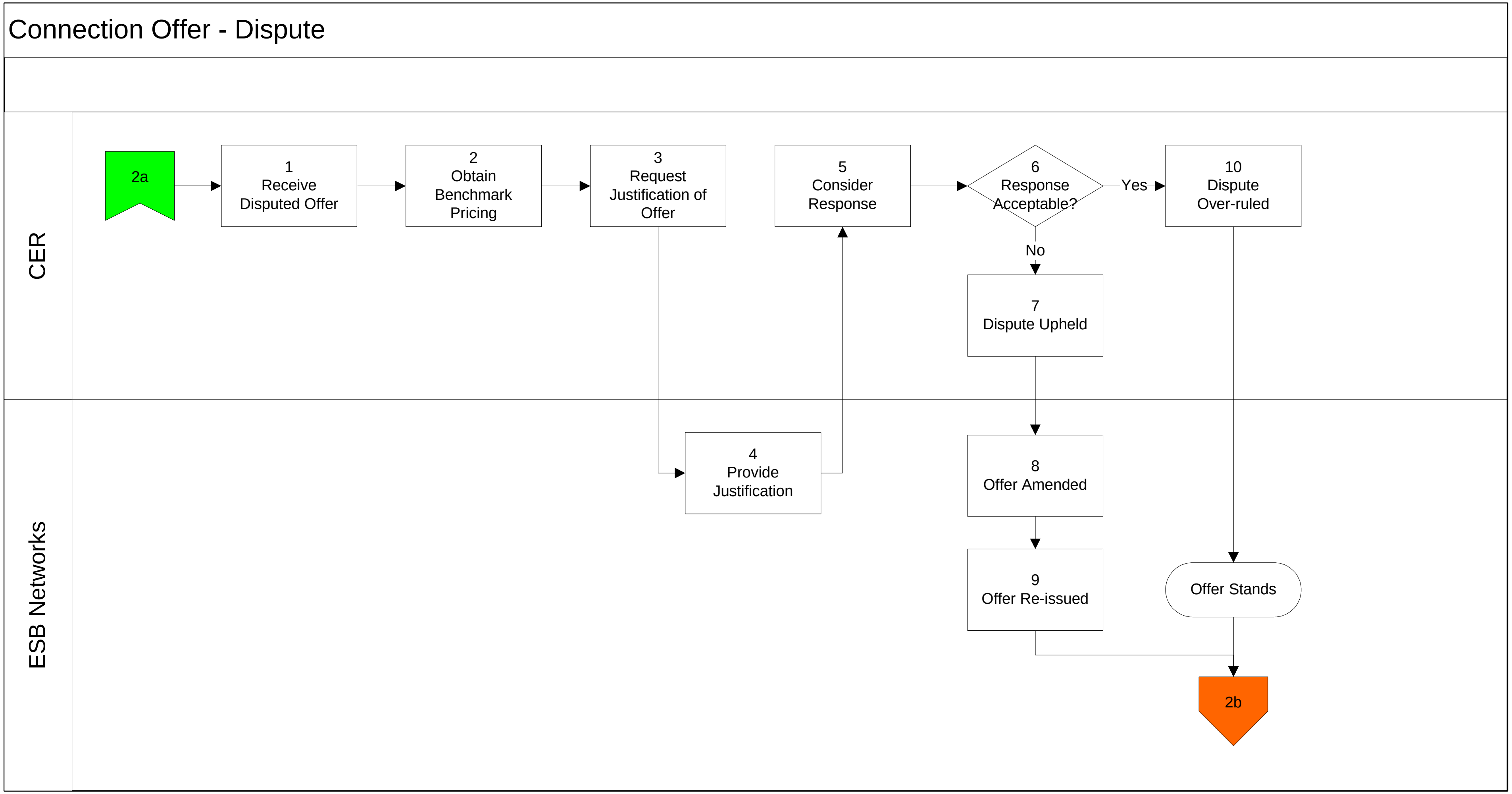
Details of connection offer under dispute; ESB justification

6.6.2 Outputs

CER decision on connection offer

6.6.3 Participants

Applicant; ESB Networks; CER; External consultants


Connection Offer - Dispute
CER
ESB Networks
2a
1
Receive
Disputed Offer
2
Obtain
Benchmark
Pricing
3
Request
Justification of
Offer
4
Provide
Justification
5
Consider
Response
6
Response
Acceptable?
Yes
No
7
Dispute Upheld
8
Offer Amended
9
Offer Re-issued
10
Dispute
Over-ruled
Offer Stands
2b

6.6.4 Process Description:

Step	Name	From	To	Description	Data Sources
1	Receive Disputed Offer	Applicant	CER	The Applicant forwards the full details of the connection offer that they are disputing with ESB Networks, to the CER.	ESB Networks Connection offer
2	Obtain Benchmark Pricing	CER	CER	The CER retains a number of technical consultants to support them in determining such disputes. The CER will, where it deems it is necessary, obtain reference pricing for similar connections from external consultants that have recent experience in construction, design or tender adjudication of equivalent distribution network connections.	External Consultants CER data base of costs (if this exists)
3	Request Justification of Offer	CER	ESB Networks	Where there are items that have a significant variance between the benchmark cost and the price included for that element within the connection offer, the CER will request a justification of the difference from ESB Networks.	
4	Provide Justification	ESB Networks	CER	ESB Networks must provide a reasoned justification for the variance in cost for those items identified by the CER. This justification may be subject to specific deadlines for response to CER.	Internal ESB Networks cost data; External tender documentation;
5	Consider Response	CER	CER	CER shall consider the ESB Networks justification and may use external technical consultants to assist in this decision making process.	
6	Response Acceptable?	CER	CER	CER will, following consideration of the ESB response, determine whether the reasons provided in support of the connection pricing by ESB are acceptable.	
6	Dispute Upheld	CER	ESB Networks	Following due consideration of the ESB Networks justification, the CER may find that the dispute was justified and instruct ESB Networks to amend its connection offer to be in line with the benchmarked pricing.	

Step	Name	From	To	Description	Data Sources
7	Offer Amended	ESB Networks	ESB Networks	ESB Networks will amend its connection offer to bring it into line with the decision by the CER.	
8	Offer Re-issued	ESB Networks	Applicant	Self explanatory	
9	Dispute Over-ruled	CER	Applicant	CER may find that the cost structure reflected within the disputed connection offer is fair and presents cost that will be properly incurred in the process of providing the connection to the ESB distribution system. The CER will inform the Applicant and ESB Network of this decision.	
10	Offer Stands	ESB Networks		ESB Networks needs take no further action prior to receipt of formal acceptance of the connection offer by the Applicant.	

6.7 Displaced Energy Benefit

Many embedded generation technologies have a unit cost of generation that is driven by their high initial capital cost, while large fossil fuel plant generation cost is more closely linked to fuel costs. This currently result in higher unit generation costs for embedded generation. Capital costs for many embedded generation plants are expected to fall, which will drive down the unit cost and reduce this cost differential.

Care needs to be taken when comparing plant simply by the unit cost of generation, which describes the cost of putting each kilowatt-hour onto the system. For deeply embedded generation (egg. Solar PV serving a building or small CHP), this is also the cost of each kilowatt-hour delivered to the customer, since the transmission and distribution systems are not used. By contract, a large centrally located plant will also have the delivery costs of using the transmission and distribution systems, and the losses associated with these. The cost / benefit issues associated with the distribution system and transmission system energy losses are captured within the other parts of the calculation methodology and it is only the displaced energy that is considered in this calculation process.

This process uses the embedded generation operating profile to determine which type of system plant will be displaced and the quantity of system generation plant energy displaced will be the difference between the 'before' and 'after' annual energy off-take at the transmission system exit point in question.[51] The calculations will be done for the first year of operation of the embedded generation plant with the results of the calculations then being projected over an agreed period – currently assumed to be 15 years.

6.7.1 Inputs:

Network Model without Generation; Network Model with Generation; Embedded Generation Price

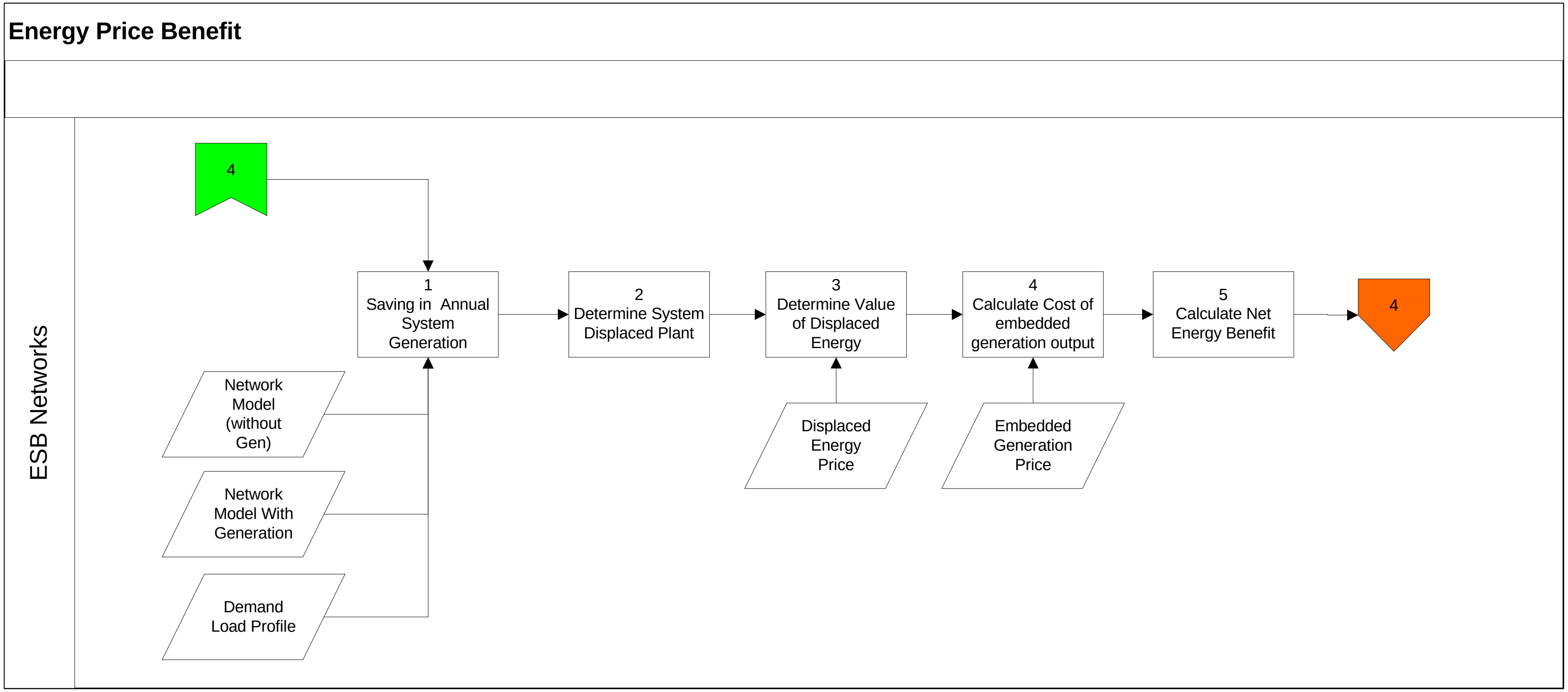
6.7.2 Outputs:

Net Energy Benefit

6.7.3 Participants:

ESB Networks

[51] It is noted here that the Market Arrangements for Electricity are presently under discussion prior to implementation in 2005. This envisages use of Locational Marginal Pricing for the wholesale market and therefore any benefit calculation under the MAE will need to take this into consideration.



Energy Price Benefit
ESB Networks
4
1 Saving in Annual System Generation
2 Determine System Displaced Plant
3 Determine Value of Displaced Energy
4 Calculate Cost of embedded generation output
5 Calculate Net Energy Benefit
4
Network Model (without Gen)
Network Model With Generation
Demand Load Profile
Displaced Energy Price
Embedded Generation Price

6.7.4 Process Description:

Step	Name	From	To	Description	Data
1	Determine Saving in Annual System Generation	ESB Networks	ESB Networks	The extent of the energy saved in supplying the off-take requirement at the relevant transmission exit node will be dependant on the operating profile of the embedded generation and the distribution load profile of the connected customer demand supplied from that exit point. The saving in the energy required will be the change in the annual energy off-take at that exit point following connection of the embedded generation. Energy Off-take (no Gen) = System Load Factor * Peak kW Embedded Generation Output = Embedded Plant Capacity (MW) * 1000 * Plant Utilisation (%) Energy Off-take (with Gen) = Energy Off-take (no Gen) - Embedded Generation Output Displaced System Energy = Energy Off-take (no Gen) - Energy Off-take (with Gen) This only looks at the delivered energy that is displaced. The cost of energy taken by the transmission and distribution systems in terms of losses is accounted for within a separate part of this calculation methodology.	Embedded Generation Profile System Load Profile

[52] It is noted here that the Market Arrangements for Electricity are presently under discussion prior to implementation in 2005. This envisages use of Locational Marginal Pricing for the wholesale market and therefore any benefit calculation under the MAE will need to take this into consideration.

Step	Name	From	To	Description	Data
2	Determine Displaced System Plant	ESB Networks	ESB Networks	It is proposed that this is determined through consideration of the embedded generation expected load factor as determined from the expected generation profile. This load factor will then identify whether the embed generation is expected to displace base load plant, mid merit plant or peaking plant. The proposed categories of plant are detailed below: • Base Load >75%LF (BNE Pricing); • Mid Merit 30 to 75%LF (ESB PG Allowable revenue); • Peaking <30% LF (Oil plant price) This selection will select the avoided energy price and the avoided fuel type (used for calculation of emissions and fuel benefits in later sections).	
3	Value of Displaced Energy	ESB Networks	ESB Networks	The Value of the Displaced Energy is calculated as follows: Value of Displaced Energy = Displaced System Energy (Step 1)* Displaced Energy Price (Step 2)	Forecast Plant Operation
4	Cost of Generated Energy	ESB Networks	ESB Networks	The costs associated with the generation of the energy by the embedded generator will need to be set off against the saving in system energy costs. The embedded generation output will not be the same as the displaced system energy at the transmission system exit point due to the impact of the embedded generation on the distribution system losses. This is taken into account in the following equation: Embedded Generation Output = Embedded Plant Capacity (MW) * 1000 * Plant Utilisation (%) Cost of Energy Generated = Embedded Generation Output * Embedded Generation Price The price of the embedded generation output will be a commercially sensitive	

Step	Name	From	To	Description	Data
				number and there will need to be sufficient assurances in place to address any issues relating to confidentiality.	
5	Net Energy Benefit			The Net Energy Benefit pa is the difference between the system generation cost and the embedded generation cost in the first year of operation of the embedded generation. Net Energy Benefit pa = Value of Displaced Energy (Step 3) - Cost of Energy Generated (Step 4) This value will need to be projected forward. •••Net Energy Benefit $=\bullet \sum_{n=1}^{15}(\text{Net Energy Benefit pa} / (1+DF)^{n})$	

6.8 Loss Benefit Calculation

The connection of embedded generation plant to a distribution network has a number of impacts for the day-to-day operation of the system and also for the longer term planning and security of the distribution system. These impacts can be localised to the generator or may have an effect further a field dependant on the size of the generator and the capability of the distribution network at the point of connection for the generator.

This process considers the steps required to determine the impact of the embedded generator on the distribution system losses. These losses arise in the form of heat in the system (predominantly load related) and in the form of inefficient use of system capacity (kW) that increases the assets required to serve a given load. Embedded generation can provide some off set of the energy losses and may release some of the capacity presently used by the losses. Each of these elements has a value associated with them.

Power Losses – in general the connection of embedded generation plant will reduce the demand on the upstream network at times of peak load whilst leaving the downstream network relatively unaffected, and this will be seen as a benefit to all users through deferred / avoided system reinforcement leading to reduced loos costs requiring recovery through the use of system charges.

Energy Losses – Although running embedded generation at times of peak load will reduce network power losses at peak load, the reverse is true at times of light load where operation of embedded generation may actually increase the losses if the generator is exporting power to the grid. Since peak load conditions only exist for a short period during the day and the period of light load covers a much longer period when electricity demand is low, the overall effect of running embedded generation throughout any 24-hour period may actually be to increase the overall energy loss.

With the present commercial arrangements developers of embedded generation are encourage to maximise their financial return by maximising their generating capacity and their "in-service" hours per year. However, as noted above, this approach is likely to increase the energy losses of individual schemes, which is in contrast with an energy saving policy. It is conceivable therefore that a time will come when developers are encouraged to consider the need to minimise losses, since a reduction in energy losses would be beneficial to the environment, with a resulting saving in the amount of fuel being used and carbon dioxide emissions.

The cost of the losses needs to be assessed over a period that represents the expected life of the embedded generation plant. Such a consideration should bring out a life cycle cost associated with the embedded generator connection to the distribution system on the basis of the system conditions at the time of connection. The calculations will be made on the basis of the existing distribution system and the presently accepted connection offers as at the date of the calculation. It is recognised that the distribution system undergoes frequent change due to new connections or de-commissioning connections that are no longer required. This does introduce a degree of uncertainty into the calculation process. However, this calculation is concerned with the *incremental* impact of the embedded generation on the system losses.

This process only considers the impact of the embedded generator on technical losses.

6.8.1 Inputs

Distribution System data – electrical parameters, operating configuration;

Load Duration data – current load shape and quantities, forecast load growth

Forward Energy Prices at the Distribution :Transmission interface

Marginal Capacity Costs for the Distribution System.

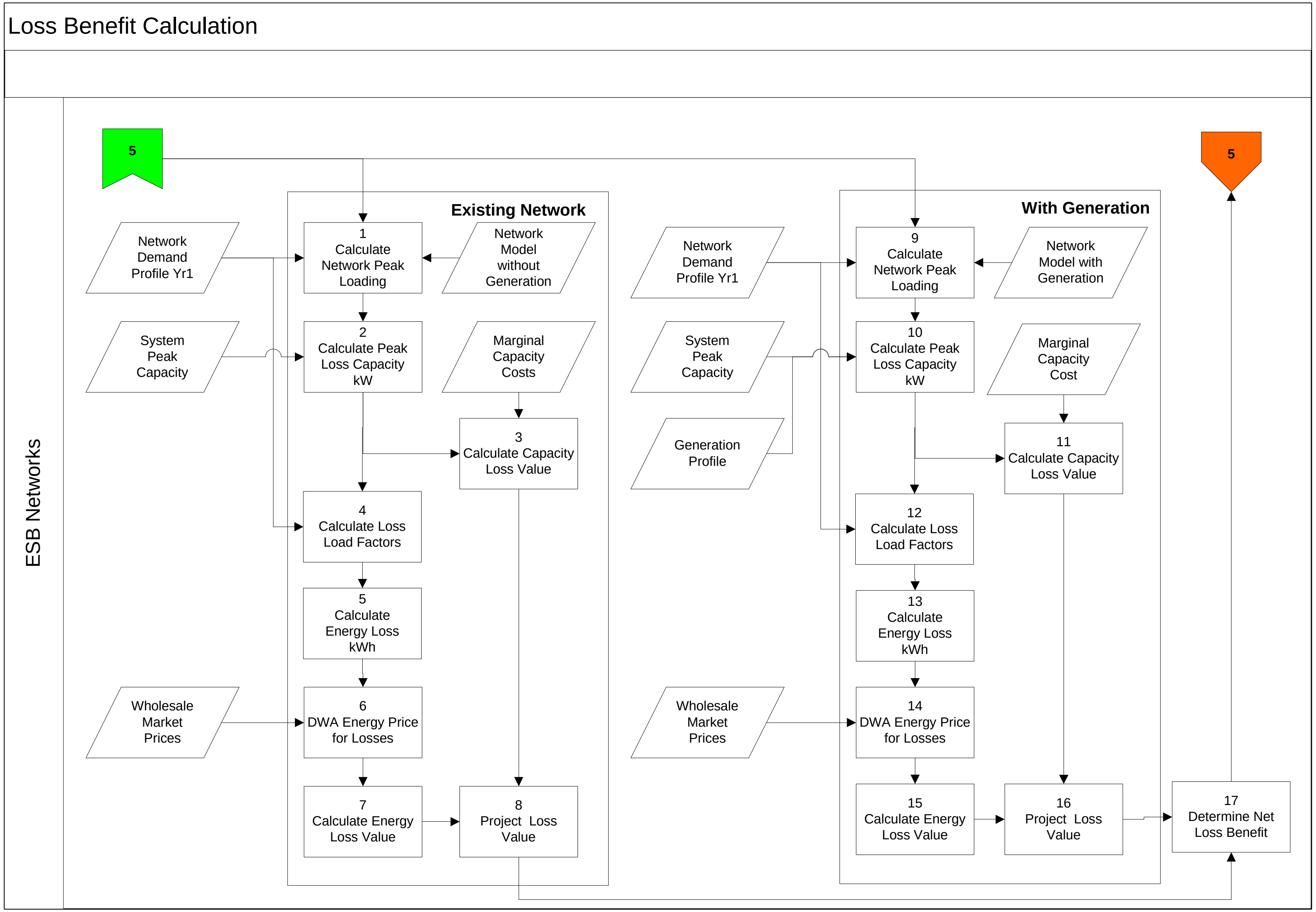
Embedded Generation expected generation profile in terms of kW and kWh.

6.8.2 Outputs

Statement of the net losses Benefit arising from the connection of the generation plant to the ESB distribution network.

6.8.3 Participants

ESB Networks


Loss Benefit Calculation
ESB Networks
5
5
Existing Network
With Generation
Network Demand Profile Yr1
System Peak Capacity
Wholesale Market Prices
1 Calculate Network Peak Loading
Network Model without Generation
2 Calculate Peak Loss Capacity kW
Marginal Capacity Costs
3 Calculate Capacity Loss Value
4 Calculate Loss Load Factors
5 Calculate Energy Loss kWh
6 DWA Energy Price for Losses
7 Calculate Energy Loss Value
8 Project Loss Value
Network Demand Profile Yr1
System Peak Capacity
Generation Profile
Wholesale Market Prices
9 Calculate Network Peak Loading
Network Model with Generation
10 Calculate Peak Loss Capacity kW
Marginal Capacity Cost
11 Calculate Capacity Loss Value
12 Calculate Loss Load Factors
13 Calculate Energy Loss kWh
14 DWA Energy Price for Losses
15 Calculate Energy Loss Value
16 Project Loss Value
17 Determine Net Loss Benefit

6.8.4 Process Description:

Step	Name	From	To	Description	Data Sources
1	Calculate Network Peak Loading	ESB Networks	ESB Networks	Taking the network model, ESB Networks will calculate the loading of each system element within the distribution network model at peak times and derive the required capacity at the transmission interface to service that peak demand.	Network Demand Profile Yr 1
2	Calculate Peak Loss Capacity kW			The difference between the kW capacity required at the network source and the demand kW served by the system. This difference is the system capacity required to support the losses at system peak demand.	
3	Calculate Capacity Loss Value			This will require knowledge of the cost to provide one kW of incremental system capacity. The calculation is the simple product of the marginal Capacity Cost and the Peak Loss Capacity amount.	Marginal Capacity Costs
4	Calculate Loss Load Factor			In order to determine the expected annual average energy loss on the network, the load factor for the energy losses can be calculated on the basis of the following equation: Copper Loss LF = A*LF^2 + LF*(1-A) where A is 0.85 Fixed Loss LF = Demand Load Factor LLF = Fixed LLF * (1-A) + Copper LLF * A	Network Demand Profile Yr 1
5	Calculate Energy Loss kWh			This Loss Load Factor can then be used to determine the approximate energy loss on the system by multiplying the peak loss capacity by the Loss Load Factor and the number of hours in the year (8760).	

Step	Name	From	To	Description	Data Sources
6	DWA Energy Price for Losses			The Demand Weighted Average energy price would ideally be derived from market prices and the forecast energy losses during each settlement period in the year. $DWA = \sum_{n=1}^{x} kWh_n * MP_n \;/\; \sum_{n=1}^{x} kWh_n$ Where: x = number of settlement periods in a year KWh_n = net system demand in each of the settlement periods in the year MP_n = market price during a settlement period Recognising that the level of detail of information may not be readily available or could be subject to interpretation, it is considered prudent to reference prices that relate to system plant operating in a similar mode:- • Base Load >75%LF (BNE Pricing); • Mid Merit 30 to 75%LF (ESB PG Allowable revenue); • Peaking <30% LF (Oil plant price). This may not provide the finest detail, however, it retains transparency in terms of price derivation and gives simplicity to the calculation process – therefore reducing the overhead required.	Market Prices Loss Load Factor Peak Loss Capacity
7	Calculate Value of Energy Losses kWh			This energy price may then be multiplied with the energy losses to derive the value of the system energy loss in the year	

Step	Name	From	To	Description	Data Sources
8	Project Value of Losses			Project the value of the losses on the basis of the network at this point in time over the proposed time horizon – 15 years. NPV = Sum of [Loss Value$_n$ / (1+DF)^n] for n = 1 to 15 where Loss Value is constant.…….	Financial Data
9	Calculate Network Peak Loading			Using the revised network model with generation developed in the LCTAS process, ESB Networks will calculate the loading of each system element within the distribution network model at peak times and derive the required kW capacity at the transmission interface to provide that demand. The system demand profile will need to be amended to take into account the expected output from the generator at the peak time. This may entail incorporating a ‘diversity’ factor to represent the intermittency of the generation output (Wind) or to factor in expected plant reliability.	Generation Profile; Network Demand Profile Year 1 Network Model with Generation
10	Calculate Peak Loss Capacity			The difference between the kW capacity required at the transmission system interface at peak time and the demand kW served by the system. This difference is the system capacity required to support the losses at system peak demand.	
11	Calculate Capacity Loss Value			This will require knowledge of the cost to provide one kW of incremental system capacity. The calculation is the simple product of the Marginal Capacity Cost and the Peak Loss Capacity amount.	Marginal Capacity Costs

Step	Name	From	To	Description	Data Sources
12	Calculate Loss Load Factor			In order to determine the expected annual average energy loss on the network, the load factor for the energy losses can be calculated on the basis of the following equation: Copper Loss LF = A*LF^2 + LF*(1-A) where A is 0.85 Fixed Loss LF = Demand Load Factor LLF = Fixed LLF * (1-A) + Copper LLF * A	
13	Calculate Energy Loss			The Loss Load Factor can then be used to determine the approximate energy loss on the system with the generation connected. This loss calculation needs to take into account that the generation will not be available 100% of the year therefore the loss benefit will not always be on the basis of the calculated peak benefit. To provide an approximation it is assumed that when the generation plant is not operating the average distribution energy loss occurs. Energy Loss with Generation = LLF * Peak Loss Capacity with Gen (kW) * Generator Availability * 8760 + (1- Generator Availability) * Energy Loss without Generation	

Step	Name	From	To	Description	Data Sources
14	DWA Energy Price for Losses			The Demand Weighted Average energy price would ideally be derived from market prices and the loss load factor to give a price for the energy loss saved. $DWA = \sum_{n=1}^{x} kWh_n * MP_n \ / \ \sum_{n=1}^{x} kWh_n$ Where: x = number of settlement periods in a year KWh_n = net system demand in each of the settlement periods in the year MP_n = market price during a settlement period Recognising that the level of detail of information may not be readily available or could be subject to interpretation, it is considered prudent to reference prices that relate to system plant operating in a similar mode:- • Base Load >75%LF (BNE Pricing); • Mid Merit 30 to 75%LF (ESB PG Allowable revenue); • Peaking <30% LF (Oil plant price). This may not provide the finest detail, however, it retains transparency in terms of price derivation and gives simplicity to the calculation process – therefore reducing the overhead required.	Loss Load Factor
15	Calculate Energy Loss Value			This energy price may then be multiplied with the energy losses to derive the value of the system energy loss in the year	
16	Project Loss Value			Project the value of the losses on the basis of the network at this point in time. Time horizon is assumed to be 15 years. NPV = Sum of [$\text{Loss Value}_n / (1+DF)^n$] for n = 1 to 15 where Loss Value_n is constant across the projection period.	Financial Data

Step	Name	From	To	Description	Data Sources
17	Calculate Annual Differences			Compare the annual loss values for the existing network and the network with the additional generation to derive a net projection of loss benefit on a year-by-year basis. Loss Benefit = Existing Loss Value – New Loss Value	

6.9 Voltage Benefit Calculation

Embedded generation are typically located closer to the load than system generation plant. This provides an opportunity for the embedded plant to offset some to the reactive power requirements at the distribution system interface with the transmission system providing a number of benefits to the distribution system. Namely – deferred capital expenditure on the reinforcement due to power factor improvement; savings on voltage control equipment and reduced take of reactive energy.

Many embedded generation plant are capable of providing reactive power to support voltage on the distribution network. Conceivably this capability could allow the embedded generator to participate in the ancillary services provision market – although this will be dependant on its connection location within the distribution system. More typically the generator will provide benefit local to its connection point in terms of improved quality of supply.

Embedded generation connection to the distribution network is expected to require a more active approach to distribution system control and operation – a change that will require further investment in assets and development of new skill sets within the DNOs. This will become more pressing as a greater number and capacity of embedded plant are connected to the network.

At the level of an individual embedded generation connection it is difficult to determine the incremental impact that the plant will have on the operational costs within the DNO. Rather any cost increases are expected to become apparent as they increase with the increase in DG connections. On this premise the costs would then be most appropriately recovered on a societal basis through the DUoS charging structure from all distribution system users, given that all system users are receiving the resultant benefits from active management of the network. As a consequence these items are not considered further within the scope of this calculation process.

The majority of ESB Networks system is characterised as typical rural networks, based on overhead distribution with long radial MV feeders supplying power to remote loads in sparsely populated areas. Such network configurations are very susceptible to poor voltage regulation under peak load conditions (ESB typically install booster transformers on the longest feeders to enable voltage criteria to be met) with significant voltage drops being experienced between the source substation and the remote end of the MV feeder. Connecting embedded generation to such networks tends to improve the situation through provision of voltage support. Although the extent of any improvement largely depends on where the generator is connected and its capacity. If the generator can provide sufficient voltage support then the DNO may avoid the need to provide additional voltage support mechanisms. However, such benefits to the DNO may come at a cost to the generator in terms of connection location, connection costs and power factor restrictions on operation.

The calculation process within this section assumes that the generator is connected to a point on the network that has sufficient short circuit capacity to allow generator switching operations whilst staying within the allowed limits for step change in voltage – required to ensure compliance with the LCTAS connection design.

Voltage flicker is a consideration, however, it is difficult to quantify given that it is predominantly driven by individuals' perception at the point of use. Similarly waveform harmonics are not qualified within this calculation process as the impact of these are accounted for within the connection costs and choice of point of connection made in the LCTAS process.

6.9.1 Inputs

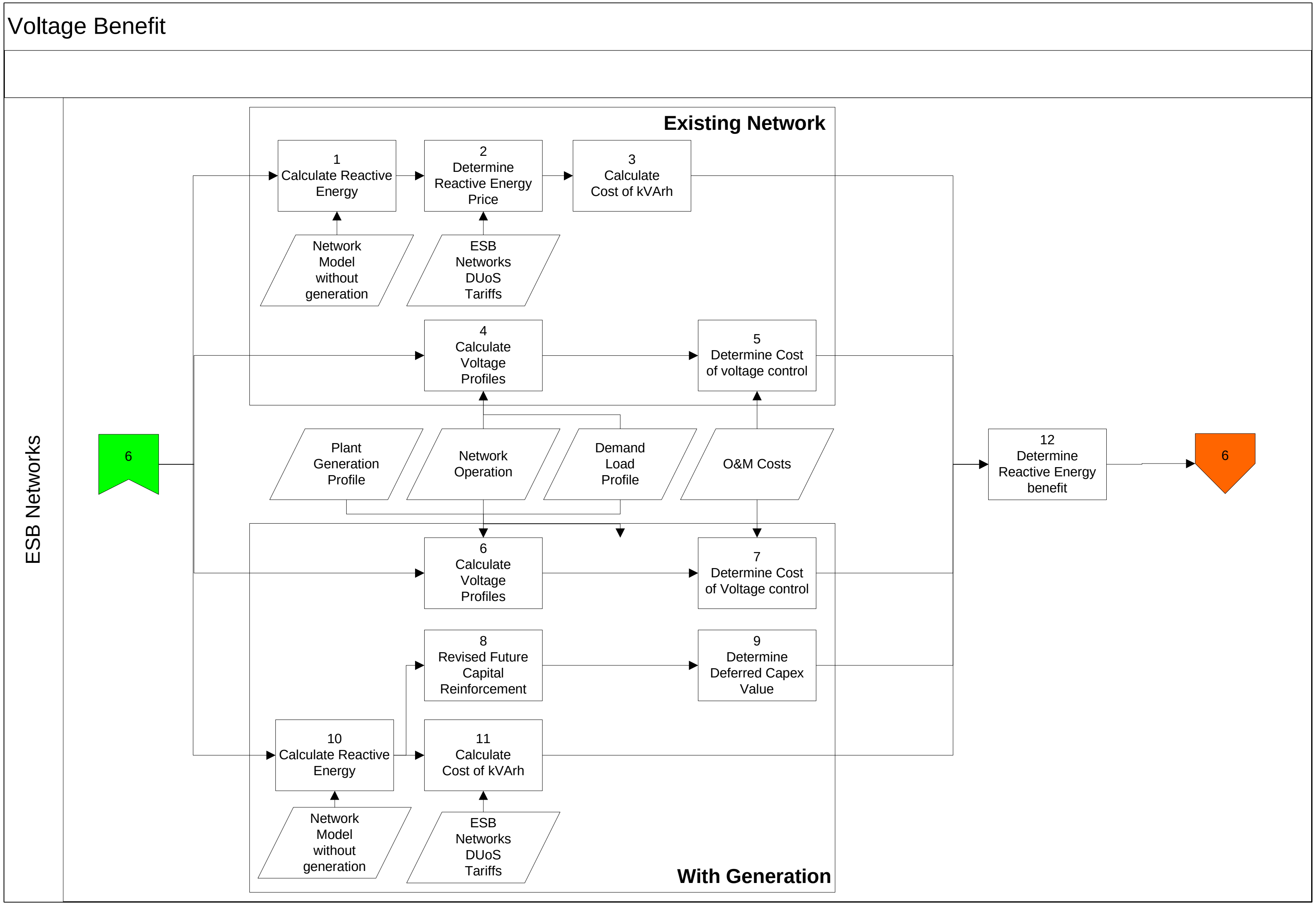
Network Parameters; Reactive Power Costs; Embedded generation profile; Demand Load Profile; O&M Costs; Asset Life Costs

6.9.2 Outputs

Net Voltage Benefit

6.9.3 Participants

ESB Networks


Voltage Benefit
ESB Networks
Existing Network
6
1 Calculate Reactive Energy
2 Determine Reactive Energy Price
3 Calculate Cost of kVArh
Network Model without generation
ESB Networks DUoS Tariffs
4 Calculate Voltage Profiles
5 Determine Cost of voltage control
Plant Generation Profile
Network Operation
Demand Load Profile
O&M Costs
6 Calculate Voltage Profiles
7 Determine Cost of Voltage control
8 Revised Future Capital Reinforcement
9 Determine Deferred Capex Value
10 Calculate Reactive Energy
11 Calculate Cost of kVArh
Network Model without generation
ESB Networks DUoS Tariffs
With Generation
12 Determine Reactive Energy benefit
6

6.9.4 Process Description:

Step	Name	From	To	Description	Data Sources
1	Calculate Reactive Energy (kVArh)	ESB Networks	ESB Networks	ESB Networks will calculate the total reactive energy to supply the demand and losses on the network. This calculation will use the total energy consumption on the network at the Distribution :Transmission interface and the annual average load factor. kVArh pa = Peak kVArh * System Demand Load Factor This assumes constant power factor throughout the year. Where specific integrated annual metering data is available for this interconnection point this data will be used to obtain the reactive energy consumed by the network during the year.	Network Model without Generation Demand Load Profile Annual Energy Demand Annual Average Power Factor Metering data (if available)
2	Determine Reactive Energy Price	ESB Networks	ESB Networks	Pricing of reactive energy charged to DNO connected customers. This assumes that the cost of the reactive energy is displaced at the point of use rather than at the point of Distribution :Transmission interface. Therefore the pricing used is that stated in the current ESB Networks UoS tariffs for reactive energy at the same voltage level as the embedded generation connection.	ESB published DUoS tariffs
3	Calculate Cost of kVArh	ESB Networks	ESB Networks	Using the annual reactive energy use and the reactive energy price calculate the cost of the annual kVArh supplied. kVArh Cost = kVArh Use * kVArh price This provides a base-line for the cost of reactive energy for the distribution network.	
4	Calculate Voltage Profiles	ESB Networks	ESB Networks	The system voltage profile will vary with the demand and the operational decisions made in respect of system configuration. These data will determine the necessary control actions required or assets to be installed as part of the normal planning process.	

Step	Name	From	To	Description	Data Sources
5	Determine Cost of Voltage Control	ESB Networks	ESB Networks	It may be possible to determine the impact of voltage control operations on the overall asset operating lives and maintenance costs associated with the assets. However, these costs will be incorporated within the analysis undertaken as part of ESB Networks normal system planning process and therefore these costs will be incorporated into the DUoS charges for cost recovery. They are not considered further within this calculation.	
6	Calculate Voltage Profiles	ESB Networks	ESB Networks	The system voltage profile will vary with the demand and the operational decisions made in respect of system configuration. The LCTAS process of determining the required connection and reinforcement to enable connection of the embedded generation will determine the impact on the system voltage profiles.	
7	Determine Cost of Voltage Control	ESB Networks	ESB Networks	The additional costs of voltage control will be accounted for within the connection offer (depending on whether a shallow or deep regime applies) and through DUoS charging.	
8	Calculate Revised Future Capital Reinforcement	ESB Networks	ESB Networks	To the extent that there is a deferral in the need to incur voltage driven system reinforcement capital spend then there will be a benefit from the connection of the embedded generation to the distribution network. The capital expenditure associated with any voltage driven capital expenditure will need to be identified , the previously planned to be implemented date and the revised implementation date.	ESB Network Plan

Step	Name	From	To	Description	Data Sources
9	Determine Deferred Capex Value	ESB Networks	ESB Networks	This calculation will derive the difference in the present value of the 'before' and 'after' voltage driven distribution system reinforcement. Deferred Capex Value = 'Before' Capex Spend / (1 + DCF)^P1 – 'After' Capex Spend / (1+DCF)^P2 where: DCF = discount factor P1 = no. of years difference between present year and initial investment year; P2 = no. of years difference between present year and the revised investment year;	
10	Calculate Reactive Energy with Generation	ESB Networks	ESB Networks	ESB Networks will calculate the total reactive energy to supply the demand and losses on the network with the generation operational. This calculation will use the expected generation profile to determine the total energy consumption on the network at the Distribution :Transmission interface and the annual average load factor. kVArh pa = Peak kVArh * System Demand Load Factor This assumes constant power factor throughout the year. Where specific integrated annual metering data is available for this interconnection point this data will be used to obtain the reactive energy consumed by the network during the year.	Generation Profile; Demand Load Profile;

Step	Name	From	To	Description	Data Sources
11	Calculate Value of kVArh Saved	ESB Networks	ESB Networks	Using the annual reactive energy use and the reactive energy price calculate the cost of the annual kVArh supplied. kVArh Cost = kVArh Use * kVArh price The kVArh price will be the value derived in Step 2. Then this value is subtracted from the result from Step 3 to derive the reactive energy benefit from the embedded generation operation in one year.	
12	Determine Reactive Energy Benefit	ESB Networks	ESB Networks	This is the sum of the deferred capex benefit (Step 9) and the Present Value of the result in Step 11 (Value of kVArh Saved) over the 15-year projection period. Reactive Energy Benefit = Deferred Capex Benefit + $\sum_{n=1}^{15}$ (Value of kVArh saved / $(1+DF)^n$) where Value of kVArh saved is constant across the period.	

6.10 CML Benefit

In the event of an incoming supply failure to an area of the distribution network in which generation is embedded, protection equipment can be set to operate (on the basis of the rate of change of frequency) to “island” the embedded generation and part of the affected network in order to ensure that at least part of the affected load remains supplied. The obvious benefit of this “islanding” capability is that it reduces the amount of lost load. In remote areas that suffer regular interruptions in supply, the savings in respect of lost load could be relatively high. The economic savings are dependent on the Value of Lost Load (VoLL) and the outage duration. The Distribution Network Operator (‘DNO’) will benefit from reductions in the number of Customer Minutes Lost (CMLs) and Customer Interruptions (CI’s) that are used to measure supply availability on the allowed DUoS revenue, whilst the customer will benefit from an improvement in the availability of supply.

To facilitate “islanding” of the network the DNO will be required to install more complex interface protection to satisfy safety and supply quality criteria.. An additional cost that also has to be borne is for a secure communications channel from the generator to the DNO’s control centre. It should be noted here that at the time of writing this report, ESB Networks prohibits “islanding” generation with matched blocks of demand due to safety and supply quality concerns. Therefore, whilst CML benefit maybe realisable, such benefit could be outweighed by the cost to implement an islanding scheme that addresses these safety and quality concerns.

The overall CML benefit will be the net of the costs associated with the implementation and operation of any “islanding” scheme for the embedded generation and the value attributable to any savings in the amount of lost load (CML saved * VoLL) and additional cost recovery through additional DUoS charges that can be made to customers. There may also be benefit derived by the DNO through cost savings from avoided penalties that could be imposed in the event that they do not meet quality of supply / CML target levels in a given period – however, these have not been included within the calculation.

6.10.1 Inputs

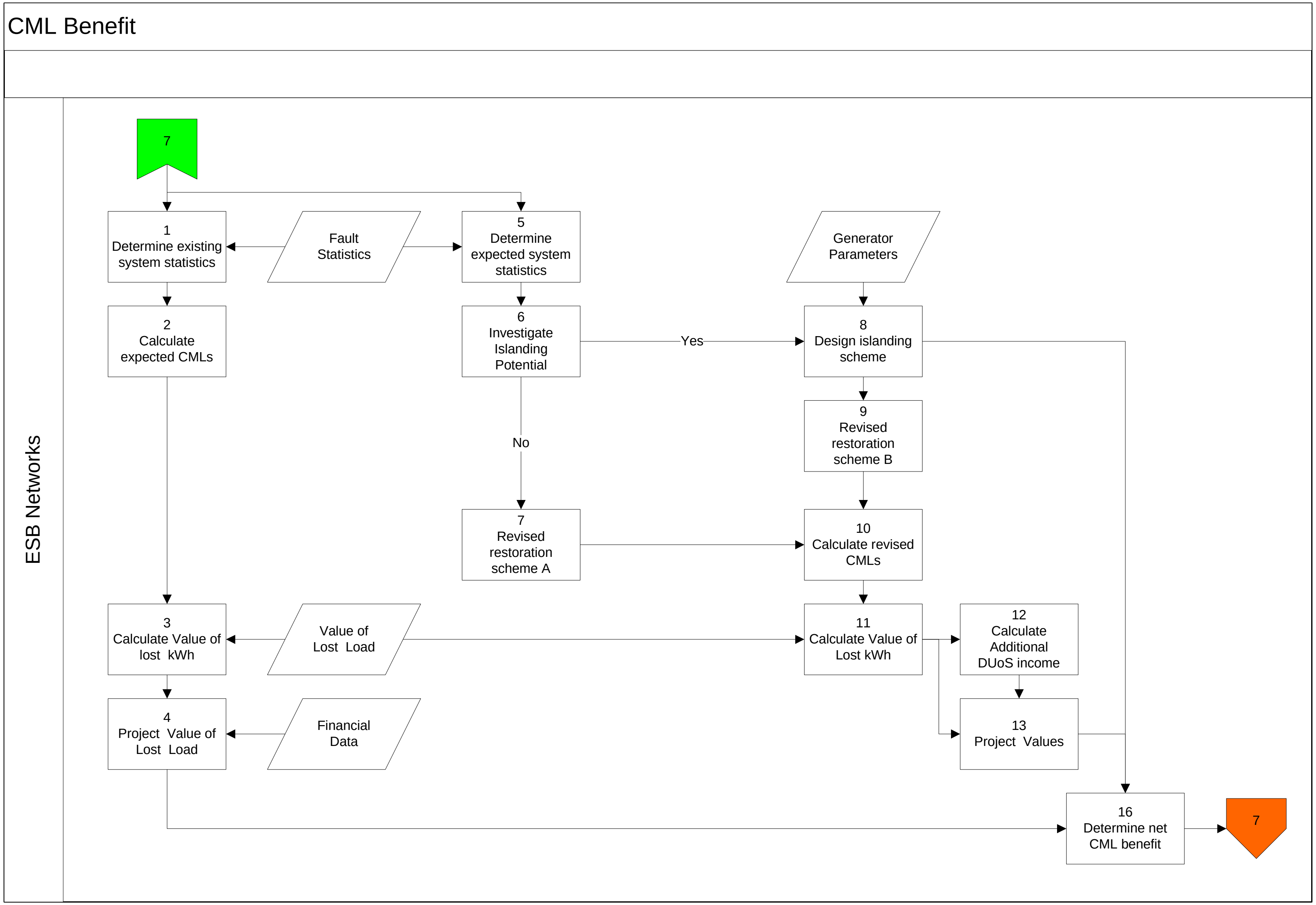
Islanding Scheme costs; Network Topography; Network Equipment Statistical data; Network Operational restoration statistics; Customer Interruption statistics; Value of Lost Load; Financial Data

6.10.2 Outputs

Net CML Benefit

6.10.3 Participants

ESB Networks


CML Benefit
ESB Networks
7
1 Determine existing system statistics
Fault Statistics
5 Determine expected system statistics
Generator Parameters
2 Calculate expected CMLs
6 Investigate Islanding Potential
Yes
8 Design islanding scheme
9 Revised restoration scheme B
No
7 Revised restoration scheme A
10 Calculate revised CMLs
3 Calculate Value of lost kWh
Value of Lost Load
11 Calculate Value of Lost kWh
12 Calculate Additional DUoS income
4 Project Value of Lost Load
Financial Data
13 Project Values
16 Determine net CML benefit
7

6.10.4 Process Description:

Step	Name	From	To	Description	Data
1	Determine Existing Network Statistics	ESB Networks	ESB Networks	The calculation of the network section System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI) values will need to be completed by ESB networks, to allow the determination of the expected CML's on that network.	Network Topography Failure statistics Network Fault statistics
2	Calculate Expected CMLs	ESB Networks	ESB Networks	This will be the product of the number of customers served by the network section, the network SAIDI and the network SAIFI. This will give the expected number of customer minutes lost on that section of the network in a year. CML pa = No of Customers * SAIDI *SAIFI	Number of customers supplied on network segment;
3	Calculate Value of Lost kWh	ESB Networks	ESB Networks	The quantity of energy supplied per customer minute for the network is calculated, multiplied by the number for customer minutes lost and then by the Value of Lost Load to determine the value of the lost kWh. Energy / Customer Minute = $\frac{\text{(Peak Power Demand * Load Factor * 8760)}}{\text{No. of customers * 60}}$ Energy Lost due to faults = CML pa * Energy / Customer Minute Value of Lost Energy = Energy Lost due to Faults * Value of Lost Load This calculation assumes that the fault incidence is random and that the customers affected by faults over a year are equivalent to an 'average' customer connected to that network. If	Value of Lost Load; Real Power Peak Demand; Demand Load Factor;

Step	Name	From	To	Description	Data
				there are specific weaknesses in the distribution network that will effect a skew to the incidence of faults towards a particular group of customers this will need to be recognised in the calculation.	
4	Project Value of Lost kWh	ESB Networks	ESB Networks	The annual value of the lost load is calculated to give a present value from a 15-year project period $\sum_{n=1}^{15}$ (Value of Lost kWh / $(1+DF)^n$) The Value of Lost Load remains constant for each year of the project.	Financial Data
5	Determine Expected System Statistics	ESB Networks	ESB Networks	Following the completion of the LCTAS connection design process the new equipment and any system reinforcement will have been identified. From the historic fault statistics for these new equipment types - a revised expectation for SAIFI - $SAIFI_g$ - can be determined.	Fault Statistics;
6	Investigate Islanding Potential	ESB Networks	ESB Networks	Prior to any significant effort being expended on developing detailed islanding scheme design, ESB should investigate the possibility for the generator to provide island support to the network. This will need to take into consideration the type of renewable generator, its electrical capabilities and expected generation profile. An intermittent generator is unlikely to be regarded as suitable for an islanding scheme, however, biomass plant or other 'non-intermittent' technologies may be seen to be suitable. If the generation is suitable then move to Step 10 – Design Islanding Scheme	Output from LCTAS
7	Revised Restoration Scheme A	ESB Networks	ESB Networks	If the scheme is not regarded as being suitable to connect the generator as an islanding scheme then ESB Networks will need to devise a revised restoration scheme for the network. This revised restoration scheme will allow calculation of the revised average system interruption duration ($SAIDI_a$) that will be used in the calculation of the expected CMLs with the generator connected (Step 10)	

Step	Name	From	To	Description	Data
8	Design Islanding Scheme	ESB Networks	ESB Networks	If the scheme is regarded as being suitable to connect the generator in island mode then ESB Networks will need to design a generator islanding scheme in order to control the load allocated to the generator and also to ensure that additional protection (egg RoCoF) is installed and that the ESB operational control centre is able to control the generator to allow re-synchronisation of the islanded network following clearance / restoration of the faulted network. The cost of implementing such an islanding scheme will be used to offset any benefit arising from reduced CMLs.	
9	Revised Restoration Scheme B			ESB Networks will need to devise a revised restoration scheme for the network to take into account the islanding capability of the generator. This revised restoration scheme will allow calculation of the revised average system interruption duration ($SAIDI_b$) that will be used in the calculation of the expected CMLs with the generator having island mode capability.	
10	Calculate the revised CMLs			ESB Networks will need to recalculate their projection of the CMLs for the network with the generation connected using either restoration scheme A or Restoration Scheme B. Revised CMLs = No of Customers * SAIDI * $SAIFI_g$ Where: SAIDI = $SAIDI_a$ when there is no islanding or $SAIDI_b$ when an islanding scheme is implemented No. of customers = Difference between the total number of customers on the network and those within the islanding scheme. As those within the islanding scheme are assumed to have no interruption in a year. Therefore the CML calculation will only apply to those customers connected outside the islanding scheme.	Generation Profile

Step	Name	From	To	Description	Data
11	Calculate the Value of Lost kWh			The quantity of energy supplied per customer minute for the network is calculated, multiplied by the number for customer minutes lost and then by the Value of Lost Load to determine the value of the lost kWh. The calculation will be slightly different depending on whether the islanding scheme is implemented or not. If it is then the amount of energy lost will be reduced due to the additional energy supplied to the customers in the affected area. This assumes that the islanding scheme provides support to customer demand able to be supplied by the generation capacity (i.e. effective use is made of the generator output) Energy Lost due to faults = CML * Energy / Customer Minute Value of Lost Energy = Energy Lost due to Faults * Value of Lost Load	Value of Lost Load

Step	Name	From	To	Description	Data
12	Calculate Additional DUoS income			To the extent that the embedded generation is able to provide energy to customers within the curtelage of the islanding scheme during times of system faults, there will be additional revenue for the DNO from DUoS charges that would otherwise have been forgone. The value of the DUoS charges has been assumed to be that levied on customers with a connection voltage similar to the embedded generator. Additional DUoS income = (Existing Lost Load – Revised Lost Load) * DUoS Where: Existing Lost Load = output from Step 3 Revised Lost Load = result of the Energy Lost due to faults calculation in Step 11	
13	Project Values of annual benefits			Value of Benefit = $\sum_{n=1}^{15}$ (Additional DUoS Income$_n$ / $(1+DF)^n$) + Value of Lost kWh (existing) – Value of Lost kWh (with Generation)	
14	Net CML Benefit			Net CML Benefit = Value of Benefit – Cost of Islanding Scheme	

6.11 Asset Benefit

The connection of embedded generation to the distribution network introduces a new source of power on to the network, that in many cases is located much closer to the demand than the existing power source, i.e. the local bulk supply point. Consequently when the generation is in service delivering power to the network it will affect the power flow between the existing source and the generator, and between the generator and the local customers. Of course the extent to which the power flow is affected will depend largely in the magnitude of the connected generation, the configuration of the network and the location of the generation itself.

