Scottish Hydropower Resource Study

Final Report

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Nick Forrest Associates
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Final Report

Submitted by:

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Black & Veatch Ltd

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Contents

Glossary

Measures of power and energy:

kW	Kilowatt, a measure of power, or the rate of energy production. Equal to 1000 Watts or 1000 Joules per second
MW	Megawatt, 1,000 kW
GW	Gigawatt, 10^6 kW
kWh	Kilowatt-hour, a measure of energy. Equal to 1 hour's production at 1kW, or 1000 Watts x 3600s = 3.6 x 10^6 Joules
MWh	Megawatt-hour, 1,000 kWh
GWh	Gigawatt-hour, 10^6 kWh
TWh	Terawatt-hour, 10^9 kWh

BSP	Bulk Supply Point
CHP	Combined Heat and Power
DNO	Distribution Network Operator
Ecost	Lifetime cost of energy (£/MWh)
FDC	Flow Duration Curve
FHSG	FREDS Hydro Sub-Group
FREDS	Forum for Renewable Energy Development in Scotland
GIS	Geographical Information System
LDC	Line Drop Compensation
LNR	Local Nature Reserves
LTDS	Long-Term Development Statement
LV	Low Voltage
p.u.	Per Unit, an expression of quantities as a fraction of a base unit
Qdes	Design flow of the turbine (m^3/s)
Q_{95}	Flow exceeded for 95% of the year
Qmean	Annual mean flow in the watercourse (m^3/s)
ROC	Renewables Obligation Certificate
SI	Sensitivity Index
SSSI	Site of Special Scientific Interest
SAC	Special Area of Conservation
SPA	Special Protection Area

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Executive Summary

Background

This report is the culmination of a study commissioned by the Scottish Government through the Hydro Sub Group of the Forum for Renewable Energy Development in Scotland (FHSG) during the first half of 2008. The study was undertaken to provide an assessment of the potential for development of hydropower resources within Scotland, and was completed by a consortium of partners from the Scottish Institute of Sustainable Technology (SISTech), Nick Forrest Associates and Black & Veatch Ltd. The study has been undertaken in a series of phases, the first of which was to provide a theoretical maximum potential for hydropower based on the country's rainfall and topography. The other stages have involved a more practical assessment of the potential using Hydrobot, a GIS-based computer model. This tool allows for an economic evaluation of all likely hydro configurations on rivers within a catchment.

In order to undertake the analysis the country was divided into a total of 60 separate rainfall catchments. The annual flow pattern was calculated for all watercourses in Scotland, using topographical and gauged flow data. Schemes were first optimised by sizing equipment to suit the location and by reiterating through multiple sizes of penstock. Options for storage dams and multiple intakes were also considered at each site. A further dataset of existing weirs was also analysed by the model. The schemes were evaluated using up-to-date costs and taking realistic prices for electricity and other variables.

Using data from Scottish Renewables, it was possible to locate all existing schemes with an installed capacity of 700kW or more. The watercourses supplying these schemes were identified, so that affected weirs, dams and reaches of river could be excluded. Other abstractions greater than 100 litres/second were also taken into account by excluding sites from the analysis where the abstraction would have a significant impact on available flow. Further constraints relate to the distribution grid, the transport network and land designations – see below.

Calibration of the model was based on project costings provided by Black & Veatch Ltd., with modifications to incorporate inputs from other industry leaders. The model was validated at several levels: firstly, to ensure that site selection was in accordance with the results expected with normal ground-reconnaissance methods; and secondly, to ensure that the model was producing realistic baseline costs for each provisional site identified and was therefore making acceptable comparisons between potential sites. The initial validation was completed at an early stage in the study with field work undertaken in several catchments and showed the physical model to be working well. The second part of the validation process was undertaken using data provided by FHSG from a costed, operational project. While the real validation scheme is rated at 1MW, the physical model of the scheme was 998kW. The total modelled capital cost was only 7% greater than the actual capital cost (updated to 2008 prices), so no further adjustment was made to the model. Additional validation schemes were sought by FHSG but were not available due to commercial sensitivity.

Nine input variables were adjusted and Hydrobot was rerun in order to test sensitivity of the national hydro resource to these factors – some legislative and some market-driven – to determine the most significant influences or barriers. These are listed in Appendix 1.