In general the effect of the embedded generation will be to reduce power flows on the distribution network when the generation is in service, although where the generation is teed into the existing network the power flow in the network in the vicinity of the generator connection may well be increased.

In cases where the change in power flow on the local network in which the generation is embedded is significant, and the output from the generation is considered a secure and reliable supply, then the embedded generation can have a positive impact as far as the DNO reinforcement of the network in a particular area.

Embedded generation within a sector of the distribution network may contribute to the security of supply within that sector, although this depends on the nature of the generation – wind for example provides little or no contribution to system security unless available in substantial quantities when aggregation can provide some contribution. In cases where the generation contributes to the security of supply of that distribution sector, the DNO can subtract the corresponding load from the capacity of the connection it requires to the transmission system. Over the longer term the reduced load may make it possible to avoid reinforcing or upgrading this connection and thus reduce costs through avoided capital expenditure.

In a similar way embedded generation on the distribution network will reduce power flow down through the transmission network to the local area bulk supply point. This can also allow the TSO to delay transmission system reinforcement, particularly at the local bulk supply point. In the longer term, the overall concentration from a much higher concentration of embedded generation on the network will be to reduce the power that would be transported across the transmission system to well below the level that would be obtained if Ireland were to continue with its reliance on conventional power stations connected to the transmission system. The load-related capital expenditure budget of the TSO under this “embedded generation” scenario will then be significantly lower than the budget for the alternative scenario in which embedded generation continues to play a minor part.

Although the effect of embedded generation on system reinforcement is seen as a reinforcement is seen as a real benefit, in that it can allow network reinforcement to be delayed or avoided altogether, there may be an ‘upfront’ cost to the DNO and the Developer. This is the cost associated with strengthening the local network, near to where the generator is connected, to allow the generation to deliver its contracted power to the network without any constraints. This is typically the cost reflected in the connection offer made by ESB Networks to a Developer for connection to the ESB Network.

6.11.1 Inputs

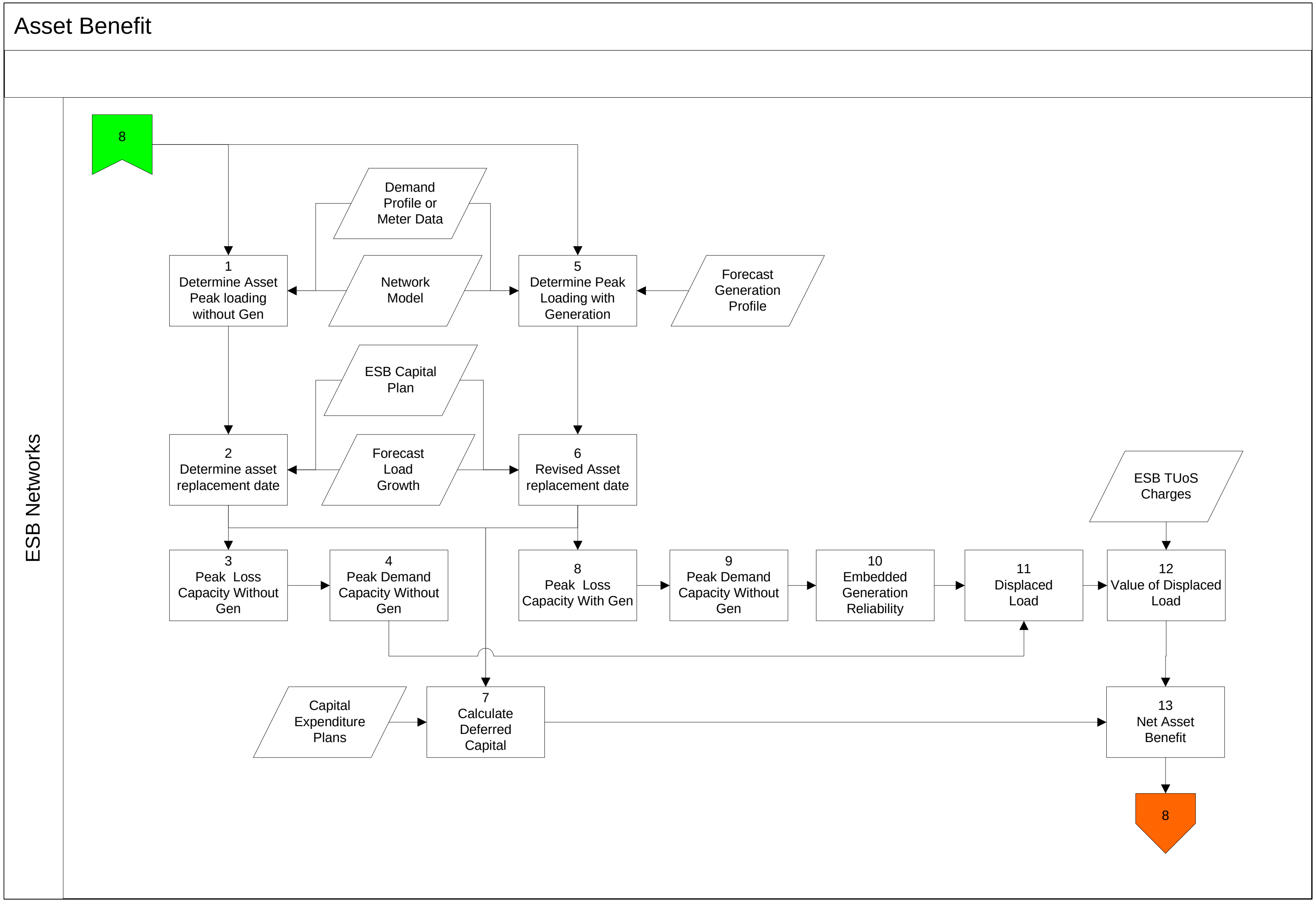
Network Demand Profile; Forecast Load Growth; Forecast Generation Profile; Asset Replacement Costs

6.11.2 Outputs

Asset Benefit

6.11.3 Participants

ESB NG; ESB Networks


Asset Benefit
ESB Networks
8
Demand Profile or Meter Data
1 Determine Asset Peak loading without Gen
Network Model
5 Determine Peak Loading with Generation
Forecast Generation Profile
ESB Capital Plan
2 Determine asset replacement date
Forecast Load Growth
6 Revised Asset replacement date
ESB TUoS Charges
3 Peak Loss Capacity Without Gen
4 Peak Demand Capacity Without Gen
8 Peak Loss Capacity With Gen
9 Peak Demand Capacity Without Gen
10 Embedded Generation Reliability
11 Displaced Load
12 Value of Displaced Load
Capital Expenditure Plans
7 Calculate Deferred Capital
13 Net Asset Benefit
8

6.11.4 Process Description:

Step	Name	From	To	Description	Data
1	Determine Asset Peak Loading without Generator	ESB Networks	ESB Networks	On the basis of the network without the generator connection, the peak loading will be calculated for the present demand profile. It is likely that there will be meter data for the distribution network off take at the transmission boundary – in which case the annual coincident reactive and real power peak readings should be used.	Network Demand Profile Network Parameters
2	Determine Asset Replacement Date	ESB Networks	ESB Networks	The asset replacement date will be determined utilising the present asset replacement policy, asset age, peak loading and expected load growth. There will be reinforcement plans in place for the network as part of the ESB Network capital plan. It is the cost and implementation date for these investments in the distribution network that are required.	Forecast Load Growth ESB Networks Capital plan
3	Peak Loss Capacity without generation	ESB Networks	ESB Networks	The calculated values of the kW and kVAr capacity requirements of the network to support the supply of electricity to the connected customers. This is for the existing network without the generator connected.	
4	Peak Demand Capacity without Generation	ESB Networks	ESB Networks	This is the arithmetic difference between the system peak kW and kVAr capacity requirements and the peak loss kW and kVAr capacity requirements. This gives the proportion of the peak kW and kVAr capacities that serve the demand.	
5	Determine Asset Peak Loading with Generation	ESB Networks	ESB Networks	Using the network model with the generation connection and generator included the network peak loading in terms of real and reactive power can be calculated. This is network modelling process is not specified in any more detail within this study as it is a normal part of the ESB system capital planning activity.	Network Model with Generation Demand Load Profile Generation Output Profile
6	Revised Asset Replacement Date	ESB Networks	ESB Networks	As a result of the connection of the embedded generation there may be a deferral in the need to reinforce the distribution network. Such a capital expenditure deferral may arise due to additional capacity being made available through the addition of the assets required to connect the embedded generator. The output of this assessment will be a value for capital expenditure and the expected implementation date(s). All capital expenditure should relate to the network segment that the embedded generation is connected to.	Forecast Load Growth ESB Capital Plan

Step	Name	From	To	Description	Data
7	Calculate Deferred Capital	ESB Networks	ESB Networks	The deferred capital expenditure will be determined by comparison of the ESB capital expenditure requirement for the network before the generation connection and the capital plan after the generation has been connected. This comparison will be the difference in the present values of the two capital expenditure profiles. These capital plans may incorporate a number of discrete investments at different points in time. The calculation of the capital plan present value in each scenario is set out below: $\text{Capital Plan PV (No Gen)} \bullet \sum_{n=1}^{15} (\text{Capital Investment}_n \ / \ (1+DF)^n)$ $\text{Capital Plan PV (Gen)} \bullet \sum_{n=1}^{15} (\text{Capital Investment}_n \ / \ (1+DF)^n)$ Deferred Capital Benefit = Capital Plan PV (No Gen) - Capital Plan PV (Gen) It is the difference between the two calculated present values that gives the deferred capital benefit. NOTE if there is no benefit as a result of the generation being connected to the DNO network the Deferred Capital Benefit = 0.	Capital Expenditure Plans before and after connection of the embedded generation plant
8	System Peak Loss Capacity with Generation			The embedded generation will impact on the system losses (either through increasing them or decreasing them) – either way this will impact on the proportion of the required system peak capacity to service the system peak demand. The financial cost of this loss impact is accounted for within the Loss Benefit calculation and therefore is not included within the calculation of 'Displaced Load' other than to determine the capacity released to service additional demand.	
9	System Peak Demand Capacity Requirement			The proportion of the peak system capacity that is solely attributable to the provision of electricity to the connected customer demand – this is exclusive of system capacity	

Step	Name	From	To	Description	Data
	with Generation			required for losses. Peak Demand Capacity requirement (kW) = Network Peak Loading with Generation (kW) (Step 3) * Peak Loss Capacity with Generation (kW) (Step 4) Peak Demand Capacity requirement (kVAr) = Network Peak Loading with Generation (kVAr) (Step 3) - Peak Loss Capacity with Generation (kVAr) (Step 4)	
10	Embedded Generation Reliability	ESB Networks	ESB Networks	The reliability of the embedded generation will need to be assessed. This is typically based on the technology and fuel used by the generator with intermittent fuel sources reducing the generation reliability from a distribution system perspective. For the purposes of the example calculations the following values for embedded generation reliability have been used: CHP = 85% Peat = 85% Biomass = 70% Hydro = 35% Wind = 25%	
11	Displaced Load	ESB Networks	ESB Networks	The amount of capacity that can be released for use by other customers or released back to the transmission network at the exit point is determined by the reliability of the generator and the difference between the peak demand capacity with and without the generation. Displaced Load = Generation Reliability * (Peak Demand Capacity (no Gen) (kW) from Step 4	

Step	Name	From	To	Description	Data
				- Peak Demand Capacity (with Gen) (kW) from Step 9)	
12	Value of Displaced Load			The value of the displaced load to ESB Networks is to the extent that they do not need to pay for the TUoS exit charge related to the avoided capacity. Value of Displaced Load = Demand Network Capacity Charge * Displaced Load	ESB National Grid TUoS charges
13	Determine Asset Benefit	ESB Networks	ESB Networks	A positive benefit arise when the costs of asset replacement under the no generation scenario are greater than the asset replacement cost under the with generation scenario. (Note: the cost of any asset replacement due to reinforcement activity related to the initial connection of the generator to the distribution system are accounted for outside this calculation through a deduction of the initial connection costs from the overall net benefits). Also the Displaced Load contribution to this benefit will need to be projected forward. It is recognised that the DNO may elect to not forgo transmission system exit capacity due to the uncertainties over load growth (i.e. it can be "chunky") or from concerns that the capacity, once released may be taken up by another party – therefore potentially increasing the DNO's future capacity costs. Irrespective there is an opportunity to reduce the transmission system exit capacity and a benefit associated with that in terms of avoided connection charges for the DNO. Asset Benefit = Deferred Capital Benefit $+ \sum_{n=1}^{15} (\text{Value of Displaced Load}_n / (1+DF)^n)$	

6.12 Transmission Benefits

The connection of embedded generation within the distribution system has a number of associated costs and benefits. Typically these have the greatest and most immediate impact on the distribution system to which they are connected. However, given the interconnected and real time nature of electricity networks the impacts of the embedded generation connection are not limited to the distribution system. The extent of the effect that embedded generation plant has on the transmission system at, and beyond the relevant transmission system exit point, is dependant on the size and electrical proximity of the embedded generation to the transmission system exit point.

The impacts that will be seen on the transmission system will parallel those seen on the distribution network. Including potential deferred capital expenditure, change in system losses and impact on the quality of supply that will impact the requirement for system ancillary service provision. This process within the calculation methodology allows the quantification of the impact of the embedded generation on the transmission system.

The impact of the displaced energy on the transmission system is accounted for within a separate part of the calculation methodology.

It is noted that the Market Arrangements for Electricity scheduled for introduction in 2005 will introduce locational marginal pricing (LMP) for each transmission entry / exit point. These LMPs will incorporate the cost of constraints, losses etc in sending a signal to the market in order that investment is made at the most appropriate places on the transmission system. In this case the loss and ancillary service cost / benefit calculation will only need look at any differential in the 'before' and 'after' LMP for the exit point to determine the impact o the embedded generation.

6.12.1 Inputs:

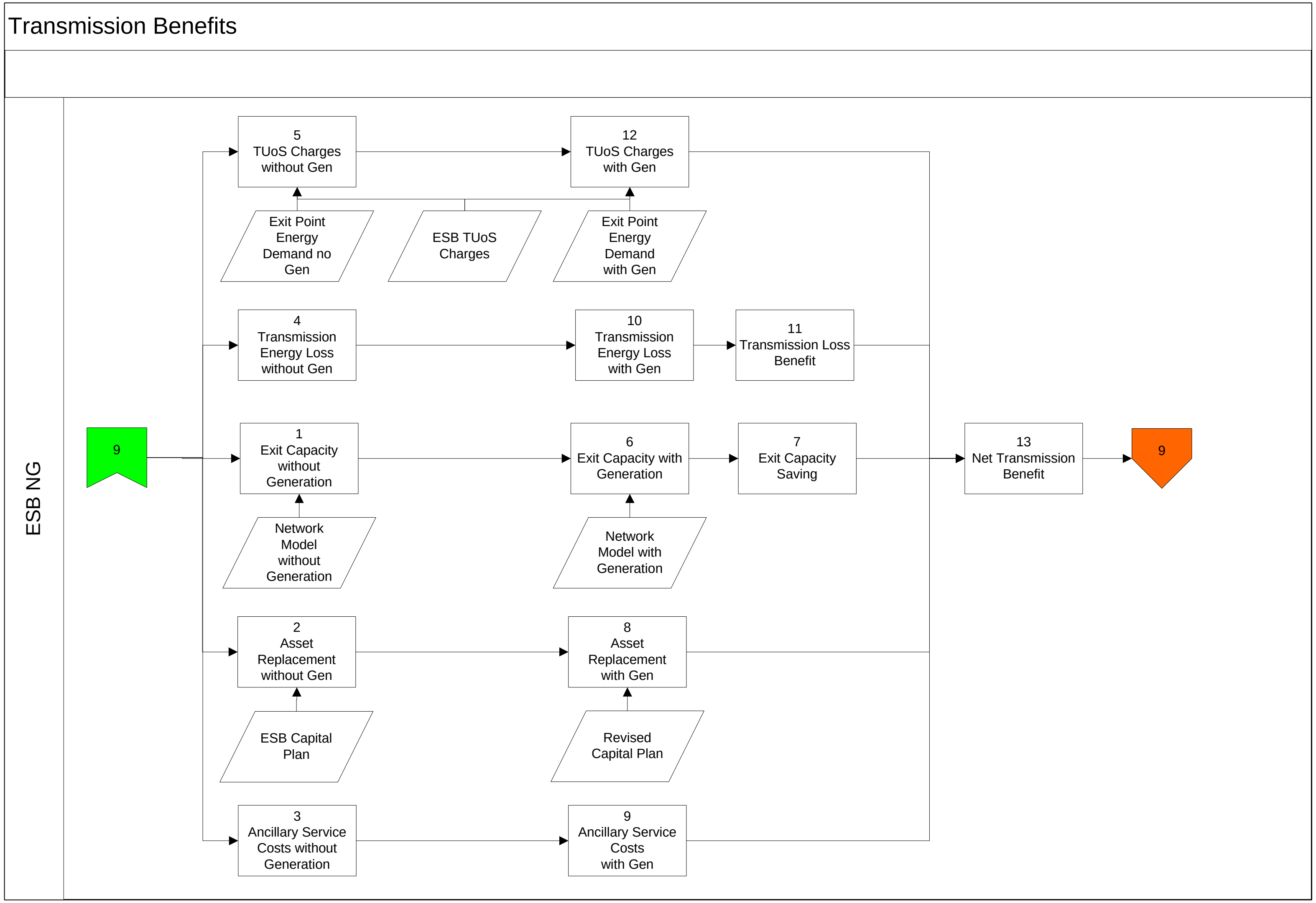
Transmission System Losses; Ancillary Service Contracts; System Operational Standards; Distribution Network Off-take capacity requirements

3.12.2 Outputs:

Net Transmission System Benefit

6.12.3 Participants:

ESB NG



Transmission Benefits
ESB NG
9
5
TUoS Charges
without Gen
12
TUoS Charges
with Gen
Exit Point
Energy
Demand no
Gen
ESB TUoS
Charges
Exit Point
Energy
Demand
with Gen
4
Transmission
Energy Loss
without Gen
10
Transmission
Energy Loss
with Gen
11
Transmission Loss
Benefit
1
Exit Capacity
without
Generation
6
Exit Capacity with
Generation
7
Exit Capacity
Saving
13
Net Transmission
Benefit
9
Network
Model
without
Generation
Network
Model with
Generation
2
Asset
Replacement
without Gen
8
Asset
Replacement
with Gen
ESB Capital
Plan
Revised
Capital Plan
3
Ancillary Service
Costs without
Generation
9
Ancillary Service
Costs
with Gen

6.12.4 Process Description:

Step	Name	From	To	Description	Data
1	Exit Capacity without Generation	ESB NG	ESB NG	This is the amount of exit capacity required to service the distribution system demand and losses at the relevant transmission exit point at peak times. This is determined by ESB Networks through modelling of the customer demands, however, where metered data is available at the transmission exit point this would be a preferable data source.	Exit Point Meter Data; ESB Networks system model
2	Asset Replacement	ESB NG	ESB NG	The requirement to replace transmission assets will be determined as part of the ESB NG capital planning process and should be identified within the capital expenditure budget for the business. The date and value of the transmission system capital spend related to the relevant transmission system exit point need to be identified.	ESB NG Capital Plan
3	Ancillary Service Costs Without DG	ESB NG	ESB NG	ESB National Grid may able to identify the cost of ancillary service arising from a particular transmission exit / entry point. In order to determine the ancillary service costs would require modelling of the Irish network in each settlement period on the basis of a number of generation dispatch scenarios. This has not been undertaken within this study.	
4	Transmission Losses without DG	ESB NG	ESB NG	This will require the annual average system loss (%), the energy off-take at the exit point (kWh) and the per unit cost of energy. Cost of Transmission Losses (Before) = Annual Average System Loss * Annual Energy Supplied at Exit Point * Energy Price	

Step	Name	From	To	Description	Data
5	TUoS Charges without Generation	ESB NG	ESB NG	This is the value of the annual TUoS charges payable by ESB Networks to supply the annual energy demand at the transmission exit point that the embedded generation is connected to. This includes the Demand Network Transfer Charge and the Demand System Service charges. The Demand Network Capacity Charge is not include within this part of the methodology since it is used to determine the value of the Displaced Load under the Asset Benefit calculation process and would be double counting if it was included here. TUoS charges (no Gen) = Demand Supplied (no Gen) (MWh) * (Demand Network Transfer Charge + Demand System Service Charge)	ESB NG TUoS charges
6	Exit Capacity with DG	ESB Networks	ESB NG	This is the amount of exit capacity required to service the distribution system demand at the relevant transmission exit point at peak times taking into account the expected generation output profile and any increase / decrease in the distribution system losses.	
7	Exit Capacity Saving	ESB Networks	ESB Networks	The difference between the ‘before’ and ‘after’ capacity required at the exit system boundary. However, the actual capacity saving will be equivalent to the quantity of displaced load. Therefore the exit capacity saving has been accounted for within the Asset Benefit calculation and recognising it again here would lead to double counting of the benefit. Further, the net impact of ESB Networks reducing the exit point capacity will lead to reduced revenue recovery for ESB NG, which over the longer term will be clawed back through higher TUoS charges for all customers.	
8	Asset Replacement with DG	ESB NG	ESB NG	The requirement to replace transmission assets may need to undergo re-planning due to the connection of the embedded generation and the delaying effect that it has on the load growth seen at the transmission exit point. To the extent that some capital expenditure items relating to the exit point can be delayed or even cancelled, there a benefit will accrue.	

Step	Name	From	To	Description	Data
				Deferred Capital Expenditure Benefit = $$\sum_{n=1}^{15} ((\text{Capital Investment (Before)}_n - \text{Capital Investment (After)}_n) / (1+DF)^n)$$	
9	Ancillary Services Costs with DG	ESB NG	ESB NG	As noted in Step 3 above this has not been included within this study.	
10	Transmission Loss with DG	ESB NG	ESB NG	This will require the annual average system loss (%), the energy off-take at the exit point (kWh) and the per unit cost of energy. Cost of Transmission Losses (After) = Annual Average System Loss * Annual Energy Supplied at Exit Point * Energy Price	
11	Transmission Loss Benefit	ESB NG	ESB NG	The Transmission Loss Benefit is the difference in the annual cost of losses associated with the provision of the energy demand (including distribution system loses) at the transmission exit point. Transmission Loss Benefit = Cost of Transmission Losses (Before) – Cost of Transmission Losses (After)	
12	TUoS charges With Generation	ESB NG	ESB NG	As in Step 5 above the Demand Network Capacity Charge is not included in this calculation. The revised annual energy off-take from the transmission system is used for this calculation. TUoS Charges with Gen = Energy Off-take with Generation (MWh) * (Demand Network Transfer Charge + Demand System Services Charge) Net TUoS Benefit = TUoS Charges (no Gen) – TUoS Charges with Gen.	

Step	Name	From	To	Description	Data
13	Transmission Net Benefit	ESB NG	ESB NG	This is the sum of all of the individual calculated elements: Transmission Net Benefit = Deferred Capital Expenditure Benefit $+ \sum_{n=1}^{15} ((\text{Transmission Loss Benefit}_n + \text{Ancillary Service Benefit}_n) / (1+DF)^n)$ $+ \sum_{n=1}^{15} (\text{Net TUoS Benefit}_n / (1+DF)^n)$	

6.13 Emissions Benefit

The use of renewable fuels for embedded generation will reduce greenhouse gas emissions and particulates. The level of reduction actually achieved will depend on factors such as:

The fossil fuel fired generation that is replaced or is avoided. For example, the replacement of existing coal fired plant by renewable generation would give a greater emissions reduction than if it is used to avoid gas-fired plant;

The strategy adopted to manage wind power variability. For example, operating thermal plants at part load to increase responsiveness will reduce their efficiency, resulting in lower emissions reductions per unit of wind energy generated;

The specific mix of embedded generation technologies adopted, remembering that not all embedded generation is renewable

Further benefit may be derived from avoided carbon trading costs under the auspices of the EU ETS. The total number of allowances must be consistent with each states Kyoto commitments but the allowance distribution is determined by national governments under the principle of subsidiarity. A reduction in generation emissions through an increase in embedded [renewable] generation could therefore make more allowances available for other Irish industries. This would reduce the number that would need to be purchased from other member states, or even provide income from sales of surplus allowances.

This process will calculate the cost of the emissions using the expected embedded generation profile to determine the type of system power plant that has been displaced. It is recognised that additional incremental emissions are likely to be caused due to the increased need for frequency response capability from the system plant to cover those occasions where the embedded generation is not producing. It is considered that the cost overhead in undertaking detailed system dispatch simulations for each embedded generation connection application would not be an efficient use of resources and as such have proposed this relatively rough assessment calculation.

6.13.1 Inputs

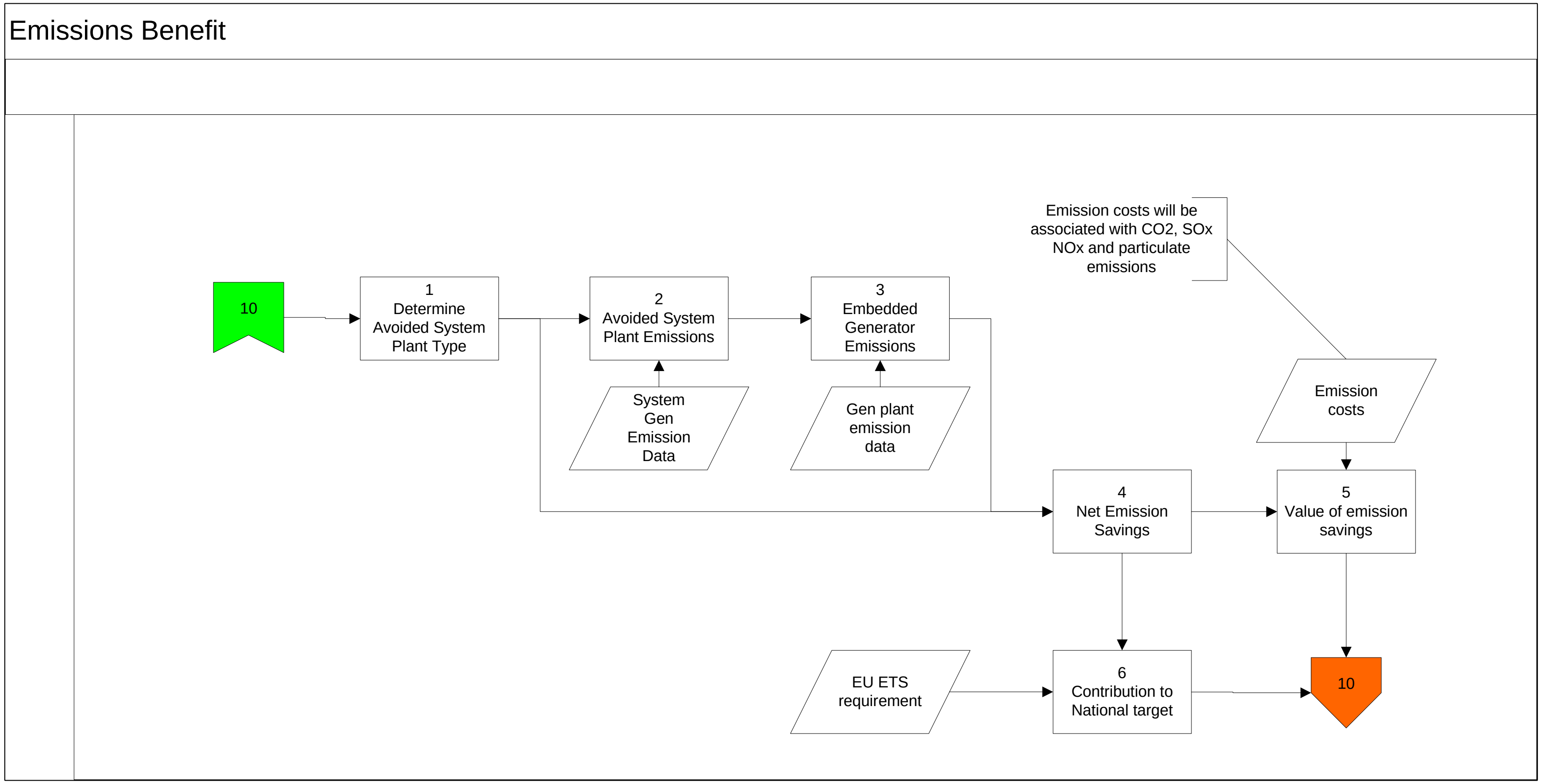
System Generation Emission data; Embedded Generator Emission Data; Emission Costs; EU ETS Requirements; System Plant Incremental Change Data

6.13.2 Outputs

Net Emission Benefit

6.13.3 Participants

ESB NG; ESB Networks


Emissions Benefit
10
1 Determine Avoided System Plant Type
2 Avoided System Plant Emissions
3 Embedded Generator Emissions
System Gen Emission Data
Gen plant emission data
Emission costs will be associated with CO2, SOx NOx and particulate emissions
Emission costs
4 Net Emission Savings
5 Value of emission savings
EU ETS requirement
6 Contribution to National target
10

6.13.4 Process Description:

Step	Name	From	To	Description	Data
1	Determine Avoided Plant Type	ESB Networks	ESB Networks	It is proposed that this is determined through consideration of the embedded generation expected load factor as determined from the expected generation profile. This load factor will then identify whether the embedded generation is expected to displace base load plant, mid merit plant or peaking plant. The proposed categories of plant are detailed below: • Base Load >75%LF • Mid Merit 30 to 75%LF; • Peaking <30% LF This selection of will determine the per unit gaseous emissions from this type of system plant.	Generation Load Profile
2	Avoided System Plant Emissions	ESB Networks	ESB Networks	The avoided system plant emissions can be calculated from the difference in the energy supplied at the transmission system exit point that the embedded generation is to be connected to. The energy supplied at the exit point takes into account any saving or increase in the distribution system losses arising from the embedded generation connection. Energy saved = Exit Point Demand (Before) – Exit Point Demand (After) Emissions Avoided (Tonnes pa) $= \frac{\text{Energy Saved * System Plant Per Unit Emissions}}{10^6}$ Where this calculation is repeated for each of the following pollutants – CO_2, NO_x and SO_x	System Plant Per Unit Emissions (g/kWh)

Step	Name	From	To	Description	Data
3	Embedded Generator Emissions	ESB Networks	ESB Networks	The emissions from the embedded generator will need to be calculated in order to determine the pollutants released by its operation. This will use the per unit emission values for the specific technology. Where possible data for the annual emissions for the specific embedded generation plant may be available as part of the environment consent application for the plant. For the purpose of this calculation methodology we have assumed that the emissions are typical for a specific technology. Embedded Generation Emissions (Tonnes pa) $= \frac{\text{EG Output (kWh pa) * EG Per Unit Emissions (g/kWh)}}{10^6}$ where this calculation is repeated for each of the pollutants CO_2, NOx an SOx	
4	Net Emissions Savings	ESB Networks	ESB Networks	This is the difference between the avoided emissions through system plant being displaced and the emissions produced by the embedded generator. Net Emissions Savings (Tonnes pa) = Emissions Avoided – Embedded Generation Emissions. This will need to be repeated for each of the pollutants CO_2, NOx and SOx.	
5	Value of Emissions Saved			A monetary value per tonne will need to be determined for each of the pollutants. For the purposes of this methodology we have used the following prices: CO_2 = market price reported value of carbon trade value =Euro 15 / T NOx and SOx are not explicitly priced or able to be traded. Any value of avoided Sulphur will be captured in the avoided energy price and energy losses calculations to system power plant operators factoring the compliance cost into their marginal cost of generation calculation. Value of Emissions = Emission Price * Emissions Saved ••	

Step	Name	From	To	Description	Data
				PV of Emissions Saved $$= \sum_{n=1}^{15} (CO_2\ Value_n + SO_x\ Value_n + NO_x\ Value_n) / (1+DF)^n)$$	
6	Contribution to National Target			The EU ETS requires individual member states to achieve specific targets. There are no financial penalties that apply to the states for any non-compliance with emissions targets, however, there is value in reporting this as a non-fiscal quantitative measure to assist in tracking the impact of renewable generation on the states achievement of target.	

6.14 Social Benefit

The Social benefit that may arise through the connection of the embedded generation may be seen through a number of different areas. Whilst the social impact of renewable plant can, theoretically be projected to include such social benefits as reduced hospital care cost due to reduced pollutants and wider economic benefits that arise from any such improvement in the general health of the population, these are not considered within the calculation methodology proposed within this study. Though it is recognised that a cumulative impact of many renewable generation projects within a country is likely to have a positive effect on health.

More immediately felt benefits will arise through the creation of local employment, wither in the provision of an indigenous fuel source in the case of biomass plant, through short-term employment during the construction phase of the project and potentially longer-term employment through the potential need for maintenance and operational staff for the larger projects.

6.14.1 Inputs

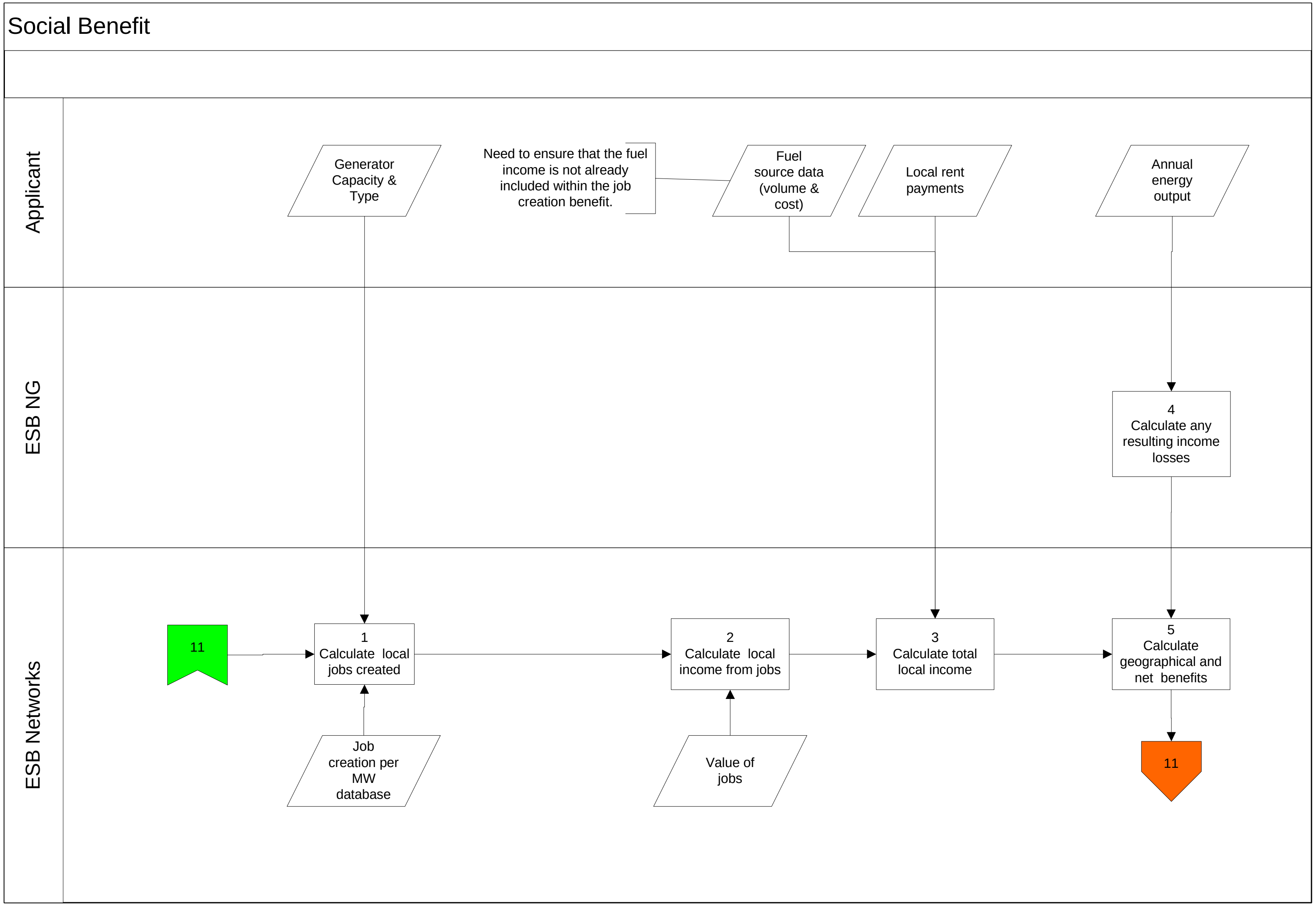
Number of Jobs; Value of Jobs

6.14.2 Outputs

Social Benefit

6.14.3 Participants

ESB Networks


Social Benefit
Applicant
ESB NG
ESB Networks
Generator Capacity & Type
Need to ensure that the fuel income is not already included within the job creation benefit.
Fuel source data (volume & cost)
Local rent payments
Annual energy output
4 Calculate any resulting income losses
11
1 Calculate local jobs created
2 Calculate local income from jobs
3 Calculate total local income
5 Calculate geographical and net benefits
Job creation per MW database
Value of jobs
11

6.14.4 Process Description:

Step	Name	From	To	Description	Data
1	Calculate Local Jobs Created			Dependent on the size of the generation project and its complexity. The larger wind farms are likely to require a manned control point – at least during office or extended office hours. The construction period and construction techniques required will also allow an estimate to be made of the number of jobs that will be created during the construction period.	Generator Size Generator Type
2	Calculate Local Income from Jobs			The type of jobs created will allow the work to be valued in terms of likely annual income for these jobs. Local Income from Jobs = No of Jobs * Job Value	Value of Jobs
3	Calculate total Local income			This will include other local benefits to the extent that rental income is paid for access and occupation of land by the project. This assumes that such rental payments are made and stay within the local community. Also there will be issues related to the confidentiality of the commercial arrangements entered into between the project developer and the landowner. As such the value of any rental income may need to be assessed on the basis of standard valuation for the land. Total Local Income = Local Income from Jobs + Rental Value	Project Rental Payments

Step	Name	From	To	Description	Data
4	Calculate any Resulting income losses			The benefits that accrued locally will be offset to some extent in the event that the displaced energy causes cash flow issues for any system plant. To the extent that this happens there will be an offsetting 'disbenefit' due to loss of employment at such system plant. This is considered to be a wider economic issue and not easily quantifiable for the purposes of a single embedded generator. However, as the capacity of embedded generation grows the combined impact on the viability of the system power plant is likely to become visible.	
5	Calculate Geographical and Net Benefits			Social Benefit = Total Local Income – Employment Costs at System Pant	

6.15 Fuel Benefit

Any fuel benefit will arise through avoided use of imported fuels in favour of indigenous fuels. This is explicit in the case of renewable energy systems, however, it is less clear for CHP plant given that they tend to be fuelled with natural gas. However, there will be a displacement benefit arising from CHP plant due to their overall higher thermal efficiency in terms of the ratio of fuel energy in to the useful energy produced (both electricity and heat). Therefore in the case of CHP plant the cycle conversion efficiency needs to be used in the calculation of any fuel benefit.

6.15.1 Inputs

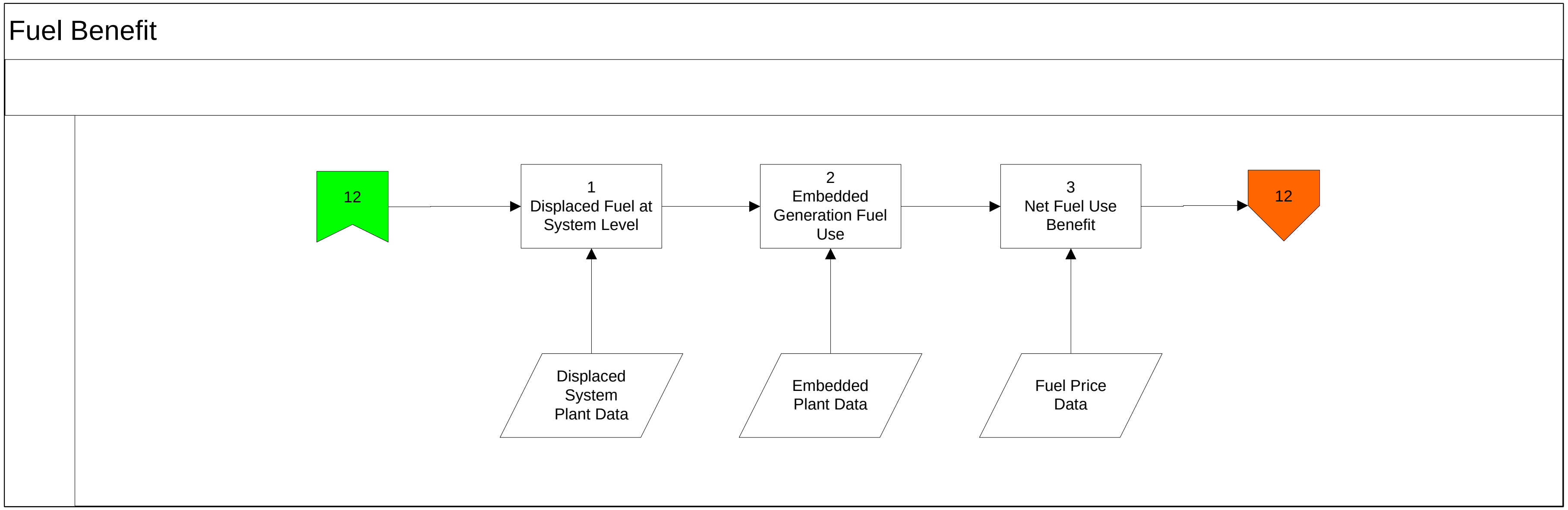
Displaced System Data; Embedded Generation Data; Energy Prices

6.15.2 Outputs

Displaced Fuel Benefit

6.15.3 Participants

To be determined


Fuel Benefit
12
1
Displaced Fuel at System Level
2
Embedded Generation Fuel Use
3
Net Fuel Use Benefit
12
Displaced System Plant Data
Embedded Plant Data
Fuel Price Data

6.15.4 Process Description:

Step	Name	From	To	Description	Data
1	Displaced Fuel at System Level			The quantity of fuel that will be displaced at the system level will be equivalent to the difference in the exit point energy demands before and after the connection of the embedded generation. The type of system plant that will be displaced is dependent on the expected operating profile of the embedded generation and was the case for the calculation of Emission Benefit and Displaced Energy Benefit the operating profile (load factor) of the embedded generation plant is used to determine the displaced system plant. This provides the required information on the displaced fuel type, plant efficiency and fuel pricing required for this calculation. $\text{Displaced Fuel at System Level} = \dfrac{\text{Displaced Energy}}{\text{System Plant Efficiency}}$ It is assumed in this calculation that the energy required to support the transmission system losses incurred in delivering the energy from the system generation to the exit point remain constant for the purpose of this element of the calculation methodology.	System Plant Data
2	Embedded Generation Fuel Use			The fuel use of the embedded generation will be zero for all renewable generation projects – including biomass (provided that this is grown indigenous to Ireland). However, where CHP is concerned there is likely to be a requirement for natural gas and so the displaced system energy will be replaced with a lower amount of gas use – i.e. an incremental benefit.	Embedded Plant Data

Step	Name	From	To	Description	Data
				The actual embedded generation output is likely to differ from the displaced system energy at the transmission exit point due to the impact that the embedded generation has on the distribution system losses. Embedded Generation Fuel Use= $\frac{\text{Embedded Generation Output}}{\text{Embedded Generation Efficiency}}$ It is recognised that CHP plant will be replacing fuel previously burnt directly in boiler plant for process heat production, and as a consequence we propose that the total cycle efficiency be used in this comparison in order to capture the efficiency benefit in terms of avoided fuel use.	
3	Net Fuel Use Benefit			The Net Fuel Use Benefit is the difference between the input fuel energy required by the system plant to provide the displaced system energy and the embedded generation plant in displacing this system energy. The value is derived using a reference fuel price – likely to be based on market price for imported energy (gas, oil, coal etc) Net Fuel Benefit = Displaced Fuel Price * (Displaced Fuel at System Level - Embedded Generation Fuel Use) NOTE: The actual fuel cost for generation will vary from time to time as market prices fluctuate. In order to facilitate this calculation it may be necessary to identify appropriate price reporting statistics that reflect energy input pricing for generation in Ireland.	Energy Prices

6.16 Example Calculations

In order to assess the impact of the constituent elements within the calculation methodology a spreadsheet has been created (soft copy provided with the final report in CD form) to allow calculation of the benefit values using assumptions and data results from the representative network modelling exercise. The detailed printouts from the spreadsheet model are included within Appendix D. A number of example calculations have been carried out to assess the difference between embedded generation technology types (i.e. "reliable" and "unreliable") and between locations on the network. Therefore the following were used as the basis for the example cost and benefit calculations:-

- Generator Size 2.5MWe
- Generator Type CHP (natural gas fired) and Wind Generation
- System Connection Points
- Mid 38kV Trunk
- Remote end of 38kV Trunk
- Remote end of Mid 38kV Trunk Spur
- Remote end of 5km 38kV Dedicated feeder

Technology	**No Gen**	**Wind Generation**			
Location	-	Mid Trunk	End Mid Trunk Spur	End Trunk	5km 38kV Feeder
Cost / Benefit					
Connection Cost	0	-€ 250,000	-€ 250,000	-€ 250,000	-€ 250,000
Displaced Energy	0	€ 721,692	€ 721,692	€ 721,692	€ 721,692
Loss Benefit	0	€ 1,182,415	€ 169,869	€ 213,015	€ 23,776
Voltage Benefit[53]	0	€ 682,083	€ 82,868	€ 167,960	€ 459,534
CML Benefit	0	€ 17,637	€ 17,637	€ 17,637	€ 17,637
Asset Benefit	0	€ 858,847	€ 447,274	€ 452,969	€ 86,692
Transmission Benefit	0	€ 640,212	€ 640,212	€ 640,212	€ 640,212
Emission benefit	0	€ 885,713	€ 885,713	€ 885,713	€ 885,713
Social Benefit	0	€ 203,288	€ 203,288	€ 203,288	€ 203,288
Combined Benefit	0	€ 4,941,887	€ 2,918,553	€ 3,052,487	€ 2,788,545
Fuel Benefit (kWh pa)	0	21,900,000	21,900,000	21,900,000	21,900,000

Table 6.2 – Wind Generation example calculation results

[53] The voltage related deferred capital spend has been assumed to remain constant across all scenarios.

Technology	No Gen	CHP (natural gas fired)			
Location	-	Mid Trunk	End Mid Trunk Spur	End Trunk	5km 38kV Feeder
Cost / Benefit					
Connection Cost	0	-€ 250,000	-€ 250,000	-€ 250,000	-€ 250,000
Displaced Energy	0	€ 478,004	€ 478,004	€ 478,004	€ 478,004
Loss Benefit	0	€ 2,428,284	€ 231,793	€ 511,448	€ 235,263
Voltage Benefit[54]	0	€ 682,083	€ 82,868	€ 323,528	€ 596,879
CML Benefit	0	€ 17,637	€ 17,637	€ 17,637	€ 17,637
Asset Benefit	0	€ 988,690	€ 654,595	€ 673,957	€ 294,754
Transmission Benefit	0	€ 1,126,549	€ 1,126,549	€ 1,126,549	€ 1,126,549
Emission benefit	0	€ 229,442	€ 229,442	€ 229,442	€ 229,442
Social Benefit	0	€ 203,288	€ 203,288	€ 203,288	€ 203,288
Combined Benefit	0	€ 5,903,976	€ 2,774,174	€ 2,921,776	€ 2,592,548
Fuel Benefit (kWh pa)	0	8,591,538	8,591,538	8,591,538	8,591,538

Table 6.3 – CHP (natural gas fired) example calculation results

From the results of these example calculations the following observations can be made:-

- The value of the loss benefits is very sensitive to generator location on the network (mid point along the trunk being the best location) due to the contribution to the benefit calculation from the avoided energy losses due to the plant location;

- The value of the displaced energy is dependent on the operational profile of the generation plant and the resultant load factor on the system. The above examples have been calculated assuming 65% LF before connection of the generation and 64% LF with the generation operating and it is recognised that there are discrepancies between the displaced energy values and the losses that would not appear when the annual generation output and system demand load profiles are utilised;

- The main items of value all include energy related components i.e. Displaced Energy, Loss Benefit and the transmission benefit;

- Asset based benefits will require access to auditable capital expenditure plans for the distribution network and the ability to discriminate between load related and voltage related capital expenditure;

- The value of the CML benefit is marginal;

- The values for the majority of the benefits are significant having been projected across a fifteen year time horizon;

[54] The voltage related deferred capital spend has been assumed to remain constant across all scenarios.

- The recognition of the various benefits will need to be made either on a cash basis through offsetting connection costs or on a societal basis similar to the arrangements under the Public Service Obligation that support the social generation plant.

6.17 Issues of note

- How are the identified benefits to be allocated between the Generator, Utilities, System Generation and Customers? Some may be able to be 'allowed' within the regulatory pricing structure for the distribution system revenues, whilst others, which are more far reaching in their derivation may not be best administered within the electricity regulatory framework. Any benefits associated with avoided losses, deferred capex or avoided reinforcement could be used to offset the connection cost for the generation plant. It is expected that further consultation will be required within the industry in order that multilateral agreement is achieved on the final sharing mechanism.

- It is recognised that there will be a number of connection offers outstanding for connection of new demand or generation to the distribution network at any one time. To this extent a judgement will need to be taken on the probability of the various connection offers being accepted following the embedded generation network modelling and benefit / cost calculations. For the purposes of the example calculations we have assumed that only those offers that have been accepted will be included in the network model.

- The calculation of benefits has been done on the basis of the distribution and transmission network topography at the time the calculations are made. Any benefit that arises from the connection of the embedded generation plant in terms of released system capacity should be credited to the plant. These benefits may be recovered by ESB Networks through connection of additional load without the need for deep reinforcement or from deferral of planned capital expenditure.

- These benefits appear to have been recognised by ESB Networks within the terms of the latest Distribution Use of System tariff publication (March 2004) that provides for a sharing payment to be made to the embedded generator should the assets included within their connection be used to provide supply to another customer within a 5 year period. Whilst this provides an element of recognition, however, it is not clear that this captures any benefit that accrues from the deep system reinforcement that the embedded generator has funded within its connection cost – it appears to only cover the dedicated connection assets.

- The benefits have been calculated for the first year of operation of the embedded generation plant. It is recognised that the plant is likely to be operating for a considerable period of time. Whilst the generation plant is unlikely to remain in service for the same amount of time seen by utility equipment (up to 80-90 years in the case of some underground cables). it is reasonable to expect that it will be in service for up to 15 years. On this basis a 15 year projection is made of the calculated annual benefits / cost. This 15 year period is significantly in excess of the 5-year sharing period recognised within the latest ESB Networks DUoS tariff statement;

- The actual value of the discount factor will need to be subject scrutiny before a final agreement is reached. It is expected that there may be a need to establish a formal equation to calculate the Discount factor on the basis of ESB Networks WACC, open market long-term interest rates and market equity returns with appropriate weightings. In order that the example calculations can be completed the discount factor used for the net present value calculations has been set at 8% given current low interest rates and inflation;

- The Marginal Capacity Costs of providing system capacity for an incremental 1kW of system demand will need to be calculated. This should be on the basis of Modern Equivalent Asset values. The exact calculation methodology for determining the marginal capacity cost is outside the scope of this review, however, for the purposes of providing the example calculations we have provided an assumed value;

- The 'actors' within the calculation methodology are predominantly ESB Networks and ESB National Grid. There may be some debate as to the involvement of an independent external party to undertake elements of the calculation process in order to protect any commercially sensitive data provided to enable the calculations. Further, there could be a perception within the development community that ESB is not necessarily the best-placed company – given skills and experience – to undertake such a multi-faceted calculation;

- Need to explore the impact of the LMP calculation and potential exemption of certain embedded generation from being exposed to TL's as they are likely to receive the average marginal price and therefore will not be subject to the LMP effect. The effect of locational pricing needs to be captured within the calculations and is most appropriately captured within exit pricing for the energy at the transmission boundary.

- There is a reliance on the provision of information relating to the development of the distribution network by ESB Networks. Such information, unless formally published through a form of Network Planning statement, could be perceived within the project development community as being non-transparent leading to lack of buy in to any cost / benefit calculation methodology. This suggests that a formal, periodic statement of the distribution system capital plan be made public in a similar vein to Transmission System Planning Statements;

- ESB Networks will need to adopt a transparent position in respect of the statistical data used for derivation of the expected CMLs for a network. These data should be available from historic fault rates in respect of the various network assets and items of equipment used by ESB Networks. Again such data may need to be made publicly available to provide the necessary transparency of input data;

- It is not envisaged that the impact of operational / maintenance policy on fault rates is drawn out separately and parameterised within the CML benefit calculation formulae. Rather, in the event of any policy amendments, the operational / maintenance policy impact on fault rates and restoration times will need to be accounted for uniformly across all ESB Network asset fault data and this will flow through into the calculation process via the distribution statistical performance measures – SAIDI and SAIFI;

- The effect of individual embedded generation plant on the thermal efficiency of system thermal generation plant is difficult to quantify given that the impact will derive from the combined operating profile of all embedded generation connected to the distribution system. As per the EirGrid report into the impact of wind generation on the cost of system operation, the calculation of the impact needs to be done at a system level not at an individual embedded plant level since the diversity effects of the embedded plant output needs to be captured;

6.18 Methodology Findings

The development of a calculation methodology to deliver a holistic statement of the costs and benefits associated with the connection of an embedded generation plant to the distribution network, requires significant data input and modelling effort if it is to present a realistic representation of the impacts. Such modelling will, out of the necessity to rein in costs and best utilise resources, require a number of simplifying assumptions to be made in respect of the network configuration, load profiles, generation operation, system generation costs, fuel prices, system losses etc.

The methodology detailed within this study provides a starting point from which it is possible to identify those benefits that deliver most value. Some of these costs and benefits are already within the internal cost structure of ESB Networks (through avoided capital expenditure, loss impacts, displaced load capacity etc) and are being recovered through the DUoS charges from customers. However, the mechanism for sharing such benefits needs to be developed such that they are shared equitably between customers and market participants.

7. Market Survey

7.1 System Charges

The charges that can be levied for the connection to and use of the transmission and distribution networks are regulated by the Commission for Energy Regulation to ensure that a balance is struck between the potentially conflicting needs of adequate revenue and return for the licencees, security of supply and value for money for customers in the charging mechanisms adopted by ESB National Grid (Transmission System) and ESB Networks (Distribution System).

7.1.1 Connection Charges

The connection to the transmission network is treated differently to connections to the distribution network.

Transmission Connections are calculated on a shallow basis with any additional reinforcement works required beyond those assets for the sole purpose of connecting the new generation or demand to the transmission system being capitalised within the asset base of ESB National Grid and recovered under the TUoS charging mechanisms.

The cost of providing the connection assets for transmission connections has a contestable element.

The payment terms will be 25% on acceptance of the offer, 50% prior to construction commencement and 25% 1 month prior to energisation. These payment terms will replace the previous requirement to post a Connection Charges Bond to mitigate non-payment risk in the event that the connection assets are put in place and the customer is then not able to pay.

Distribution Connections are calculated on a deep charging basis under the Least Cost Technically Acceptable Solution policy. However, embedded generation connections are required to pay the full deep charges as they are not liable to pay DUoS on exported energy. Demand connections, depending on their classification, pay a proportion of the connection asset costs.

Should there by any further connections made to the distribution network within 5 years that make use of the new connection assets, the original customer will receive a rebate proportional to the extent of the sharing provided the standard charges (typically used for small demand connections) were not applied.

7.1.2 Use of System Charges

TUoS charges are not applicable for embedded generators with a MEC > MIC and MEC <10MW. However, these benefits are not passed through in their entirety in the energy supply tariffs although it is almost the case for LV connected auto producers. Therefore an element of this avoided TUoS charge is retained within the supply business as additional margin.

Table 7-1 ESB Capacity Charge Reductions

	Capacity Charge Reduction
LV	99%
MV	63%
38kV Looped	37%
38kV Teed	37%

The Distribution use of system charges are not payable by embedded generation on their exported energy since they pay for the full cost of their connection assets (including any reinforcements to the network). Embedded generators pay DUoS charges on any imported energy on the basis of the business user category that best describes the embedded generators off-take characteristics.

7.1.3 Treatment of Losses

The treatment of losses is expected to change under the new MAE rules to be introduced in 2005. Presently transmission losses are recovered 100% against system generation – with demand ultimately paying for these through the energy charges from the system generators. Each generator is allocated a Transmission Loss Adjustment Factor (TLAF) that is used during the scheduling (system balance) and settlement (loss cost recovery) processes.

The distribution losses are recovered across all connections through the allocation of a Distribution Loss Adjustment Factor (DLAF). The DLAFs are allocated to demand customers on the basis of their connection voltage, and to embedded generation on the basis of the site specific impact that the embedded generator has on the distribution system. These values are updated annually and subject to approval by the CER.

7.2 Trading Arrangements

7.2.1 Compliance with EU Directive 2001/77/EC

European Directive 2001/77/EC sets indicative reference values for Member States' targets for renewable electricity generation[55]. It also includes a number of provisions to promote renewables, including some concerning access to the grid (Article 7).

The key points of Article 7 and how they are reflected in the current and proposed market arrangements are discussed in Table 7.2 below.

[55] Directive 2001/77/EC on the promotion of electricity produced from renewable energy sources in the internal electricity market, 27th September 2001

Table 7.2 – Current or planned provisions reflecting Directive 2001/77/EC

Article in 2001/77/EC	***Article content***	***Provision in MAE[56] or elsewhere***
7.1	Requires that renewable generation be given priority dispatch by TSO, insofar as the operation of the grid permits *[Note - no mention is made of the structuring of the* ***price*** *that generators should receive for their electricity]*	Self-dispatch for units less than 5 MVA effectively guarantees dispatch. For larger renewable generators, 2 options available (although only dispatchable units can choose option 1): 1. generator offers price & quantity, but risks not being dispatched; 2. generator receives market floor price, but is guaranteed dispatch. Option 2 allows all renewable generators access to priority dispatch.
	Requires guarantee of the transmission and distribution of renewable electricity (i.e. effectively that they ensure dispatch). Recital 21 of the Directive recognises that this may not be possible for operational reasons and **allows** for financial compensation.	Dispatch addressed above. Current MAE proposals require generators to accept the market floor price in return for guaranteed dispatch. No arrangements currently for compensation in lieu of dispatch.
	TSO/DSO **may** provide priority access to the grid system for renewable electricity. The implication is that this refers to the allocation of network access rights (i.e. of available connection capacity).	Current allocation of network access does not discriminate between different types of generation, i.e. does not prioritise renewables.
7.2	TSO/DSO to publish rules relating to how grid connection and reinforcement costs are borne.	Rules for connection costs are published by ESB Networks and ESB NG [57].
	Rules to be non-discriminatory and to take account of all costs and benefits.	Current rules do not distinguish between types of generation. Deep reinforcement charges do not take account of benefits of EG.

[56] CER/04/214, "Implementation of the Market Arrangements for Electricity in relation to CHP, Renewable and Small-scale generation", 9th June 2004

[57] CER/ESB/2000/10, "Connection Asset Costs: Guiding Principles", 12th April 2000

7.3	Member States **may** require TSO/DSO to bear these costs.	Not taken up at present (except transmission reinforcement costs)
7.4	TSO/DSO to provide generator with detailed connection cost estimate. Member States **may** allow contestability.	Connection Offers from ESB Networks and ESB NG provide cost estimate. Contestability element established for transmission connections. Contestability provision for distribution connections in draft Electricity Bill.
7.5	TSO/DSO to publish standard rules for sharing connection costs between all generators benefiting from them.	Qualitative principles for shared connection costs are published by ESB Networks and ESB NG. ESB NG publishes anonymous list of interacting connections at Transmission and Distribution level (>4 MW)
	Rules to be non-discriminatory and to take account of all the benefits to generators, TSO and DSO.	Charges do not take account of benefits to DSO.
7.6	Transmission and distribution charges should not discriminate against RE, especially that in remote areas. TSO/DSO to ensure charges reflect cost benefits of EG.	CER currently reviewing tariff structure, including how to reward EG if it provides cost benefits (e.g. reduced losses)

From the review in Table 7.2 above, reflecting the benefits of EG in the charging system is the most significant gap in the current procedures. CER is consulting on tariff structures that include this area[58].

The Internal Electricity Market Directive 2003/54/EC59 also includes provisions of relevance to embedded generation – these are generally aligned with those of 2001/77/EC described above.

[58] CER/04/239, Electricity Tariff Structure Review: Alternative Tariff Structures, 1st July 2004

[59] Directive 2003/54/2003 concerning common rules for the internal market in electricity and repealing Directive 96/92/EC, 26th June 2003

7.2.2 Perceived costs and benefits of renewable and embedded generation

It is widely recognised that embedded generation can provide benefits from its connection to the distribution network through avoided losses (if located close to customer demand), additional system security and potential betterment for supply quality. However, it appears that to date these benefits have been subject to a degree of oversight within an industry that has been focussed on the implementation and management of a system based around a small number of large system power generation plant.

The perception of embedded generation within the electricity industry still appears to be that these generators cause more costs than benefits (which may well be true) in terms of the local distribution network, however, this view of costs and benefits does not consider wider issues related to the embedded generation operation that need to be accounted for in order to see the full picture. To the contrary, there is a perception outside the electricity industry that the adoption of large capacities of wind and other forms of renewable energy generation will provide a panacea for the potential future environmental problems.

Both perceptions are equally valid for those who hold them, however, neither one is based on a sufficiently broad view of the overall benefits that embedded generation plant may have outside limited terms of reference.

7.3 General Market Issues

The present market structures for the connection and use of the transmission and distribution network are undergoing a process of review that is still running its course. A number of elements are presently being consulted on within the scope of the new Market Arrangements for Electricity due to be introduced in 2005. These include:

- Relevance of Transmission Losses within a market that includes Locational Market Pricing;
- Introduction of Ancillary Services market;
- Financial Transmission Rights mechanisms;
- Costs to be recovered through the TUoS charging mechanism when the new MAE is introduced.

Within the context of this relatively fluid environment the principles behind the allocation of the costs and sharing of benefits from embedded generation may be significantly altered. However, the costs and benefits identified within this study can be reallocated to reflect any changes to the market rules and charging mechanisms.

8. Stakeholder Views

8.1 Stakeholder Questionnaire

In order to gain a view of the opinions of industry stakeholders, a questionnaire was sent to a representative selection of organisations. The full text of the questionnaire is included in Appendix E, along with a list of the organisations consulted. The aim of the questionnaire was to gather views on how embedded generation is encouraged at present, and how this could be improved in future, as well as what the costs and benefits of such generation would be. Questions covered the broad themes of:

- Connection and use of system charges
- Trading arrangements and market issues
- Technical issues

8.2 Response from Stakeholders

Of the ten stakeholders questioned, seven responded within the timeframe for inclusion in this report. As might be expected, certain stakeholders focussed on particular questions, and the bulk of the responses covered the areas of charges and trading arrangements for renewable electricity generation.

8.3 Analysis of stakeholder responses

In order to preserve anonymity given the small number of stakeholders consulted, the following analysis does not identify specific respondent comments. Instead, it seeks to provide a summary of the viewpoints expressed in a number of key areas.

8.3.1 Connections

The area of deep connection charges on the distribution system received a number of comments, and unsurprisingly there was a wide range of opinions. There was a view from some generators that they are being asked to bear the full cost of reinforcements that others also benefit from. Another respondent, however, pointed out that generators do not pay DUoS charges once connected.

There were a variety of comments on how to improve the connection regime to encourage embedded generation. Proportional charging of deep reinforcement costs was suggested as a means to allocate costs amongst all the beneficiaries. Other suggestions included the development of common processes between the DSO and TSO, the recovery of connection costs through use of system charges and the discouragement of continual reapplications by some developers that negatively affect others.

Contestability of distribution network connections was supported by most respondents, who view connection costs as a major barrier to the deployment of embedded generation.

8.3.2 Treatment of Losses

There was a general wish amongst developers to see a more transparent process for calculating the Distribution Loss Adjustment Factor (DLAF).

A specific suggestion to promote embedded generation was to remove the Transmission Loss Adjustment Factor for generation whose output can be shown never to reach the transmission system. However, another stakeholder noted that a generator connected to a 38 kV substation and considered to be embedded may actually export through the transmission system and thus cause losses without having to bear the cost.

One respondent noted that the introduction of Bulk Supply Point metering should allow better measurement of losses.

8.3.3 Market Arrangements

There was a broad view that the 30 MW limit for self-dispatch may be a barrier to wind farms above this threshold. However, it was also suggested that central dispatching of large wind will be needed in order to optimise wind penetration. This was linked to a desire for the subsequent curtailment to be fully compensated.

Generators strongly stated a desire for new market arrangements to be bankable, in order to allow a broad range of generators to enter the market. They were also of the view that CfDs were helpful but insufficient to provide certainty to investors, and that investment in embedded generation would continue to be deterred by the uncertainty inherent in market pricing. Other respondents felt that CfDs would provide sufficient investor confidence, however.

A number of respondents felt that the single top-up/spill price in the new arrangements are an improvement over the current regime.

8.3.4 Location Pricing

Some respondents believed that location marginal prices (LMP) will tend to discourage embedded generation (principally remote wind farms), since much of the wind resource is in remote locations where LMP will be low. One respondent commented that increasing wind generation at a particular location would cause the LMP to drop even further. These stakeholders believed embedded generation should receive the Uniform Wholesale Spot Price (UWSP) or a fixed tariff. One suggested embedded generation should receive the UWSP plus a premium to reflect environmental benefits.

Other respondents felt that all generators above a certain capacity should receive the LMP, reflecting the value of their output at that location and sending the appropriate market signals.

8.3.5 Flexibility of generation

The new arrangements will favour flexible plant due to its ability to respond rapidly to changing market prices. There was an expectation among respondents that this will encourage greater flexibility from thermal plant. However, it was commented that wind is not genuinely flexible – due to the nature of the resource, it cannot be operated at will and therefore cannot respond readily to the market. It was felt that this would place wind embedded generation at a disadvantage versus thermal plant.

The potential for embedded generation to see negative prices was considered by some to be detrimental to wind generation, although others commented that actual instances of negative prices were likely to be rare. Other respondents considered that all generators including embedded generation should see negative prices in order to encourage flexibility.

The possibility of embedded generation receiving a UWSP averaged over a week or month was suggested by one stakeholder as a means to protect embedded generation from market volatility, although others were keen for any support mechanisms to be completely outside the market to avoid possible distortion.

8.3.6 Reserve Costs

The question of allocating reserve costs unsurprisingly divided respondents between those who supported the "causer pays" principle, and those who believed that they should be allocated so as not to discourage wind generation.

One respondent commented that the allocation should be on the basis of all the characteristics of each technology. For example, this would include aspects such as ability to reduce emissions as well as capability to provide reserve.

8.3.7 Small vs. large generators

There was general recognition of ESB's dominant position in both overall generation and renewables / embedded generation, and concern over how this may hinder the access to investment needed by smaller generators.

Respondents commented that careful regulation was necessary to ensure that small generators can participate in the market.

8.3.8 Technical Issues

A number of technical comments and suggestions were made by stakeholders in the general area of encouraging EG:

- Allowing constraining-off as part of the design for wind farms could allow greater capacity to be connected, or the same capacity to be connected at lower cost. For example, planned constraining-off during the few hours per year that limit connection capacity (e.g. windy summer nights) might allow a larger capacity to be connected and overall embedded generation output to be higher.
- The proposed requirement to provide ride-through-capability needs to be considered in light of the extra burdens it imposes on wind generation
- Permissible voltage margins on the distribution network are narrow, and are a barrier to embedded generation
- The use of Remedial Action Schemes to strengthen networks would allow higher penetration of embedded generation.
- Improving information about interacting connection applications would reduce the uncertainty from this source
- Smaller embedded generation could be facilitated by requiring larger projects to connect to the transmission system.

8.3.9 CHP

Only a limited number of stakeholders responded to the questions on CHP. A specific area of concern was the charging policy based on Maximum Import Capacity (MIC) and Maximum Export Capacity (MEC), which can result in a CHP generator who is a net exporter of electricity still being classed as a demand user and thus paying DUoS charges. A tariff based on actual volumes of electricity rather than capacities was suggested.

8.3.10 Microgeneration

There was a general view among stakeholders that net metering would be the appropriate means to meter very small generation (e.g. domestic CHP). Meters with several different tariff bands could be used to make sure the time-of-day value of the output was appropriately rewarded.

8.4 Key Findings of Stakeholder Survey

There was a range of views on many issues, which is not surprising given the range of stakeholders questioned. This section attempts to summarise these views and identify key themes.

There was a general acknowledgment of the need to reduce uncertainty in order to encourage deployment of EG. Developers' underlying concern was the bankability of projects, rather than on what the market mechanisms are *per se*. Compensation or protection from the variations in a large market pool was a key theme. Other respondents were more concerned with ensuring market mechanisms provide a level playing field for all generators. A separate, predictable support mechanism outside the market might best meet the range of needs expressed.

Costs of connection and reinforcement associated with new embedded generation connections clearly need to be allocated in some manner, although existing deep connection charges are viewed as a discouragement to embedded generation by most generators. Repayment of costs over a number of years might mitigate this, effectively converting the upfront capital cost into a form of DUoS charge. Allocation of part of the costs to other beneficiaries of the reinforcement would also encourage embedded generation.

There were differing views on flexibility of generation. While the proposed market arrangements would encourage generators to be more flexible, it was pointed out by some that wind is inherently inflexible – due to resource intermittency, it cannot always choose when to generate (although it can choose when not to). There is therefore a concern that wind may be disadvantaged as thermal plant makes itself more flexible.

On the treatment of losses, there was a general desire for a more transparent means of calculation and allocation. An underlying theme was to avoid general limits or definitions that would result in some embedded generation causing losses and not being charged, and vice versa.

The question of location pricing divided respondents between those believe that it will discriminate against wind generation (where the resource is often best in remote areas where LMP is low), and those who believe that all generators should receive price signals related to location. However, there was general acceptance that only generators above a certain capacity should receive LMP, while those below would receive the UWSP. CER have now set this cut-off limit[60].

---

[60] See CER/04/214, "Implementation of the Market Arrangements for Electricity (MAE) in relation to CHP, Renewable and Small-scale Generation", 9th June 2004

9. Treatment of Costs and Other Issues Related to Connection of Embedded Generation

9.1 Purpose

The purpose of this section of the report is to review the approaches for cost / benefit sharing within a number of different markets. These markets are at various stages in their process of moving towards full competition for the supply of electricity, have various degrees of renewable embedded generation connections at distribution voltages and have differing market models for wholesale electricity transactions.

The intention is to enable an overview of the various approaches adopted and, where possible, identify those which have relevance for the treatment of embedded generation costs / benefits within the Irish market.

9.2 International Review

The jurisdictions reviewed are Australia, New Zealand and Singapore. A view of a number of mainland European markets is also included. The documentation reviewed included the Market Rules, Grid Codes and other relevant regulatory documentation.

9.2.1 Australia

The Australian market is split into 5 distinct markets – Australia Capital Territory, Queensland, South Australia, Victoria and New South Wales. Each market retains its own independent local regulatory body with distribution and transmission price regulation on the basis of a CPI-X formula with a revenue cap.

The countrywide market rules are governed through the National Electricity Code Administrator – NECA. NECA is a company formed by the five participating jurisdictions specifically to manage and maintain the market rules. Final determination for any unresolved disputes within the terms of the market rules will be made by referral to the Australian Competition and Consumer Commission (ACCC).

The electricity market has been implemented to provide open access to transmission and distribution networks and to enable inter-state energy trading through the national electricity market. This national electricity market is operated and maintained by the National Electricity Market Management Company – NEMMCO. The NEMMCO has responsibility for the scheduling and dispatch of system generation plant and managing transmission system constraints.

Connection Costs	Connection costs to the Distribution Networks is on the basis of a negotiated connection agreement that must comply with the minimum standards, or, at the request of the applicant, provide a service to a higher standard. Any costs associated with a requested higher standard of service are attributed to the applicant 100%. Discussions are underway into the possibility of a dual connection charging approach to separate small connections (say a domestic Photovoltaic project) from larger connections to the distribution system.
TUoS Treatment	Generators connected to the Distribution Network are passed through the full value of the avoided TUoS costs arising from their operation during the 10 highest

	demand periods on the system. This calculation is undertaken each year and utilises meter readings for peak capacity and energy.
DUoS / Asset Benefit	Once connected to the Distribution Network the generators and customers are required to pay ongoing DUoS charges on the basis of their respective use of the Distribution Network (for entry or exit). The charging mechanisms recognise that the Distribution Network continues to be developed to cater for new load or replaced to cater for life expired assets subject to criteria on allowable pass through of costs. Consequently the generators and customers are required to support the cost of new network investments (categorised into large network investments and small network investments) pro-rata to the benefit they receive from its installation. *New Large Network Assets* - Benefit calculation allocates to generators as a class then to generators individually pro-rated to their proportion of the benefit received. This percentage proportion is then used to determine the capital cost recovered from each generator. All other costs associated with the new network investment are recovered from the remaining customers via the TUoS or DUoS charges. *Small Network Investments* - Cost of new small network investment is split across generators and customers connected to the relevant network pro-rated to their benefit from the investment. The proportion of costs allocated to the generators is then recovered through a capacity based charge – New Small Network Investment Charge – from all generators. The remaining proportion of the costs are recovered through the TUoS or DUoS charges as appropriate.
Losses	Calculation is made by the Distribution company and sharing is open to negotiation between the parties as part of the commercial arrangements for the connection to the distribution network.
Emissions	Not recognised within the benefits
Displaced Load	Displaced load capability of embedded generation is not recognised within the connection calculation methodology. Some discussions are underway into the possibilities of allowing rebates to be payable to embedded generation to the extent that other customers utilise assets that the generator originally paid for as part of their connection to the distribution network. Any rebates made could be allowable within the regulated revenues of the distribution company.
Displaced Energy	Not recognised within the benefits.
Social	Not recognised within the benefits
CML	Ability of the embedded generation to provide support to the distribution network local to its connection is not formally recognised within the connection methodology, however, it has been recognised that it can provide a contribution

	to system security.
Information Availability	One state has required that the distribution network operator provide a distribution planning statement covering a 5-year time horizon to address the increasing recognition that the information provided about the distribution network is not sufficient in quantity or detail to provide market signals to embedded generation developers in respect of plant siting.
Asset Benefit	Discussions are underway to explore the potential to recognise avoided distribution network investment costs calculated as a Net Present Value of the avoided network investments. It is proposed that these benefits be shared to the extent that the minimum share should be that amount of the benefit that would allow the generator to be commercially viable.

Table 9-1 Australian Market Summary

Where costs or benefits are recognised there will be a need to identify a suitable allocation methodology. Within the Australian context the following allocation methods are under consideration.

Costs Allocation Methods	*Market Analysis* – over range of scenarios for demand, plant operation (system and generating), other planned augmentations and ancillary service provision. NPV calculations made on the basis of range of Discount Factors and utilise the changes in Generation variable costs, reduced load costs and change in generation total profits. Allocation to class proportionate to total benefit for the class and then on a capacity basis within class.
	Network Analysis – substitutes each generator on the system at the Regional Reference Node in turn to determine their incremental impact on the new asset. Only positive increases are counted. Allocation of the costs is prorated against the relative use the generator makes of the new asset.
	Energy Deprival – uses the ratio of the reduction of unserved energy for loads to the total additional energy able to be delivered to the market by the generators as a result of the new investment; and the additional energy supplied by generators less the reduction in unserved energy all divided by the additional energy. These ratios are used to deliver the split of benefit between load and generator classes.
	Incremental Investment – a base line taking into account the cost of load related investment is used to determine the extent of any generation related incremental investment required. Any increase in investment due to the generation will be allocated with the load class picking up the proportion that is equivalent to the base line scenario with the excess being picked up by the generators.

Table 9-2 Australian Market Cost Allocation Methods

9.2.2 New Zealand

New Zealand has recently replaced the NZ Electricity Market (NZEM) with Electricity Governance Regulations (EGR) to address concerns about the ability of the NZEM structures to deliver security of supply and optimum energy use given the reliance of the NZ market on Hydro-electric generation. Such generation being energy constrained.

- The new arrangements have established a System Operator to whom all parties (including embedded generation greater than 1MW in capacity) must provide capability statements.
- Embedded generators may trade power in the market, however, they will be required to enter into appropriate 'conveyance' arrangements with the DNO to get the power to the transmission system entry point.
- Embedded generation greater than 10MW must provide technical information to the System Operator (SO) on a regular basis or as and when requested by the SO. This information will include provision of maintenance plans for each year;
- Embedded generation is not required to provide offers to the market;
- The SO will contact those embedded generation plant which it determines need to participate in the offer processes;
- Electricity Commission has been established specifically to oversee the operation of the electricity market under the auspices of the Electricity Governance Regulations.

Item	Comments
Connection Costs	New asset payments on a deep basis restricted to the first point of connection beyond 11kV up to the next voltage level. To the extent that the generator connects to assets installed <15yrs ago, or which have been upgraded <15years ago and for which contributions are still being made by other distributed generation - the new generator will contribute to the cost of the line. Connection contracts vary between distribution companies and there are efforts underway to seek the implementation of standard contracts for distribution generation connections.
TUoS	The distribution companies will provide an 85% pass through of avoided TUoS costs benefit
DUoS	Any embedded generation connected to load will only pay DUoS charges on the basis of the imported electricity amounts – no additional charges will be levied ion the exported amounts; Embedded generation should pay reasonable incremental operational costs for the system, but not a full use fee. Such ongoing operations charges should be restricted to 5% of the amount chargeable to an equivalent sized load. Also this

	charge will be netted off any TUoS benefit received;
Asset Benefit	Deferred network investment payment over minimum time horizon of 10 years. The uncertainty of network investment is to be factored into this NPV calculation; Not clear how transparency will be provided to the investor on the calculation method for the incremental costs;
Energy	Clear rules have not been created for the interconnection of embedded generation in the lines networks and for trading of small amounts of energy from embedded generation in the market.
Emissions	Not included in the calculation
Social	Not included in the calculation
Fuel	Not included in the calculation

Table 9-3 New Zealand Market Summary

9.2.3 Singapore

Singapore has a newly established wholesale market structure – having gone live in January 2004. The market is split between the Generators, Retailers and monopoly Transmission / Distribution companies. The transmission voltages range from 66kV upwards (inclusive) and distribution from 22kV (inclusive) downwards.

Connection to the transmission or distribution network must be done through a proscribed application procedure.

The generation plant owners / operators need to obtain a generation licence for their facilities prior to operation. This rule applies unless the generator falls within the exempt generation category:-

- Less than 10MW nameplate capacity then exempt from generation licence;
- If between 1MW and 10MW nameplate and connected to the transmission system then generator is not exempt;

Charging:

- Charges levied on the basis of the required connection capacity. This connection capacity is fixed over the first 5-year period following the connection. If the customer disconnects during this time any shortfall of the 5-year pmt will be recovered. (Stranded Asset avoidance);
- The capacity may be reduced after the initial 5 year period subject to some restrictions;
- All customers are charged Use of System charges on the basis of net imported energy during each settlement period. I.e. if no import then no UoS charge. If import to generating plant is through distinct import connection then the Connection Capacity Charge applies;

- High voltage connections are made on the basis that the costs of making the connection to the Singapore PowerGrid system are borne by the customer / generator (shallow charging). Connection is designed for a single contingency event. Connection to higher standard than (n-1) will need to pay for this in full (deep charging);

- Customers can choose to have Singapore PowerGrid pay for and have ownership of any dedicated substation / assets in return SP can sell on any excess capacity not immediately required by the customer. However, the customer retains a capacity call option on Singapore PowerGrid up to the capacity of the connection assets;

The Singapore approach to renewable energy is in a fledgling state. As such there is a focus on the conversion of extant system oil fired generating plant to gas firing to capture the reduced emissions and improved efficiency available from gas generation technology over oil. To this end the charging mechanisms for embedded generation reflect the shallow costs for connection to provide an n-1 security with additional costs for higher standards being fully to the customers account (deep charging). The generator pays use of system only to the extent that they have a net import or have a separate import connection point for station supplies.

Sharing of avoided loss, transmission use of system charges etc is not currently specified within the market documentation and therefore it is presumed that any additional benefits of embedded generation connection fall 100% to the customers local to the plant (voltage benefits, security of supply etc) or are determined under bi-lateral negotiations with energy retailers (TUoS avoided, distribution losses etc).

9.2.4 Germany[61] [62] [63] [64]

The German electricity market is divided between the large transmission system and system generation plant owners and operators such as RWE, EoN, VEAG, BEWAG etc and the smaller, municipally owned distribution network operators. The market is open for 100% of the customer demand.

The distribution network operators have obligations to ensure the continued safe and reliable supply of electricity to all connected customers, however, the distribution system operator may, in exceptional cases, agree with the customer to provide supply outside the required limits.

The distribution network operators are responsible for ensuring that they have sufficient control over the reactive power flows in the distribution network to maintain the voltage within the specified limits. Typically this is achieved through the operation of reactive compensation in the network and through the control of distribution connected generation plant via commercial arrangements specifically to cover these issues.

There are requirements placed on the network connected generation units to provide the following information to the distribution network operator:

- Measured values of current, voltage and power;

- Limit values for active and reactive power;

[61] EU Energy Directorate, 3rd Benchmarking Report, March 2004 (europa.eu.int)

[62] German Network Operators Association (Verband der Netzbetreiber)

[63] RWE (www.rwe.com)

[64] EoN (www.eon.com)

- Circuit breaker settings / step switch positions;
- Protection signals;
- Generating unit start up and reduction of output

The distribution network operator has obligations to inform the connected generation plant of any network congestion that arises due to network disturbances an scheduled or current switching measures that restrict the generating units output.

Transmission Connection Charging	Access to the transmission system is provided under negotiated third party access agreements negotiated on a bilateral basis between the DNO and the generator. Both generation and demand pay deep connection charges (including maintenance, reinforcement and operating costs increases associated with the connection).
TUoS Charging	Transmission use of system charging is payable only by demand to recover the ongoing costs associated with the maintenance, renewal and operation of the network. The charges are split to identify the metering costs, kW capacity usage and kWh energy usage. These are payable monthly or annually. Customers are also able to pay for reserve capacities (non-firm capacity) and reactive power services.
Distribution Connection Charging	Demand and generation pay for the connection to the distribution network on a deep charging basis. The generation also pays for the maintenance, renewal and operating costs of the connection assets.
DUoS Charging	Use of system charges are payable by demand customer only. However, embedded generation is entitled to receive payment in lieu of avoided Use of System costs from the higher voltage levels. These payments are applicable for non-renewable based generation (renewable plant receive support as a result of the Renewables Energy Act). Payments for smaller embedded generation without power metering is made on the basis of seasonal synthetic output profiles for the units. Further, where the embedded generating plants have a load factor of >30% it is considered that the DNO is able to utilise the output to offset the system capital expenditure requirement. Such offset is proportional to the generating plant availability. The loss of generation during maintenance outages is then provided for by the DNO under a system reserve capacity contract from the transmission network.

Table 9-4 German Market Summary

9.2.5 Spain[65] [66] [67] [68]

The Spanish market comprises of the market operator (OMEL), the grid operator and asset owner (REE) and the main electricity supply and distribution companies (Union Fenosa, Iberdrola and Endesa). All activities in the electricity market are governed by the terms of the Royal Decree 1955/2000. The electricity market is regarded as being fully open with an active energy regulator and legal separation of Distribution system operators. The generation market is still dominated by the largest three generation market incumbents.

Transmission Connection Charging	Generators and demand make payments for connection to the transmission system that include the costs of the connection assets and any other reinforcement necessary to provide the capacity required. Users that subsequently connect (within 5 years) to the transmission system and use the same assets are required to make a contribution to the original cost of the connection assets pro-rata to its own connection capacity.
TUoS charging	Only demand pays use of system charges that include both capacity and energy components with reactive energy charges being applied in the form of a surcharge or reduction dependent on the actual use of reactive energy by the demand. The network use system charges include distribution and transmission use of system charges.
Distribution Connection Charging	Demand customer connection costs are paid through regulated charges on the basis of the kW capacity requirements with the pricing varying with capacity and voltage level. Generation plant is required to pay for the full connection costs. Rebates are paid if new users connect to the assets within 5 years of commissioning.
DUoS	Distribution use of system charges are rolled up into the network tariffs. See TUoS charging above.
Losses	Transmission Loss factors are calculated by REE for each transmission system node and published on a daily basis ex-post.

Table 9-5 Spanish Market Summary

[65] Comision Nacional de Energia (www.cne.es)

[66] Endesa (www.endesa.es)

[67] Iberdrola (www.iberdrola.es)

[68] European Union Energy Directorate (europa.eu.int/comm./energy)

9.2.6 Netherlands [69] [70]

The Dutch electricity market is regarded as being open to competition for the medium and large industrial and commercial customer base. Distribution companies have legal separation from the energy supply and transmission companies, and a regulator is in place. Further the generation market is regarded as being competitive given that the market share of the largest three generation companies is around 33% of the total generation capacity.

Transmission Connection Charging	The connection charging includes an initial connection charge for making the break into the grid system. The user will need to pay for the costs for the connection assets over and above that allowed for within the initial connection charge. Additonally, there is an ongoing charge to cover maintenance of the assets and future refurbishment costs (the latter item can be deferred provided that the user pays in full when the assets need replacing)
TUoS	Transmission use of system charges are levied on both generation (25% of total revenue) and demand (75% of revenue). These charges include costs for metering services (excluding provision of the meter). For demand the charges are split 50% as a stamp charge on the basis of the contracted capacity and 50% on the basis of the energy off take. There are separate charges for ancillary service charges and reactive energy use.
Distribution Connection Charges	Connection charges are comprised of the initial investment costs and the maintenance costs to be constructed to include a one-off contribution, compensation for capital expenditure of reusable and compensation for maintenance costs. There are no special provisions for renewable or CHP generators.
DUoS	Charges and billing determinants vary by voltage level.

Table 9-6 Dutch Market Summary

[69] European Union, 3rd Benchmarking Report on Electricity Market Liberalisation, March 2004

[70] Tennet (www.tennet.nl)

9.2.7 Norway [50] [71]

The Norwegian electricity market is regarded as being full y open to competitive energy supply. The transmission asset owner and system operator are separated by corporate ownership, with the distribution companies providing separate regulatory accounts. A regulator is in place and the generation market is regarded as being competitive with the market share of the largest three generating companies being ~25%.

Transmission Connection Charging	The grid companies recover the connection cost through an investment charge or connection fee. Investment charges are over and above the regulated income cap for the companies. Generation and demand pay shallow charges for connection with refunds applying to assets within a ten year period following commissioning. There are no special provisions for renewable or CHP based generation.
TUoS	Transmission use of system charges are levied on the basis of energy (kWh), capacity (kW) and peak load (kW). The charges are split between generation (30%) and demand (70%). Capacity charges are on a stamp basis with energy being on the basis of use and determined on a nodal basis.
Distribution Connection Charges	The connection charging is based on shallow charges to the connection point with both customers and generators paying for the dedicated connection assets. There are no special provisions for renewable or CHP generators.
DUoS charges	These vary by voltage level.

Table 9-7 Norwegian Market Summary

9.3 Recommendations for Irish Market

The various markets reviewed have not provided any strong evidence for pro-active support for renewable and CHP generation plant within the charging structures for connection and use of distribution and transmission systems. Germany appears to provide the most pro-active support through the provision of feed-in tariffs at the transmission level which filter through to the generation users in the form of offset payments made to them by the distribution companies.

Connection charges are generally applied on a deep charging basis for embedded generation plant, with some jurisdictions applying use of system charges to both demand off- take and generation export onto the system. Where this is the case the split in terms of recovery of the allowable use of system revenue is of the order of 30% from generation and 70% from demand.

A number of jurisdications have adopted a rebate methodology to enable future offset of the deep connection costs, with the cut-off for rebates ranging from 5 years out to 15 years.

[71] Stattnett (www.statnett.no)

In developing recommendations for the Irish market the elements identified within the calculation methodology have been grouped into three categories – system focussed, energy focussed and macro-economic. Each item is discussed individually with a view to identifying possible mechanisms for their treatment in the Irish market.

9.3.1 System Focussed

These are the benefits / costs that can be recovered or controlled by the distribution and transmission operators. Therefore there is the capability within the regulatory framework to determine how the allocation of these costs and benefits should be made. The items considered to fall into this category are:

Losses – to the extent that losses are saved through the operation of the embedded generation the benefit accrues to the distribution company since cost of the system operation will be reduced. Therefore the allocated distribution loss factors will be too high leading to over-recovery of use of system charges from the energy suppliers using the network and, ultimately, the end customer.

Recognition of this could be through applying an uplift to the generator distribution loss factor that represents a share (say 85%) of the avoided system loss, this uplift could be applied for a defined period of time (say 5 years) – after which the uplift is incorporated into the embedded generators loss factor and is removed from the allowable use of system revenues. This will allow regulatory oversight of the revenue, provide ESB with some benefit initially and the customer with the long-term benefit through reduced losses cost;

- **Asset Benefit** – sharing of this benefit should be in proportion to the use made of the distribution system. The demand customers connected to the network will see this in the long term through downward movement in the DUoS charges following regulatory reviews (to the extent that reinforcement has been deferred due to the embedded generation connection).

  Since the embedded generator is effectively funding the assets that provide the ability to defer or delay capital expenditure, any benefit should be used to offset the cost of the deep connection cost to the generator. There is a strong case to argue that the full amount of any benefit should be utilised.

  The deep connection charging could be replaced with shallow charging (dedicated connection assets only) and a generator DUoS charge levied on the exported energy from the embedded generation site. These DUoS charges could then provide locational signals and a mechanism for apportionment of the benefits to embedded generators.

  Clear and transparent rules for defining the security contribution of the various types of embedded generation will need to be established to allow consistent calculation of the embedded generation benefits.

  Availability of information is key to the efficient performance of any market. To assist in achieving this objective it would be worthwhile reviewing the value for a regular publication of the distribution network development plans in the form of a statement that provides indications to prospective developers as to those areas on the distribution network that are best able to accept embedded generation capacity.[72] Whilst there is an argument against such publications given the fluid nature of the distribution network, it is expected that this argument will weaken as the DNO is required to evolve the network into a more active 'transmission-like' system.

[72] Such a statement is provided by Scottish Power for its Manweb distribution network in the UK.

Voltage Benefit – on the basis that the generation plant provides reactive power into the local distribution system the distribution company will benefit to the extent that:-

(i) the apparent power factor at the transmission exit point improves (i.e. they require less reactive energy) and therefore they incur lower reactive energy charges[73]. The reactive energy production from the embedded generation plant should be assigned a value and payments made on the basis of metered reactive power production. Any payments made by the distribution company to embedded generators would be on the basis of the reactive power charge within the published DUoS tariff for the connection voltage level. Further, those payments made to the generator for reactive power should be allowable within the distribution revenues and therefore will pass through to the energy supply businesses and ultimately the customer, and;

(ii) the voltage profile on the local distribution network improves such that any capital expenditure required for voltage reasons could be deferred. As has been proposed for the asset benefit, any voltage benefit should be used to offset the cost of connection for the embedded generator;

(iii) consideration is given to the possibility that the generator may provide voltage support 'on-demand' for the DNO at the time of designing the generation connection. A mechanism will be required to allow the DNO to recover any additional operational costs associated with active distribution networks. Identifying sections of network to be used to pilot such active network management techniques would enable costs to be ring-fenced on a project by project basis and also allow network performance to be monitored against the actions taken. The identification will need agreement between the DNO and the embedded generation connected to that section.

CML Benefit – is dependent on the statistical performance of the network. The value of the CML benefit is rather more intangible than the other benefits discussed above. The impact of an embedded generation connection on the local demand customers may well improve the overall supply quality and reliability. However, whilst customer payments may be made for the loss of supply lasting longer than a specified duration, it is only when significant penalties and incentives are placed on the distribution company that the financial balance begins to favour generation islanding schemes.

Transmission Benefit – comprises the asset and losses elements that apply to the distribution system, but at a transmission system level. These benefits will accrue to the transmission company to the extent that the embedded generation connects to the distribution network and operates reliably. The benefits will initially be to the Transmission companies account as an over-recovery or ability to re-divert the capital expenditure to other projects within the regulatory period. Such over-recovery or re-direction will benefit other customers connected to the transmission system or indirectly, the customer through reduced pass through charges.

The exemption of smaller embedded generation plant (MEC<10MW and MIC<MEC) from DUoS charge payment means that there is no mechanism in place to allow the benefit to flow through to the generator. Any sharing of this benefit would need to flow via the distribution company that has the contractual relationship with the transmission company and the embedded generator.

One mechanism to release this benefit to the embedded generators in the absence of generator DUoS charging would be to establish reward for the generators proportional to their contribution to the reduced capacity requirement at the transmission-distribution interface.

---

[73] Assuming that the Reactive Energy charging is implemented as per CER/04/239 1 July 2004.

9.3.2 Energy focussed

This is the Displaced Energy benefit that are derived from avoided energy costs that will be passed through to the energy supply companies, prior to reaching the customer. Given that the renewable plant are able to sell their output to ESB PES and ESB PES subsequently recovers the cost difference between embedded plant output price and the BNE price through the Public Service Obligation (PSO), it is not clear how any calculated benefit can be shared since the PSO already provides support for the embedded plant output over and above the cost of the new entrant system generation plant.

The main difference arises in the approaches adopted by the PSO and this proposed calculation methodology. The PSO approach assumes that all renewable generation capacity will displace the best new entrant cost of generation. However, the renewable generation output displaces operating generation plant. The type of plant that will be displaced depends on the generation profile of the embedded generator and therefore the price of the avoided energy will vary accordingly. To the extent that there is a positive benefit arising from the displacement of energy (i.e. the cost of the system plant energy is greater than the cost of the embedded plant energy), the benefit should be passed through to the end customer as a reduction in the PSO levy applied by ESB PES to the customer energy sales.

The embedded generator is indifferent to this since they are receiving their required energy output price that is supported by the PSO. There may be an argument for the embedded generator to receive a share of the benefit from any upside, however, the converse would also need to be true to ensure symmetry and the embedded generator would therefore need to accept that they incur a cost where the benefit is negative. This is unlikely to be acceptable as this would undermine the support provided by the PSO in the first instance.

9.3.3 Macro Economic

Those benefits that are considered to require treatment within a macro-economic context are - Emissions Benefit, Fuel Benefit and Social benefit. However, there is no direct contractual link between the embedded generator and a third party that allows these benefits to be realised directly through existing mechanisms.

> **Emissions Benefit** – to date only really includes value for avoided carbon dioxide emissions. The forthcoming EU ETS envisages emissions trading between member states in the EU and at a national level. When the carbon trading arrangements are put in place and begin to take effect, the embedded generation owners should be able to participate in the emissions markets within Ireland and the EU and thereby realise direct financial benefit for any avoided emissions.
>
> However, the emissions benefit may be seen as a mechanism by which the PSO support for the alternative energy requirements is reduced as the embedded renewable generation plant will be able to source revenue to support their business from emission trading. This would prevent a windfall crystallising in favour of the embedded generation plant and serve to reduce the overall cost to the end customers.
>
> **Fuel Benefit** – the financial value of the fuel benefit is captured within the calculation of the displaced energy benefit. This benefit does however, provide a step towards improved energy self-sufficiency and sustainability for Ireland. As such this will present a less exposed position for Ireland in the face of short term world energy price volatility and increase the overall "value added" within the Irish economy.
>
> **Social Benefit** – this is a benefit that is very much related to the local community and the employment opportunities that it may create as a result of the embedded generation construction and operation. It will be intrinsic to the operating budget structure of the embedded generation. The benefit will flow directly

into the local community in the form of wages and no other form of sharing mechanism needs to be put in place.

9.3.4 Micro- and Small Scale Generation

The very nature of SSEG means that it is connected at LV, typically within domestic or small commercial premises. The benefits that accrue for larger embedded generators with direct connections to the MV and HV distribution network will also accrue for SSEG – albeit an order of magnitude lower. However, one of the issues in respect of the larger embedded generation connections is that it is a point source, whereas the SSEG is likely to be dispersed across numerous distribution substations along the length of an HV or MV trunk.

To this extent the impact of the SSEG connections is likely to be less sudden and will allow ESB Networks to take account of it within their LV network designs in a similar way to their projections of load growth that drive the load related expenditure.

Further, applying the embedded generation connection application process to SSEG generation plant will be a significant barrier to market entry. It will effectively restrict competition in the supply market and prevent end users from having a free choice of energy supplier. The connection process for larger embedded generation requires the parties involved in the transaction to be informed participants with development resource and an understanding of the mechanisms in place for regulation of the electricity industry.

Given that the expected end user for SSEG will be a typical domestic customer, the position is significantly different. The product will be sold on the basis of its utility and cost saving potential meaning that, as with consumer goods and commodities, the transaction process (which will include the electrical connection) will need to be as standard as possible within the statutory constraints of the distribution licence. Such standardised connection terms could be applicable for SSEG below a de-minimis level to be determined. These standardised connection terms may provide a sliding scale of connection charges linked to the generator capacity and incorporating the costs and benefits associated with typical import/export profiles for this class of customer.

9.4 Next Steps

Following the above analysis and suggestions for the Irish market, it is suggested that a number of areas be explored further.

- Examine the potential benefits of establishing 'Active Network Areas' to provide incentive on the DNO to partner with embedded generation and/or responsive demand connections to investigate the potential for alternative voltage control mechanisms;

- Determine the level of system security support can be attributed to embedded generation, the process to determine this and the value of the avoided / deferred cost of network capital expenditure;

- Determine the impact and value of introducing an element of 'Non-firm' capacity to the connections for embedded generators and the operational controls that would need to be implemented to control the capacity used;

- Investigate the present costs for islanding schemes and the validity of the ESB Networks prohibition on establishing islanded portions of the distribution network;

- Seek to have ESB Networks publish a distribution network statement to provide detailed information on the development plans for the distribution network and the opportunity areas for generation and/or demand location. Such a statement would have information relating to network fault statistics, CMLs, in addition to the capacity available and fault levels on the network;

- Study into the possibility of establishing an incentive within the ESB Networks regulatory formulae to incentivise investment in technology and mechanisms that reduce the overall system losses. This should provide a notional allowable value to losses such that benefit can be derived by ESB where they manage the network with losses below the target amount.

- Determine the process to ensure that any deferred capital expenditure or loss benefits are recycled to the appropriate party and accounted for within the LCTAS connection process or under regular payments;

- Determine the standard connection terms and costs to facilitate connection of micro- and small-scale embedded generation to the distribution network;

- Determine the load profile for a typical SSEG installation associated with domestic, small commercial and small industrial customer categories. These profiles can then be adopted within the planning process for new LV networks;

- Undertake independent assessment will need to be made of the impact on ESB Networks' operational costs should elements of the embedded generation calculation methodology be adopted within the LCTAS connection process;

- Examine the potential for utilising embedded generation to provide local Ancillary Services within the distribution system. This would include provision of Black Start, Reactive Compensation Services etc and would need to determine the technical capability of the technology and the cost of any specific control equipment necessary to enable the service (both within the DNO and the generator);

Appendix A – terms of reference

SUSTAINABLE ENERGY IRELAND

INVITATION TO TENDER
COSTS AND BENEFITS OF EMBEDDED GENERATION IN IRELAND

Introduction

Sustainable Energy Ireland is Ireland's national energy authority. The Authority, which was established on May 1st 2002 under the Sustainable Energy Act 2002, has a mission to promote and assist the development of sustainable energy. This encompasses environmentally and economically sustainable production, supply and use of energy, in support of Government policy, across all sectors of the economy. Its remit relates mainly to improving energy efficiency, advancing the development and competitive deployment of renewable sources of energy and combined heat and power, and reducing the environmental impact of energy production and use, particularly in respect of greenhouse gas emissions.

The Authority is charged with implementing significant aspects of the Green Paper on Sustainable Energy and the National Climate Change Strategy as provided for in the National Development Plan.

Sustainable Energy Ireland (SEI) manages programmes aimed at:

- assisting deployment of superior energy technologies in each sector as required;
- raising awareness and providing information, advice and publicity on best practice;
- stimulating research, development and demonstration (RD&D);
- stimulating preparation of necessary standards and codes;
- publishing statistics and projections on sustainable energy and achievement of targets.

Context

The Government is currently considering its future policy and programmes on renewable energy for the period beyond 2005, taking into account future climate change commitments and the European Directive " On the promotion of electricity produced from renewable energy sources in the internal electricity market" (2001/77/EC). Sustainable Energy Ireland is commissioning a series of studies to assist the formulation and implementation of the policy. This study forms part of that series.

Invitation to tender

SEI invites tenders from suitably qualified individuals or organisations for the purposes of carrying out a detailed study on the costs and benefits that may accrue from incorporating embedded generation in the electricity transmission and distribution networks. It will be carried out as a public good research work, funded and published by SEI.

Objectives of Study

The study should undertake a comprehensive technical, financial and economic cost benefit analysis of the impacts of distributed generation in Ireland. It should examine commercial and technical arrangements that might be put in place which would minimise costs and maximise benefits and the impacts which these might have upon electricity suppliers, the Transmission System Operator (TSO), the Distribution System Operator (DSO), the embedded generator and the electricity consumer.

SUSTAINABLE ENERGY IRELAND

INVITATION TO TENDER
COSTS AND BENEFITS OF EMBEDDED GENERATION IN IRELAND

Overview

The Green Paper on Sustainable Energy 1999 set a target of increasing electricity generation from renewable energy sources in Ireland by 500 MWe in the period 2000-2005. The EU Directive 2001/77/EC, on the promotion of electricity produced from renewable energy sources in the internal electricity market, converts a component of Ireland's Kyoto target into a requirement to generate 13.2% of electricity from RE sources by 2010. The Government renewable electricity price support scheme or Alternative Energy Requirement (AER) has been the key instrument for achieving these targets. AER V in 2002 authorised a total of 363 MW of generating capacity to be awarded power purchase agreements. In the AER VI competition of 2003, the target of a total of 578 MW of renewable electricity generating capacity was set. This capacity is not necessarily additional to the capacity allocated in AER V. A large portion of the generation that will be installed under these schemes will be in the 100 kW – 100 MW size range, non-despatchable and typically, though not exclusively, connected to the medium voltage distribution network. Generators in this class are often referred to as "embedded" generators.

Achieving the targets set out above will involve a step change in the penetration of embedded generation in an electricity network in which current penetration is low. The impacts of this step change in penetration will have to be anticipated if the additional embedded generation is to be incorporated in an efficient and cost effective manner. The costs and benefits of connecting embedded generation, for electricity suppliers, the TSO, the DSO, the embedded generator and the electricity consumer, must be clearly identified in order that they may be allocated to the appropriate parties, with a view to promoting activity which is beneficial to all parties.

Article 7 of the EU Directive 2001/77/EC places specific obligations upon member states relating to the connection of renewable generation to the electricity transmission and distribution grids. Electricity network operators within member states will be obliged to ensure that rules on connecting and charging renewable generators comply with the requirements of this directive. Similar requirements will form part of the EU Directive on CHP, which is currently in draft form.

The current principles relating to embedded generation and the transmission and distribution systems in Ireland are listed in the ESBNG documents " Connection Asset Costs: Guiding Principles", "Statement of Charges 2003"[1] and "Structure of Transmission Use of System Charges"; and the ESB Networks documents "Statement of Distribution Use of Service Charges 2003"[2] The charging regime which currently pertains to embedded generators is that connecting generators are charged the full cost of connection assets including the cost of "deep" reinforcements, generators connected to the distribution grid do not pay "Distribution Use of System" (DuoS) charges. Generators less than 10MW in size are not charged "Transmission Use of System" (TuoS) charges. <u>All</u> generators are also charged a site-specific "Distribution Loss Adjustment Factor" (DLAF) and a transmission grid entry point specific "Transmission Loss Adjustment Factor" (TLAF).

[1] http://www.cer.ie/cerdocs/cer02125.pdf
[2] http://www.cer.ie/cerdocs/cer02123.pdf

SUSTAINABLE ENERGY IRELAND

INVITATION TO TENDER
COSTS AND BENEFITS OF EMBEDDED GENERATION IN IRELAND

Sustainable Energy Ireland intends to commission studies to inform renewable electricity stakeholders and policymakers in Ireland on the costs and benefits of embedded generation and on the implications of implementing Directive 2001/77/EC. This invitation to tender is for one such study for an examination of the costs benefits arising from embedded generation. It will examine the commercial arrangements that might be used to maximise the benefits and minimise the cost and the impact of these issues on electricity suppliers, the TSO, the DSO, the embedded generator and the consumer. The study will provide options as regards to implementation of policy relating to the incorporation of embedded generation in the electricity networks and inform debate on complex associated issues.

Outline of Service

The study shall, as a minimum, have the following scope:

- A detailed, rigorous technical examination of the costs and benefits of embedded generation within the Irish electricity networks is required. Technical analysis will be carried out of the effects of these costs, when fairly apportioned, on electricity suppliers, the TSO, the DSO, the embedded generator and the consumer, with increasing embedded generation penetration. The analysis will be rendered specific to Irish conditions by including examples of effects upon typical network segments bearing the characteristics that are predominant in Ireland. All analyses will include consideration of the influence of advanced generator designs upon the possible costs and benefits for network users.
- Meet with the CER, ESB National Grid and ESB Networks to ascertain network planning strategies in relation to embedded generation, to clarify any high-level principles on the treatment of embedded generation which may not be highlighted in the relevant documentation and to poll the opinions of these institutions on how the requirements of Directive 2001/77/EC might best be implemented in Ireland.
- Identify the costs and benefits to users associated with connecting embedded generation to the electricity networks in relation to the following headings:
    - Utilisation of network assets
    - System losses and overall system efficiency
    - Security and quality of supply
    - System reinforcement needs associated with connection of embedded generation
    - Avoided or deferred reinforcement
    - Systém control, load balance and safety

  The analysis of costs and benefits should include examples of generator connection to specific characteristic network segments and allow for variation according to the class and electrical specification of the generator being connected.
- Propose options for methodologies that would allow appropriate assessment of the costs and benefits of generic embedded generator connection classes to be routinely carried out. The proposed methodology options should allow the requirements of Directive 2001/77/EC to be implemented within commercial arrangements. The methodologies should allow for variations in costs and benefits in line with local network topography and the specific characteristics of the generator to be connected.

- Provide details of novel commercial arrangements that have been implemented in other jurisdictions giving recognition to benefits of connecting embedded generation. Carry out an analysis of whether these arrangements would fairly allocate costs and benefits among network users and providers using the appropriate cases from the previous analysis as examples.
- Where tendering parties deem it appropriate, alterations to the scope may be proposed. The proposed alterations must be clearly identified, along with reasons for adopting them and assumptions associated with the alterations.

The tendering parties may require permission from CER, ESBNG and ESB Networks to access electricity system data and to publish results of analyses using this data.

Property Rights

SEI will own any deliverables specified in the Invitation to Tender. Title to any Intellectual Property arising out of or in relation to the Services shall be vested in SEI. Intellectual Property shall mean all copyrights, patents, rights in design and software development. All outputs from, computer software and models created during, and data collected within, the study shall be the property of SEI and shall provided to SEI upon completion of the study. Where prior intellectual property rights or use of proprietary data conflict with this requirement, the affected intellectual property or data should be clearly identified within the tender proposal.

Study Duration

It is anticipated that the study will be completed within a six (6) month time period. Tendering parties are encouraged to propose staged work programmes with multiple deliverables, such as interim reports on key study phases.

Deliverables

The Contractor will be required to provide:

1. An interim report covering the proposed analysis, any interim results, progress to date, and a proposed contents and format for the final report.
2. A draft final report allowing SEI three weeks to comment and propose changes, edits, and the like.
3. The final report. Six paper copies and one Microsoft Word file will be required plus final data sets and models as agreed.

In addition, it will be critical to have some interim feedback that can be produced in the time frame that the CER envisages for consultation and decision on the details of the new electricity market rules. This is currently an unspecified date most likely to occur within the first three months of the project.

Further Work

Where appropriate, the final report should provide details of further work that may be necessary in the subject area but which lies outside of the defined/agreed scope of the study at hand. Suggestions on a work programme, which might the fulfil requirement for further work, should also be provided.

Collaboration

Where a study may require both local knowledge and international experience, SEI would encourage the formation of partnerships between Irish and international concerns for the purposes of that study. The formation of such partnerships is in line with SEI's objectives of increasing the sustainable energy technology knowledge base within Ireland and allowing Ireland to benefit from best internationally available practice. If a partnership submits a proposal, they must appoint a prime contractor who will be authorised to sign a contract on behalf of all partnership members and will assume overall responsibility for delivery.

Format of Tender

Tenders should take the following format:

- Demonstration of ability to address all aspects of this brief and where appropriate experience of similar activities
- The proposed approach to meeting this overall brief
- A detailed schedule of the programme of work including a breakdown of resources
- The CVs of personnel proposed
- Schedule of Costs
- Any comments on the brief
- Confirmation that tenders are valid for a period of 90 days from the final date for the receipt of tenders

Evaluation Criteria

Tenders will be evaluated on the basis of the most economically advantageous tender in terms of the following:

- Range and depth of previous relevant experience
- Quality and level of resources to be applied to the contract
- Understanding of the requirements of the brief
- Quality of the study proposals and methodology
- Quality of proposal
- Ability to meet the timescale for the study
- Value for money

Written Clarification

During the evaluation period clarification may be sought in writing from tenderers. Response to requests for clarification may not materially change any of the elements of the tenders submitted. No unsolicited communications from tenderers will be entertained during the evaluation period. A number of the most competitive tenderers may be invited to make presentations on their proposals for the purpose of elaboration, clarification and/or aiding understanding.

Conflict of Interest

The tenderer is required to formally notify SEI of any circumstances that might lead to a conflict of interest or the possibility of the perception of a conflict of interest arising. All relevant information must be furnished at time of submission of tender.

Additional Information

Queries arising from this tender document should be submitted by fax or e-mail to:
Legal & Contracts Manager,
Sustainable Energy Ireland,
Glasnevin,
Dublin 9, Ireland
email: micheal.mccarthy@sei.ie

SUSTAINABLE ENERGY IRELAND

INVITATION TO TENDER
COSTS AND BENEFITS OF EMBEDDED GENERATION IN IRELAND

Fax: 01 8082244
The deadline for receipt of queries is **23 July 2003.** No other communication may be entered into with any member of SEI in relation to this invitation to tender during the tendering period. All responses to queries raised will be transmitted to each tenderer with the identity of the authors of the queries deleted. SEI will endeavour to dispatch all such replies no later than **28 July.** SEI accepts no responsibility for the successful delivery of e-mail.

Payment

Staged payment, based upon the satisfactory achievement of agreed milestones, may be arranged where appropriate. Where staged payment is sought the scope of work should be structured so as to deliver discreet stand-alone outputs, such as publishable reports, which can be used to inform stakeholders of progress and the remaining work programme. Staged payments can be made for properly incurred costs on submission of interim reports and draft final report subject to a retention of 20 % of the fees until the final report is accepted by SEI.

Schedule of Costs

- Costs must be quoted on the basis of providing of all the required services.
- All costs must be quoted in Euro.
- VAT must be quoted separately
- The tenderer must quote an overall price based on the services to be provided and this must be the tenderer's best and final offer for the award of the fixed price contract.
- Any allowances which the tenderer wishes to make for expenses, travel, subsistence etc. must be quantified and included within the fixed price overall cost quoted.
- Unquantified costs will not be accepted.
- The tenderer must confirm that the tender, including all costs, holds good for the duration of the contract.
- Please indicate clearly any discounts to which Sustainable Energy Ireland may be entitled, including:
  - Public sector discounts
  - Early payment discounts
  - Any other discounts
- SEI will not be responsible for any errors on the calculation of the costs provided in response to this Invitation to tender. It is the responsibility of tenderers to ensure that the costs quoted are correct and properly calculated.

Tax Clearance Requirements

Tenderers are obliged to furnish SEI with a valid tax clearance certificate on submission of tender. Non-residents are obliged to produce a statement of suitability available from the Irish Revenue Commissioners. Application for tax clearance may be made to the Irish Revenue Commissioners at the Office of the Collector General, Tax Clearance Section, Sarsfield House, Limerick, Ireland (Tel: +353 61 310310) All payments under contract will be conditional on the company being in possession of a valid tax clearance certificate at all times.

Cost of Preparation of Tender

SEI will not be liable in respect of any costs incurred by tenderers in the preparation of tenders or any associated work effort.

SUSTAINABLE ENERGY IRELAND

INVITATION TO TENDER
COSTS AND BENEFITS OF EMBEDDED GENERATION IN IRELAND

Tender Submission

Three copies of the tender should be delivered in printed form not later than 12.00 hours on the 7th **August 2003.** The tender envelope should be sealed and clearly marked:

Tender For: "Costs and benefits of Distributed Generation"
Legal & and Contracts Manager
Sustainable Energy Ireland
Glasnevin, Dublin 9, Ireland.

Sustainable Energy Ireland does not bind itself to accept the lowest or any tender. Sustainable Energy Ireland undertakes to use its best endeavours to hold confidential any information provided by you in response to this tender subject to its obligations under law, including the Freedom of Information Act 1997. Should you wish that any of the information supplied by you in this tender should not be disclosed because of its sensitivity, you should, when providing the information, identify the same and specify the reasons for its sensitivity. Sustainable Energy Ireland will consult with you about this sensitive information before making a decision on any Freedom of Information request received. In the event that Sustainable Energy Ireland decides to change, revise, or amend the specification and such changes, revisions or amendments to the specification are not substantial, Sustainable Energy Ireland reserves the right to invite all tenderers to amend their tenders accordingly.

APPENDIX B – TOPOGRAPHICAL ANALYSIS

B.1 Objectives and Methodology

Topographical analysis was undertaken on a sample of urban, semi-urban and rural distribution networks, identified as typical, by ESB Networks, the Distribution Network Operator to establish the physical and technical properties that characterise each network. The objective of this network characterisation was to identify the principal network types that exist on the Irish electricity distribution system and to use this information to develop representative network models for use in power system studies. The studies then establish the technical performance of each network and from the results further analysis was undertaken to turn these figures into actual costs and benefits in monetary terms.

B.2 Sample of Network Types

The topographical analysis was based on physical data for each network in the sample provided by ESB Networks. The data included single line diagrams and maps of the network, standard equipment data (i.e. for overhead lines, cables, transformers and switchgear) and information obtained directly from ESB Networks in discussions with their system planning engineers.

The results of the analysis of each network, which in every case included more than one primary substation, is presented in Tables B.1 to B.7. The networks analysed were based in the following areas:

a) Trillick (Northern Donegal),

b) Donegall Town

c) Arigna (Leitrim)

d) Tralee (Kerry)

e) Blake (Kildare)

f) Inchicore (outskirts of Dublin)

g) Central Dublin

B.3 Network Topography

The results of the analysis of the individual networks have been sorted in Tables B.8, B.9 and B.10 respectively, to define the characteristics of the sample of rural, semi-urban and dense urban networks.

Table B.8 separates the 10 kV and 20 kV medium voltage networks to identify the specific characteristics at the two voltage levels.

B.4 Derivation of system model

From Tables B.8 to B.10 the characteristics of four representative network models have been derived. The models specifically relate to:

a) Rural 10 kV networks

b) Rural 20 kV networks

c) Semi-urban 10 kV networks

d) Dense urban 10 kV networks.

Tables B11 to B.14 present the results of this analysis for the respective network types. The characteristics defined in these four tables form the basis of the network models described in Section 4 and studied in Section5 of the report.

Although the analysis has principally concentrated on the medium voltage networks Tables B.8 to B.14 include data for the respective 38 kV networks that supply the medium voltage networks.

Table B.1: Topographical analysis of a sample of rural distribution networks TRILLICK area

Primary substation and feeder description	Feeder No.	Resupply feeder	Voltage (kV)	No. of boosters	Circuit segment	Spur No.	Feeder lengths: 3-phase (km)	1-phase (km)	Total	Nos. of transformers by capacity in kVA: 3 kVA	5 kVA	15 kVA	25 kVA	33 kVA	50 kVA	100 kVA	150 kVA	200 kVA	400 kVA	630 kVA	1000 kVA	Total capacity (kVA)	Peak load (MW)	No. of load points
Ballymacarry																								
Feeder No. 1 is an																								
interconnector with	1	Buncrana	10	2	Trunk	-	1.5	0	1.5									2	2			2200	McCarters	4
adjacent network		No. 1			Feeder Totals		1.5	0	1.5	0	0	0	0	0	0	0	0	2	2	0	0	2200	1.24	4
Feeder No. 2 supplies	2	-	20	0	Trunk	-	13.1	0	13.1			27		11	8	7		6	1			3468		60
local load only					Spur	2a	0	5.5	5.5			12		3								279		15
					Spur	2b	0	6.5	6.5			17		2								321		19
					Stubs	1 - 6	4.3	9	13.3			40		9	1				1			1347		51
					Feeder Totals		17.4	21	38.4	0	0	96	0	25	9	7	0	6	2	0	0	5415	1.09	145
Buncrana																								
Feeder No. 1 supplies	1	-	10	0	Trunk	-	25.5	2.2	27.7	1	18	51	2	27	3	5		5				3449		112
local load only					Spur	1a	7	23.1	30.1	2	26	44		16	3	2		1				1874		94
					Spur	1b	1.5	4	5.5		5	12		4	1							387		22
					Spur	1c	1.7	6	7.7		8	10		3		1						389		22
					Stubs	1 - 13	4.5	15	19.5		8	40		18	1	1		1				1584		69
					Feeder Totals		40.2	50.3	90.5	3	65	157	2	68	8	9	0	7	0	0	0	7683	2.52	319
Feeder No. 2 supplies	2	-	20	0	Trunk	-	30.4	0	30.4		6	72		18	8	4		5	1	1		4534		115
local load only					Spur	2a	0	5.1	5.1			11		3								264		14
					Spur	2b	5	0	5			10		1	2				1			683		14
					Spur	2c	0	5.9	5.9			22		2								396		24
					Stubs	1 - 13	8.1	21.1	29.2		5	71		11	4	3		1				2153		95
					Feeder Totals		43.5	32.1	75.6	0	11	186	0	35	14	7	0	6	2	1	0	8030	3.0781667	262
Feeder No. 3 supplies	3	-	20	0	Trunk		-	2	6.5	8.5		2	15			4	2		1				835	24
local load only					Stubs		1 - 3	0	4.6	4.6			9										135	9
					Feeder Totals		2	11.1	13.1		2	24			4	2	0					970	0.3718333	32
Feeder No. 4 supplies	4	-	10	0	Trunk		-	0.2	0	0.2													0	0
local load only					Stubs		1 - 3	2	0	2					1	1	2			5			2283	9
					Feeder Totals		2.2	0	2.2	0	0	0	0	1	1	2	0	0	5	0	0	2283	0.71	9

Note: For the purposes of this study a spur is identified as a circuit length equal to 5km or more (and not dedicated to generator).

Table B.1 (continued): Topographical analysis of a sample of rural distribution networks TRILLICK area (continued)

Primary substation and feeder description	Feeder No.	Resupply feeder	Voltage (kV)	No. of boosters	Circuit segment	Spur No.	Feeder lengths			Nos. of transformers by capacity in kVA												Total capacity (kVA)	Peak load (MW)	No. of load points
							3-phase (km)	1-phase (km)	Total	3 kVA	5 kVA	15 kVA	25 kVA	33 kVA	50 kVA	100 kVA	150 kVA	200 kVA	400 kVA	630 kVA	1000 kVA			
Carndonagh																								
Feeder No. 1 supplies	1	2	10	0	Trunk	-	13	0	13	1	8	37	1	13	1	1		4				2002		66
local load only					Spur	1a	7.8	0	7.8	1		3										48		4
					Spur	1b	4.2	2.7	6.9		7	10		5	2							450		24
					Spur	1c	0	8.3	8.3		2	13		4								337		19
					Stubs	1 - 3	4.5	1	5.5		7	9		7	5	3						951		31
					Feeder Totals		29.5	12	41.5	2	24	72	1	29	8	4	0	4	0	0	0	3788	1.06	144
Feeder No. 2 supplies	2	-	10	1	Trunk	-	28.9	4	32.9		39	67		11	3	8		1				2713		129
local load only					Spur	2a	6.6	4.5	11.1		11	24		12	4							1011		51
					Spur	2b	0	5	5		8	13		1								268		22
					Spur	2c	0	5	5		10	7										155		17
					Stubs	1 - 12	4.7	21.9	26.6		30	64		13	2	1						1739		110
					Feeder Totals		40.2	40.4	80.6	0	98	175	0	37	9	9	0	1	0	0	0	5886		329
Feeder No. 3 supplies	3	-	10	0	Trunk	-	2.5	0	2.5		1		1		1	2		5				1280		10
town load & resupply					Feeder Totals		2.5	0	2.5	0	1	0	1	0	1	2	0	5	0	0	0	1280		10
Feeder No.4 supplies	4	-	10	0	Trunk	-	4.9	0	4.9		5	12		2		3		2				971		24
local load only					Spur	4a	2.1	10.4	12.5	3	8	21		11	2	1						927		46
					Spur	4b	0	6.9	6.9		8	18		4								442		30
					Feeder Totals		7	17.3	24.3	3	21	51	0	17	2	4	0	2	0	0	0	2340		100
Moville																								
Feeder No. 1 supplies	1	-	10	1	Trunk		-	14	0	14	2	23	30		4				1				903	60
local load only					Spur		1a	10	12	22	4	25	34		6								845	69
					Spur		1b	0	5.5	5.5	1	6	9		1								201	17
					Spur		1c	0	8.8	8.8		7	13		4								362	24
					Stubs		1 - 5	0	9.3	9.3	1	5	24		1								421	31
					Feeder Totals		24	35.6	59.6	8	66	110	0	16	0	0	0	1	0	0	0	2732	0.87	201
Feeder No. 2 supplies	2	-	10	0	Trunk		-	9	0	9		10	31		27	1	2		2				2056	73
local load only					Stubs		1 - 7	4	6.5	10.5		8	17		11	1	2		4	1			2108	44
					Feeder Totals		13	6.5	19.5	0	18	48	0	38	2	4	0	6	1	0	0	4164	1.2	117
Feeder No. 3 supplies	3	-	10	0	Trunk		-	11.6	0	11.6		12	29		5	2	3		6				2260	57
local load only					Spur		3a	0	5	5		4	15		3								344	22
					Spur		3b	3.5	2.5	6		7	8		2	1							271	18
					Spur		3c	0	6	6			10		3								249	13
					Stubs		1 - 4	0	10.5	10.5	1	13	22		8								662	44
					Feeder Totals		15.1	24	39.1	1	36	84	0	21	3	3	0	6	0	0	0	3786	1.26	154

Table B.2: Topographical analysis of a sample of rural distribution networks DONEGAL area

Primary substation and feeder description	Feeder No.	Resupply feeder	Voltage (kV)	No. of boosters	Circuit segment	Spur No.	Feeder lengths 3-phase (km)	1-phase (km)	Total	Nos. of transformers by capacity in kVA 3 kVA	5 kVA	15 kVA	25 kVA	33 kVA	50 kVA	100 kVA	150 kVA	200 kVA	400 kVA	630 kVA	1000 kVA	Total capacity (kVA)	Peak load (MW)	No. of load points
Donegal Town																									
Feeder No. 1 supplies	1	5	10	1 (2x150)	Trunk	-	11.6	0	11.6		15	59	2	11	3	8	1	3	1	1		4103		104
local load only					Spur	1a	2	15	17	1	19	31		4	1							745		56
					Spur	1b	1	39.7	40.7	6	46	82		3	2							1677		139
					Stubs	1 - 4	3.2	5.5	8.7	2	10	32		3	2	2		2	1			1735		54
					Feeder Totals		17.8	60.2	78	9	90	204	2	21	8	10	1	5	2	1	0	8260	2.77	353
Feeder No. 2 connects	2	3	10		Trunk	-	13.5	0	13.5													0	Meenaguse	0
small hydro					Feeder Totals		13.5	0	13.5	0	0	0	0	0	0	0	0	0	0	0	0	0		0
Feeder No. 3 connects	3	2,5	10	1 (2x100)	Trunk	-	5.8	0	5.8	2	6	16	1	1	1	1		1				684		29
a cluster of three small					Spur	3a	7.7	2	9.7	1	11	29			1				1			943		43
hydros and supplies					Stubs	1 - 2	0	6	6	3	7	37		1								632		48
local load					Cluster	-	14.9	0.8	15.7	1	15	34		1	3							771		54
					Feeder Totals		28.4	8.8	37.2	7	39	116	1	3	5	1	0	1	1	0	0	3030		174
Feeder No.4 connects	4	-	10		Trunk	-	5.5	0	5.5													0	Meenadreen	0
windfarm					Feeder Totals		5.5	0	5.5	0	0	0	0	0	0	0	0	0	0	0	0	0		0
Feeder No. 5 supplies	5	1,3	10		Trunk	-	9.5	0	9.5	2	6	28	1	3	2	2		1		2		2340		47
local load only					Spur	5a	3	2	5			9		4		4		7		3	1	4957		28
					Spur	5b	0	23	23	5	18	25										480		48
					Spur	5c	5.5	0	5.5	1	4	21		1		1						471		28
					Spur	5d	0	6	6	3	18	8		1								252		30
					Stubs	1	3	0	3		1	13			1	1						350		16
					Feeder Totals		21	31	52	11	47	104	1	9	3	8	0	8	0	5	1	8850		197

Table B.3: Topographical analysis of a sample of rural distribution networks ARIGNA area

Primary substation and feeder description	Feeder No.	Resupply feeder	Voltage (kV)	No. of boosters	Circuit segment	Spur No.	Feeder lengths 3-phase (km)	1-phase (km)	Total	Nos. of transformers by capacity in kVA 3 kVA	5 kVA	15 kVA	25 kVA	33 kVA	50 kVA	100 kVA	150 kVA	200 kVA	400 kVA	630 kVA	1000 kVA	Total capacity (kVA)	Peak load (MW)	No. of load points
Arigna supplies load and interconnects with adjacent network	2	Other network	20		Trunk	-	22.1	0	22.1		2	77		2	12	7		1		2		3991		103
	2		20	2x100	spur	2b	15.2	18.3	33.5		1	108		7	16			1				2856		133
	2		20		spur	2c	4.8	13.3	18.1			47		1	3							888		51
	2		20		spur	2d	6.7	15	21.7		1	48		2	1							841		52
	2		20		spur	2e	6	0	6			16		4	3							522		23
	2		20		stub	1-7	2	19.3	21.3		1	75		5								1295		81
					Feeder Totals		56.8	65.9	122.7	0	5	371	0	21	35	7	0	2	0	2	0	10393	1.81	443
Connectes a cluster of generators and feeds into the primary 4 wind farms connected	1		20		Trunk		4	0	4													0	Arigna Fuels	1
	1		20		Cluster		12.4	0	12.4												-14.4	-14400		4
	2		20		spur		18.6	12.1	30.7	20	32	27		7	6	4		1				1756	Glen Quarry	97
	2		10		spur		7.5	4.8	12.3	1	20	17	1	3		2						682		44
					Feeder Totals		16.4	0	16.4	0	0	0	0	0	0	0	0	0	0	0	-14.4	-14400		5

Note: For the purposes of this study a spur is identified as a circuit length equal to 5km or more (and not dedicated to generator).

Table B.4: Topographical analysis of a sample of rural distribution networks TRALEE area

Primary substation and feeder description	Feeder No.	Resupply feeder	Voltage (kV)	No. of boosters	Circuit segment	Spur No.	Feeder lengths			Nos. of transformers by capacity in kVA												Total capacity (kVA)	Peak load (MW)	No. of load points
							3-phase (km)	1-phase (km)	Total	3 kVA	5 kVA	15 kVA	25 kVA	33 kVA	50 kVA	100 kVA	150 kVA	200 kVA	400 kVA	630 kVA	1000 kVA			
Abbeyfeale																								
Feeder No. 1 supplies	1	-	10		Trunk	-	20.6	0	20.6			47		3	3	2		1				1354		56
local load only					Spur	1a	0	7.8	7.8			25										375		25
					Spur	1b	0	6.5	6.5			20										300		20
					Spur	1c	4.5	13.5	18			55		2	2							991		59
					Spur	1d	0	9	9			17										255		17
					Stubs	1 - 13	1.2	25.1	26.3			95		4								1557		99
					Feeder Totals		26.3	61.9	88.2	0	0	259	0	9	5	2	0	1	0	0	0	4832	0.91	276
Feeder No. 2 supplies	2	3	10	1 (2x100)	Trunk	-	13.2	0	13.2	1		44		7	2	2		2	1			1994		59
local load only					Spur	2a	1.3	5.5	6.8			26		2	1							506		29
					Spur	2b	0	9.8	9.8			24		3								459		27
					Spur	2c	14.6	21.1	35.7			103		8	1	1		1				2159		114
					Spur	2d	0	6.5	6.5		1	15										230		16
				1 (2x100)	Stubs	1 - 4	0	9.3	9.3		1	61		9	1	1		4	2			2967		79
					Feeder Totals		29.1	52.2	81.3	1	2	273	0	29	5	4	0	7	3	0	0	8315	2.49	324
Feeder No. 3 supplies	3	2	10	1 (2x150)	Trunk	-	15.4	0	15.4			57		10	8	5		2	3			3685		85
local load only					Spur	3a	4	5.5	9.5			40		1	1	3						983		45
					Spur	3b	0	6	6			31		2								531		33
					Spur	3c	0	12	12			38		3								669		41
					Spur	3d	0	10.5	10.5		1	31		4								602		36
					Spur	3e	0	9.5	9.5			16										240		16
					Spur	3f	0	12	12			37		3								654		40
					Stubs	1 - 5	3.5	9.3	12.8	1	2	66		5	4			1				1568		79
					Feeder Totals		22.9	64.8	87.7	1	3	316	0	28	13	8	0	3	3	0	0	8932	1.84	375
Feeder No. 4 provides	4	-	10		Trunk	-	1.2	0	1.2						1							50		1
resupply to adjacent fdr					Feeder Totals		1.2	0	1.2	0	0	0	0	0	1	0	0	0	0	0	0	50		1
Feeder No. 5 provides	5	-	10		Trunk	-	1.6	0	1.6										1			1400	Kostal	1
resupply to adjacent fdr					Feeder Totals		1.6	0	1.6	0	0	0	0	0	0	0	0	0	1	0	0	1400	1.61	1

Table B.5: Topographical analysis of a sample of rural distribution networks MIDLANDS area

							Feeder lengths			Nos. of transformers by capacity in kVA														
Primary substation and feeder description	**Feeder No.**	**Resupply feeder**	**Voltage (kV)**	**No. of boosters**	**Circuit segment**	**Spur No.**	**3-phase (km)**	**1-phase (km)**	**Total**	**3 kVA**	**5 kVA**	**15 kVA**	**25 kVA**	**33 kVA**	**50 kVA**	**100 kVA**	**150 kVA**	**200 kVA**	**400 kVA**	**630 kVA**	**1000 kVA**	**Total capacity (kVA)**	**Peak load (MW)**	**No. of load points**
Blake																								
supplies load and	1	Other network	10		Trunk	-	10.3	0	10.3	1	2	17	1	6	3	3		1				1141		34
interconnects with adjacent	1	-			Spur	1a	0	13.45	13.45	3	9	29		5								654		46
network	1	Other network			Stub	1	0	0	0													0		0
	1	-			Stub	2-6	2.1	8.2	10.3		3	11		8	1	1	1	1				1944	Timahoe	27
					Feeder Totals		10.3	0	34.05	4	14	57	1	19	4	4	1	2	0	0	0	3739	1.03	107
supplies town load & resupply	2	-	10		Trunk	-	11.95	0	11.95	1	2	13		2	3	1		1				724		23
	2	3			Stub	1	0	0	0													0		0
	2	-			Stub	2-6	3.25	10.5	13.75	2	1	21		7		1		1		1		1487		34
					Feeder Totals		15.2	10.5	25.7	3	3	34	0	9	3	2	0	2	0	1	0	2211	0.73	57
supplies load and	3	-	10		Trunk	-	6.45	0	6.45	1	4	15		4	5	2		1				1030		32
interconnects with adjacent	3	Other network			Spur	3a	3.8	3.5	7.3		5	14		5	2							500		26
network	3	2			Stub	1	0	0	0													0		0
	3	-			Stub	2-6	0	4.75	4.75		2	12		7								421		21
					Feeder Totals		10.25	8.25	18.5	1	11	41	0	16	7	2	0	1	0	0	0	1951	0.81	79
supplies town load & resupply	4	Edenderry 1	10	1 (2x150)	Trunk	-	10.35	0	10.35		7	17		6	1							538		31
	4	-			Spur	4a	5.6	3.75	9.35		3	22		8	2			1				909		36
	4	-			Spur	4b	2	5	7	2	2	15		2	1	3		3				1257		28
	4	-		1	Stub	1-7	2.3	11.2	13.5	4	6	19		3	1			2	1			1276		36
					Feeder Totals		20.25	19.95	40.2	6	18	73	0	19	5	3	0	6	1	0	0	3980	1.56	131

Edenderry																								
supplies town load & resupply	1	Blake 4	10		Trunk	-	3.5	0	3.5		6	3		4								207		13
	1	-			Stub	1	0	1.5	1.5		2	4										70		6
					Feeder Totals		3.5	0	5	0	8	7	0	4	0	0	0	0	0	0	0	277	??	19
dedicated feeder	2	-	10		Trunk	-	8.5	0	8.5													1000	EuroPeat	1
					Feeder Totals		8.5	0	8.5	0	0	0	0	0	0	0	0	0	0	0	0	1000	??	1
supplies town load & resupply	3	4	10		Trunk	-	3.3	0	3.3		1	1						10	1			2420		13
	3	4			Stub	1	1.35	0	1.35							1		1	1			700		3
	3	-			Stub	2	0.5	1	1.5		4	1		1		1		1				368		8
					Feeder Totals		5.15	1	6.15	0	5	2	0	1	0	2	0	12	2	0	0	3488	??	24
supplies load and	4	Other network	10	1 (2x100)	Trunk	-	14.95	1	15.95	1	9	16	2	5	2	1		6	1	1		2933		44
interconnects with adjacent	4	-			Spur	4a	1.6	22.3	23.9	2	5	45		7	1							987		60
network	4	-		1 (2x150)	Spur	4b	7.3	19.15	26.45	6	19	45		7	1							1069		78
	4	Other network	10	1x100	Spur	4c	22.6	59.2	81.8	10	38	120		23	1	4		2	3		1	5829		202
	4	-			Spur	4d	0	7.75	7.75	1	6	11										198		18
	4	3			Stub	1	1	0	1		3	1		1								63		5
	4	3			Stub	2	0	0	0													0		0
	4	-			Stubs	3-17	4.3	6.85	11.15	2	15	14	1	2	6	2		5	2			2682		49
					Feeder Totals		51.75	116.25	168	22	95	252	3	45	11	7	0	13	6	1	1	13761	??	456

Note: For the purposes of this study a spur is identified as a circuit length equal to 5km or more (and not dedicated to generator).

Table B.6: Topographical analysis of a sample of semi-urban distribution networks INCHICORE area (Dublin outskirts)

Primary substation and feeder description	Feeder No.	Resupply feeder	Voltage (kV)	No. of boosters	Circuit segment	Spur No.	Feeder lengths: 3-phase (km)	1-phase (km)	Total	Nos. of transformers by capacity in kVA: 3 kVA	5 kVA	15 kVA	25 kVA	33 kVA	50 kVA	100 kVA	150 kVA	200 kVA	400 kVA	630 kVA	1000 kVA	Total capacity (kVA)	Peak load (MW)	No. of load points
Ballymount																								
supplies town load & resupply	1	2	10		Trunk	-	1.09	0	1.09										2	2	2	4060		6
					Feeder Totals		1.09	0	1.09	0	0	0	0	0	0	0	0	0	2	2	2	4060	0.83	6
supplies town load & resupply	2	Semperit 12	10		Trunk	-	1.78	0	1.78										3	3		3090		6
supplies town load & resupply	2	1			Stub	1	1.4	0	1.4									1	1		1	1600		3
					Feeder Totals		3.18	0	3.18	0	0	0	0	0	0	0	0	1	4	3	1	4690	2.1	9
supplies town load & resupply	3	Inchicore Central 6	10		Trunk	-	3.9	0	3.9						1			1	8	1		4080		11
supplies town load & resupply	3	2 and 5			Stub	1	1.23	0	1.23			1				1		2				515		4
supplies town load & resupply	3	4			Stub	2	0.17	0	0.17											1		630		1
resupply only	3	Clondalkin 4			Stub	3	0	0	0													0		0
					Feeder Totals		5.3	0	5.3	0	0	1	0	0	1	1	0	3	8	2	0	5225	0.81	16
supplies town load & resupply	4	Clondalkin 4	10		Trunk	-	3.53	0	3.53									1	3	2	2	4660		8
supplies town load & resupply	4	3			Stub	1	0.29	0	0.29											1		630		1
					Feeder Totals		3.82	0	3.82	0	0	0	0	0	0	0	0	1	3	3	2	5290	1.32	9
supplies town load & resupply	5	3	10		Trunk	-	1.25	0	1.25									1	2			1000		3
supplies load and interconnects with adjacent network	5	unknown			Stub	1	2.44	0	2.44							1		1	1	3		2590		6
supplies load and interconnects with adjacent network	5	unknown			Stub	2	0.52	0	0.52										2			800		2
					Feeder Totals		4.21	0	4.21	0	0	0	0	0	0	1	0	2	5	3	0	4390	2.29	11
supplies local load only	6	-	10		Trunk	-	0.84	0	0.84											2	1	2260		3
					Feeder Totals		0.84	0	0.84	0	0	0	0	0	0	0	0	0	0	2	1	2260	0.33	3

Clondalkin																								
supplies town load & resupply	1	2	10		Trunk	-	2.82	0	2.82										3	3		3090		6
					Feeder Totals		2.82	0	2.82	0	0	0	0	0	0	0	0	0	3	3	0	3090	1.31	6
supplies town load & resupply	2	4	10	0	Trunk	-	4.13	0	4.13							1		3	3	2	1	4160		10
resupply only	2	1			Stub	3	0	0	0													0		0
supplies load and interconnects with adjacent network	2	Other network			Stub	4a	1.74	0	1.74									4	6			3200		10
resupply only	2	Ballymount 4			Stub	4b	0.4	0	0.4													0		0
supplies town load & resupply	2	Semperit 11			Stub	5	0.58	0	0.58										1			400		1
					Stubs	1 - 2	0.44	0	0.44							1			1			500		2
					Feeder Totals		7.29	0	7.29	0	0	0	0	0	0	2	0	7	11	2	1	8260	3.59	23
supplies town load & resupply	3	Ballymount 3	10	0	Trunk	-	5.72	0	5.72									1	3	3		3290		7
supplies town load & resupply	3	Semperit 11			Stub	1	1.25	0	1.25										1		1	1400		2
local load only	3	-			Stub	2	0.37	0	0.37											1		630		1
supplies town load & resupply	3	Ballymount 4			Stub	3	0.4	0	0.4										1	1		1030		2
					Feeder Totals		7.74	0	7.74	0	0	0	0	0	0	0	0	1	5	5	1	6350	1.89	12
supplies load and interconnects with adjacent network	4	Other network	10		Trunk	-	4.76	0	4.76										6	5	1	6550		12
local load only	4	-			Stub	1	0.1	0	0.1									1				200		1
resupply only	4	Semperit 11			Stub	2	1.6	0	1.6													0		0
local load only	4	-			Stub	3	0.46	0	0.46										1	1		1030		2
local load only	4	-			Stub	4	0.3	0	0.3											1		630		1
					Feeder Totals		7.22	0	7.22	0	0	0	0	0	0	0	0	1	7	7	1	8410	3.4	16

Table B.6 (continued): Topographical analysis of a sample of semi-urban distribution networks INCHICORE area (Dublin outskirts) continued

							Feeder lengths			Nos. of transformers by capacity in kVA														
Primary substation and feeder description	Feeder No.	Resupply feeder	Voltage (kV)	No. of boosters	Circuit segment	Spur No.	3-phase (km)	1-phase (km)	Total	3 kVA	5 kVA	15 kVA	25 kVA	33 kVA	50 kVA	100 kVA	150 kVA	200 kVA	400 kVA	630 kVA	1000 kVA	Total capacity (kVA)	Peak load (MW)	No. of load points
Semperit																								
supplies load and interconnects with adjacent network	1	Other network	10		Trunk	-	4.1	0	4.1									2	7	4		5720		13
supplies local load only	1	-			Stub	1	3.2	0	3.2									3	3	3		3690		9
supplies local load only	1	-			Stub	2	0.34	0	0.34										1			400		1
interconnects with adjacent network	1	Other network			Stub	3	0.26	0	0.26													0		0
					Feeder Totals		7.9	0	7.9	0	0	0	0	0	0	0	0	5	11	7	0	9810	3.01	23
supplies town load & resupply	2	Inchicore Central 1	10		Trunk	-	3.32	0	3.32									2	6	1		3430		9
supplies local load only	2	-			Stub	1	0.23	0	0.23									1				200		1
resupply only	2	Inchicore Central 2			Stub	2	0	0	0													0		0
supplies local load only	2	-			Stub	3	0.34	0	0.34			1				1			1			515		3
supplies load and interconnects with adjacent network	2	Other network			Stub	4	0.79	0	0.79									2	1			800		3
supplies load and interconnects with adjacent network	2	Other network			Stub	5	0.46	0	0.46									1	2			1000		3
					Feeder Totals		5.14	0	5.14	0	0	1	0	0	0	1	0	6	10	1	0	5945	2	19
supplies local load only	3	-	10		Trunk	-	1.83	0	1.83					1	1	1		2	2	2		2643		9
supplies local load only	3	-			Stub	1	0.18	0	0.18										1			400		1
resupply	3	Inchicore Central 7			Stub	2	0	0	0													0		0
					Feeder Totals		2.01	0	2.01	0	0	0	0	1	1	1	0	2	3	2	0	3043	1.79	10
supplies town load & resupply	4	Inchicore Central direct	10		Trunk	-	2.59	0	2.59									1	2	2		2260		5
supplies local load only	4	-			Stub	1	0.1	0	0.1										1			400		1
resupply	4	Inchicore Central 2			Stub	2	0.1	0	0.1													0		0
					Feeder Totals		2.79	0	2.79	0	0	0	0	0	0	0	0	1	3	2	0	2660	1.32	6
supplies local load only	5	-	10		Trunk	-	1.17	0	1.17												2	2000		2
					Feeder Totals		1.17	0	1.17	0	0	0	0	0	0	0	0	0	0	0	2	2000	0.02	2
supplies local load only	6	-	10		Trunk	-	0.5	0	0.5													0	John Player MV	1
					Feeder Totals		0.5	0	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	??	1
supplies no load	7	-	10		Trunk	-	0.63	0	0.63													0		0
					Feeder Totals		0.63	0	0.63	0	0	0	0	0	0	0	0	0	0	0	0	0	??	0

Table B.6 (continued): Topographical analysis of a sample of semi-urban distribution networks INCHICORE area (Dublin outskirts) continued

							Feeder lengths			Nos. of transformers by capacity in kVA														
Primary substation and feeder description	**Feeder No.**	**Resupply feeder**	**Voltage (kV)**	**No. of boosters**	**Circuit segment**	**Spur No.**	**3-phase (km)**	**1-phase (km)**	**Total**	**3 kVA**	**5 kVA**	**15 kVA**	**25 kVA**	**33 kVA**	**50 kVA**	**100 kVA**	**150 kVA**	**200 kVA**	**400 kVA**	**630 kVA**	**1000 kVA**	**Total capacity (kVA)**	**Peak load (MW)**	**No. of load points**
supplies town load & resupply	8	10			Trunk	-	1.31	0	1.31												2	2000		2
					Feeder Totals		1.31	0	1.31	0	0	0	0	0	0	0	0	0	0	0	2	2000	2.86	2
resupply	9	11	10		Trunk	-	0.5	0	0.5													0		0
					Feeder Totals		0.5	0	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	??	0
supplies town load & resupply	10	9	10		Trunk	-	5.99	0	5.99										4	7	5	11010		16
resupply	10	8			Stub	1	0	0	0													0		0
					Feeder Totals		5.99	0	5.99	0	0	0	0	0	0	0	0	0	4	7	5	11010	0.5	16
supplies town load & resupply	11	Clondalkin 3	10		Trunk	-	1.46	0	1.46													0	Bailey MV	0
supplies town load & resupply	11	Clondalkin 4			Stub	1	0.71	0	0.71										1	1		1030		2
supplies town load & resupply	11	Inchicore Central 5			Stub	2	0.5	0	0.5										2			800		2
resupply	11	Clondalkin 2			Stub	3	0	0	0													0		0
					Feeder Totals		2.67	0	2.67	0	0	0	0	0	0	0	0	0	3	1	0	1830	2.57	4
supplies local load only	12	-			Trunk	-	3.46	0	3.46									2	2	1		1830		5
supplies local load only	12	-			Stub	1	0.3	0	0.3											1		630		1
resupply	12	Inchicore Central 4			Stub	2	0	0	0													0		0
resupply	12	Inchicore Central 6			Stub	3	0	0	0													0		0
supplies local load only	12	-			Stub	4	0.4	0	0.4										1			400		1
supplies local load only	12	-			Stub	5	0.14	0	0.14							1					1	1100		2
resupply	12	Ballymount 2			Stub	6	0	0	0													0		0
					Feeder Totals		4.3	0	4.3	0	0	0	0	0	0	1	0	2	3	2	1	3960	1.94	9

Table B.6 (continued): Topographical analysis of a sample of semi-urban distribution networks INCHICORE area (Dublin outskirts) continued

							Feeder lengths			Nos. of transformers by capacity in kVA														
Primary substation and feeder description	**Feeder No.**	**Resupply feeder**	**Voltage (kV)**	**No. of boosters**	**Circuit segment**	**Spur No.**	**3-phase (km)**	**1-phase (km)**	**Total**	**3 kVA**	**5 kVA**	**15 kVA**	**25 kVA**	**33 kVA**	**50 kVA**	**100 kVA**	**150 kVA**	**200 kVA**	**400 kVA**	**630 kVA**	**1000 kVA**	**Total capacity (kVA)**	**Peak load (MW)**	**No. of load points**
Inchicore Central																								
supplies town load & resupply	1	Semperit 2	10		Trunk	-	4.76	0	4.76									2	6	4		5320		12
supplies local load only	1	-			Stub	1	1.53	0	1.53									5				1000		5
					Feeder Totals		6.29	0	6.29	0	0	0	0	0	0	0	0	7	6	4	0	6320	??	17
supplies town load & resupply	2	Semperit 2	10		Trunk	-	4.03	0	4.03							1		3	4	1	1	3930		10
resupply	2	Semperit 4			Stub	1	0	0	0													0		0
					Feeder Totals		4.03	0	4.03	0	0	0	0	0	0	1	0	3	4	1	1	3930	??	10
supplies load and interconnects with adjacent network	3	Other network	10		Trunk	-	1.83	0	1.83										2			800		2
					Feeder Totals		1.83	0	1.83	0	0	0	0	0	0	0	0	0	2	0	0	800	??	2
supplies town load & resupply	4	Semperit 12	10		Trunk	-	3.82	0	3.82									2	8	2		4860		12
supplies town load & resupply	4	6			Stub	1	0.4	0	0.4										1	1	1	2030		3
supplies local load only	4				Stub	2	0.37	0	0.37													0	Kylemore Tranction	1
					Feeder Totals		4.59	0	4.59	0	0	0	0	0	0	0	0	2	9	3	1	6890	??	16
supplies town load & resupply	5	Clondalkin 4	10		Trunk	-	2.37	0	2.37													0		0
resupply	5	Semperit 11			Stub	1	0.34	0	0.34													0		0
					Feeder Totals		2.71	0	2.71	0	0	0	0	0	0	0	0	0	0	0	0	0	??	0
supplies town load & resupply	6	Ballymount 3	10		Trunk	-	3.32	0	3.32									2	2			1200		4
resupply	6	Semperit 12			Stub	1	0	0	0													0		0
resupply	6	4			Stub	2	0.14	0	0.14													0		0
supplies local load only	6	-			Stub	3	0.2	0	0.2													0	Truck Centre MV	1
					Feeder Totals		3.66	0	3.66	0	0	0	0	0	0	0	0	2	2	0	0	1200	??	5

Note: For the purposes of this study a spur is identified as a circuit length equal to 5km or more (and not dedicated to generator).

Table B.7 : Topographical analysis of a sample of dense urban distribution networks CENTRAL DUBLIN AREA

Primary substation and feeder description	Feeder No.	Resupply feeder	Voltage (kV)	No. of boosters	Circuit segment	Spur No.	Feeder lengths 3-phase (km)	1-phase (km)	Total	Nos. of transformers by capacity in kVA 3 kVA	5 kVA	15 kVA	25 kVA	33 kVA	50 kVA	100 kVA	150 kVA	200 kVA	400 kVA	630 kVA	1000 kVA	Total capacity (kVA)	Peak load (MW)	No. of load points
Morrowbone Lane																								
resupply	1	Guinness and	10		Trunk	-	1	0	1													0		0
		Watling St 1			Feeder Totals		1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	??	0
supplies load and interconnects with adjacent network	2	Other network	10		Trunk	-	0.73	0	0.73										3			1200	0.37	3
					Feeder Totals		0.73	0	0.73	0	0	0	0	0	0	0	0	0	3	0	0	1200	0.37	3
supplies load and interconnects with adjacent network	3	Other network	10		Trunk	-	1.72	0	1.72										1	2		1660	0.93	4
					Feeder Totals		1.72	0	1.72	0	0	0	0	0	0	0	0	0	1	2	0	1660	0.93	4
supplies town load, resupply &	4	Newmarket	10		Trunk	-	1.79	0	1.79											5	1	4150	2.26	6
interconnects with adjacent	4	Other network	10		Stub	1	0	0	0													0		0
network					Feeder Totals		1.79	0	1.79	0	0	0	0	0	0	0	0	0	0	5	1	4150	2.26	6
supplies town load & resupply	5	Kingsbridge	10		Trunk	-	1.4	0	1.4													0	St James' Hospital	1
					Feeder Totals		1.4	0	1.4	0	0	0	0	0	0	0	0	0	0	0	0	0	??	1
supplies town load & resupply	6	Newmarket	10		Trunk	-	1.94	0	1.94											8	1	6040		9
local load only	6	-	10		Stub	1	0.27	0	0.27											1		630		1
					Feeder Totals		2.21	0	2.21	0	0	0	0	0	0	0	0	0	0	9	1	6670	2.93	10
resupply	7	Newmarket	10		Trunk	-	0	0	0													0		0
					Feeder Totals		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	??	0
resupply	8	Newmarket	10		Trunk	-	0	0	0													0		0
					Feeder Totals		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	??	0
Watling Street																							Guinness	
supplies town load & resupply	1	M'bone Lane 1	10		Trunk	-	0.1	0	0.1													0	-2.53	1
					Feeder Totals		0.1	0	0.1	0	0	0	0	0	0	0	0	0	0	0	0	0	-2.53	1
resupply	2	Kingsbridge	10		Trunk	-	0	0	0													0		0
					Feeder Totals		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	??	0
supplies town load & resupply	3	Kingsbridge	10		Trunk	-	2.32	0	2.32										1	6	2	6180	3.79	9
					Feeder Totals		2.32	0	2.32	0	0	0	0	0	0	0	0	0	1	6	2	6180	3.79	9
supplies town load & resupply	4	Wolfetone St	10		Trunk	-	1.68	0	1.68										2	4	2	5320	1.85	8
resupply	4	Kingsbridge	10		Stub	1	0	0	0															
					Feeder Totals		1.68	0	1.68	0	0	0	0	0	0	0	0	0	2	4	2	5320	1.85	8
supplies town load & resupply	5	Phibsborough	10		Trunk	-	2.065	0	2.065										1	7	2	6810	0.4	10

resupply	5	Phibsborough	10	Stub	1	0.2	0	0.2											1				
				Feeder Totals		2.265	0	2.265	0	0	0	0	0	0	0	0	0	1	8	2	6810	0.4	11

Note: For the purposes of this study a spur is identified as a circuit length equal to 5km or more (and not dedicated to generator).

Table B.8: Topographical analysis of a sample of rural distribution networks (i.e. 10 kV and 20

Area	Primary substations (Network)	Voltage (kV)	Capacity (MVA)	2003 Peak Demand (MW)	2003 Valley Demand (MW)	Area of supply (km2)	Max Load Density (kW/km2)	Feeder Case	Installed capacity (kVA)	Peak load (MW)	Voltage (kV)	No. of feeders	No. of spurs	No. of stubs	No. of clusters	Length of Trunk ccts (km)	Length of Spur ccts (km)	Length of stub ccts (km)	Length of cluster ccts (km)	Total feeder length (km)	No of Booster Tx's
North Donegal	Ballymacarry Pry	38/20/10	1x5	1.09	0.30	38	28.7	Shortest	2200	1.24	10	-	-	-	-	-	-	-	-	-	
								Longest	5415	1.09	20	-	2	6	0	13.1	12	13.3	0	38.4	
	10kV cct ignored because it is a dedicated feeder							Total	7615	2.33	10/20	1	2	6	0	13.1	12	13.3	0	38.4	
	Buncrana Pry	38/20/10	2x5	6.68	1.71	171	39.1	Shortest	2283	0.71	10	-	0	3	0	0.2	0	2	0	2.2	0
								Longest	7683	2.52	10	-	3	13	0	27.7	43.3	19.5	0	90.5	0
								Total	18966	6.68	10/20	4	8	32	0	66.8	71.3	68.6	0	206.7	0
	Carndonagh Pry		1x2, 1x5	4.39	1.26	141	31.1	Shortest	1280	**0.42**	10	-	0	0	0	2.5	0	0	0	2.5	0
		38/10						Longest	5886	**1.94**	10	-	3	12	0	32.9	21.1	26.6	0	80.6	1
								Total	13294	4.39	10	4	8	15	0	53.3	63.5	32.1	0	148.9	1
	Moville Pry	38/10	2x5	3.11	0.94	116	26.8	Shortest	4164	1.2	10	-	0	7	0	9	0	10.5	0	19.5	0
								Longest	2732	0.87	10	-	3	5	0	14	36.3	9.3	0	59.6	1
								Total	10682	3.11	10	3	6	16	0	34.6	53.3	30.3	0	118.2	1
South Donegal	Donegal Town Pry	38/10	2x5	6.89	1.99	205	33.6	Shortest	3030	**1.04**	10	-	1	2	1	5.8	9.7	6	15.7	37.2	1
								Longest	8260	**2.83**	10	-	2	4	0	11.6	57.7	8.7	0	78	1
	* excludes two feeders directly connecting EG to primary							Total*	20140	6.89	10	3	7	7	1	26.9	106.9	17.7	15.7	167.2	2
Leitrim	Arigna BSP	110/20	1x15	1.81	1.01	173	10.5	Shortest		-	-	-	-	-	-	-	-	-	-	-	
								Longest	10393	1.81	20	-	4	7	0	22.1	79.3	21.3	0	122.7	
	**** only one feeder supplying load, the other links to a cluster of generators							Total****	10393	1.81	20	1	4	7	0	22.1	79.3	21.3	0	122.7	
Kerry	Abbeyfeale Pry	38/10	2x5	6.85	2.59	295	23.2	Shortest	8315	2.49	10	-	4	1	0	13.2	58.8	9.3	0	81.3	2
								Longest	4832	0.91	10	-	4	13	0	20.6	41.3	26.3	0	88.2	0
	** excludes re-supply with no gens or load connected							Total**	22079	5.24	10	3	14	22	0	49.2	159.6	48.4	0	257.2	3
Kildare	Edenderry Pry	38/20/10	2x5	10.73	3.09	128	83.8	Shortest	277	**0.17**	10	-	0	1	0	3.5	0	1.5	0	5	0
								Longest	13761	**8.43**	10	-	4	17	0	16	139.9	12.2	0	168.1	3
	*** excludes feeder directly connecting EG to primary							Total***	17516	10.73	10	3	4	20	0	22.8	139.9	16.5	0	179.3	3
	Blake Pry	38/20/10	2x5	4.13	1.46	77	53.6	Shortest	1951	0.81	10	-	1	6	0	6.5	7.3	4.8	0	18.6	0
								Longest	3980	1.56	10	-	2	7	0	10.4	16.3	13.5	0	40.2	2
								Total***	10881	4.13	10	4	4	25	0	39.1	37.1	42.3	0	118.5	2

Table B8 (Cont'd)

Notes: Estimated values (shown in purple) assumed when not provided

Analysis of Total Sample	Lowest	1.81	1.01	173	10.5	Shortest	23500	8.08	Total	7	6	20	1	40.7	75.8	34.1	15.7	166.3	
	density					Average	3357	1.15	Average	-	1	3	0	5.8	10.8	4.9	2.2	23.8	
	Average	5.08	1.59	149	34.0	All	131566	45.31	Total	26	57	150	1	327.9	722.9	290.5	15.7	1357.1	
	density					Average	5060	1.74	Average	-	2	6	0	12.6	27.8	11.2	0.6	52.2	
	Highest	10.73	3.09	128	83.8	Longest	62942	21.96	Total	9	27	84	0	168.4	447.2	150.7	0	766.3	
	density					Average	6994	2.44	Average	-	3	9	0	18.7	49.7	16.7	0.0	85.1	
Analysis of 10 kV Sample	Lowest	6.85	2.59	295	23.2	Shortest	23500	8.08	Total	7	6	20	1	40.7	75.8	34.1	15.7	166.3	3
	density					Average	3357	1.15	Average	-	1	3	0	5.8	10.8	4.9	2.2	23.8	0
	Average	5.63	1.74	150	37.7	All	106758	38.96	Total	22	46	121	1	253.8	603.6	208.8	16	1082	12
	density					Average	4853	1.77	Average	-	2	6	0	11.5	27.4	9.5	0.7	49.2	1
	Highest	10.73	3.09	128	83.8	Longest	47134	19.06	Total	7	21	71	0	133.2	355.9	116.1	0	605.2	8
	density					Average	6733	2.72	Average	-	3	10	0	19.0	50.8	16.6	0	86.5	1
Analysis of 20 kV Sample	Lowest	1.81	1.01	173	10.5	Shortest	5415	1.09	Total	1	2	6	0	13.10	12	13.30	0.00	38.40	
	density					Average	5415	1.09	Average	-	2	6	0	13.10	12	13.30	0.00	38.40	
	Average	2.08	0.72	99	21.0	All	24808	6.35	Total	4	11	29	0	74.1	119.3	81.7	0	275.1	
	density					Average	6202	1.59	Average	-	3	7	0	18.5	29.8	20.4	0.0	68.8	
	Highest	6.68	1.71	171	39.1	Longest	10393	1.81	Total	1	4	7	0	22.1	79.3	21.3	0	122.7	
	density					Average	10393	1.81	Average	-	4	7	0	22.1	79.3	21	0	123	

Table B 9: Topographical analysis of a sample of semi-urban distribution networks

Area	Primary substations (Network)	Voltage (kV)	Capacity (MVA)	2003 Peak Demand (MW)	2003 Valley Demand (MW)	Area of supply (km2)	Max Load Density (kW/km2)	Feeder Case	Installed capacity (kVA)	Peak load (MW)	Voltage (kV)	No. of feeders	No. of spurs	No. of stubs	No. of clusters	Length of Trunk ccts (km)	Length of Spur ccts (km)	Length of stub ccts (km)	Length of cluster ccts (km)	Total feeder length (km)
Inchicore	Ballymount	38/10	2x10	7.73	3.27	2.00	3865.0	Shortest	2260	0.33	10	-	0	0	0	0.84	0	0	0	0.84
								Longest	5225	0.81	10	-	0	2	0	3.9	0	1.4	0	5.3
								Total	25915	7.73	10	6	0	6	0	12.39	0	6.05	0	18.44
	Clondalkin	38/10	2x10	10.19	2.991636	3.00	3396.7	Shortest	3090	1.31	10	-	0	0	0	2.82	0	0	0	2.82
								Longest	6350	1.89	10	-	0	3	0	5.72	0	2.02	0	7.74
								Total	26110	10.19	10	4	0	10	0	17.43	0	7.64	0	25.07
	Semperit	38/10	3x10	16.03	3.8	5.00	3206.0	Shortest	2000	2.86	10	-	0	0	0	1.17	0	0	0	1.17
								Longest	9810	3.01	10	-	0	2	0	4.1	0	3.54	0	7.64
	** - excluding feeder to John Player (unknown load)							Total	42258	16.03	10	9	0	13	0	25.23	0	7.79	0	33.02
	Inchicore Central	38/10	1x10	6.45	1.93	3.00	2150.0	Shortest	800	**0.27**	10	-	0	0	0	1.83	0	0	0	1.83
								Longest	6320	**2.13**	10	-	0	1	0	4.76	0	1.53	0	6.29
								Total	19140	6.45	10	5	0	4	0	17.76	0	2.64	0	20.4
		Analysis of Total Sample	Lowest density	6.45	1.93	3	2150	Shortest	8150	4.77	Total	4	0	0	0	6.66	0	0	0	6.66
								Average	2038	1.19	Average	-	0	0	0	1.7	0.0	0.0	0.0	1.7
			Highest density	16.03	2.991636	3	3396.666667	Longest	27705	7.84	Total	4	0	8	0	18.48	0	8.49	0	26.97
								Average	6926	1.96	Average	-	0	2	0	4.6	0.0	2.1	0.0	6.7
			Average density	10.10	3.00	3	3154.4	Total	113423	40.40	Total	24	0	33	0	72.81	0	24.12	0	96.93
								Average	4726	1.68	Average	-	0	1	0	3.0	0.0	1.0	0.0	4.0

Notes: Estimated values (shown in purple) assumed when not provided

Table B 10: Topographical analysis of a sample of dense urban distribution networks

Area	Primary substations (Network)	Voltage (kV)	Capacity (MVA)	2003 Peak Demand (MW)	2003 Valley Demand (MW)	Area of supply (km2)	Max Load Density (kW/km2)	Feeder Case	Installed capacity (kVA)	Peak load (MW)	Voltage (kV)	No. of feeders	No. of spurs	No. of stubs	No. of clusters	Length of Trunk ccts (km)	Length of Spur ccts (km)	Length of stub ccts (km)	Length of cluster ccts (km)	Total feeder length (km)
Dublin Central	Marrowbone Lane	38/10	1x15	6.5	3.19	0.765	8497	Shortest	1200	0.37	10	-	0	0	0	0.73	0	0	0	0.73
								Longest	6670	2.93	10	-	0	1	0	1.94	0	0.27	0	2.21
								Total	31990	6.5	10	5	0	1	0	7.58	0	0.27	0	7.85
	Watling Street	38/10	1x10	3.81	1.97	0.625	6096	Shortest	5320	1.85	10	-	0	0	0	1.68	0	0	0	1.68
								Longest	6180	3.79	10	-	0	0	0	2.32	0	0	0	2.32
	* - Excludes the Guinness connections							Total*	18310	3.81	10	3	0	0	0	6.165	0	0	0	6.165
		Analysis of Total Sample	Lowest density	3.81	1.97	0.625	6096	Shortest	6520	2.22	Total	2	0	0	0	2.41	0	0	0	2.41
								Average	3260	1.11	Average	-	0	0	0	1.2	0.0	0.0	0.0	1.2
			Highest density	6.5	3.19	0.765	8497	Longest	12850	6.72	Total	2	0	1	0	4.26	0	0.27	0	4.53
								Average	6425	3.36	Average	-	0	1	0	2.1	0.0	0.1	0.0	2.3
			Average density	1.15	0.57	0.15	1621	Total	50300	10.31	Total	8	0	1	0	13.745	0	0.27	0	14.015
								Average	6288	1.29	Average	-	0	0	0	1.7	0.0	0.0	0.0	1.8

Table B11 - Rural 10 kV networks

	Feeder No.	Trunk (km)		Spurs (km)		Stub (km)	
		3-ph	1-ph	3-ph	1-ph	3-ph	1-ph
Ballymacarry	1	1.5	0	0	0	0	0
	2						
Buncrana	1	25.5	2.2	10.2	33.1	4.5	15
	2						
	3						
	4	0.2	0	0	0	2	0
Carndonagh	1	13	0	12	11	4.5	1
	2	28.9	4	6.6	14.5	4.7	21.9
	3	2.5	0	0	0	0	0
	4	4.9	0	2.1	17.3	0	0
Moville	1	14	0	10	26.3	0	9.3
	2	9	0	0	0	4	6.5
	3	11.6	0	3.5	13.5	0	10.5
Donegal Town	1	11.6	0	3	54.7	3.2	5.5
	3	5.8	0	7.7	2	0	6
	5	9.5	0	8.5	31	3	0
Arigna	1						
	2						
Abbeyfeale	1	20.6	0	4.5	36.8	1.2	25.1
	2	13.2	0	15.9	42.9	0	9.3
	3	15.4	0	4	55.5	3.5	9.3
Edenderry	1	3.5	0	0	0	0	1.5
	3	3.3	0	0	0	1.9	1
	4	15.0	1	31.5	108.4	5.3	6.9
Blake	1	10.3	0	0	13.5	2.1	8.2
	2	12.0	0	0	0	3.3	10.5
	3	6.5	0	3.8	3.5	0	4.8
	4	10.4	0	7.6	8.8	2.3	11.2
	Total (km)	246.5	7.2	130.9	472.7	45.4	163.4
	%	97.2	2.8	21.7	78.3	21.7	78.3

Table B12 - Rural 20 kV networks

	Feeder No.	Trunk (km)		Spurs (km)		Stub (km)	
		3-ph	1-ph	3-ph	1-ph	3-ph	1-ph
Ballymacarry	1						
	2	13.1	0	0	12	4.3	9
Buncrana	1						
	2	30.4	0	5	11	8.1	21.1
	3	2	6.5	0	0	0	4.6
	4						
Carndonagh	1						
	2						
	3						
	4						
Moville	1						
	2						
	3						
Donegal Town	1						
	3						
	5						
Arigna	1	4	0	26.1	16.9	0	0
	2	22.1	0	32.7	46.6	2	19.3
Abbeyfeale	1						
	2						
	3						
Edenderry	1						
	3						
	4						
Blake	1						
	2						
	3						
	4						
	Total (km)	71.6	6.5	63.8	86.5	14.4	54
	%	91.7	8.3	42.4	57.6	21.1	78.9

Table B 13 - Semi-urban 10 kV networks

	Feeder No.	Trunk (km)		Spurs (km)		Stub (km)	
		3-ph	1-ph	3-ph	1-ph	3-ph	1-ph
Ballymount	1	1.09	0	0	0	0	0
	2	1.78	0	0	0	1.4	0
	3	3.9	0	0	0	1.4	0
	4	3.53	0	0	0	0.29	0
	5	1.25	0	0	0	2.96	0
	6	0.84	0	0	0	0	0
Clondalkin	1	2.82	0	0	0	0	0
	2	4.13	0	0	0	3.16	0
	3	5.72	0	0	0	2.02	0
	4	4.76	0	0	0	2.46	0
Semperit	1	4.1	0	0	0	3.8	0
	2	3.32	0	0	0	1.82	0
	3	1.83	0	0	0	0.18	0
	4	2.59	0	0	0	0.2	0
	5	1.17	0	0	0	0	0
	6	0.5	0	0	0	0	0
	8	1.31	0	0	0	0	0
	10	5.99	0	0	0	0	0
	11	1.46	0	0	0	1.21	0
	12	3.46	0	0	0	0.84	0
Inchicore Central	1	4.76	0	0	0	1.53	0
	2	4.03	0	0	0	0	0
	3	1.83	0	0	0	0	0
	4	3.82	0	0	0	0.77	0
	5	2.37	0	0	0	0.34	0
	6	3.32	0	0	0	0.34	0
	Total (km)	75.68	0	0	0	24.72	0
	%	100.0	0.0	-	-	100.0	0.0

Table B 14 - Dense urban 10 kV networks

	Feeder No.	Trunk (km)		Spurs (km)		Stub (km)	
		3-ph	1-ph	3-ph	1-ph	3-ph	1-ph
Marrowbone Lane	2	0.73	0	0	0	0	0
	3	1.72	0	0	0	0	0
	4	1.79	0	0	0	0	0
	5	1.4	0	0	0	0	0
	6	1.94	0	0	0	0.27	0
Watling Street	1	0.1	0	0	0	0	0
	3	2.32	0	0	0	0	0
	4	1.68	0	0	0	0	0
	5	2.07	0	0	0	0.2	0
	Total (km)	13.745	0	0	0	0.47	0
	%	100.0	0.0	-	-	100.0	0.0

Table B.15: Summary of Principal Model Characteristics for each Medium Voltage Network Type

	Rural 10 kV circuits			Rural 20 kV circuits			Semi-urban 10 kV circuits			Dense urban 10 kV circuits		
Parameter	**Shortest**	**Average**	**Longest**	**Shortest**	**Average**	**Longest**	**Shortest**	**Average**	**Longest**	**Shortest**	**Average**	**Longest**
Trunk section length (km)	1.41	1.40	1.42	1.50	1.68	1.67	0.42	0.43	0.42	0.40	0.34	0.36
Trunk sections	4	8	13	8	10	11	4	7	11	3	5	6
Trunk boosters	0	0	2	0	0	0	0	0	0	0	0	0
Trunk section loads (MW)	0.108	0.083	0.078	0.07	0.082	0.085	0.298	0.176	0.131	0.37	0.258	0.534
Total Trunk length (km)	5.64	11.2	18.46	12	16.835	18.37	1.68	3.01	4.62	1.2	1.7	2.16
Total trunk load (MW)	0.432	0.664	1.014	0.56	0.82	0.935	1.192	1.232	1.441	1.11	1.29	3.204
No. of spurs	1	2	3	2	3	4	0	0	0	0	0	0
Spur length (km)	2.35	2.98	3.68	1.8	3.02	6.02	0	0	0	0	0	0
Spur boosters	0	0	0	0	0	0	0	0	0	0	0	0
Spur loads (MW)	0.417	0.32	0.328	0.155	0.151	0.129	0	0	0	0	0	0
Total Spur length (km)	2.35	5.96	11.04	3.6	9.06	24.08	0	0	0	0	0	0
Total Spur load (MW)	0.417	0.64	0.984	0.31	0.453	0.516	0	0	0	0	0	0
No. of stubs	3	6	10	6	7	7	0	1	2	0	0	1
Stub length (km)	0.35	0.34	0.36	0.5	0.612	0.63	0	1.01	1.06	0	0	0.14
Stub loads (MW)	0.099	0.076	0.07	0.036	0.045	0.051	0	0.448	0.261	0	0	0.157
Total Stub length (km)	1.05	2.04	3.6	3	4.284	4.41	0	1.01	2.12	0	0	0.14
Total Stub load (MW)	0.297	0.456	0.7	0.216	0.315	0.357	0	0.448	0.522	0	0	0.157
Total circuit length (km)	9.04	19.2	33.1	18.6	30.179	46.86	1.68	4.02	6.74	1.2	1.7	2.3
Total load (MW)	1.146	1.76	2.698	1.086	1.588	1.808	1.192	1.68	1.963	1.11	1.29	3.361

Appendix C – Network Studies

C.1 Power system studies of representative 110/38/10 kV rural network

Tables C.1.1 to C.1.3 present a summary of the significant results of power system studies of the 110/38/10 kV rural network, including power flows, power losses, voltage profiles, circuit utilisation and fault levels, for the 1 MW embedded generation case.

Tables C.1.4 to C.1.6 present the corresponding results for the 2.5 MW embedded generation case and Tables C.1.7 to C.1.9 the results for the 5 MW generation case.

Table C1.1 – 1MW; 10 kV Rural Network; Shortest Feeder Studies

	Study Number					
	1	2	3	4	5	6
Generator Position	-	200	299	202	204	208
Generator Size	-	1	1	1	1	1
Reactive Power (kVAr)				328	328	328
Total Losses - kW	744.3	731.8	743.4	703	705.7	702.5
Total Losses - kVAr	804.6	709.2	728.6	687	692	690
Sending Voltage - (200)	1.024	1.027	1.027	1.027	1.027	1.027
Endpoint Voltage - (207)	0.984	0.987	0.987	1.014	1.038	1.026
Fault level - HV (38kV) - (100) - Amps	1280	1359	1352.8	1351	1245	1343
Fault level - MV (10kV) - Sending (200) - Amps	3104	3439	3411.7	3404	3379	3370
Fault level - MV (10kV) - Ending (207) - Amps	859	822.3	880	976	1125	1037
Transformer flow - kW	3045	2539	2545	2508	2526	2524
Transformer flow - kVAr	1279	1071	1080	1045	1062	1061
Power leaving MV Prim - kW	1180	1180	1180	136	154	151
Power leaving MV Prim - kVAr	395	395	395	11	52	50
Load levels - kW	1.14	1.14	1.14	1.14	1.14	1.14
Load levels - kVAr	0.375	0.375	0.375	0.375	0.375	0.375

Loading Matrix

	Study Number					
Section	1	2	3	4	5	6
Tx	63	52	53	52	52	52
A	32	32	32	3	4	4
B	26	26	26	2	1	2
C	20	20	20	20	7	7
D	6	6	6	6	21	6
E	12	11	11	11	11	16
	Voltage Bus					
	1	2	3	4	5	6
200	1.024	1.027	1.027	1.027	1.027	1.027
201	1.009	1.012	1.012	1.026	1.025	1.025
202	0.997	1	1	1.027	1.026	1.026
203	0.987	0.991	0.991	1.017	1.029	1.029
203.5	0.979	0.982	0.982	1.009	1.02	1.041
204	0.985	0.988	0.988	1.015	1.039	1.026
205	0.984	0.987	0.987	1.014	1.038	1.026

Table C 1.2 – 1MW; 10 kV Rural Network; Average Feeder Studies

Study Number						
	1	**2**	**3**	**4**	**5**	**6**
Generator Position	-	200	299	234	246	238
Generator Size	-	1	1	1	1	1
Reactive Power (kVAr)				330	330	330
Total Losses - kW	744.3	731.8	743.4	636	634.3	640
Total Losses - kVAr	804.6	709.2	728.6	646.8	645.4	649
Sending Voltage - (200)	1.024	1.027	1.027	1.027	1.027	1.027
Endpoint Voltage - (238)	0.927	0.93	0.93	0.985	1.011	1.035
Fault level - HV (38kV) - (100) - Amps	1280	1359	1352.8	1341	1330.6	1331
Fault level - MV (10kV) - Sending (200) - Amps	3104	3439	3411.7	3363	3316.7	3318
Fault level - MV (10kV) - Ending (238) - Amps	522.5	531.2	530	625	700.6	820
Transformer flow - kW	3045	2539	2545	2491	2485	2489
Transformer flow - kVAr	1279	1071	1080	1039	1035	1038
Power leaving MV Prim - kW	1801	1800	1800	706	696	704
Power leaving MV Prim - kVAr	624	623	623	242	234	239
Load levels - kW	1.68	1.68	1.68	1.68	1.68	1.68
Load levels - kVAr	0.553	0.553	0.553	0.553	0.553	0.553

Loading Matrix

Study Number						
Section	**1**	**2**	**3**	**4**	**5**	**6**
Tx	63	52	53	51	51	51
A	49	49	49	19	19	19
B	44	44	44	15	14	14
C	40	39	39	10	10	10
D	29	28	28	1	1	1
E	24	24	24	22	5	5
F	19	19	19	18	10	10
G	7	7	7	7	7	20
H	9	9	9	8	19	8
I	2	2	2	2	2	25

Voltage Bus						
	1	**2**	**3**	**4**	**5**	**6**
230	1.024	1.027	1.027	1.027	1.027	1.027
231	1.001	1.005	1.004	1.019	1.019	1.019
232	0.981	0.985	0.984	1.012	1.012	1.012
233	0.963	0.967	0.966	1.007	1.008	1.007
234	0.95	0.954	0.954	1.008	1.008	1.008
235	0.94	0.943	0.943	0.997	1.011	1.01
236	0.931	0.935	0.934	0.989	1.015	1.014
236.5	0.923	0.926	0.926	0.982	1.033	1.007
237	0.928	0.931	0.931	0.986	1.012	1.024
238	0.927	0.93	0.93	0.985	1.011	1.035

Table C 1.3 1MW; 10kV Rural Network; Longest Feeder Studies

Study Number						
	1	2	3	4	5	6
Generator Position	-	200	299	266	273	286
Generator Size	-	1	1	1	1	1
Setting of booster (263)						
setting of booster (267)						
Reactive Power (kVAr)				330	330	330
Total Losses - kW	744.3	731.8	743.4	418	316	321
Total Losses - kVAr	804.6	709.2	728.6	411	346	350
Sending Voltage - (200)	1.024	1.027	1.027	1.016	1.016	1.016
Endpoint Voltage - (283)	0.983	0.987	0.986	0.993	0.995	0.995
Fault level - HV (38kV) - (100) - Amps	1280	1359	1352.8	1321	1305	1303
Fault level - MV (10kV) - Sending (200) - Amps	3104	3439	3411.7	3298	3234	3225
Fault level - MV (10kV) - Ending (283) - Amps	293.4	297	296.6	366	569	515
Transformer flow - kW	3045	2539	2545	2373	2328	2331
Transformer flow - kVAr	1279	1071	1080	915	886	889
Power leaving MV Prim - kW	3091	3085	3086	1752	1661	1668
Power leaving MV Prim - kVAr	1249	1244	1244	629	579	583
Load levels - kW	2.52	2.52	2.52	2.52	2.52	2.52
Load levels - kVAr	0.83	0.83	0.83	0.83	0.83	0.83

Loading Matrix

Study Number						
Section	1	2	3	4	5	6
Tx	63	52	53	48	47	47
A	85	85	85	48	45	46
B	81	81	81	44	41	42
C	77	77	77	40	38	38
D	93	92	92	36	33.6	34
E	55	55	55	25	22	23
F	51	51	51	21	18	19
G	47	46	47	47	14	14
H	81	80	80	43	10	10
I	27	27	27	31	1	1
J	23	23	23	26	6	6
K	19	19	19	22	10	10
L	15	15	15	17	14	14
M	4	4	4	5	25	4
N	9	9	9	10	9	20

Table C 1.3 (cont'd)

Voltage Bus						
	1	2	3	4	5	6
260	1.024	1.027	1.027	1.016	1.016	1.016
261	0.984	0.987	0.987	0.994	0.995	0.995
262	0.945	0.949	0.949	0.973	0.976	0.976
263	0.909	0.913	0.913	0.954	0.959	0.958
264	0.969	0.974	0.973	0.937	0.943	0.943
265	0.944	0.948	0.948	0.926	0.933	0.932
266	0.92	0.925	0.924	0.916	0.924	0.923
267	0.898	0.903	0.903	0.894	0.918	0.917
268	0.975	0.98	0.98	0.874	0.913	0.912
269	0.962	0.967	0.967	0.86	0.914	0.913
270	0.951	0.957	0.956	0.847	0.916	0.915
271	0.942	0.948	0.947	0.837	0.921	0.92
272	0.935	0.941	0.94	0.829	0.927	0.926
272.5	0.924	0.93	0.93	0.817	0.916	0.951
273	0.933	0.939	0.938	0.827	0.939	0.924
274	0.983	0.987	0.986	0.993	0.995	0.995

Table C 1.4 – 2.5MW; 10 kV Rural Network; Shortest Feeder Studies

Study Number						
	1	2	3	4	5	6
Generator Position	-	200	299	202	204	208
Generator Size	-	2.5	2.5	2.5	2.5	2.5
Reactive Power (kVAr)				315	-937	-1091
Total Losses - kW	744.3	730	780	754	915	964
Total Losses - kVAr	804.6	610	725	639	794	834
Sending Voltage - (200)	1.024	1.025	1.024	1.021	1.011	1.011
Endpoint Voltage - (207)	0.984	0.985	0.985	1.038	1.049	1.049
Fault level - HV (38kV) - (100) - Amps	1280	1464	1433	1434	1407	1399
Fault level - MV (20kV) - Sending (200) - Amps	3104	3949	3789	3776	3611	3568
Fault level - MV (20kV) - Ending (207) - Amps	859	906	896	1133	1520	1225
Transformer flow - kW	3045	1788	1822	1800	1880	1905
Transformer flow - kVAr	1279	775	829	1042	1746	1842
Power leaving MV Prim - kW	1180	1180	1180	-1306	-1174	-1130
Power leaving MV Prim - kVAr	395	395	395	88	1415	1593
Load levels - kW	1.14	1.14	1.14	1.14	1.14	1.14
Load levels - kVAr	0.375	0.375	0.375	0.375	0.375	0.375

Loading Matrix

Study Number						
Section	**1**	**2**	**3**	**4**	**5**	**6**
Tx	63	37	38	40	49	50
A	32	32	32	34	48	51
B	26	26	26	39	50	53
C	20	20	20	19	53	55
D	6	6	6	6	62	6
E	12	11	11	11	11	61

Voltage Bus						
	1	**2**	**3**	**4**	**5**	**6**
200	1.024	1.025	1.024	1.021	1.011	1.011
201	1.009	1.01	1.009	1.034	1.015	1.015
202	0.997	0.998	0.997	1.05	1.022	1.022
203	0.987	0.989	0.988	1.041	1.033	1.033
203.5	0.979	0.98	0.979	1.033	1.024	1.024
204	0.985	0.986	0.985	1.039	1.05	1.05
205	0.984	0.985	0.985	1.038	1.049	1.049

Table C 1.5 2.5MW; 10 kV Rural Network; Average Feeder Studies

Study Number						
	1	**2**	**3**	**4**	**5**	**6**
Generator Position	-	200	299	234	246	238
Generator Size	-	2.5	2.5	2.5	2.5	2.5
Reactive Power (kVAr)				-50.6	-1092	-1117
Total Losses - kW	744.3	730	780	699	1028	1043
Total Losses - kVAr	804.6	610	725	617	876	887
Sending Voltage - (200)	1.024	1.025	1.024	1.018	1.009	1.009
Endpoint Voltage - (238)	0.927	0.928	0.927	1.029	1.016	1.05
Fault level - HV (110kV) - (100) - Amps	1280	1464	1433	1401	1363	1363
Fault level - MV (20kV) - Sending (200) - Amps	3104	3949	3789	3611	3410	3411
Fault level - MV (20kV) - Ending (238) - Amps	522.5	539	535	758	883	1287
Transformer flow - kW	3045	1788	1822	1773	1936	1944
Transformer flow - kVAr	1279	775	829	1214	1863	1882
Power leaving MV Prim - kW	1801	1801	1801	-745	-444	-428
Power leaving MV Prim - kVAr	624	624	624	648	1860	1893
Load levels - kW	1.68	1.68	1.68	1.68	1.68	1.68
Load levels - kVAr	0.553	0.553	0.553	0.553	0.553	0.553

Loading Matrix

Study Number						
Section	**1**	**2**	**3**	**4**	**5**	**6**
Tx	63	37	38	41	51	51
A	49	49	49	25	50	50
B	44	44	44	28	50	50
C	40	39	39	31	50	51
D	29	28	29	39	53	53
E	24	24	24	21	55	55
F	19	19	19	17	57	57
G	7	7	7	7	7	64
H	9	9	9	8	62	8
I	2	2	2	2	2	67
Voltage Bus						
	1	**2**	**3**	**4**	**5**	**6**
230	1.024	1.025	1.024	1.018	1.009	1.009
231	1.001	1.003	1.002	1.022	1.003	1.002
232	0.981	0.982	0.982	1.029	0.999	0.998
233	0.963	0.965	0.964	1.037	0.998	0.997
234	0.95	0.952	0.951	1.05	1.003	1.001
235	0.94	0.941	0.94	1.04	1.01	1.008
236	0.931	0.932	0.931	1.033	1.02	1.018
236.5	0.923	0.924	0.923	1.025	1.05	1.01
237	0.928	0.929	0.928	1.03	1.017	1.032
238	0.927	0.928	0.927	1.029	1.016	1.05

Table C 1.6 2.5MW; 10kV Rural Network; Longest Feeder Studies

Study Number						
	1	**2**	**3**	**4**	**5**	**6**
Generator Position	-	200	299	266	273	286
Generator Size	-	2.5	2.5	2.5	2.5	2.5
Reactive Power (kVAr)				822	-451	-577
Total Losses - kW	744.3	730	780	264	553	682
Total Losses - kVAr	804.6	610	725	224	436	523
Sending Voltage - (200)	1.024	1.025	1.024	1.021	1.011	1.009
Endpoint Voltage - (283)	0.983	0.984	0.984	1.019	0.997	0.993
Fault level - HV (110kV) - (100) - Amps	1280	1464	1433	1360	1319	1314
Fault level - MV (20kV) - Sending (200) - Amps	3104	3949	3789	3474	3265	3241
Fault level - MV (20kV) - Ending (283) - Amps	293.4	299	298	471	1060	778
Transformer flow - kW	3045	1788	1822	1555	1687	1750
Transformer flow - kVAr	1279	775	829	579	1315	1420
Power leaving MV Prim - kW	3091	3089	3090	122	380	506
Power leaving MV Prim - kVAr	1249	1247	1248	63	1484	1679

Load levels - kW	2.52	2.52	2.52	2.52	2.52	2.52
Load levels - kVAr	0.83	0.83	0.83	0.83	0.83	0.83

Loading Matrix

Study Number						
Section	**1**	**2**	**3**	**4**	**5**	**6**
Tx	63	37	38	32	41	43
A	85	85	85	4	40	46
B	81	81	81	1	38	44
C	77	77	77	4	36	42
D	93	93	93	7.9	35.4	40.6
E	55	55	55	18	35	39
F	51	51	51	22	35	39
G	47	47	47	41	36	39
H	81	81	81	36.9	37.9	40.6
I	27	27	27	27	44	45
J	23	23	23	23	46	48
K	19	19	19	19	49	50
L	15	15	15	15	52	53
M	4	4	4	4	60	4
N	9	9	9	9	8	58

Table C1.6 (cont'd)

Voltage Bus						
	1	2	3	4	5	6
260	1.024	1.025	1.024	1.021	1.011	1.009
261	0.984	0.985	0.984	1.02	0.998	0.994
262	0.945	0.947	0.946	1.02	0.987	0.98
263	0.909	0.91	0.91	1.021	0.978	0.969
264	0.969	0.971	0.97	1.025	0.971	0.959
265	0.944	0.945	0.944	1.033	0.969	0.955
266	0.92	0.922	0.92	1.043	0.969	0.954
267	0.898	0.9	0.899	1.025	0.972	0.954
268	0.975	0.977	0.975	1.007	0.977	0.957
269	0.962	0.964	0.962	0.995	0.986	0.965
270	0.951	0.953	0.952	0.985	0.998	0.975
271	0.942	0.944	0.943	0.976	1.013	0.988
272	0.935	0.937	0.935	0.969	1.029	1.003
272.5	0.924	0.926	0.925	0.959	1.019	1.05
273	0.933	0.935	0.934	0.967	1.05	1.001
274	0.983	0.984	0.984	1.019	0.997	0.993

Table C1.7 - 5MW; 10kV Rural Network; Shortest Feeder Studies

Study Number						
	1	2	3	4	5	6
Generator Position	-	200	299	202	204	208
Generator Size	-	5	5	5	5	5
Reactive Power (kVAr)				-1844	-2420	-2420
Total Losses - kW	744.3	722	965.4	1185	1691	1811
Total Losses - kVAr	804.6	514	915.8	932	1286	1358
Sending Voltage - (200)	1.024	1.026	1.029	0.997	0.998	0.997
Endpoint Voltage - (207)	0.984	0.986	0.99	1.038	1.085	1.046
Fault level - HV (38kV) - (100) - Amps	1280	1614	1522	1523	1455	1438
Fault level - MV (20kV) - Sending (200) - Amps	3104	4801	4240	4130	3757	3677
Fault level - MV (20kV) - Ending (207) - Amps	859	938	915	1311	2251	1458
Transformer flow - kW	3045	534	656	768	999	1040
Transformer flow - kVAr	1279	309	513	2269	2718	2727
Power leaving MV Prim - kW	1180	1180	1180	-3516	-2963	-2862
Power leaving MV Prim - kVAr	395	395	395	2455	3273	3283
Load levels - kW	1.14	1.14	1.14	1.14	1.14	1.14
Load levels - kVAr	0.375	0.375	0.375	0.375	0.375	0.375

Loading Matrix

Study Number						
Section	**1**	**2**	**3**	**4**	**5**	**6**
Tx	63	12	16	45	55.000	56
A	32	32	32	110	116	114
B	26	26	26	114	118	117
C	20	20	20	19	121	119
D	6	6	6	6	129	5
E	12	11	11	11	11	124
Voltage Bus						
	1	**2**	**3**	**4**	**5**	**6**
200	1.024	1.026	1.029	0.997	0.998	0.997
201	1.009	1.011	1.015	1.01	1.022	1.009
202	0.997	0.999	1.003	1.05	1.029	1.027
203	0.987	0.99	0.993	1.041	1.053	1.049
203.5	0.979	0.981	0.984	1.033	1.045	1.097
204	0.985	0.987	0.991	1.039	1.085	1.046
205	0.984	0.986	0.99	1.038	1.085	1.046

Table C 1.8 - 5MW; 10kV Rural Network; Average Feeder Studies

Study Number						
	1	**2**	**3**	**4**	**5**	**6**
Generator Position	-	200	299	234	246	238
Generator Size	-	5	5	5	5	5
reactive power from generator				-2420	-2420	-2420
Total Losses - kW	744.3	722	965.4	1539	2391	2445
Total Losses - kVAr	804.6	514	915.8	1199	1729	1779
Sending Voltage - (200)	1.024	1.026	1.029	0.991	0.995	0.993
Endpoint Voltage - (238)	0.927	0.929	0.933	1.028	1.044	1.102
Fault level - HV (110kV) - (100) - Amps	1280	1614	1522	1448	1378	1380
Fault level - MV (20kV) - Sending (200) - Amps	3104	4801	4240	3737	3413	3417
Fault level - MV (20kV) - Ending (238) - Amps	522.5	549	542.5	887	1083	2209
Transformer flow - kW	3045	534	656	941	1306	1384
Transformer flow - kVAr	1279	309	513	2687	2891	2972
Power leaving MV Prim - kW	1801	1801	1800	-2479	-1702	-1589
Power leaving MV Prim - kVAr	624	623	623	3450	3801	3950
Load levels - kW	1.68	1.68	1.68	1.68	1.68	1.68
Load levels - kVAr	0.553	0.553	0.553	0.553	0.553	0.553

Loading Matrix

Study Number						
Section	**1**	**2**	**3**	**4**	**5**	**6**
Tx	63	12	16	54	60	62
A	49	49	49	112	110	112
B	44	44	44	114	111	113
C	40	39	39	116	112	114
D	29	28	28	122	116	117
E	24	24	24	21	118	119
F	19	19	19	17	120	121
G	7	7	7	7	7	127
H	9	9	9	8	125	8
I	2	2	2	2	2	130
Voltage Bus						
	1	**2**	**3**	**4**	**5**	**6**
230	1.024	1.026	1.029	0.991	0.995	0.993
231	1.001	1.004	1.007	0.998	0.991	0.988
232	0.981	0.984	0.987	1.01	0.992	0.987
233	0.963	0.966	0.969	1.026	0.997	0.991
234	0.95	0.953	0.956	1.05	1.01	1.003
235	0.94	0.942	0.946	1.04	1.027	1.02
236	0.931	0.933	0.937	1.032	1.048	1.041
236.5	0.923	0.925	0.929	1.025	1.109	1.033
237	0.928	0.93	0.934	1.029	1.045	1.069
238	0.927	0.929	0.933	1.028	1.044	1.102

Table C 1.9 - 5MW; 10kV Rural Network; Longest Feeder Studies

Study Number						
	1	**2**	**3**	**4**	**5**	**6**
Generator Position	-	200	299	266	273	286
Generator Size	-	5	5	5	5	5
Reactive power				-1772	-1824	-1679
Total Losses - kW	744.3	722	965.4	1126	2838	3231
Total Losses - kVAr	804.6	514	915.8	778	1876	2124
Sending Voltage - (200)	1.024	1.026	1.029	0.999	0.99	0.989
Endpoint Voltage - (283)	0.983	0.986	0.989	0.997	0.963	0.958
Fault level - HV (110kV) - (100) - Amps	1280	1614	1522	1385	1325	1319
Fault level - MV (20kV) - Sending (200) - Amps	3104	4801	4240	3493	3219	3195
Fault level - MV (20kV) - Ending (283) - Amps	293.4	302.7	301	533	1795	944
Transformer flow - kW	3045	534	656	719	1592	1789
Transformer flow - kVAr	1279	309	513	2169	2730	2782
Power leaving MV Prim - kW	3091	3086	3080	-1529	173	564
Power leaving MV Prim - kVAr	1249	1245	1241	3161	4155	4232

Load levels - kW	2.52	2.52	2.52	2.52	2.52	2.52
Load levels - kVAr	0.83	0.83	0.83	0.83	0.83	0.83

Loading Matrix

Study Number						
Section	**1**	**2**	**3**	**4**	**5**	**6**
Tx	63	12	16	43	60	63
A	85	85	85	92	110	113
B	81	81	81	93	109	112
C	77	77	77	94	108	110
D	93	93	92	95	108	110
E	55	55	54	99	108	108
F	51	51	50	101	108	108
G	47	47	46	40	109	109
H	81	81	80	37	111	110
I	27	27	27	26	115	114
J	23	23	23	22	118	116
K	19	19	19	19	120	119
L	15	15	15	4	130	4
M	4	4	4	9	8	125
N	9	9	9	3	2	3

Table C1.9 (cont'd)

Voltage Bus						
	1	**2**	**3**	**4**	**5**	**6**
260	1.024	1.026	1.029	0.999	0.99	0.989
261	0.984	0.986	0.99	0.997	0.964	0.958
262	0.945	0.948	0.952	0.999	0.941	0.931
263	0.909	0.912	0.916	1.005	0.923	0.907
264	0.969	0.972	0.977	1.014	0.909	0.889
265	0.944	0.947	0.952	1.03	0.904	0.878
266	0.92	0.923	0.928	1.05	0.903	0.872
267	0.898	0.901	0.907	1.031	0.907	0.872
268	0.975	0.979	0.984	1.014	0.916	0.876
269	0.962	0.966	0.972	1.002	0.933	0.89
270	0.951	0.955	0.961	0.992	0.955	0.908
271	0.942	0.946	0.952	0.983	0.981	0.931
272	0.935	0.939	0.945	0.976	1.012	0.959
272.5 (286)	0.924	0.928	0.934	0.966	1.002	1.05
273	0.933	0.937	0.943	0.974	1.05	0.957
274 (283)	0.983	0.986	0.989	0.997	0.963	0.958

C.2 Power system studies of representative 110/38/20 kV rural network

Tables C.2.1 to C.2.3 present a summary of the significant results of power system studies of the 110/38/20 kV rural network, including power flows, power losses, voltage profiles, circuit utilisation and fault levels, for the 1 MW embedded generation case.

Tables C.2.4 to C.2.6 present the corresponding results for the 2.5 MW embedded generation case and Tables C.2.7 to C.2.9 the results for the 5 MW generation case.

Table C2.1 - 1MW; 20kV Rural Network; Shortest Feeder Studies

	Study Number					
	1	2	3	4	5	6
Generator Position	-	200	299	204	218	208
Generator Size	-	1	1	1	1	1
Total Losses - kW	11.1	9.9	12.87	2.55	7.8	7
Total Losses - kVAr	24.7	5.5	10.23	1.45	2.9	4
Sending Voltage - (200)	1.012	1.011	1.011	0.999	0.994	0.988
Endpoint Voltage - (208)	0.998	0.998	0.997	0.997	0.997	0.998
Fault level - HV (38kV) - (100) - Amps	2676	2751	2748	2746	2743	2742
Fault level - MV (20kV) - Sending (200) - Amps	1440	1608	1604	1591	1580	1575
Fault level - MV (20kV) - Ending (208) - Amps	748	786	785	829	858	890
Transformer flow - kW	1097	96	99.1	88.5	93.8	93.3
Transformer flow - kVAr	383	34.8	39.5	30.7	32	33.2
Power leaving MV Prim - kW	1096	1096	1096	88.5	93.8	93.2
Power leaving MV Prim - kVAr	363	363	363	30.5	31.9	33.1
Load levels - kW	1.09	1.09	1.09	1.09	1.09	1.09
Load levels - kVAr	0.36	0.36	0.36	0.36	0.36	0.36

Loading Matrix

	Study Number					
Section	**1**	**2**	**3**	**4**	**5**	**6**
Tx	22.1	1.9	2	1.8	1.9	1.9
A	11.4	11.4	11.4	0.9	1	1
B	13.5	13.5	13.5	0.2	0.2	0.2
C	12.1	12.1	12.1	1.7	1.6	1.7
D	9	9	9	4.8	4.8	4.8
E	7.5	7.5	7.5	7.5	6.2	6.3
F	6.1	6.1	6.1	6.1	7.7	7.8
G	2.9	2.9	2.9	2.9	2.9	10.9
H	1.5	1.5	1.5	1.5	1.5	12.4
P	0.7	0.7	0.7	0.7	0.7	0.7

Voltage Bus						
	1	**2**	**3**	**4**	**5**	**6**
200	1.012	1.011	1.011	0.999	0.994	0.988
201	1.011	1.01	1.01	0.999	0.993	0.988
202	1.007	1.007	1.007	0.999	0.993	0.988
203	1.005	1.004	1.004	1	0.994	0.988
204	1.002	1.002	1.002	1.001	0.995	0.989
205	1	1	1	0.999	0.997	0.993
206	0.999	0.999	0.999	0.998	0.998	0.991
206.5					1.005	
207	0.998	0.998	0.998	0.997	0.998	0.995
208	0.998	0.998	0.997	0.997	0.997	0.998

Table C2.2 - 1MW; 20kV Rural Network; Average Feeder Studies

Study Number						
	1	**2**	**3**	**4**	**5**	**6**
Generator Position	-	200	299	263	272	270
Generator Size	-	1	1	1	1	1
Total Losses - kW	32.85	30.4	40.2	15.4	13.88	8.12
Total Losses - kVAr	58.2	22.5	33.5	14	10.6	9.75
Sending Voltage - (200)	1.02	1.026	1.002	1.026	1.021	1.02
Endpoint Voltage - (270)	0.99	0.996	0.97	1.005	1.011	1.025
Fault level - HV (110kV) - (100) - Amps	2896	2792	2967	2969	2964	2962
Fault level - MV (20kV) - Sending (200) - Amps	1483	1658	1634	1651	1635	1629
Fault level - MV (20kV) - Ending (270) - Amps	607	633.1	620	658.5	695	760
Transformer flow - kW	1621	618	708	603	602	596
Transformer flow - kVAr	583	219	231	210	207	206
Power leaving MV Prim - kW	1618	1618	1768	603	602	595
Power leaving MV Prim - kVAr	542	542	547	204	201	200
Load levels - kW	1.59	1.59	1.59	1.59	1.59	1.59
Load levels - kVAr	0.523	0.523	0.523	0.523	0.523	0.523

Loading Matrix

Study Number						
Section	**1**	**2**	**3**	**4**	**5**	**6**
Tx	32.8	12.5	14.2	12.2	12.1	12
A	16.6	16.5	18.4	6.2	6.2	6.1
B	20.2	20.1	22.1	6.4	6.4	6.4
C	18.5	18.4	20.2	4.7	4.7	4.6
D	15.3	15.2	16.7	15.1	1.5	1.5
E	13.6	13.5	14.8	13.4	0.2	0.3
F	11.8	11.7	12.8	11.6	1.9	2
G	8.6	8.5	9.3	8.4	8.4	5.2
H	6.8	6.8	7.4	6.7	6.7	6.9
I	5	5	5.5	5	4.9	8.6
J	1.8	1.8	1.9	1.7	1.7	11.8
K	3.1	3	3.5	3	16.6	3

Voltage Bus						
	1	**2**	**3**	**4**	**5**	**6**
260	1.02	1.026	1.002	1.026	1.021	1.02
261	1.018	1.024	1	1.025	1.02	1.019
262	1.013	1.019	0.994	1.024	1.019	1.017
263	1.008	1.014	0.989	1.022	1.017	1.016
264	1.003	1.009	0.984	1.018	1.017	1.016
265	1	1.006	0.98	1.014	1.017	1.016
266	0.996	1.003	0.977	1.011	1.017	1.016
266.5						
267	0.994	1	0.974	1.009	1.015	1.018
268	0.992	0.998	0.972	1.007	1.013	1.02
269	0.991	0.997	0.971	1.006	1.012	1.022
270	0.99	0.996	0.97	1.005	1.011	1.025
272	0.995		0.974	1.009	1.028	1.014

Table C 2.3 - 1MW; 20kV Network; Longest Feeder

Study Number						
	1	2	3	4	5	6
Generator Position	-	200	299	233	245	241
Generator Size	-	1	1	1	1	1
Total Losses - kW	43.71	42.4	45.3	24	25.7	11.1
Total Losses - kVAr	69.8	32.8	37.5	22.3	18	14.6
Sending Voltage - (200)	1.014	1.019	1.019	1.019	1.019	1.019
Endpoint Voltage - (253)	0.978	0.983	0.983	0.992	1.007	1.022
Fault level - HV (110kV) - (100) - Amps	5359	5367	5367	5367	5367	5366
Fault level - MV (20kV) - Sending (200) - Amps	4122	4307	4303	4299	4279	4280
Fault level - MV (20kV) - Ending (253) - Amps	658.5	664	663	681	725	789
Transformer flow - kW	1852	851	853	833	834	819
Transformer flow - kVAR	665	299	304	288	284	281
Power leaving MV Prim - kW	1851	1850	1850	833	834	819
Power leaving MV Prim - kVAr	618	618	618	279	275	272
Load levels - kW	1.81	1.81	1.81	1.81	1.81	1.81
Load levels - kVAr	0.595	0.595	0.595	0.595	0.595	0.595

Loading Matrix

Study Number						
Section	**1**	**2**	**3**	**4**	**5**	**6**
Tx	13	6	6	5.8	5.8	5.7
A	19.1	19.1	19.1	8.6	8.6	8.4
B	23.4	23.2	23.2	9.4	9.4	9.3
C	20.4	20.3	20.3	6.5	6.5	6.3
D	18.5	18.5	18.5	18.3	4.7	4.5
E	15.6	15.5	15.5	15.4	1.8	1.6
F	13.7	13.6	13.6	13.5	0.1	0.3
G	11.8	11.7	11.7	11.6	1.9	2.1
H	8.8	8.7	8.7	8.6	8.5	5.1
I	6.9	6.8	6.8	6.8	6.7	6.9
J	3.8	3.8	3.8	3.8	3.7	9.8
K	1.9	1.9	1.9	1.9	1.9	11.7
L	2.6	2.6	2.6	2.6	17	2.6

Table C2.3 (Cont'd)

Voltage Bus						
	1	2	3	4	5	6
230	1.014	1.019	1.019	1.019	1.019	1.019
231	1.012	1.017	1.016	1.018	1.018	1.018
232	1.006	1.011	1.011	1.016	1.016	1.016
233	1	1.005	1.005	1.014	1.014	1.014
234	0.995	1	1	1.009	1.013	1.013
235	0.991	0.996	0.996	1.005	1.012	1.012
236	0.987	0.992	0.992	1.001	1.012	1.012
237	0.984	0.989	0.989	0.998	1.013	1.013
237.5					1.034	
238	0.982	0.986	0.986	0.995	1.01	1.014
239	0.98	0.985	0.985	0.994	1.008	1.016
240	0.979	0.984	0.983	0.992	1.007	1.019
241	0.978	0.983	0.983	0.992	1.007	1.022
253	0.978	0.983	0.983	0.992	1.007	1.022

Table C 2.4 - 2.5MW; 20kV Rural Network; Shortest Feeder Studies

Study Number						
	1	2	3	4	5	6
Generator Position	-	200	299	204	218	208
Generator Size	-	2.5	2.5	2.5	2.5	2.5
Total Losses - kW	11.1	11.7	30	32	91.8	86.8
Total Losses - kVAr	24.7	36.8	64.7	49	66.8	78.2
Sending Voltage - (200)	1.012	1.014	1.013	0.984	0.98	0.97
Endpoint Voltage - (208)	0.998	1	1	0.998	1.009	1.017
Fault level - HV (38kV) - (100) - Amps	2676	2843	2835	2822	2809	2805
Fault level - MV (20kV) - Sending (200) - Amps	1440	1864	1840	1797	1754	1741
Fault level - MV (20kV) - Ending (208) - Amps	748	836	830	940	1026.8	1133
Transformer flow - kW	1097	-1402	-1384	-1382	-1322	-1327
Transformer flow - kVAr	383	-425	-397	-413	-393	-384
Power leaving MV Prim - kW	1096	1096	1096	-1384	-1324	-1329
Power leaving MV Prim - kVAr	363	363	363	-445	-423	-414
Load levels - kW	1.09	1.09	1.09	1.09	1.09	1.09
Load levels - kVAr	0.36	0.36	0.36	0.36	0.36	0.36

Loading Matrix

Study Number						
Section	**1**	**2**	**3**	**4**	**5**	**6**
Tx	22.1	27.9	27.4	27.5	26.3	26.3
A	11.4	11.3	11.3	14.7	11.4	14.3
B	13.5	13.5	13.5	20.9	20.4	20.3
C	12.1	12.1	12.1	22.3	21.6	21.8
D	9	9	9	25.5	24.7	25
E	7.5	7.5	7.5	7.5	26.2	26.5
F	6.1	6	6	6	27.7	27.9
G	2.9	2.9	2.9	2.9	2.9	31.1
H	1.5	1.5	1.5	1.5	1.5	31.5
P	0.7	0.7	0.7	0.7	0.7	0.7

Voltage Bus						
	1	**2**	**3**	**4**	**5**	**6**
200	1.012	1.014	1.013	0.984	0.98	0.97
201	1.011	1.013	1.012	0.986	0.981	0.972
202	1.007	1.009	1.009	0.991	0.986	0.977
203	1.005	1.006	1.006	0.996	0.991	0.982
204	1.002	1.004	1.004	1.003	0.997	0.988
205	1	1.002	1.002	1.001	1.003	0.995
206	0.999	1.001	1.001	0.999	1.01	1.002
206.5	0.998					
207	0.998	1	1	0.999	1.01	1.009
208	0.998	1	1	0.998	1.009	1.017

Table C2.5 - 2.5MW; 20kV Rural Network; Average Feeder Studies

	Study Number					
	1	2	3	4	5	6
Generator Position	-	200	299	263	272	270
Generator Size	-	2.5	2.5	2.5	2.5	2.5
Total Losses - kW	32.8	30.5	45.8	22.8	100.7	92.4
Total Losses - kVAr	58.2	28.4	53.2	24.6	48.2	63.2
Sending Voltage - (200)	1.02	1.029	1.054	1.019	0.977	0.97
Endpoint Voltage - (270)	0.99	1	1.016	1.011	0.996	1.027
Fault level - HV (38kV) - (100) - Amps	2896	3064	3065	3052	3021	3014
Fault level - MV (20kV) - Sending (200) - Amps	1483	1917	1919	1875	1763	1741
Fault level - MV (20kV) - Ending (270) - Amps	607	663.4	674	719	789	985
Transformer flow - kW	1620	-882	-866	-890	-812	-820
Transformer flow - kVAr	583	-267	-242	-270	-247	-232
Power leaving MV Prim - kW	1618	1618	1616	-890	-812	-820
Power leaving MV Prim - kVAr	542	542	540	-238	-258	-244
Load levels - kW	1.59	1.59	1.59	1.59	1.59	1.59
Load levels - kVAr	0.523	0.523	0.523	0.523	0.523	0.523

Loading Matrix

	Study Number					
Section	1	2	3	4	5	6
Tx	32.8	17.5	17.1	17.7	16.2	16.2
A	16.6	16.5	16.1	9.1	8.7	8.8
B	20.2	20	19.5	13.7	13.2	13.4
C	18.5	18.3	17.9	15.5	15	15.2
D	15.3	15.2	14.8	15	18.3	18.5
E	13.6	13.4	13.1	13.2	20.1	20.3
F	11.8	11.7	11.4	11.6	21.8	22
G	8.6	8.5	8.3	8.4	8.5	25.3
H	6.8	6.7	6.6	6.7	6.8	27
I	5	5	4.9	4.9	5	28.8
J	1.8	1.8	1.7	1.7	1.8	31.9
K	3.1	3	3	3	45.9	3.1

Table C2.5 (Cont'd)

	Voltage Bus					
	1	2	3	4	5	6
260	1.02	1.029	1.054	1.019	0.977	0.97
261	1.018	1.027	1.053	1.02	0.978	0.971
262	1.013	1.022	1.047	1.024	0.981	0.975
263	1.008	1.017	1.042	1.028	0.985	0.979
264	1.003	1.013	1.038	1.024	0.99	0.984
265	1	1.009	1.035	1.02	0.996	0.99
266	0.996	1.006	1.032	1.017	1.002	0.996
267	0.994	1.004	1.029	1.015	1	1.003
268	0.992	1.002	1.028	1.013	0.998	1.01
269	0.991	1	1.026	1.012	0.996	1.018
270	0.99	1	1.016	1.011	0.996	1.027
272	0.995	1.004	1.03	1.015	1.03	0.994

Table C 2.6 - 2.5MW; 20V Rural Network; Longest Feeder Studies

	Study Number					
	1	2	3	4	5	6
Generator Position	-	200	299	233	245	241
Generator Size	-	2.5	2.5	2.5	2.5	2.5
Total Losses - kW	43.7	41.7	59.5	26.7	161.2	94.6
Total Losses - kVAr	69.8	28.2	56.1	24.5	57.1	58.2
Sending Voltage - (200)	1.014	1.025	1.025	1.013	0.974	0.97
Endpoint Voltage - (253)	0.978	0.99	0.989	0.998	0.994	1.029
Fault level - HV (110kV) - (100) - Amps	5359	5379	5378	5372	5354	5353
Fault level - MV (20kV) - Sending (200) - Amps	4122	4585	4559	4498	4224	4226
Fault level - MV (20kV) - Ending (253) - Amps	659	672	671	705	783.3	934
Transformer flow - kW	1852	-650	-632	-665	-531	-597
Transformer flow - kVAr	665	-197	-169	-205	-168	-167
Power leaving MV Prim - kW	1851	1850	1850	-665	-531	-597
Power leaving MV Prim - kVAr	618	618	618	-211	-172	-172
Load levels - kW	1.81	1.81	1.81	1.81	1.81	1.81
Load levels - kVAr	0.595	0.595	0.595	0.595	0.595	0.595

Loading Matrix

Study Number						
Section	**1**	**2**	**3**	**4**	**5**	**6**
Tx	13	4.5	4.3	4.6	3.7	4.1
A	19.1	18.9	18.9	6.9	5.7	6.4
B	23.4	23.1	23.1	10.9	9.4	10.3
C	20.4	20.2	20.2	13.8	12.5	13.4
D	18.5	18.3	18.3	18.2	14.4	15.3
E	15.6	15.4	15.4	15.3	17.4	18.3
F	13.7	13.6	13.5	13.4	19.3	20.2
G	11.8	11.6	11.6	11.5	21.2	22.1
H	8.8	8.7	8.7	8.6	8.6	25.1
I	6.9	6.8	6.8	6.7	6.7	26.9
J	3.8	3.8	3.8	3.8	3.8	29.9
K	1.9	1.9	1.9	1.9	1.9	31.7
L	2.6	2.6	2.6	2.6	45.2	2.6

Voltage Bus						
	1	**2**	**3**	**4**	**5**	**6**
230	1.014	1.025	1.025	1.013	0.974	0.97
231	1.012	1.023	1.023	1.014	0.974	0.971
232	1.006	1.017	1.017	1.016	0.977	0.974
233	1	1.012	1.011	1.02	0.98	0.977
234	0.995	1.007	1.006	1.015	0.984	0.981
235	0.991	1.002	1.002	1.011	0.989	0.986
236	0.987	0.999	0.998	1.007	0.994	0.992
237	0.984	0.996	0.995	1.004	1	0.998
237.5					1.056	
238	0.982	0.993	0.993	1.002	0.997	1.005
239	0.98	0.991	0.992	1.001	0.996	1.012
240	0.979	0.99	0.991	0.999	0.995	1.02
241	0.978	0.99	0.989	0.998	0.994	1.029
253	0.978	0.99	0.989	0.998	0.994	1.029

Table C2.7 - 5MW; 20kV Rural Network; Shortest Feeder Studies

Study Number						
	1	**2**	**3**	**4**	**5**	**6**
Generator Position	-	200	299	204	218	208
Generator Size	-	5	5	5	5	5
Total Losses - kW	11.1	24.55	95	187	426.9	403.87
Total Losses - kVAr	24.7	251.43	351	337.1	398.7	432.37
Sending Voltage - (200)	1.012	1.009	1.013	0.975	0.973	0.973
Endpoint Voltage - (208)	0.998	0.995	0.999	1.015	1.042	1.074
Fault level - HV (38kV) - (100) - Amps	2676	2951	2932	2903	2870	2868
Fault level - MV (20kV) - Sending (200) - Amps	1440	2279	2193	2095	1951	1947
Fault level - MV (20kV) - Ending (208) - Amps	748	895	881	1116	1299	1606
Transformer flow - kW	1097	-3889	-3819	-3726	-3487	-3509
Transformer flow - kVAr	383	-1033	-913	-962	-901	-867
Power leaving MV Prim - kW	1096	1096	1096	-3740	-3499	-3522
Power leaving MV Prim - kVAr	363	363	363	-1186	-1095	-1063
Load levels - kW	1.09	1.09	1.09	1.09	1.09	1.09
Load levels - kVAr	0.36	0.36	0.36	0.36	0.36	0.36

Loading Matrix

Study Number						
Section	**1**	**2**	**3**	**4**	**5**	**6**
Tx	22.1	76.6	74.9	73.3	68.6	68.9
A	11.4	11.4	11.5	40.1	37.5	37.6
B	13.5	13.6	13.7	54.3	50.9	51.1
C	12.1	12.1	12.1	55.8	52.4	52.6
D	9	9	9	58.9	55.5	55.7
E	7.5	7.5	7.5	7.4	57	57.2
F	6.1	6.1	6	5.9	58.4	58.6
G	2.9	2.9	2.9	2.9	2.8	61.1
H	1.5	1.5	1.5	1.4	1.4	62.9
P (218)	3.1	3.1	3.1	3.1	90.5	3

Voltage Bus						
	1	**2**	**3**	**4**	**5**	**6**
200	1.012	1.009	1.013	0.975	0.973	0.973
201	1.011	1.008	1.012	0.978	0.976	0.976
202	1.007	1.004	1.009	0.991	0.989	0.988
203	1.005	1.002	1.006	1.005	1.002	1.001
204	1.002	0.999	1.004	1.019	1.015	1.015
205	1	0.998	1.002	1.018	1.029	1.029
206	0.999	0.996	1	1.016	1.043	1.043
207	0.998	0.995	0.999	1.015	1.042	1.058
208	0.998	0.995	0.999	1.015	1.042	1.074

Table C2.8 - 5MW; 20kV Rural Network; Average Feeder Studies

Study Number						
	1	2	3	4	5	6
Generator Position	-	200	299	263	272	270
Generator Size	-	5	5	5	5	5
Total Losses - kW	32.8	41.25	110.7	120.7	483.5	476.3
Total Losses - kVAr	58.2	197.9	298.6	239.7	343.2	413.3
Sending Voltage - (200)	1.02	1.018	1.021	0.999	0.97	0.97
Endpoint Voltage - (270)	0.99	0.988	0.991	1.012	1.033	1.101
Fault level - HV (110kV) - (100) - Amps	2896	3171	3153	3139	3073	3061
Fault level - MV (20kV) - Sending (200) - Amps	1483	2328	2241	2190	1919	1885
Fault level - MV (20kV) - Ending (270) - Amps	607	692	684	794	947	1473
Transformer flow - kW	1620	-3371	-3302	-3292	-2929	-2935
Transformer flow - kVAr	583	-917	-817	-875	-772	-747
Power leaving MV Prim - kW	1618	1618	1618	-3302	-2937	-2943
Power leaving MV Prim - kVAr	542	542	542	-1054	-921	-851
Load levels - kW	1.59	1.59	1.59	1.59	1.59	1.59
Load levels - kVAr	0.523	0.523	0.523	0.523	0.523	0.523

Loading Matrix

Study Number						
Section	1	2	3	4	5	6
Tx	32.8	66.5	64.8	64.9	57.7	57.7
A	16.6	16.7	16.6	34.5	31.6	31.4
B	20.2	20.3	20.2	47.3	43.4	43.3
C	18.5	18.5	18.5	49	45.2	45
D	15.3	15.3	15.3	15	48.5	48.3
E	13.6	13.6	13.6	13.3	50.2	50
F	11.8	11.8	11.8	11.5	51.9	52
G	8.6	8.6	8.6	8.4	8.2	54.8
H	6.8	6.8	6.8	6.7	6.5	56.6
I	5	5	5	4.9	4.8	58.1
J	1.8	1.8	1.8	1.7	1.7	61.1
K	3.1	3.1	3.1	3	89.2	2.9

Table C2.8 (cont'd)

Voltage Bus						
	1	**2**	**3**	**4**	**5**	**6**
260	1.02	1.018	1.021	0.999	0.97	0.97
261	1.018	1.016	1.019	1.002	0.973	0.973
262	1.013	1.011	1.014	1.015	0.985	0.985
263	1.008	1.005	1.009	1.028	0.998	0.997
264	1.003	1.001	1.004	1.024	1.011	1.01
265	1	0.998	1.001	1.021	1.025	1.024
266	0.996	0.994	0.997	1.018	1.039	1.038
267	0.994	0.992	0.995	1.015	1.037	1.053
268	0.992	0.99	0.993	1.013	1.035	1.068
269	0.991	0.989	0.992	1.012	1.033	1.084
270	0.99	0.988	0.991	1.012	1.033	1.101

Table C2.9 - 5MW; 20kV Rural Network; Longest Feeder Studies

Study Number						
	1	**2**	**3**	**4**	**5**	**6**
Generator Position	-	200	299	233	245	241
Generator Size	-	5	5	5	5	5
Total Losses - kW	43.7	43.7	119.3	114.8	694.5	490.1
Total Losses - kVAr	69.8	69.8	269.7	198.2	348.1	380.7
Sending Voltage - (200)	1.014	1.014	1.009	0.982	0.957	0.972
Endpoint Voltage - (253)	0.978	0.978	0.976	0.988	1.026	**1.112**
Fault level - HV (110kV) - (100) - Amps	5359	5383	5381	5369	5349	5357
Fault level - MV (20kV) - Sending (200) - Amps	4122	4932	4840	4691	4232	4349
Fault level - MV (20kV) - Ending (253) - Amps	659	678	665	726	884	1408
Transformer flow - kW	1852	-3145	-3107	-3077	-2498	-2702
Transformer flow - kVAr	665	-886	-778	-847	-699	-664
Power leaving MV Prim - kW	1851	1851	1834	-3081	-2500	-2704
Power leaving MV Prim - kVAr	618	618	622	-984	-972	-770
Load levels - kW	1.81	1.81	1.81	1.81	1.81	1.81
Load levels - kVAr	0.595	0.595	0.595	0.595	0.595	0.595

Loading Matrix

Study Number						
Section	**1**	**2**	**3**	**4**	**5**	**6**
Tx	13	21.6	21.1	21.1	17.1	18.4
A	19.1	19.2	19.1	32.8	27.3	28.8
B	23.4	23.5	23.5	45.1	37.9	39.8
C	20.4	20.5	20.5	48	40.9	42.8
D	18.5	18.6	18.7	18.3	42.8	44.7
E	15.6	15.7	15.7	15.4	45.8	47.6
F	13.7	13.7	13.8	13.5	47.7	49.5
G	11.8	11.8	11.9	11.7	49.5	51.3
H	8.8	8.8	8.8	8.7	8.4	54.1
I	6.9	6.9	6.9	6.8	6.5	55.9
J	3.8	3.8	3.9	3.8	3.7	58.6
K	1.9	1.9	1.9	1.9	1.8	60.3
L	2.6	2.6	2.6	2.6	86	2.5

Table C2.9 (cont'd)

Voltage Bus						
	1	2	3	4	5	6
230	1.014	1.009	1.009	0.982	0.957	0.972
231	1.012	1.007	1.007	0.985	0.96	0.975
232	1.006	1.001	1.001	0.997	0.97	0.986
233	1	0.995	0.995	1.01	0.981	0.998
234	0.995	0.99	0.99	1.005	0.993	1.01
235	0.991	0.986	0.986	1.001	1.005	1.023
236	0.987	0.982	0.982	0.998	1.018	1.036
237	0.984	0.979	0.979	0.994	1.032	1.05
238	0.982	0.974	0.974	0.992	1.03	1.065
239	0.98	0.973	0.973	0.99	1.028	1.08
240	0.979	0.973	0.973	0.989	1.027	1.096
241	0.978	0.973	0.973	0.989	1.026	1.112
253	0.978	0.976	0.976	0.988	1.026	1.112

C.3 Power system studies of representative 110/38/10 kV semi-urban network

Tables C.3.1 to C.3.3 present a summary of the significant results of power system studies of the 110/38/10 kV semi-urban network, including power flows, power losses, voltage profiles, circuit utilisation and fault levels, for the 1 MW embedded generation case.

Tables C.3.4 to C.3.6 present the corresponding results for the 2.5 MW embedded generation case and Tables C.3.7 to C.3.9 the results for the 5 MW generation case.

Table C3.1 - 1MW; 10kV Semi-Urban Network; Shortest Feeder Studies

	Study Number					
	1	**2**	**3**	**4**	**5**	**6**
Generator Position	-	200	299	202	203	204
Generator Size	-	1	1	1	1	1
Total Losses - kW	38.15	34.3	39.7	32.2	32	32.4
Total Losses - kVAr	251.7	162	167	161.2	161	161.2
Sending Voltage - (200)	1.012	1.016	1.016	1.016	1.016	1.016
Endpoint Voltage - (204)	1.013	1.013	1.013	1.015	1.016	1.017
Fault level - HV (38kV) - (100) - Amps	5724	5803	5802	5803	5802.8	5802
Fault level - MV (10kV) - Sending (200) - Amps	4961	5308	5305	5306	5305	5304
Fault level - MV (10kV) - Ending (204) - Amps	2601	4406	4400	4460	4486	4510
Transformer flow - kW	4873	3869	3865	3868	3867	3867
Transformer flow - kVAr	1842	1424	1422	1423	1423	1423
Power leaving MV Prim - kW	1195	1194	1194	192	192	193
Power leaving MV Prim - kVAr	393	393	393	64.4	64.3	64.2
Load levels - kW	1.19	1.19	1.19	1.19	1.19	1.19
Load levels - kVAr	0.39	0.39	0.39	0.39	0.39	0.39

Loading Matrix

	Study Number					
Section	**1**	**2**	**3**	**4**	**5**	**6**
Tx	50	39.3	39.3	39.2	39.2	39.2
A	24.8	24.7	24.7	4	4	4
B	18.6	18.5	18.5	2.2	2.2	2.2
C	12.4	12.3	12.3	12.3	-8.3	-8.3
D	6.2	6.2	6.2	6.2	6.2	-14.5

	Voltage Bus					
	1	**2**	**3**	**4**	**5**	**6**
200	1.012	1.016	1.016	1.016	1.016	1.016
201	1.011	1.014	1.014	1.015	1.015	1.015
202	1.01	1.014	1.014	1.016	1.016	1.016
203	1.009	1.013	1.013	1.015	1.016	1.016
204	1.009	1.013	1.013	1.015	1.016	1.017

Table C3.2 - 1MW; 10kV Semi-Urban Network; Average Feeder Studies

Study Number						
	1	**2**	**3**	**4**	**5**	**6**
Generator Position	-	200	299	232	238	237
Generator Size	-	1	1	1	1	1
Total Losses - kW	38.15	34.3	39.7	29.95	27.25	27.87
Total Losses - kVAr	251.7	162	167	159.95	158.6	158.8
Sending Voltage - (200)	1.012	1.016	1.016	1.016	1.016	1.016
Endpoint Voltage - (280)	1.005	1.009	1.009	1.011	1.013	1.016
Fault level - HV (38kV) - (100) - Amps	5724	5803	5802	5802	5801	5801
Fault level - MV (10kV) - Sending (200) - Amps	4961	5308	5301	5305	5300	5300
Fault level - MV (10kV) - Ending (237) - Amps	3596	3770	3763	3819	3864	3933
Transformer flow - kW	4873	3869	3869	3865	3863	3862
Transformer flow - kVAr	1842	1424	1424	1422	1420	1421
Power leaving MV Prim - kW	1689	1689	1689	685	682	682
Power leaving MV Prim - kVAr	557	557	557	227	226	226
Load levels - kW	1.68	1.68	1.68	1.68	1.68	1.68
Load levels - kVAr	0.55	0.55	0.55	0.55	0.55	0.55

Loading Matrix

Study Number						
Section	**1**	**2**	**3**	**4**	**5**	**6**
Tx	50	39.3	39.3	40	39.2	39.2
A	35	34.9	34.9	14.1	14.1	14.1
B	31.4	31.2	31.2	10.5	10.5	10.5
C	27.7	27.6	27.6	27.5	6.8	6.8
D	24	23.9	23.9	23.9	3.2	3.2
E	11	11	11	11	10.9	9.7
F	7.3	7.3	7.3	7.3	7.3	-13.4
G	3.7	3.7	3.7	3.7	3.6	-17
H	9.3	9.3	9.3	9.3	-11.4	9.3

Voltage Bus						
	1	**2**	**3**	**4**	**5**	**6**
230	1.012	1.016	1.016	1.016	1.016	1.016
231	1.01	1.014	1.014	1.015	1.015	1.015
232	1.009	1.012	1.012	1.014	1.014	1.014
233	1.007	1.011	1.011	1.013	1.014	1.014
234	1.006	1.01	1.01	1.012	1.014	1.014
234.5	1.005				1.015	
235	1.005	1.009	1.009	1.011	1.013	1.014
236	1.005	1.009	1.009	1.011	1.013	1.015
237	1.005	1.009	1.009	1.011	1.013	1.016

Table C3.3 - 1MW; 10kV Semi-Urban Network; Longest Feeder Studies

	Study Number					
	1	2	3	4	5	6
Generator Position	-	200	299	264	273	271
Generator Size	-	1	1	1	1	1
Total Losses - kW	38.15	34.3	39.7	24.36	21.75	21.96
Total Losses - kVAr	251.7	162	167	157	155.7	156.1
Sending Voltage - (200)	1.012	1.016	1.016	1.016	1.016	1.016
Endpoint Voltage - (271)	0.973	1.004	1.004	1.008	1.012	1.015
Fault level - HV (110kV) - (100) - Amps	5724	5803	5802	5802	5800	5800
Fault level - MV (10kV) - Sending (200) - Amps	4961	5308	5305	5301	5294	5293
Fault level - MV (10kV) - Ending (271) - Amps	1162	3153	3150	3228	3301	3357
Transformer flow - kW	4873	3869	3865	3859	3857	3857
Transformer flow - kVAr	1842	1424	1422	1420	1418	1418
Power leaving MV Prim - kW	2045	1980	1979	970	967	967
Power leaving MV Prim - kVAr	658	652	652	320	319	319
Load levels - kW	1.96	1.96	1.96	1.96	1.96	1.96
Load levels - kVAr	0.64	0.64	0.64	0.64	0.64	0.64

Loading Matrix

	Study Number					
Section	1	2	3	4	5	6
Tx	50	39.3	39.3	39.2	39.9	39.1
A	41	40.9	40.9	20	20	20
B	38.3	38.2	38.2	17.3	17.3	17.3
C	35.6	35.5	35.5	14.6	14.6	14.6
D	32.8	32.7	32.7	11.9	11.8	11.8
E	24.7	24.6	24.6	24.5	3.7	3.7
F	21.9	21.9	21.9	21.8	1	1
G	19.2	19.1	19.1	19.1	-1.7	-1.7
H	16.4	16.4	16.4	16.3	-4.4	-4.4
I	8.2	8.2	8.2	8.2	-8.1	-12.5
J	5.5	5.5	5.5	5.5	5.4	-15.2
K	2.7	2.7	2.7	2.7	2.7	-18
L	5.5	5.5	5.5	5.4	-15.3	5.4

Table C3.3 (cont'd)

Voltage Bus						
	1	2	3	4	5	6
260	1.012	1.016	1.016	1.016	1.016	1.016
261	1.01	1.014	1.014	1.015	1.015	1.015
262	1.008	1.012	1.012	1.014	1.014	1.014
263	1.006	1.01	1.01	1.013	1.013	1.013
264	1.003	1.009	1.009	1.013	1.013	1.013
265	1.002	1.007	1.007	1.011	1.012	1.012
266	1.001	1.006	1.006	1.01	1.012	1.012
267	1.001	1.005	1.005	1.009	1.012	1.012
268	1.001	1.005	1.005	1.009	1.013	1.013
268.5		1.004			1.015	
269	1	1.004	1.004	1.008	1.012	1.013
270	1	1.004	1.004	1.008	1.012	1.014
271	1	1.004	1.004	1.008	1.012	1.015

Table C3.4 - 2.5MW; 10kV Semi-Urban Network; Shortest Feeder Studies

Study Number						
	1	2	3	4	5	6
Generator Position	-	200	299	202	203	204
Generator Size	-	2.5	2.5	2.5	2.5	2.5
Total Losses - kW	38.15	30.16	63.1	32.07	35.12	39.5
Total Losses - kVAr	251.68	67.74	96.8	68.67	70.13	72.3
Sending Voltage - (200)	1.012	1.021	1.021	1.021	1.021	1.021
Endpoint Voltage - (204)	1.009	1.018	1.018	1.023	1.026	1.028
Fault level - HV (38kV) - (100) - Amps	5724	5908	5906	5906	5905	5904
Fault level - MV (10kV) - Sending (200) - Amps	4960	5834	5820	5822	5817	5812
Fault level - MV (10kV) - Ending (204) - Amps	4164	4761	4720	4905	4975	5042
Transformer flow - kW	4873	2365	2362	2367	2370	2375
Transformer flow - kVAr	1842	838	836	839	840	843
Power leaving MV Prim - kW	1195	1194	1195	-1303	-1301	-1296
Power leaving MV Prim - kVAr	393	393	393	-426	-425	-423
Load levels - MW	1.19	1.19	1.19	1.19	1.19	1.19
Load levels - MVAr	0.39	0.39	0.39	0.39	0.39	0.39

Loading Matrix

Study Number						
Section	1	2	3	4	5	6
Tx	50	23.9	23.9	23.9	23.9	34
A	24.8	24.5	24.5	26.7	26.7	26.6
B	18.6	18.4	18.4	32.9	32.8	32.7
C	12.4	12.3	12.3	12.2	38.9	38.8
D	6.2	6.1	6.1	6.1	6.1	44.9

Voltage Bus						
	1	**2**	**3**	**4**	**5**	**6**
200	1.012	1.021	1.021	1.021	1.021	1.021
201	1.011	1.02	1.02	1.022	1.022	1.022
202	1.01	1.019	1.019	1.0244	1.0244	1.0244
203	1.009	1.018	1.018	1.023	1.026	1.026
204	1.009	1.018	1.018	1.023	1.026	1.028

Table C3.5 - 2.5MW; 10kV Semi-Urban Network; Average Feeder Studies

Study Number						
	1	**2**	**3**	**4**	**5**	**6**
Generator Position	-	200	299	232	238	237
Generator Size	-	2.5	2.5	2.5	2.5	2.5
Total Losses - kW	38.15	30.16	63.1	26.72	35.61	34.9
Total Losses - kVAr	251.68	67.74	96.8	66.07	70.43	72.3
Sending Voltage - (200)	1.012	1.021	1.021	1.021	1.021	1.021
Endpoint Voltage - (280)	1.005	1.014	1.014	1.019	1.024	1.032
Fault level - HV (38kV) - (100) - Amps	5724	5908	5899	5906	5901	5900
Fault level - MV (10kV) - Sending (200) - Amps	4960	5834	5786	5820	5794	5791
Fault level - MV (10kV) - Ending (237) - Amps	3596	4020	3987	4145.9	4263	4457.1
Transformer flow - kW	4873	2365	2396	2362	2370	2375
Transformer flow - kVAr	1842	838	865	836	841	842
Power leaving MV Prim - kW	1689	1688	1689	-814	-806	-802
Power leaving MV Prim - kVAr	557	557	557	-265	-261	-259
Load levels - MW	1.68	1.68	1.68	1.68	1.68	1.68
Load levels - MVAr	0.55	0.55	0.55	0.55	0.55	0.55

Loading Matrix

Study Number						
Section	**1**	**2**	**3**	**4**	**5**	**6**
Tx	50	23.9	23.9	24.3	23.9	24
A	35	34.7	34.7	16.7	16.5	16.4
B	31.4	31.1	31.1	-20.3	-20.1	-20
C	27.7	27.4	27.4	-27.3	-23.7	-23.7
D	24	23.8	23.8	23.7	-27.3	-27.3
E	11	10.9	10.9	10.9	10.8	-40
F	7.3	7.3	7.3	7.3	7.2	-43.6
G	3.7	3.6	3.6	3.6	3.6	-47.2
H	11	9.3	9.3	9.2	-41.8	9.2

Voltage Bus						
	1	2	3	4	5	6
230	1.012	1.021	1.021	1.021	1.021	1.021
231	1.01	1.019	1.019	1.022	1.022	1.022
232	1.009	1.018	1.018	1.023	1.023	1.023
233	1.007	1.017	1.017	1.022	1.024	1.024
234	1.006	1.015	1.015	1.02	1.025	1.025
234.5					1.03	
235	1.005	1.015	1.015	1.02	1.025	1.027
236	1.005	1.014	1.014	1.019	1.025	1.03
237	1.005	1.014	1.014	1.019	1.024	1.032

Table C3.6 - 2.5MW; 10kV Semi-Urban Network; Longest Feeder Studies

Study Number						
	1	2	3	4	5	6
Generator Position	-	200	299	264	273	271
Generator Size	-	2.5	2.5	2.5	2.5	2.5
Total Losses - kW	38.15	30.16	63.1	20.52	37.5	21.97
Total Losses - kVAr	251.68	67.74	96.8	64.33	73.4	155.9
Sending Voltage - (200)	1.012	1.021	1.021	1.009	1.002	1.016
Endpoint Voltage - (271)	1	1.009	1.009	1.007	1.011	1.015
Fault level - HV (110kV) - (100) - Amps	5724	5908	5906	5898.6	5898.6	5800
Fault level - MV (10kV) - Sending (200) - Amps	4960	5834	5820	5763.4	5703	5294
Fault level - MV (10kV) - Ending (271) - Amps	3034	3319	3296	3476.7	3655	3357.8
Transformer flow - kW	4873	2365	2362	2355	2372	3858
Transformer flow - kVAr	1842	838	836	830	839	1418
Power leaving MV Prim - kW	1980	1980	1979	-531	-514	968
Power leaving MV Prim - kVAr	652	652	652	-172	-156	319
Load levels - MW	1.96	1.96	1.96	1.96	1.96	1.96
Load levels - MVAr	0.64	0.64	0.64	0.64	0.64	0.64

Loading Matrix

Study Number						
Section	**1**	**2**	**3**	**4**	**5**	**6**
Tx	50	23.9	23.9	23.8	24	39.1
A	41	40.7	40.7	11	10.7	20
B	38.3	38	38	13.7	13.5	17.3
C	35.6	35.3	35.3	16.5	16.2	14.6
D	32.9	32.6	32.6	19.2	18.9	11.9
E	24.7	24.5	24.5	24.5	27.1	3.7
F	21.9	21.7	21.7	21.8	29.8	1
G	19.2	19	19	19.1	32.6	1.7
H	16.5	16.3	16.3	16.3	35.3	4.4
I	8.2	8.2	8.2	8.2	8.2	12.5
J	5.5	5.4	5.4	5.5	5.5	15.2
K	2.7	2.7	2.7	2.7	2.7	18
L	5.5	5.4	5.4	5.4	-46.2	5.4

Table C3.6 (cont'd)

Voltage Bus						
	1	**2**	**3**	**4**	**5**	**6**
260	1.012	1.021	1.021	1.009	1.002	1.016
261	1.01	1.019	1.019	1.009	1.003	1.015
262	1.008	1.017	1.017	1.01	1.004	1.014
263	1.006	1.016	1.016	1.011	1.004	1.013
264	1.005	1.014	1.014	1.012	1.005	1.013
265	1.003	1.013	1.013	1.01	1.007	1.012
266	1.002	1.012	1.012	1.009	1.008	1.012
267	1.001	1.011	1.011	1.008	1.01	1.012
268	1.001	1.01	1.01	1.008	1.011	1.013
268.5					1.017	
269	1	1.01	1.01	1.007	1.011	1.013
270	1	1.009	1.009	1.007	1.011	1.014
271	1	1.009	1.009	1.007	1.011	1.015

Table C3.7 - 5MW; 10kV Semi-Urban Network; Shortest Feeder Studies

Study Number						
	1	**2**	**3**	**4**	**5**	**6**
Generator Position	-	200	299	202	203	204
Generator Size	-	5	5	5	5	5
Total Losses - kW	38	28	161	59	75	95
Total Losses - kVAr	252	13	123	25	33	42
Sending Voltage - (200)	1.012	1.005	1.005	1.005	1.005	1.005
Endpoint Voltage - (204)	1.009	1.002	1.002	1.012	1.017	1.022
Fault level - HV (38kV) - (100) - Amps	5724	6039	6011	6033	6030	6027
Fault level - MV (10kV) - Sending (200) - Amps	4960	6616	6429	6574	6554	6532
Fault level - MV (10kV) - Ending (204) - Amps	4164	5233	5084	5547	5702	5853
Transformer flow - kW	4873	-134	-9	-109	-91	-71
Transformer flow - kVAr	1842	-37	72	-25	-17	-8
Power leaving MV Prim - kW	1195	1183	1200	-3758	-3759	-3750
Power leaving MV Prim - kVAr	393	391	393	-1230	-1227	-1218
Load levels - MW	1.19	1.19	1.19	1.19	1.19	1.19
Load levels - MVAr	0.39	0.39	0.39	0.39	0.39	0.39

Loading Matrix

Study Number						
Section	**1**	**2**	**3**	**4**	**5**	**6**
Tx	51	-1	-1	-1	-1	-1
A	25	25	25	-78	-78	-78
B	19	19	19	-84	-84	-84
C	12	12	13	12	-91	-91
D	6	6	6	6	6	-97

Voltage Bus						
	1	2	3	4	5	6
200	1.012	1.005	1.005	1.005	1.005	1.005
201	1.011	1.004	1.004	1.009	1.009	1.009
202	1.01	1.003	1.003	1.013	1.013	1.013
203	1.009	1.002	1.002	1.012	1.017	1.017
204	1.009	1.002	1.002	1.012	1.017	1.022

Table C3.8 - 5MW; 10kV Semi-Urban Network; Average Feeder Studies

Study Number						
	1	2	3	4	5	6
Generator Position	-	200	299	232	238	237
Generator Size	-	5	5	5	5	5
Total Losses - kW	38	28	161	46	115	130
Total Losses - kVAr	252	13	123	20	51	57
Sending Voltage - (200)	1.012	1.005	1.005	1.005	1.005	1
Endpoint Voltage - (280)	1.005	0.998	0.998	0.998	1.018	1.028
Fault level - HV (38kV) - (100) - Amps	5724	6039	6011	6032	6017	6012
Fault level - MV (10kV) - Sending (200) - Amps	4960	6616	6429	6570	6467	6433
Fault level - MV (10kV) - Ending (237) - Amps	3596	4317	4208	4579	4820	5257
Transformer flow - kW	4873	-134	-9	-118	-50	-14
Transformer flow - kVAr	1842	-37	72	-30	1	7
Power leaving MV Prim - kW	1689	1674	1697	3276	-3234	-3203
Power leaving MV Prim - kVAr	557	555	557	-1071	-1045	-1035
Load levels - MW	1.68	1.68	1.68	1.68	1.68	1.68
Load levels - MVAr	0.55	0.55	0.55	0.55	0.55	0.55

Loading Matrix

Study Number						
Section	1	2	3	4	5	6
Tx	51	-1	-1	-1	1	0
A	35	35	35	-68	-67	-67
B	31	31	32	-72	-71	-71
C	28	28	28	27	-75	-74
D	24	24	24	24	-78	-78
E	11	11	11	11	11	-91
F	7	7	7	7	7	-95
G	4	4	4	4	4	-98
H	9	9	9	9	-93	9

Voltage Bus						
	1	**2**	**3**	**4**	**5**	**6**
230	1.012	1.005	1.005	1.005	1.005	1
231	1.01	1.003	1.003	1.009	1.008	1.003
232	1.009	1.002	1.002	1.012	1.012	1.007
233	1.007	1.001	1.001	1.011	1.015	1.01
234	1.006	0.999	0.999	1.01	1.019	1.014
234.5					1.03	
235	1.005	0.999	0.999	0.999	1.019	1.019
236	1.005	0.998	0.998	0.999	1.018	1.024
237	1.005	0.998	0.998	0.998	1.018	1.028

Table C3.9 - 5MW; 10kV Semi-Urban Network; Longest Feeder Studies

Study Number						
	1	**2**	**3**	**4**	**5**	**6**
Generator Position	-	200	299	264	273	271
Generator Size	-	5	5	5	5	5
Total Losses - kW	38	28	161	56	161	178
Total Losses - kVAr	252	13	123	24.5	71	78
Sending Voltage - (200)	1.012	1.005	1.005	1.005	0.988	0.982
Endpoint Voltage - (271)	1	0.993	0.993	1.013	1.016	1.025
Fault level - HV (110kV) - (100) - Amps	5724	6039	6011	6025	5991	5986
Fault level - MV (10kV) - Sending (200) - Amps	4960	6616	6429	6521	6294	6260
Fault level - MV (10kV) - Ending (271) - Amps	3034	3492	3417	3883	4249	4615
Transformer flow - kW	4873	-134	-9	-100	0.2	0.6
Transformer flow - kVAr	1842	-37	72	-26	23	27.3
Power leaving MV Prim - kW	1980	1962	1989	-2999	-2862	-2887
Power leaving MV Prim - kVAr	652	649	653	-972	-923	-919
Load levels - MW	1.96	1.96	1.96	1.96	1.96	1.96
Load levels - MVAr	0.64	0.64	0.64	0.64	0.64	0.64

Loading Matrix

Study Number						
Section	**1**	**2**	**3**	**4**	**5**	**6**
Tx	51	-1	-1	-1	0	0
A	41	41	42	-63	-60	-62
B	38	38	39	-65	-63	-64
C	36	36	36	-68	-66	-67
D	33	33	33	-70	-69	-70
E	25	25	25	24	-77	-76
F	22	22	22	22	-80	-81
G	20	20	19	19	-83	-84
H	16	16	17	16	-85	-87
I	8	8	8	8	8	-95
J	6	6	6	5	5	-98
K	3	3	3	3	3	-101
L	6	6	6	5	-96	6

Table C3.9 (cont'd)

Voltage Bus						
	1	2	3	4	5	6
260	1.012	1.005	1.005	1.005	0.988	0.982
261	1.01	1.003	1.003	1.008	0.991	0.985
262	1.008	1.001	1.001	1.011	0.994	0.988
263	1.006	1	0.999	1.015	0.997	0.992
264	1.005	0.998	0.998	1.018	1.001	0.995
265	1.003	0.997	0.997	1.017	1.004	0.999
266	1.002	0.996	0.996	1.016	1.008	1.003
267	1.001	0.995	0.995	1.015	1.012	1.007
268	1.001	0.994	0.994	1.014	1.016	1.011
268.5					1.028	
269	1	0.994	0.993	1.014	1.016	1.016
270	1	0.993	0.993	1.013	1.016	1.02
271	1	0.993	0.993	1.013	1.016	1.025

C.4 Power system studies of representative 110/38/10 kV dense urban network

Tables C.4.1 to C.4.3 present a summary of the significant results of power system studies of the 110/38/10 kV dense urban network, including power flows, power losses, voltage profiles, circuit utilisation and fault levels, for the 1 MW embedded generation case.

Tables C.4.4 to C.4.6 present the corresponding results for the 2.5 MW embedded generation case and Tables C.4.7 to C.4.9 the results for the 5 MW generation case.

Table C4.1 - 1MW; 10kV Dense Urban Network; Shortest Feeder Studies

Study Number						
	1	2	3	4	5	6
Generator Position	-	200	299	201	202	203
Generator Size	-	1	1	1	1	1
Total Losses - kW	41.92	37.31	42.7	36.2	35.8	36
Total Losses - kVAr	348.72	240.83	245.9	240.2	240	240.1
Sending Voltage - (200)	1.016	1.02	1.02	1.02	1.02	1.02
Endpoint Voltage - (204)	1.014	1.018	1.018	1.019	1.02	1.021
Fault level - HV (38kV) - (100) - Amps	8188	8235	8234	8235	8234	8234
Fault level - MV (10kV) - Sending (200) - Amps	7248	7606.5	7599	7605	7604	7603
Fault level - MV (10kV) - Ending (203) - Amps	6039	6287	6280	6325	6361	6395.2
Transformer flow - kW	5893	4798	4804	4797	4797	4797
Transformer flow - kVAr	2242	1806	1811	1805	1805	1805
Power leaving MV Prim - kW	1112	1112	1112	111	110	111
Power leaving MV Prim - kVAr	367	367	367	38.4	38.1	38.4
Load levels - MW	1.11	1.11	1.11	1.11	1.11	1.11
Load levels - MVAr	0.36	0.36	0.36	0.36	0.36	0.36

Loading Matrix

Study Number						
Section	**1**	**2**	**3**	**4**	**5**	**6**
Tx	59.2	48.8	48.8	48.8	48.8	48.8
A	23	22.9	22.9	2.3	2.3	2.3
B	15.3	15.2	15.2	15.2	5.3	5.3
C	7.7	7.6	7.6	7.6	7.6	12.9

Voltage Bus						
	1	**2**	**3**	**4**	**5**	**6**
200	1.016	1.02	1.02	1.02	1.02	1.02
201	1.015	1.019	1.019	1.02	1.02	1.02
202	1.014	1.018	1.018	1.019	1.02	1.02
203	1.014	1.018	1.018	1.019	1.02	1.021

Table C4.2 - 1MW; 10kV Dense Urban Network; Average Feeder Studies

Study Number						
	1	**2**	**3**	**4**	**5**	**6**
Generator Position	-	200	299	232	234	235
Generator Size	-	1	1	1	1	1
Total Losses - kW	41.92	37.31	42.7	35.25	34.8	35.2
Total Losses - kVAr	348.72	240.83	245.9	239.7	239.5	239.6
Sending Voltage - (200)						
Endpoint Voltage - (235)						
Fault level - HV (38kV) - (100) - Amps	8188	8235	8234	8235	8235	8235
Fault level - MV (10kV) - Sending (200) - Amps	7248	7606.5	7599	7604	7602	7602
Fault level - MV (10kV) - Ending (235) - Amps	5572	5780	5774	5840	5896	5922.4
Transformer flow - kW	5893	4798	4804	4796	4796	4796
Transformer flow - kVAr	2242	1806	1811	1804	1804	1804
Power leaving MV Prim - kW	1293	1293	1293	291	291	291
Power leaving MV Prim - kVAr	426	426	426	97.3	97.1	97.3
Load levels - MW	1.29	1.29	1.29	1.29	1.29	1.29
Load levels - MVAr	0.42	0.42	0.42	0.42	0.42	0.42

Loading Matrix

Study Number						
Section	**1**	**2**	**3**	**4**	**5**	**6**
Tx	59.2	48.8	48.8	48.8	48.8	48.8
A	26.7	26.6	26.6	6	6	6
B	21.4	21.3	21.3	0.7	0.7	0.7
C	16	16	16	15.9	4.6	4.6
D	10.7	10.6	10.6	10.6	9.9	9.9
E	5.3	5.3	5.3	5.3	5.3	15.2

Voltage Bus						
	1	2	3	4	5	6
230	1.016	1.02	1.02	1.02	1.02	1.02
231	1.015	1.019	1.019	1.02	1.02	1.02
232	1.014	1.018	1.018	1.02	1.02	1.02
233	1.014	1.017	1.017	1.019	1.02	1.02
234	1.013	1.017	1.017	1.019	1.02	1.02
234.5	1.013	1.017	1.017	1.019	1.02	1.02
235	1.013	1.017	1.017	1.018	1.02	1.021

Table C4.3 - 1MW; 10kV Dense Urban Network; Longest Feeder Studies

Study Number						
	1	2	3	4	5	6
Generator Position	-	200	299	262	266	267
Generator Size	-	1	1	1	1	1
Total Losses - kW	41.92	37.31	42.7	29.45	23.5	26.62
Total Losses - kVAr	348.72	240.83	245.9	242.04	238.7	240.5
Sending Voltage - (200)	1.016	1.02	1.02	1.007	1.007	1.007
Endpoint Voltage - (271)	1.006	1.01	1.01	0.999	1.002	1
Fault level - HV (110kV) - (100) - Amps	8188	8235	8234	8224	8223	8223
Fault level - MV (10kV) - Sending (200) - Amps	7248	7606.5	7599	7531	7526	7529
Fault level - MV (10kV) - Ending (266) - Amps	5192	5370	5364	5369.5	5477	5397
Transformer flow - kW	5893	4798	4804	4789	4783	4787
Transformer flow - kVAr	2242	1806	1811	1803	1799	1802
Power leaving MV Prim - kW	3385	3385	3385	2376	2370	2373
Power leaving MV Prim - kVAr	1113	1113	1113	781	778	780
Load levels - MW	3.36	3.36	3.36	3.36	3.36	3.36
Load levels - MVAr	1.1	1.1	1.1	1.1	1.1	1.1

Loading Matrix

Study Number						
Section	1	2	3	4	5	6
Tx	59.2	48.8	48.8	48.7	48.7	48.7
A	69.9	69.6	69.6	49.5	49.3	49.4
B	58.8	58.6	58.6	38.3	38.2	38.3
C	47.7	47.5	47.5	48.1	27	27.1
D	33.4	33.2	33.2	33.6	12.6	33.6
E	22.3	22.2	22.2	22.4	1.4	22.4
F	11.1	11.2	11.2	11.2	9.7	11.2
G	3.3	3.3	3.3	3.3	3.3	-17.6

Voltage Bus						
	1	2	3	4	5	6
260	1.016	1.02	1.02	1.007	1.007	1.007
261	1.013	1.018	1.017	1.005	1.005	1.005
262	1.011	1.015	1.015	1.003	1.003	1.003
263	1.009	1.013	1.013	1.001	1.002	1.002
264	1.007	1.011	1.011	1	1.002	1.001
265	1.006	1.01	1.01	0.999	1.002	1
266	1.006	1.01	1.01	0.999	1.002	1
267	1.009	1.012	1.012	1.01	1.002	1.003

Table C4.4 - 2.5MW; 10kV Dense Urban Network; Shortest Feeder Studies

Study Number						
	1	2	3	4	5	6
Generator Position	-	200	299	201	202	203
Generator Size	-	2.5	2.5	2.5	2.5	2.5
Total Losses - kW	41.9	32.45	56.6	33.1	35.3	39.2
Total Losses - kVAr	348.72	120.5	150.5	120.8	121.9	124
Sending Voltage - (200)	1.016	1.019	1.019	1.019	1.019	1.019
Endpoint Voltage - (203)	1.014	1.017	1.017	1.019	1.022	1.024
Fault level - HV (38kV) - (100) - Amps	8188	8221	8288	8221	8221	8221
Fault level - MV (10kV) - Sending (200) - Amps	7248	7552	8060	7551	7550	3549
Fault level - MV (10kV) - Ending (203) - Amps	6039	6249	6576	6290	6329	6367
Transformer flow - kW	5803	3294	3327	3295	3296	3301
Transformer flow - kVAr	2242	1194	1223	1194	1196	1197
Power leaving MV Prim - kW	1112	1112	1112	-1388	-1386	-1381
Power leaving MV Prim - kVAr	367	367	367	-453	-452	-450
Load levels - MW	1.11	1.11	1.11	1.11	1.11	1.11
Load levels - MVAr	0.36	0.36	0.36	0.36	0.36	0.36

Loading Matrix

Study Number						
Section	1	2	3	4	5	6
Tx	59.2	33.4	33.8	33.4	33.4	33.4
A	23	22.9	22.9	28.5	28.5	28.4
B	15.3	15.3	15.3	15.2	36.1	36
C	7.7	7.6	7.6	7.6	7.6	43.6

Voltage Bus						
	1	2	3	4	5	6
200	1.016	1.019	1.019	1.019	1.019	1.019
201	1.015	1.018	1.018	1.02	1.02	1.02
202	1.014	1.017	1.017	1.02	1.022	1.022
203	1.014	1.017	1.017	1.019	1.022	1.024

Table C4.5 - 2,5MW; 10kV Dense Urban Network; Average Feeder Studies

Study Number						
	1	2	3	4	5	6
Generator Position	-	200	299	232	234	235
Generator Size	-	2.5	2.5	2.5	2.5	2.5
Total Losses - kW	41.9	32.45	56.6	33.11	37.7	41.1
Total Losses - kVAr	348.72	120.5	150.5	120.8	123.1	125.1
Sending Voltage - (200)	1.016	1.019	1.018	1.019	1.019	1.019
Endpoint Voltage - (235)	1.013	1.016	1.016	1.02	1.024	1.026
Fault level - HV (38kV) - (100) - Amps	8188	8221	8288	8221	8221	8221
Fault level - MV (10kV) - Sending (200) - Amps	7248	7552	8060	7550	7548	7548
Fault level - MV (10kV) - Ending (235) - Amps	5572.5	5748	6015	5812	5873	5902
Transformer flow - kW	5803	3294	3327	3294	3298	3303
Transformer flow - kVAr	2242	1194	1223	1194	1196	1198
Power leaving MV Prim - kW	1293	1293	1293	-1207	-1202	-1198
Power leaving MV Prim - kVAr	426	426	426	-394	-391	-390
Load levels - MW	1.29	1.29	1.29	1.29	1.29	1.29
Load levels - MVAr	0.42	0.42	0.42	0.42	0.42	0.42

Loading Matrix

Study Number						
Section	1	2	3	4	5	6
Tx	59.2	33.4	33.8	34.3	33.4	33.5
A	26.7	22.6	26.6	24.8	24.7	24.6
B	21.4	21.3	21.3	30.1	30	29.9
C	16	16	16	15.9	35.3	35.2
D	10.7	10.7	10.7	10.6	40.6	40.5
E	5.3	5.3	5.3	5.3	5.3	45.8

Voltage Bus						
	1	2	3	4	5	6
230	1.016	1.019	1.018	1.019	1.019	1.019
231	1.015	1.018	1.017	1.02	1.02	1.02
232	1.014	1.017	1.016	1.021	1.021	1.021
233	1.014	1.017	1.016	1.021	1.023	1.023
234	1.013	1.016	1.016	1.02	1.024	1.024
235	1.013	1.016	1.016	1.02	1.024	1.026
299	1.013	1.016	1.034			

Table C4.6 - 2.5MW; 10kV Dense Urban Networks; Longest Feeder Studies

Study Number						
	1	2	3	4	5	6
Generator Position	-	200	299	262	266	267
Generator Size	-	2.5	2.5	2.5	2.5	2.5
Total Losses - kW	41.9	32.45	56.6	17.4	15.24	14.8
Total Losses - kVAr	348.72	120.5	150.5	114.03	112.9	112.6
Sending Voltage - (200)	1.016	1.019	1.019	1.013	1.013	1.013
Endpoint Voltage - (266)	1.009	1.012	1.011	1.001	1.012	1.013
Fault level - HV (110kV) - (100) - Amps	8188	8221	8288	8216	8283	8245
Fault level - MV (10kV) - Sending (200) - Amps	7248	7552	8060	7514	8032	8047
Fault level - MV (10kV) - Ending (266) - Amps	5192.7	5342.7	5563	5377	6000	5785
Transformer flow - kW	5803	3294	3327	3279	3276	3275
Transformer flow - kVAr	2242	1194	1223	1187	1186	1186
Power leaving MV Prim - kW	3385	3384	3385	869	867	867
Power leaving MV Prim - kVAr	1113	1113	1113	286	285	285
Load levels - MW	3.36	3.36	3.36	3.36	3.36	3.36
Load levels - MVAr	1.1	1.1	1.1	1.1	1.1	1.1

Loading Matrix

Study Number						
Section	1	2	3	4	5	6
Tx	59.2	33.4	33.8	33.2	33.2	33.2
A	69.9	69.6	69.7	18	18	17.9
B	58.8	58.6	58.6	6.9	6.9	6.9
C	47.7	47.6	47.6	47.7	4.2	4.2
D	33.4	33.3	33.3	33.3	18.5	33.3
E	22.3	22.2	22.2	22.2	29.5	22.2
F	11.1	11.1	11.1	11.1	40.6	11.1
G	3.3	3.3	3.3	3.3	3.3	48.5

Voltage Bus						
	1	2	3	4	5	6
260	1.016	1.019	1.019	1.013	1.013	1.013
261	1.013	1.016	1.016	1.012	1.012	1.012
262	1.011	1.014	1.013	1.012	1.012	1.012
263	1.009	1.012	1.011	1.01	1.012	1.011
264	1.007	1.01	1.01	1.008	1.013	1.01
265	1.006	1.009	1.009	1.007	1.014	1.009
266	1.006	1.009	1.009	1.007	1.016	1.012
267	1.009	1.012	1.011	1.01	1.012	1.013

Table C 4.7 - 5MW; 10kV Dense Urban Network; Shortest Feeder Studies

Study Number						
	1	2	3	4	5	6
Generator Position	-	200	299	201	202	203
Generator Size	-	5	5	5	5	5
Total Losses - kW	49.1	28.5	158	41	56.5	75
Total Losses - kVAr	349.7	18.9	129.3	24.74	32	40.7
Sending Voltage - (200)	1.016	1.015	1.014	1.015	1.015	1.015
Endpoint Voltage - (203)	1.014	1.013	1.012	1.018	1.023	1.027
Fault level - HV (38kV) - (100) - Amps	8188	8372	8353	8370	8368	8366
Fault level - MV (10kV) - Sending (200) - Amps	7248	8930	8733	8909	8889	8869
Fault level - MV (10kV) - Ending (203) - Amps	6040	7134	6975	7343	7548	7745.4
Transformer flow - kW	5803	790	919	802	817	836
Transformer flow - kVAr	2242	269	379	275	282	290
Power leaving MV Prim - kW	1112	1112	1112	-3876	-3860	-3842
Power leaving MV Prim - kVAr	367	367	367	-1271	-1264	-1256
Load levels - MW	1.11	1.11	1.11	1.11	1.11	1.11
Load levels - MVAr	0.36	0.36	0.36	0.36	0.36	0.36

Loading Matrix

Study Number						
Section	1	2	3	4	5	6
Tx	59.2	7.9	9.5	8.1	8.2	8.4
A	23	23	23	80	79.7	79.3
B	15.3	15.3	15.3	15.2	87.3	86.9
C	7.7	7.7	7.7	7.6	7.6	94.5

Voltage Bus						
	1	2	3	4	5	6
200	1.016	1.015	1.014	1.015	1.015	1.015
201	1.015	1.014	1.013	1.019	1.019	1.019
202	1.014	1.014	1.013	1.018	1.023	1.023
203	1.014	1.013	1.012	1.018	1.023	1.027

Table C4.8 - 5MW; 10kV Dense Urban Network; Average Feeder Studies

Study Number						
	1	2	3	4	5	6
Generator Position	-	200	299	232	234	235
Generator Size	-	5	5	5	5	5
Total Losses - kW	49.1	28.5	158	48.95	76.6	93
Total Losses - kVAr	349.7	18.9	129.3	28.32	41.1	48.7
Sending Voltage - (200)	1.016	1.015	1.014	1.015	1.015	1.015
Endpoint Voltage - (235)	1.013	1.012	1.011	1.02	1.028	1.032
Fault level - HV (38kV) - (100) - Amps	8188	8372	8353	8368	8365	8363.4
Fault level - MV (10kV) - Sending (200) - Amps	7248	8930	8733	8895	8859	8841.5
Fault level - MV (10kV) - Ending (235) - Amps	5573	6466	6329	6790	7112	7269
Transformer flow - kW	5803	790	919	810	838	854
Transformer flow - kVAr	2242	269	379	278	291	298
Power leaving MV Prim - kW	1293	1293	1293	-3687	-3659	-3643
Power leaving MV Prim - kVAr	426	426	426	-1208	-1196	-1188
Load levels - MW	1.29	1.29	1.29	1.29	1.29	1.29
Load levels - MVAr	0.42	0.42	0.42	0.42	0.42	0.42

Loading Matrix

Study Number						
Section	1	2	3	4	5	6
Tx	59.2	7.9	9.5	8.2	8.4	8.6
A	26.7	26.7	26.7	76.1	75.5	75.2
B	21.4	21.4	21.4	81.4	80.8	80.5
C	16	16	16	15.9	86.1	85.8
D	10.7	10.7	10.7	10.6	91.4	91.1
E	5.3	5.3	5.3	5.3	5.3	96.3

Voltage Bus						
	1	2	3	4	5	6
230	1.016	1.015	1.014	1.015	1.015	1.015
231	1.015	1.014	1.013	1.018	1.018	1.018
232	1.014	1.014	1.013	1.022	1.021	1.021
233	1.014	1.013	1.012	1.021	1.025	1.025
234	1.013	1.013	1.011	1.021	1.028	1.028
235	1.013	1.012	1.011	1.02	1.028	1.032
299	1.013	1.013	1.045	1.021	1.028	

Table C4.9 - 5MW; 10kV Dense Urban Network; Longest Feeder Studies

Study Number						
	1	2	3	4	5	6
Generator Position	-	200	299	262	266	267
Generator Size	-	5	5	5	5	5
Total Losses - kW	49.1	28.5	158	18.6	54.2	27.6
Total Losses - kVAr	349.7	18.9	129.3	14.4	30.9	18.5
Sending Voltage - (200)	1.016	1.015	1.014	1.009	1.009	1.009
Endpoint Voltage - (266)	1.009	1.008	1.007	1.011	1.015	1.017
Fault level - HV (110kV) - (100) - Amps	8188	8372	8353	8360	8352	8357
Fault level - MV (10kV) - Sending (200) - Amps	7248	8930	8733	8840.7	8757	8812
Fault level - MV (10kV) - Ending (266) - Amps	5193	5934	5815	6207.8	6835.6	6360
Transformer flow - kW	5803	790	919	779	815	789
Transformer flow - kVAr	2242	269	379	264	281	268
Power leaving MV Prim - kW	3385	3385	3385	-1626	-1590	-1616
Power leaving MV Prim - kVAr	1113	1113	1113	-535	-519	-531
Load levels - MW	3.36	3.36	3.36	3.36	3.36	3.36
Load levels - MVAr	1.1	1.1	1.1	1.1	1.1	1.1

Loading Matrix

Study Number						
Section	**1**	**2**	**3**	**4**	**5**	**6**
Tx	59.2	7.9	9.5	7.8	8.2	7.9
A	69.9	69.9	70	33.8	33	33.6
B	58.8	58.8	58.9	44.9	44.1	44.6
C	47.7	47.8	47.8	47.6	55.1	55.7
D	33.4	33.4	33.4	33.3	69.4	33.2
E	22.3	22.3	22.3	22.2	80.4	22.1
F	11.1	11.1	11.1	11.1	91.4	11.1
G	3.3	3.3	3.3	3.3	3.3	100

Voltage Bus						
	1	**2**	**3**	**4**	**5**	**6**
260	1.016	1.015	1.014	1.009	1.009	1.009
261	1.013	1.013	1.011	1.011	1.011	1.011
262	1.011	1.01	1.009	1.013	1.012	1.013
263	1.009	1.008	1.007	1.011	1.015	1.015
263.5	1.009	1.008	1.007	1.011	1.015	1.017
264	1.007	1.007	1.006	1.009	1.018	1.013
265	1.006	1.006	1.005	1.008	1.021	1.013
266	1.006	1.005	1.004	1.008	1.025	1.012

Appendix d – example calculations

SEI Costs and Benefits of Embedded Generation

Inputs

Embedded Generation Type	CHP (gas)	
Displaced System Plant	Base Load	
Generator Size	2.5	MW
Generator Utilisation	85%	
Connection Voltage	38kV	

	Base	With Gen	
Real Power Peak	18,298	15572	kW
Reactive Power Peak	8,340	8366	kVAr
Real Power Loss Capacity - Peak	2,384	2342	kW
Reactive Power Loss Capacity - Peak	3,178	2276	kVAr
Exit Point TLAF	1.0150	1.0145	

Capital Asset Replacement (Load)

Value	€ 3,000,000	
Year	7	10

Capital Asset Replacement (Voltage)		
Value	€ 500,000	
Year	2005	2010
Transmission Capex		
Value	€ 3,000,000	
Year	2010	2012
System Load Factor	65%	
Network Load Factor with Generation	64%	Revised Load Factor to be calculated from the revised load profile net of generation output
Empirical Constant	85%	

Marginal Capacity Cost	€	200	Estimated replacement marginal cost	
Discount Factor		8%	Estimated DCF	
Projection Period		15	Years	
Reactive Energy Price	€	0.01	/kVArh	From the ESB Networks MV Customer DUoS tariffs for 2004

Emissions Data (values in g/kWh)

	CO2	NOx	SOx	Energy Price	Eff	fuel	Technology
Base Load	396.00	0.32	0.00	43.00	50%	Gas	Gas Fired CCGT (BNE Pricing)
Mid Merit	900.00	51.48	13.68	56.00	35%	Coal	Coal Plant (allowed ESB PG Pricing)
<30%LF	720.00	1.73	13.54	60.00	30%	Oil	Conventional Oil Plant

	CO2	NOx	SOx	Eff	MCG	Fuel	Price (c/kWh)	Reliability
Wind	0	0	0	n/a	45.00	Wind	0.00	25%
Biomass	0	0	0	n/a	60.00	Biomass	1.50	70%
Peat	0	0	0	n/a	55.00	Peat	1.00	85%
Hydro	0	0	0	n/a	50.00	Hydro	0.00	35%
CHP (gas)	300	0.4	0	65%	40.00	Gas	1.20	85%

Value per Tonne

CO2	€ 15.00	Based on EU ETS expectations
NOx	€ 0.00	Not explicitly valued at present
SOx	€ 0.00	Not explicitly valued at present

Displaced Energy Benefit

Step				
1	**Determine Saving in Annual System Generation**			
	Network Energy Supplied	104,188,812	kWh pa	Determined from the studies undertaken for LCTAS and provided generation profile
	Network Energy Supplied w Gen	85,573,812	kWh pa	Assumes all embedded generator output offsets demand
	Displaced System Generation	18,615,000	kWh pa	
2	**Determine System Plant Displaced**			
	Avoided Plant Type	Base Load		
	Avoided Plant Energy Cost	€ 43.00	/MWh	
3	**Value of Displaced Energy**	€ 800,445	pa	
4	**Cost of generated units**			
	Embedded Generation Type	CHP (gas)		
	Embedded generation unit price	€ 40.00	/MWh	
	Embedded Generator Output	18,615,000	kWh	Plant Output offsets energy demand not losses
	Cost of Embedded Generation	€ 744,600	pa	
5	**Net Energy Benefit**	€ 55,845		
	Present Value	**€ 478,004**		

Loss Calculation

Step				
1	**Establish Network Model**			
	Model of representative network (No Generation)			
2	**Calculate Network Peak Loading**			
	Network Peak Loading	18298	kW	Rural 110_38_10kV load growth analysis; Study 1
		8340	kVAr	Rural 110_38_10kV load growth analysis; Study 1
	System Capacity Required	20,109	kVA	
3	**Calculate Peak Loss Capacity**			Includes 110kV, 38kV and 10kV fixed and variable line and Tx losses
	Peak Loss Capacity	2,384	kW	Rural 110_38_10kV load growth analysis; Study 1
		3,178	kVAr	Rural 110_38_10kV load growth analysis; Study 1
	System Capacity Required	3,973	kVA	
4	**Calculate Capacity Loss Value**			
	Marginal Capacity Cost	€ 200	/kVA	Estimated - will need to be quantified and possibly approved by CER
	Capacity Cost of Losses	€ 794,560		i.e. cost of assets provided purely to service system losses
5	**Calculate Loss Load Factor**			
	Network Load Factor	65%		
	Empirical Constant	85%		
	Loss Load Factor (Variable)	46%		
	Loss Load Factor (Fixed)	65%		
	Combined LLF	49%		
6	**Calculate Energy Loss**			
	kWh loss	10,141,845	kWh pa	
7	**DWA Energy Price for Losses**			
	Avoided Plant Type	Base Load		
	Avoided Plant Energy Price	€ 43	/MWh	
8	**Calculate Value of Energy Losses**			
		€ 436,099	pa	

9	**Project Value of Losses**			
	Discount Factor	8%		
	Evaluation Period	15	years	
	Base Loss Value	€ 4,527,343	no inflation of annual energy loss - calculated in real terms; capacity cost not projected	
10	**Establish Network Model**			
	Model of representative network (with Generation)			
11	**Calculate Network Peak Loading**			
	Network Peak Loading	15,572	kW	
		8,366	kVAr	
	System Capacity Required	17,677	kVA	
12	**Calculate Peak Loss Capacity**			Includes 110kV, 38kV and 10kV fixed and variable line and Tx losses
	Peak Loss Capacity	2,342	kW	
		2,276	kVAr	
	System Capacity Required	3,266	kVA	
13	**Calculate Capacity Loss Value**			
	Marginal Capacity Cost	€ 200	/kVA	Estimated - will need to be quantified and possibly approved by CER
	Capacity Cost of Losses	€ 653,151		i.e. cost of assets provided purely to service system losses
14	**Calculate Loss Load Factor**			
	Network Load Factor	64%		this is likely to alter following connection of the generation plant dependent on its generating profile
	Empirical Constant	85%		
	Loss Load Factor (Variable)	44%		
	Loss Load Factor (Fixed)	64%		
	Combined LLF	47%		
15	**Calculate Energy Loss**			
	kWh loss	9,779,049	kWh pa	Prorates loss benefit by the availability of the generator
16	**DWA Energy Price for Losses**			
	Avoided Plant Type	Base Load		
	Avoided Plant Energy Price	€ 43	/MWh	

17	**Calculate Value of Energy Losses**		
		€ 420,499	pa
18	**Project Value of Losses**		
	Discount Factor	8%	
	Evaluation Period	15	years
	Loss Value with Generation	€ 3,599,253	no inflation of annual energy loss - calculated in real terms; capacity cost not projected
19	**Determine Net Losses Benefit**		
	Base Loss Value	€ 4,527,343	no inflation of annual energy loss - calculated in real terms; capacity cost not projected
	Loss Value with Generation	€ 4,252,404	no inflation of annual energy loss - calculated in real terms; capacity cost not projected
	Net Losses Benefit	**€ 274,939**	

Voltage Benefit Calculation

Step				
1	**Calculate Reactive Energy**			
	Reactive Power Peak	8,340	kVAr	Rural 110_38_10kV load growth analysis; Study 1
	Network Load Factor	65%		Assumes that the pf remains constant over the year.
	Reactive Energy	47,487,960	kVArh	More accurate to use consumption data from Reactive metering at Transmission exit point
2	**Reactive Energy Price**			
	Reactive Energy Price	€ 0.006	/kVArh	Based on 2004 ESB DUoS tariff for MV connected customers
3	**Value of kVArh**			
	Value of kVArh	€ 294,425		
4	**Calculate Voltage Profiles**		These will be determined within the normal ESB System planning process	
			Costs associated with investment in and operation of voltage control will be	
5	**Determine Cost of Voltage Control**		recovered through the DUoS tariffs	
6	**Calculate Voltage Profiles**		These will be determined within the calculation of the LCTAS connection offer.	
			Additional investment to manage any voltage issues will be caught in that calculation	
7	**Determine Cost of Voltage Control**		Therefore this would be double counting if included here.	
8	**Calculate Revised Future Capital Reinforcement**			
	Determine the extent to which any voltage driven required system reinforcement implementation can be delayed after following connection of the embedded generation. For e.g. If network was on the limit / outside its quality standards then it may require reconductoring or installation of boosted transformer, or increase in the operating voltage from 10kV to 20kV. - say this was some 500,000Euros			
	Deferred Capex	€ 500,000		for example (new transformers at the 38kV:MV interface)
	Initial Spend Year	2005		as per DNO capital plan prior to generation connection
	Revised Spend Year	2010		as per DNO capital plan post generation connection

9	**Determine Deferred Capex Value**		
	Discount Factor	8%	
	Value of Deferred Capex	€ 136,924	

10	**Calculate Reactive Energy with Generation**		
	Network Peak Loading	8,366	kVAr
	Network Load Factor with Gen	64%	
	Reactive Energy with Gen.	46,903,142	kVArh
11	**Calculate Value of Reactive Energy Saved**		
	Reactive Energy Saved	584,818	kVArh
	Value of Saved VArh	€ 3,626	pa
12	**Overall Voltage Benefit**		
	Deferred Capex	€ 136,924	
	Saved VArh	€ 31,036	
	Voltage Benefit	**€ 167,960**	

CML Benefit

Step				
1	**Determine Existing Network Statistics**			
	System Average Interruption Duration Index (SAIDI)		60	minutes per interruption
	System Average Interruption Frequency Index (SAIFI)		5%	- result from analysis of network fault statistics / historic performance
2	**Calculate Expected CMLs**			
	Number of Customers		6000	
	CMLs		18000	minutes
3	**Calculate Value of Lost kWh**			
	Value of Lost Load		€ 7.00	/kWh
	Network Energy Supplied		104,188,812	kWh pa
	Customer Average Consumption		17365	kWh pa
	Energy Supplied per customer minute		0.033	kWh per customer minute
	Energy Lost due to Network Faults		595	kWh pa
	Value of Lost kWh		€ 4,163	pa
4	**Project value of Lost kWh**			
	Present Value of Lost kWh		€ 35,631	
5	**Determine Expected System Statistics**			
	System Average Interruption Frequency Index		4%	
6	**Investigate Islanding Potential**			
	Is Islanding feasible? ('Y' or 'N')		N	

7	**Restoration Scheme A**				
	System Average Interruption Duration Index (A)		48	minutes	
8	**Design Islanding Scheme**				
	Islanding Scheme Costs		€ 250,000		
9	**Restoration Scheme B**				
	System Average Interruption Duration Index (B)		36	minutes	
10	**Calculate Revised CMLs**				
	Customers within Islanding Scheme		1261	customers	
	Customer Minutes Lost (A)		9099	minutes	
	Customer Minutes Lost (B)		0	minutes	
11	**Calculate Value of Lost kWh**				
	CMLs		9099	minutes	
	Energy Lost Due to Network Faults		301	kWh pa	
	Value of Lost kWh		€ 2,104	pa	
12	**Calculate Additional DUoS Income**				
	Additional Units delivered		294	kWh pa	
	DUoS Charge		€ 0.006	/kWh	from 2004 approved ESB Network DUoS charging statement
	Additional Revenue		€ 1.91	pa	
13	**Project Value of Lost**				
	Total Savings		€ 2,061	pa	
	Value of loss savings and DUoS		€ 17,637		
14	**Net CML Benefit**		€ 17,637		

Asset Benefit

Step				
1	**Determine Asset Peak Loading without Generator**			
	Peak Demand	18,298	kW	Rural 110_38_10kV load growth analysis; Study 1
	Peak Reactive Power	8,340	kVArh	Rural 110_38_10kV load growth analysis; Study 1
	Required Network Capacity	20,109	kVA	
2	**Determine Asset Replacement Date**			
	Asset Replacement Year	7		Rural 110_38_10kV load growth analysis; Study 1 Interpolation
3	**System Peak Loss Capacity Requirements**			
	Peak Loss Capacity	2,384	kW	Rural 110_38_10kV load growth analysis; Study 1
		3,178	kVAr	Rural 110_38_10kV load growth analysis; Study 1
	System Capacity Required	3,973	kVA	
4	**System Peak Demand Capacity Requirements**			
	Peak Demand Capacity	15,914	kW	
		5,162	kVAr	
	Peak System Capacity - Demand	16,136	kVA	
5	**Determine Asset Peak Loading with Generation**			
	Network Peak Loading	15,572	kW	
		8,366	kVAr	
	Required Network Capacity	17,677	kVA	
6	**Revised Asset Replacement Date**			to the extent that the capital expenditure cause was demand led.
	Asset Replacement Year	10		
7	**Calculate Deferred Capital Benefit**			Assumes only one investment is affected (there could be multiple instances)
	Asset Replacement Capacity	15,000	kVA	Estimated
	Asset Replacement Cost	€ 3,000,000		Need to ensure that this is not double counting any voltage asset benefit.
	Discount Factor	8%		
	Present Value without Generation	€ 1,750,471		
	Present Value with Generation	€ 1,389,580		
	Deferred Capital Benefit	€ 360,891		

8	**System Peak Loss Capacity Requirement w DG**		Accounted for within the Loss Benefit	
	Peak Loss Capacity	2,342	kW	
		2,276	kVAr	
	System Capacity Required	3,266	kVA	
9	**System Peak Demand Requirement w DG**			
	Peak Demand Capacity	13,230	kW	
		6,090	kVAr	
	Peak System Capacity - Demand	14,564	kVA	
10	**Embedded Generation Reliability**			
	Embedded Generation Type	CHP (gas)		
	Generator Reliability	85%		
11	**Displaced Load**			
	Displaced kW	2,281	kW	
12	**Value of Displace Load**			
	Demand Network Capacity Charge	€ 3,048	per month	DTS - D1 2004
	Value of Displaced Load	€ 36,575	pa	
13	**Net Asset Benefit**	**€ 673,957**		

Transmission System Benefits

Step				
1	**Exit Capacity without Generation**			
	Network Peak Loading	18298	kW	Rural 110_38_10kV load growth analysis; Study 1
		8340	kVAr	Rural 110_38_10kV load growth analysis; Study 1
	System Capacity Required	20,109	kVA	
2	**Asset Replacement**			
	Planned Replacement Year	2010		
	Asset Replacement Cost	€ 3,000,000		
3	**Ancillary Service Costs without DG**	€ -		
4	**Transmission Losses without DG**			
	Annual Average System Loss	1.0150		for example
	Energy Supplied	104,188,812	kWh pa	Rural 110_38_10kV load growth analysis; Study 1
	Losses to supply exit node	1,562,832	kWh pa	
	Energy Price without DG	€ 43.00		
	Cost of Energy Losses	€ 67,202	pa	
5	**TUoS Charges Without Generation**			
	Demand Network Capacity Charge	-	Accounted for within the Asset (Displaced Load) calculation	
	Demand Network Transfer Charge	€ 246,563	pa	DTS - D1 Tariff 2004
	Demand System Services Charge	€ 249,293	pa	DTS - D1 Tariff 2004
	Total TUoS Income	**€ 495,855**	pa	
6	**Exit Capacity with Generation**			
	Network Peak Loading	15,738	kW	
		8,652	kVAr	
	System Capacity Required	17,959	kVA	
7	**Exit Capacity Saving**	2,150	kVA	Would be double counted as covered under Displaced Load
8	**Asset Replacement with DG**			
	Revised Replacement Year	2012		Interpolation
	Deferred Capital Expenditure	€ 249,724		
9	**Ancillary Service Costs with DG**	€ -		

10	**Transmission Losses with DG**			
	Loss rate	1.0145		for example
	Energy Supplied at Exit node with DG	85,573,812	kWh pa	
	Losses to supply exit node	1,240,820	kWh pa	
	Energy Price with DG	€ 43.00	/MWh	
	Cost of Energy Losses	€ 53,355	pa	
11	**Transmission Loss Benefit**	€ 13,847	pa	
12	**TUoS Charges With Generation**			
	Demand Network Capacity Charge	-	Accounted for within the Asset (Displaced Load) calculation	
	Demand Network Transfer Charge	€ 202,510	pa	DTS - D1 Tariff 2004
	Demand System Services Charge	€ 204,752	pa	DTS - D1 Tariff 2004
	Total TUoS Income	€ 407,263	pa	
	Net TUoS Benefit	€ 88,593	pa	
13	**Transmission Benefits**			
	Deferred Capital Expenditure	€ 249,724		
	Ancillary Service Benefit	€ -		
	Transmission Loss Benefit	€ 118,519		
	TUoS Benefit	€ 758,306		
		€ 1,126,549		

Emission Benefit

Step					
1	**Determine Avoided Plant Type**				
	Avoided Plant Type	Base Load			
	Avoided Plant per unit emissions	CO2	NOx	SOx	
		396	0.324	0.000	g/kWh
2	**Avoided System Plant Emissions**				
	Network Energy Supplied	104,188,812	kWh pa		
	Network Energy Supplied w Gen	85,573,812	kWh pa		
	Displaced System Generation	18,615,000	kWh pa	Includes effect of losses in distribution network	
	Emissions Avoided				
	CO2	7,371.54	Tonnes pa		
	NOx	6.03	Tonnes pa		
	SOx	0.00	Tonnes pa		
3	**Embedded Generator Emissions**				
	Generator Type	CHP (gas)			
	Embedded Gen per unit emissions	CO2	NOx	SOx	
		300	0.400	0.000	g/kWh
	Embedded Generator Emissions				
	CO2	5,585	Tonnes pa		
	NOx	7	Tonnes pa		
	SOx	0	Tonnes pa		
4	**Net Emission Savings**				
	CO2	1787.04	Tonnes pa		
	NOx	-1.41	Tonnes pa		
	SOx	0.00	Tonnes pa		

5	**Value of Emissions Saved**		Per annum	PV
		CO2	€ 26,806	€ 229,442
		NOx	€ -	€ -
		SOx	€ -	€ -
		Total	**€ 26,806**	**€ 229,442**
6	**Contribution to National Target**		**Target**	**Contrib**
		CO2		
		NOx		
		SOx		

Social benefit

Step

	Calculate Local Jobs Created			
	Generator Installed Capacity	2.50	MW	
1	Jobs per MW	1.0		for example
	Calculate Income from Local Jobs			
	Value of Jobs	€ 7,500	pa	for example
2	Local Income from Jobs Created	€ 18,750	pa	
	Total Local Income from Plant			
	Fuel Supply	€ -		only likely to have real value for Peat or Biomass plant
	Land Rental	€ 5,000	pa	not including cost of connection asset way leaves, easements
3	Total Local Benefits	€ 23,750	pa	
4	**Resulting Income Losses**	€ -	pa	possibly through job losses at displaced system generation plant
	Calculate Geographical and Net Benefit			
		€ 23,750	pa	
5		**€ 203,288**		

Fuel Benefit

Step			
1	**Displaced Fuel at system level**		
	Displaced Electricity	18,615,000	kWh pa
	Displaced Plant Type	Base Load	
	Plant Thermal Efficiency	50%	
	Fuel Type	Gas	
	Displaced Fuel Energy	37,230,000	kWh pa
2	**Embedded Generation Fuel Use**		
	Plant Type	CHP (gas)	
	Fuel Type	Gas	
	Plant Thermal Efficiency	65%	includes for heat usage also
	Embedded Generation Output	18,615,000	kWh pa
	Fuel Energy	28,638,462	kWh pa
3	**Net Fuel Use Benefit**		
	Fuel Energy Benefit	8,591,538	/kWh pa

APPENDIX E – Stakeholder Questionnaire

System Charges

Connection charges

Q. 1. Do the present deep reinforcement connection charging arrangements discriminate against embedded generators compared to grid connected generation?

Q. 2. What changes could be made to connection charging policy that would promote the development of embedded generation?

Q. 3. Does the Guidelines Connection to the Distribution System, Customer Charter and Standard Connection Agreement aid the process of connecting embedded generation in terms of :

a. A defined connection offer/delivery timetable?

b. A defined schedule of charges?

c. Contestability of connection?

Use of system charges

CHP issues

Q. 4. What changes could be made to promote EG.

Q. 5. Do the existing use of system charging arrangements favour any particular type of generation, i.e favouring ?

Q.6. Would a change in use of system policy for CHP make this form of generation more financially attractive, or is gas price the major factor

Q.7. Is the above considered to be a significant barrier to entry?

Q.8 Have CHP generators been able to obtain competitive contracts with suppliers?

Treatment of losses

Q.9. What changes could be made to promote EG.

Trading arrangements

Compliance with EU Directive 2001/77/EC

Q.10 Is the limit (10 MW units associated with TUoS charges or 30MW for self despatch) perceived as a barrier to larger wind farms?

Perceived benefits for renewables and embedded generation

Guaranteed market for RE

Q.11 Response requested:

Removes risk of top-up and spill pricing differentials

Q.12 Response requested:

Closer to real time dispatch allowing more accurate trading

Q.13 Response requested:

Locational marginal pricing for generation

Q.14 As, the location of embedded generation is more likely to be resource driven (especially for CHP, wind and hydro plants) rather than being strongly influence by LMP's, should embedded generation pay location marginal prices?

Q.15 Alternatively should embedded generation be seen as negative demand and pay (typo, should be get paid) the Uniform Wholesale Spot Market price?

Q.16 Should this decision be linked to the capacity limits for dispatchable plant, or related to the individual operator's choice of whether its plant is dispatchable or not

Allowable trading strategies

Q.17 Whilst allowing a negative pricing strategy clearly favours conventional generation plant, do the proposed trading arrangements disadvantage renewable and embedded plant that will be totally exposed to the volatility of a market price that is set by other, predominantly thermal, generation?

Q.18 Will the inflexibility of thermal generation dominate the market trading arrangements such that it is effectively making renewable and embedded generation fit in around a thermal based market, instead of setting a level playing field?

Q.19 Should the new market arrangements provide a greater signal to increase thermal plant flexibility by setting a zero price level for all?

Q.20 Should the price floor for renewables be zero or a negative value in line with any implied subsidy?

Q.21 Does such a strategy contradict the requirements of EU Directive 2001/77/EC as it will force renewable generation to switch off for financial reasons, and not that of grid security?

Q.22 Do the existing and proposed trading arrangements cause sufficient financial uncertainty to deter investment in renewable and embedded generation?

Q.23 Should intermittent generators be price takers or should they be allowed to set the market price at certain times of the day?

Appropriate allocation of market reserve costs

Q.24 Is CER's position in line with 2001/77/EC directive?

Q.25 Should costs of reserve be allocated across all demand and passed onto demand customers?

Q.26 Should individual generators be liable for their contribution to reserve requirements, e.g. large thermal as well as intermittent generation?

Use of financial hedging tools such as CfDs.

Q.27 What support mechanisms should be implemented?

Q.28 Would market based systems such as CfDs be sufficient to support the step change in development of RE and embedded generation required to meet stated Government and EU targets?

Q.29 Will CfDs provide sufficient financial certainty to investors or can this only be determined through market experience and hence new RE and EG is likely to be postponed in the short to medium term (chicken and egg situation)?

Micro-generation

Q.30 What method of metering and payment for exports would best encourage micro-generation (in particular small and domestic CHP), both from a customer and a supplier point of view?

General Questions:

Q.31 Should the operation of Renewable Energy be

i. outside of the proposed pool mechanism;

ii. non-dispatchable;

iii. must run?

ESB's dominant market position

Q.32 What is the perceived effect of ESB's market position?

Q.33 How can relatively small generators compete on a level playing ground with larger conventional generation?

Technical issues

Q.34 To what extent does uncertainty with respect to connection requirements, costs and timescale discourage/complicate embedded generation connections.

Q.35 Do the stakeholders have a view on any of the technical issues discussed above that they may see as a particular barrier to the future development of embedded generation on the network.

The questionnaire was distributed to the following stakeholders:

- Saorgus
- Meitheal na Gaoithe
- CER
- ESB Networks
- ESB National Grid
- Hibernian Wind Power
- Irish Wind Energy Association
- Irish Hydropower Association
- Irish Combined Heat & Power Association
- Airtricity

Costs and Benefits of Embedded Generation

Micro-Generation Addendum

CONTENTS

1. Introduction

This report forms an addendum to the PB Power report for Sustainable Energy Ireland entitled 'Costs and Benefits of Embedded Generation – Final Report'. This addendum focuses on micro-generation.

Definitions of micro-generation vary, but this addendum focuses on generating units rated up to 16A per phase, these are likely to be single phase and connected at 230V within a domestic or light commercial property. Devices that are close to market are in the 1kW to 5kW range.

This addendum describes the high level costs and benefits that would be seen by ESB Networks with the connection of micro-generation onto its LV network. This is a qualitative description which keys into the discussion and items raised in Section 3 "Review of Perceived Costs and Benefits of Embedded Generation" within the main report.

There is also a description of a typical ESB urban LV network and its characteristics, and a brief analysis of the effects of micro-generation on that network. The impact of the positioning and quantity of micro-generation is examined. Finally, recommendations have been made on how the connection of such small units may be assisted.

This addendum should be read in conjunction with the main report.

2. Review of Perceived Costs and Benefits of Micro- And Small Scale Embedded Generation (SSEG)

2.1 Introduction

In this section we identify the potential costs and benefits that can be obtained from the connection of embedded micro-generation to the distribution network. A full analysis has been carried out in the main report for all types of embedded generation. This addendum therefore summarises where there are any differences in emphasis for micro-generation. Micro-generation differs from other types of embedded generation in that: -

- each generator is typically in the 1 to 5 kW range, and is located within domestic or light commercial premises
- the generators are connected to the low voltage, 230V, single phase network and in most cases there will only be one possible connection point
- the load is connected at the same point as the generator, or else where there is a mismatch between generation output and load required, there will be transfer over a very short distance
- the reduction in demand and possible export from an individual device is relatively small, but significant for multiple devices
- the effect on the distribution network is minimal for a single device, and the only connection cost is that associated with the local connection of the device
- for multiple devices there may eventually need to be changes and modifications to the existing distribution system

The contribution from SSEG units will be effected at the point of use of electricity for LV consumers. This means that these units will be able to offset the LV system losses to a greater or lesser extent. As identified in Table 3.2 of the main report, the losses in the MV/LV transformation and LV network amount to some 35% of the overall transmission / distribution system losses and almost 50% of the typical distribution system loss. Therefore there is significant value from SSEG both in terms of its potential to avoid load related capital expenditure and to offset energy loss costs.

The connection of significant quantities of SSEG to a particular LV distribution network will present itself on the MV or HV network in a similar way to a direct connected larger embedded generator and the costs and benefits discussed in Sections 3.1 through 3.9 of the main report will be evident. The discussion below considers some of these items further in relation to SSEG connections;

2.2 Utilisation of Network Assets

Micro-generation is, by its nature, connected close to its load. Its overall effect is to reduce demand on the system. With micro-generation the upstream assets will be the assets from the LV feeder upwards, so the reduction in utilisation prolongs the life of a greater range of assets.

Consider, for example, an urban distribution network where there is a concentration of households using gas central heating, and who have installed micro-CHP. Micro-CHP is generally sized to supply the average domestic load, but will only operate when the central heating system is on. When the majority of households with micro-CHP are using their central heating systems, there will be a reduction in the system demand. This will reduce the winter demand on cables and transformers connected upstream of the micro-generators and so prolong the life of the upstream assets.

There will also be a reduction in the winter peak demand. The extent of the reduction in winter peak will be a function of the number of installations and the diversity to be expected in their use. This could allow network reinforcement to be delayed or even avoided. At the times of day and year that the micro-CHP sets are not operating then the system demand will be unchanged.

There will also be times when the micro-CHP installations could be feeding power back up through the LV network, for example, in the summer when hot water is required but electrical demand is low. Given the small sizes of individual installations, and the expected diversity in the behaviour of different users, this not a highly likely scenario. Previous studies carried out on similar LV networks have shown that this scenario would not overload existing assets, but could potentially cause voltage control problems.

Other types of micro-generation, for example photovoltaic, are also generally sized to supply the average domestic load, but the output will depend upon the climatic conditions. They will tend to be at full output when the micro-CHP devices are not (warm, sunny weather), and will have a different effect on the demand profile.

2.3 System Losses

Micro-generation effectively reduces system demand during the winter months, when central heating is being used (for micro-chp), and at other times depending upon the climatic conditions (PV and wind). Since the generation is local to the load, the system losses will be reduced during these periods. The peak load power loss will certainly be reduced, and it is very likely that energy losses will be reduced.

There may be short periods of time when there could be an increase in energy losses, because there is a net export of power back up through an LV feeder. This is an unlikely, and certainly short duration scenario, since it would only occur if, for example, all of the householders in a particular area used their micro-CHP for heating or hot water at a time when they were not using their high demand electrical appliances. This scenario would be outbalanced by the longer duration, and more likely, scenarios, in which energy losses are reduced or maintained at current levels. Theses scenarios would be where all of the householders in a particular area, for example, had their central heating switched on whilst using their high demand electrical appliances, or were using their electrical appliances without any micro-generation (the current situation).

2.4 Voltage Regulation

The units will provide voltage support to the LV network through the displacement of demand at the point of use. The voltage profile for the LV Network and the tap setting on the local MV/LV distribution transformer will determine the extent to which the voltage rise may exceed accepted distribution network ‘ design’ limits. However, there is the potential to adjust the MV/LV transformer taps (off-circuit) on that part of the system to take into account the changed voltage profile.

2.5 Voltage Unbalance

There is a ‘background’ level of voltage imbalance on LV networks due to the random connection of users to particular phases along a feeder. This effect is more pronounced the further away from the distribution transformer. The voltage imbalance at the distribution transformer LV terminals is lower since they are not affected by the feeder cable voltage drops and this will mitigate the impact of multiple SSEG on voltage unbalance at the MV and HV levels.

2.6 Power Flow

Whilst the SSEG penetration remains below the level of demand on an LV network it is unlikely that there will be issues related to reverse power flow through the distribution transformer. However, should there be reverse flow (real power or reactive power) through the distribution transformer there may be issues related to the protection systems and tap changer equipment associated with the transformer, and there could well be cost issues for the connection of the SSEG beyond this level.

The distribution company may need to consider providing statements on the allowable penetration of SSEG on their LV networks and certainly should consider a mechanism for treatment of connections that require capital expenditure on the LV network.

2.7 Fault Levels

The introduction of multiple SSEG units onto an LV network will increase the fault level. However, recent studies for the UK distribution system, have shown that the impact is not significant due to the impedance of the LV network. Further, the contribution to the fault level at higher voltage levels has also been shown to be minimal.

2.8 Voltage Step Changes

The SSEG units may be sensitive to the voltage transients that can be seen on LV networks, say from the disconnection of an adjacent distribution transformer. If this is the case it is likely that the action of circuit breakers or fuses local to the fault will not cause loss of supply to the un-faulted transformer. However, protection equipment on the SSEG units may operate and trip the generation and this secondary effect will result in voltage step change. This may lead to a standard range of protection settings for SSEG plant on a given LV network, or possibly a generic ‘fault ride through’ capability.

2.9 Generation Location

The location of the SSEG units on the LV network will influence the extent of their effect on the LV network. Those located at the remote end of feeders will have the greatest impact on the ability of the remote end voltage to stay within design limits. The location on the MV/HV network of those LV networks with significant SSEG penetration will have a similar influence on the MV/HV networks as does the location of a larger directly connected embedded generator.

3. Representative Network Identification and Modelling

3.1 System Model

3.1.1 Introduction

Studies have previously been carried out for the UK urban distribution system, to examine the effect of increasing levels of micro-generation. The ESB urban low voltage system is similar in topology, but there are differences in the voltages used, the transformer sizes and the cable sizes used. A representative ESB urban low voltage system has therefore been modelled to check whether the conclusions drawn from studying UK distribution systems are also valid for ESB low voltage systems.

The network used has tapered cables, this is no longer ESB practice, but would be typical of the older ESB low voltage urban networks in-situ, to which domestic micro-generation would be connected.

3.1.2 Input Data

The generic urban model is shown in figure 3.1. Table 3 summarises the data used.

Each 10kV feeder represents a 3.0km feeder cable supplying ten 10/0.433kV 400kVA ground mounted distribution transformers and 400V substations. Four of the feeders are modelled as simple lumped loads whilst the fifth feeder is represented in full detail.

Each 400V substation represents an urban cable distribution system with four outgoing radial feeders, each 300m long. There are a total of 312 domestic single-phase house loads, distributed equally between the feeder cables. The feeder cables are tapered and the loads are distributed evenly along the length of the cable. Since the domestic loads are single phase, each point of connection, or service joint, on the feeder cable supplies three domestic loads, one connected to each phase. From a modelling perspective, there are therefore 26 three phase loads spaced evenly along the length of the feeder cables. Three of the 400V feeders are represented as simple lumped loads with only the fourth being represented in detail.

The micro-generator is nominally 230V, 50 Hz, and 1.1kW single phase, operating at a power factor of 0.95 lagging or unity.

Figure 3.1 38/10/0.4 kV Power System Model used in the Simulations

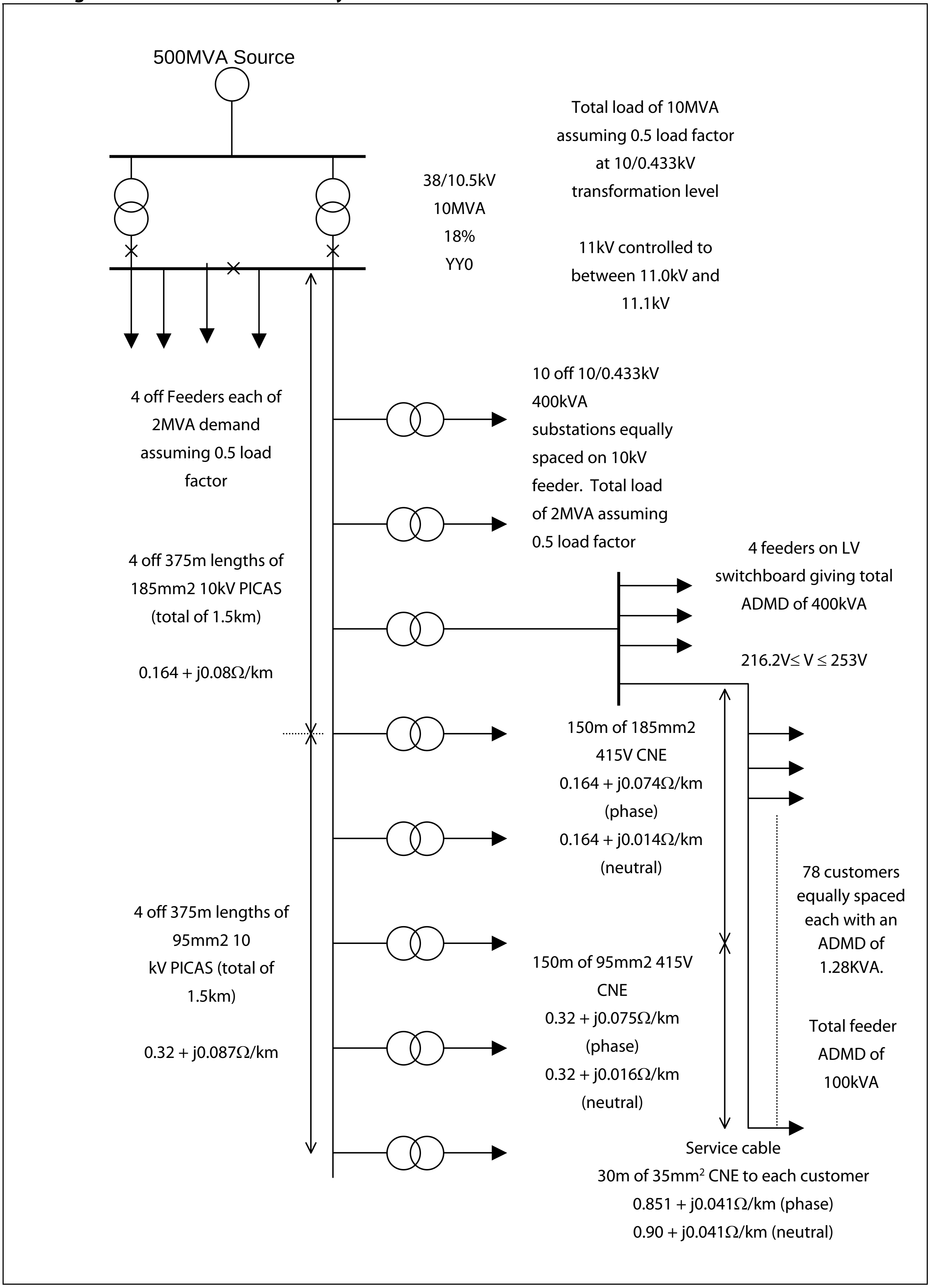


Table 3 Generic Model Data

Component	Description	Comments
10kV detailed Feeder Circuit	• Fourth feeder circuit comprising 10 x 400kVA substations. • Feeder cable comprises 1.5km of 185mm^2 3 core PICAS plus 1.5km of 95m^2 3 core PICAS • 400KVA substations distributed equally along 3km feeder	185mm^2 Cable parameters: - 0.164 + j0.080•/km 95mm^2 Cable parameters: - 0.32 + j0.087•/km
10/0.433kV Substation	• Comprises one 400kVA transformer • Four outgoing 400V 3 phase feeders • ADMD of each feeder is 100kVA • No load volts < or = 253V • Full load volts > or = 220 V • Load factor = 0.5 (MD on sub is 200kVA) • 312 customers supplied • ADMD = 1.28kVA per customer	Three feeders modeled as lumped loads and generators
10/0.433kV Transformer	• 400kVA • 5% impedance • Dy11 windings • X/R ratio of 15 • Taps set at 0% on HV side • Off load ratio of 10/0.433kV	
400V Detailed Feeder	• Feeder comprises two segments of cable, 150m of 185mm^2 CNE and 150m of 95mm^2 CNE cable • 78 customers distributed evenly along feeder • customers distributed evenly across three phases • Service joints distributed evenly along feeder cable segments • Up to four consumers per service joint	185mm^2 Cable parameters: - 0.164 + j0.074•/km (phase) 0.164 + j0.014•/km (neutral) 95mm^2 Cable parameters: - 0.32 + j0.075•/km (phase) 0.32 + j0.016•/km (neutral)
Individual customers	• ADMD of 1.28kVA, 1.0pf • Minimum demand of 0.16kVA, 1.0pf • Micro-generator of 1.1kVA, 0.95pf • 30m of service cable, 35mm^2 CNE • G74 motor load fault in-feed	Cable parameters: - 0.851 + j0.041•/km (phase) 0.9 + j0.041•/km (neutral)

3.1.3 System Loading

Each 10kV feeder supplies ten 10/0.433kV 400kVA transformers. The feeder is therefore designed to supply the full load of each transformer, giving a total feeder load of 4MVA. This is unlikely to occur in practice due to the diversity of demand, therefore a load factor is normally applied to the substation loads to provide a more representative maximum feeder demand. For a load factor of 0.5 the total feeder load would reduce to 2MVA, or 200kVA per substation.

With five 10kV feeders the total load on the 10kV substation is 20MVA. This reduces to 10MVA when the 0.5 load factor is taken into account, giving a load of 100% of the firm capacity of the 38/10.5 kV transformers. This is pessimistic, since it is the highest load that could be supplied by this substation.

The feeder cables from the 10/0.433kV substation are also designed to supply the estimated maximum demand of the connected services. Load demand figures produced by the UK Electricity Association data show that the minimum and maximum demand figures are 0.16kVA and 1.3kVA respectively. Irish domestic demand figures have been assumed to be similar. With 78 consumers connected to a single feeder cable, the maximum demand at the substation would be approximately 100kVA. This allows up to four such feeder cables to be fed from each 400kVA substation. For the 10kV system it is unlikely that the maximum demands on the feeders coincide and a load factor is normally used to take account of the diversity.

3.2 Studies and Results

Previous studies, for the UK distribution system, identified the threshold levels of micro-generation that could necessitate distribution system or equipment changes. The studies were pessimistic, in that they considered extremes of operation, namely: -

- Maximum load, zero generation
- Minimum load, zero generation
- Maximum load, maximum generation
- Minimum load, maximum generation

The first two cases represent the current extremes of operation for the network. The third and fourth cases are unlikely future scenarios, given the likely diversity in micro-generation technologies and users' behaviour patterns, but do give the worst cases. These extreme cases have been studied for the ESB representative urban low voltage network described above.

The studies confirmed the validity of the conclusions drawn in previous studies on similar systems. The key issues that can require distribution system changes as a result of multiple connection of SSEG are: -

- reverse power flows, when the generation exceeds demand for the system, such that there is reverse flow (real power or reactive power) through the distribution transformer
- voltage rise at the remote end of the LV feeder due to reverse power flows

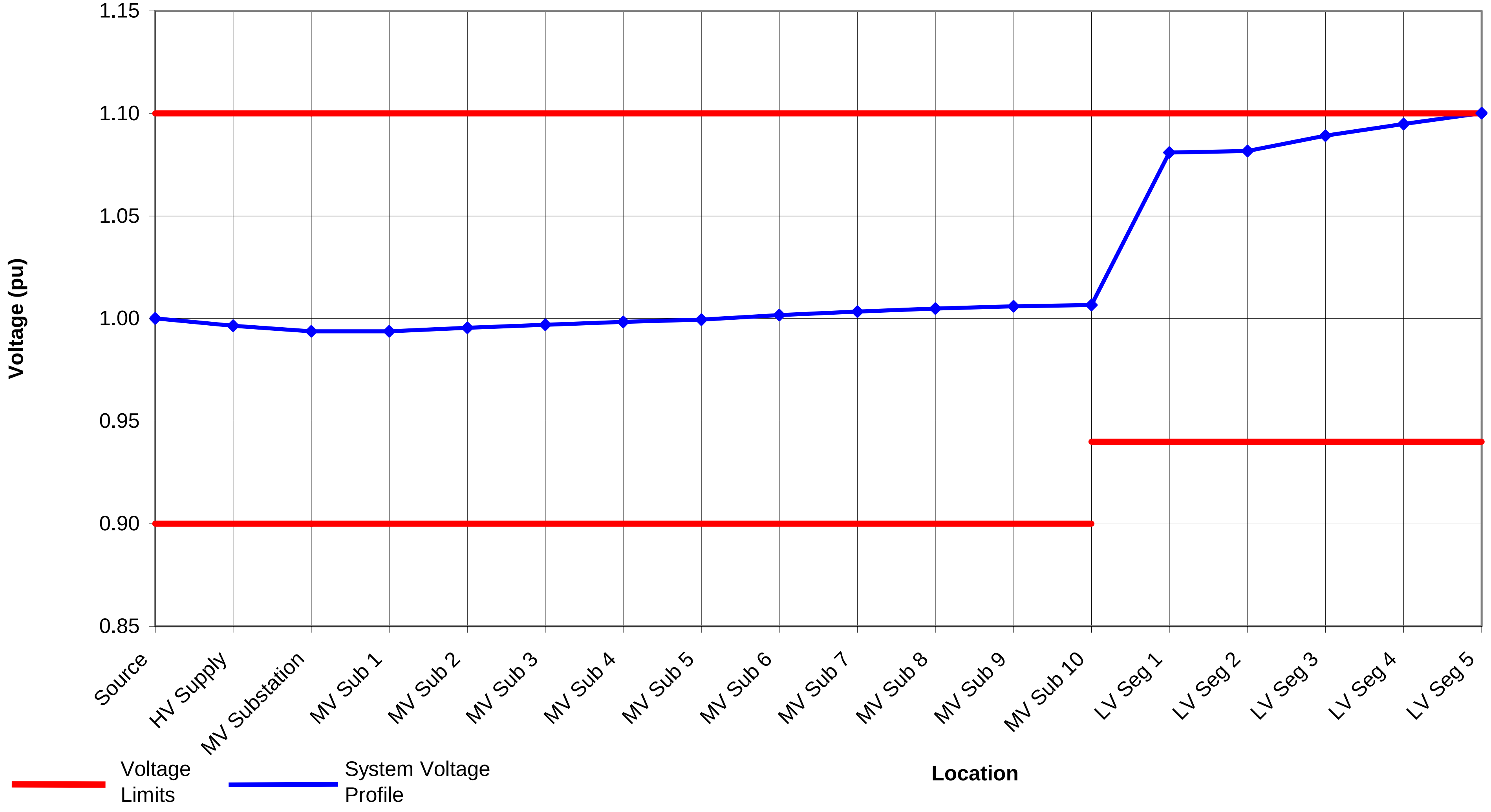
The penetration levels of SSEG at which this occur will depend upon the design of the network, the distribution of the SSEG down the feeder, and the operational profile of the SSEG, compared with the local demand profile. Typically a concentration of SSEG in premises connected at the far end of a long 10kV feeder would give the greatest difficulties with voltage rise.

There are other issues that can arise, including voltage unbalance and increases in fault level, however, these only become an issue at higher levels of SSEG.

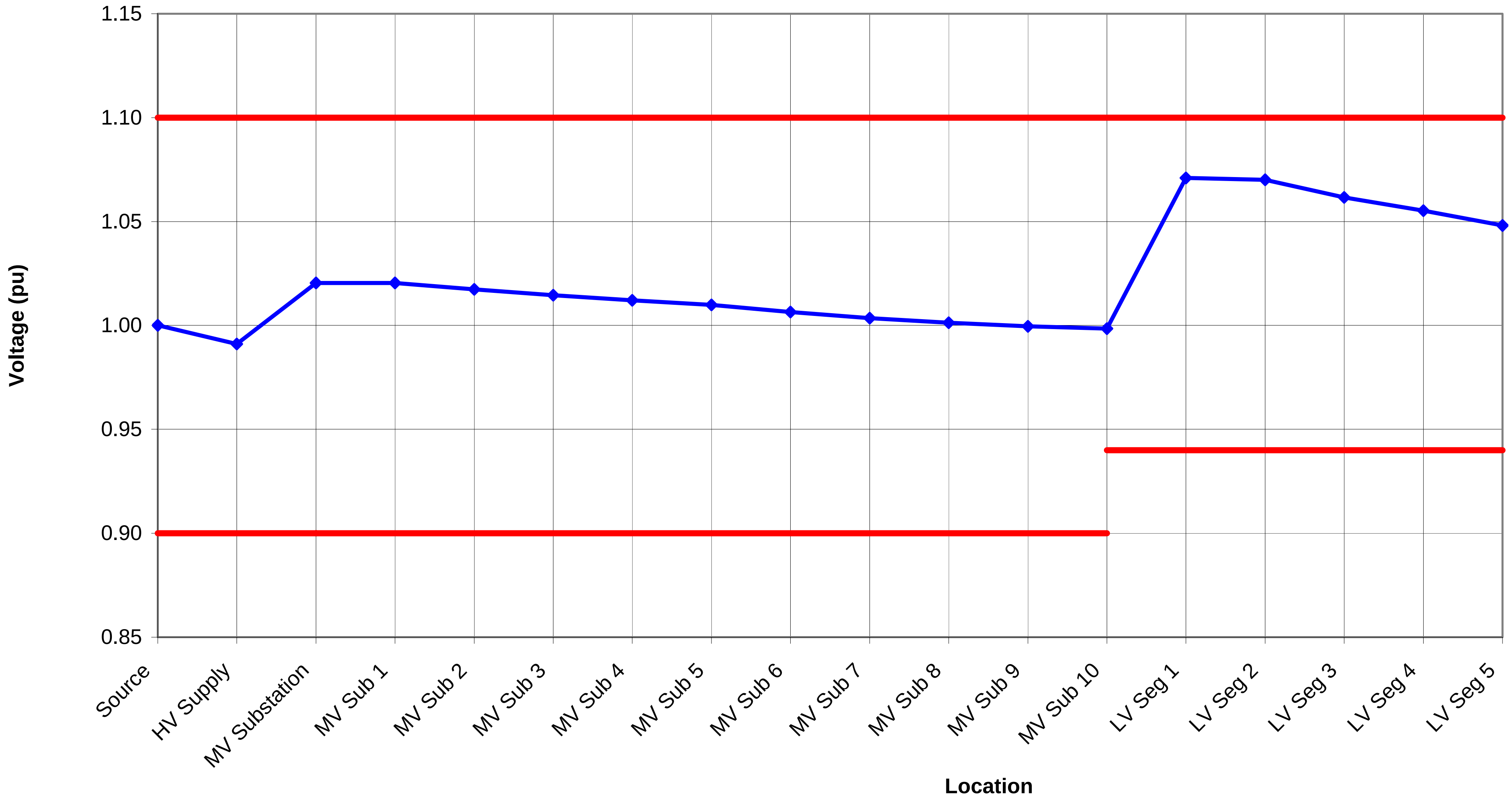
The worst case for voltage rise occurs when there is maximum generation and minimum load. Graph 3.1 illustrates this for the particular network studied, with maximum generation (1.1kW per consumer) distributed uniformly. The graph shows the voltage profile down the 10kV feeder to the remotest 10kV/400V supply point, and then along that remotest 400V feeder to the end. The voltage rise at the remote end is due to the flow of real power back up through a mainly resistive network. For this particular scenario, it can be seen that the voltage rise at the remote end is at +10% above nominal. For this particular network, it would therefore be possible to connection a 1.1kW generator within each consumer's premises without having voltage problems.

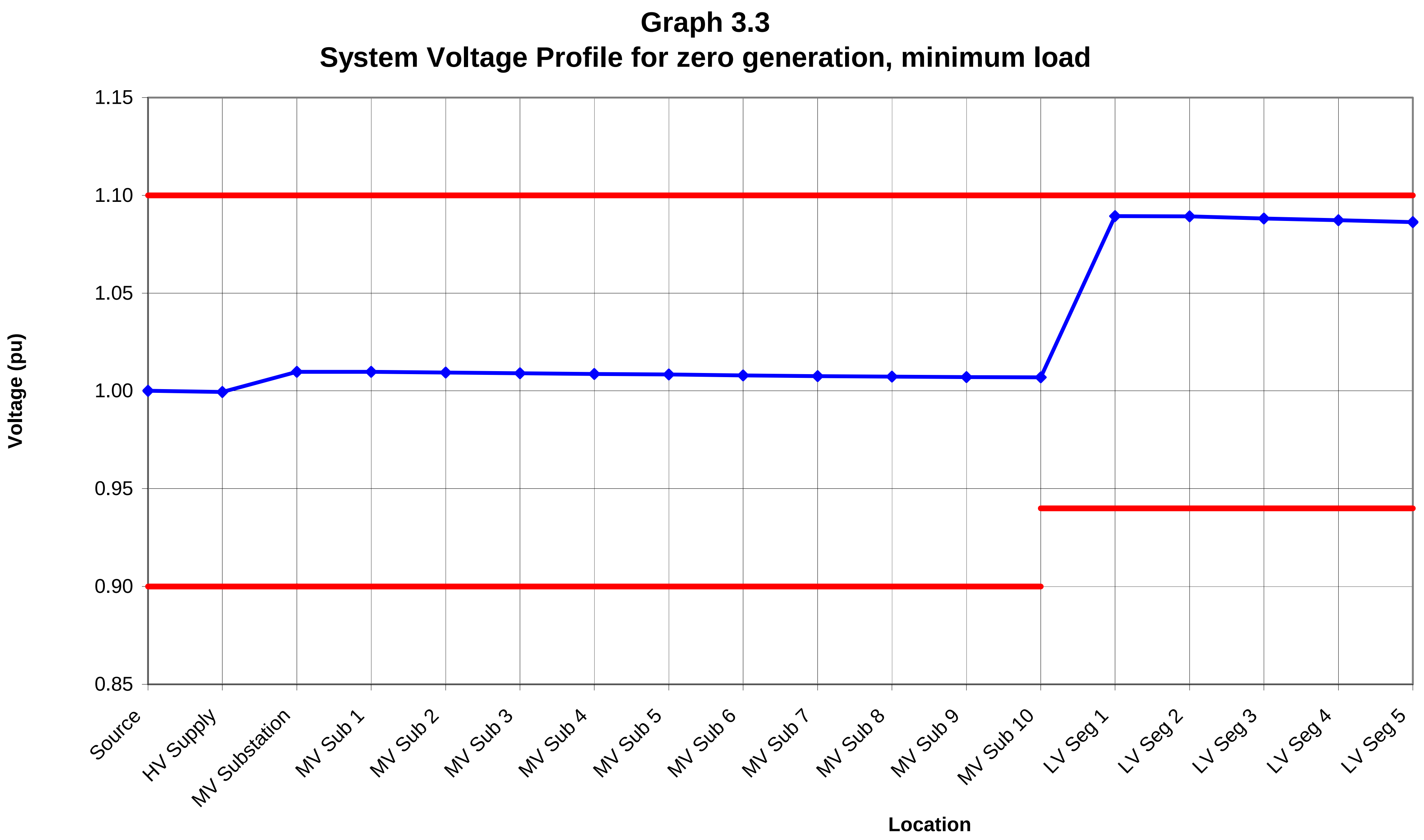
Graphs 3.2 and 3.3 illustrate the voltage along the same feeder for the two extremes of operation without SSEG, namely maximum load and minimum load. It is important that ESB gain an understanding of the levels of SSEG penetration, network designs and locations for which widespread connection should not cause any concerns.

Graph 3.1
System Voltage Profile for maximum generation, minimum load



Graph 3.2
System Voltage Profile for zero generation, maximum load




Graph 3.3
System Voltage Profile for zero generation, minimum load
Voltage (pu)
1.15
1.10
1.05
1.00
0.95
0.90
0.85
Source
HV Supply
MV Substation
MV Sub 1
MV Sub 2
MV Sub 3
MV Sub 4
MV Sub 5
MV Sub 6
MV Sub 7
MV Sub 8
MV Sub 9
MV Sub 10
LV Seg 1
LV Seg 2
LV Seg 3
LV Seg 4
LV Seg 5
Location

4. Treatment of Costs and Other Issues Related to Connection of Embedded Micro-Generation

4.1.1 Inherent Characteristics of Micro-Generation

As discussed in Section 2.1, there are some very fundamental differences between micro-generation connected to the LV network and larger embedded generators connected at 10kV and 38kV. There are other characteristics that affect the treatment of costs and benefits, namely:

- the owner and operator of the generator is likely to be the domestic or commercial consumer, i.e. the Generator and Customer are one and the same entity
- the owner and operator will have limited knowledge of trading arrangements
- micro-generators are likely to be mass-market devices. For the particular case of micro-CHP, 80% of installations are likely to occur when the existing central heating boiler fails. Rapid and simple connection is required for these 'distressed purchases'

4.1.2 Connection Process for Micro-Generation

Applying the embedded generation connection application process to SSEG generation plant will be a significant barrier to market entry. It will effectively restrict competition in the supply market and prevent end users from having a free choice of energy supplier. The connection process for larger embedded generation requires the parties involved in the transaction to be informed participants with development resource and an understanding of the mechanisms in place for regulation of the electricity industry. It also requires a timescale that is incompatible with 'distressed purchases'.

Given that the expected end user for SSEG will be a typical domestic customer, the position is significantly different. The product will be sold on the basis of its utility and cost saving potential meaning that, as with consumer goods and commodities, the transaction process (which will include the electrical connection) will need to be as standard as possible within the statutory constraints of the distribution licence. Such standardised connection terms could be applicable for SSEG below a de-minimis level to be determined.

In the UK this approach has been taken for devices with a rating of 16A per phase or less, through the use of Engineering Recommendation G83/1. G83/1 specifies all of the technical interface requirements that the generation unit must meet, including isolation, protection, earthing, and EMC emission standards. Type testing of the generation units is required in order to demonstrate that the units meet the G83/1 requirements.

G83/1 also outlines very clearly the process that needs to be followed with the distribution network operator in order to connect small generators. It offers the option of a very simple and quick process for single installations, and a more lengthy but straight forward process for multiple installations, where the distribution network operator will need to look more closely at network design issues.
A European approach to the connection of micro-generation is being developed. The first step in this was a CEN Workshop Agreement, and this is currently being developed into a European Norm.

It is essential that ESB develop a simpler and more rapid connection process for micro-generation, based on similar principles to those used in the UK, and being developed at the European level.

4.2 Calculation of Costs and Benefits

The benefits that accrue for larger embedded generators with direct connections to the MV and HV distribution network will also accrue for SSEG connected to LV networks. The cumulative benefit for multiple SSEG's could actually be higher than for an equivalent size larger generator, given the additional energy and losses savings.

The same calculation approach as that used for the larger generators could also be used to identify the costs and benefits associated with SSEG, however it would not be possible or desirable to integrate it into the connection process. The calculation would also need an understanding of the likely operating regime of the SSEG versus the demand profile. Rather than evaluating individual SSEG's, a more efficient approach would be evaluate the costs and benefits associated with forecast levels of SSEG, taking into account likely penetrations of different SSEG technologies on different types of ESB networks (urban, rural etc). This would be a significant piece of work requiring forecasts of SSEG market penetration.

The impact of SSEG connections on distribution networks will develop over time, as market penetration increases. This will allow ESB Networks to take account of it within their LV network designs in a similar way to their projections of load growth that drive the load related expenditure. It will also enable a considered approach as to how the costs and benefits can be calculated and apportioned.

4.3 Apportioning Costs and Benefits

A number of approaches would be possible. Reward mechanisms should be efficient (i.e. in economic terms), encourage competition, be transparent (i.e. easily understood), be accessible to those qualifying for them, and be robust in the long term.

Recent work carried out in the UK for the Distributed Generation Co-coordinating Group identifies alternative approaches in some detail.

One approach would be to develop standardised SSEG connection terms that would provide a sliding scale of connection charges linked to the generator capacity, and incorporating the costs and benefits associated with typical import/export profiles for this class of customer. However given the minimal effect that individual SSEG's have on the network, a better mechanism could be through modifications to the tariffs used for this class of customer.

4.4 Next Steps

- Determine the standard interface arrangements, connection terms and costs to facilitate connection of micro- and small-scale embedded generation to the Irish distribution network, taking into consideration the draft European Norm;

- Determine the load profile for typical SSEG installations associated with domestic, small commercial and small industrial customer categories. These profiles can then be adopted within the planning process for new LV networks;

- Determine the levels of SSEG that can be connected to different designs and types of ESB distribution network without requiring changes to the network

- Determine the longer-term costs and benefits associated with multiple SSEG connections, based on market forecasts for different technologies.

- Determine the best mechanisms for apportioning costs and benefits, given the likely ownership of SSEG

5. References

'The Impact of Small Scale Embedded Generation on the Operating Parameters of Distribution Networks' by PB Power for DTI New & Renewable Energy Programme Report number K/EL/00303/04/01

'Ninth Meeting of the DGCG held on Wednesday 29th October 2003 - Summary of Discussion'

'DGCG, Technical Steering Group, Work Stream 4 P02A Working Paper 4 Reward Mechanisms for Micro-Generation'

'Micro-Map Mini and Micro CHP – Market Assessment and Development Plan Summary Report'