Results

In Phase 1 of the study, using rainfall and river gauging data over the 60 catchment areas, the theoretical ceiling for hydropower in Scotland study was found to be 5.4 GW. This would imply an annual energy of 47.3 TWh. ***In practical terms this is not achievable, since it would require all rainwater to be used for hydropower.*** *It is simply an estimate of the absolute ceiling that hydropower in Scotland could never exceed. Phase 1 involved no site modelling. The results are tabulated in Appendix 3.*

In Phase 2, Hydrobot modelled 36,252 separate sites that were deemed practical and technically feasible. These would total 2,593 MW. Reducing this to financially viable hydropower production (schemes that would actually make a profit within the desired timeframe), the baseline scenario of the study used input values appropriate to a typical commercial hydropower investment. This indicated that there are 1,019 potential schemes across Scotland. These include run-of-river schemes and new storage schemes identified by the model, with a total practical potential of 657 MW that could deliver 2.77 TWh of electricity annually. A map illustrating the catchment boundaries and power density across Scotland is located in Appendix 2; the financially viable power within each catchment is listed in Appendix 4. ***Table 1*** *includes the number and combined power of financially viable schemes, but also lists the total number of schemes modelled including those that are not commercially viable.* ***Table 2*** *shows the relationship between the various power totals above.*

Table 1. Summary of results for baseline scenario. *Total* values include all technically possible schemes in Scotland modelled by Hydrobot, including those with a negative NPV. *Financially viable* values in include schemes with a positive NPV after the recovery period (25 years in baseline scenario).

Total number of schemes	Total potential power (MW)	Total potential annual energy (MWh)	Financially viable schemes	Financially viable power (MW)	Financially viable annual energy (MWh)
36,252	2,593	10,644,403	1,019	657	2,766,682

Table 2. Summary of the different elements of Scotland's hydro potential as calculated in this study. The financially viable resource (A) is added to the schemes that will not yield a positive NPV in the desired period (B) to give the total for all technically feasible schemes modelled by Hydrobot (C). Existing schemes (D) includes those currently in planning and development. Column E shows the effective power within runoff in sites that are deemed technically unfeasible, i.e. areas that are too flat and where there is no existing weir or dam, or where there is already a significant abstraction for another purpose. Thus E is the resource that will probably never be harnessed. Adding C, D and E gives the total potential power in all runoff from Scotland (F).

A	B	C	D	E	F
Financially viable	Financially unviable	All modelled schemes	Existing schemes	Unsuitable for hydro	Total energy in runoff
657 MW	1,936 MW	2,593 MW	1,354 MW	1,459 MW	5,404 MW

Potential schemes where water might be diverted from one catchment to another have not been considered, as defining such schemes requires considerable human intervention.

Constraints

Various constraints and issues will need to be addressed in realising Scotland's hydropower potential, such as the capacity of the national grid. While line and sub-station limits were considered on a case-by-case basis during the Phase 2 site modelling, the cumulative impacts that would result from connecting all predicted sites, taking into account planned grid reinforcements, would require a level of modelling far beyond the scope of the current study. However, factors constraining the amount of generation that can be connected have been modelled on a sample area, and are discussed in Appendix 5.

Assessing the extent of these constraints is made difficult by the fact that models of the network are not readily available, and both the network and generation mix are changing rapidly. Voltage rise is likely to be the first constraint encountered, particularly for connections at 11kV in rural areas. Thermal limits and fault levels are also a constraint as the amount of embedded generation increases. Rules of thumb were taken from previous studies and applied to the results in a representative catchment. This analysis suggested that, under the current network conditions, 33% of new hydropower generation could not be accommodated on the grid. However, this is presented only as an approximate quantification of the current network constraint; any hydro scheme would require a detailed network assessment as part of a feasibility study and contact with the Distribution Network Operator would be recommended as early as possible.

Areas designated for their natural heritage value will also limit the number of sites available for development. The environmental impacts of hydro are considered in detail in Appendix 6. As part of the process of site selection, designated areas were incorporated into the model and the hydro potential in these areas was reduced to reflect the level of environmental protection the designation implied. Without such reductions, the analysis indicates that around 337 potential hydro schemes could be located in designated areas, and would be capable of providing 357MW of power. Using a modest level of protection (as in the baseline scenario), the potential in designated areas would reduce to a potential power of 227 MW. Approximately 480 MW of potential lies outside designated areas, bringing the total power to 657 MW for the baseline scenario.

A series of 16 sensitivity analyses was undertaken for a wide range of key variables that had been agreed with FHSG. These indicated that the most influential factors were, in descending order of importance:

1. *Discount rate applied to future cashflows*
2. *Electricity revenue price*
3. *Investment recovery period*
4. *Natural heritage land designations*
5. *Business rates*
6. *Threshold for earning double ROCs*
7. *SEPA subsistence charge threshold*
8. *Fee to cross a railway*
9. *SEPA licence threshold*

Different parties will have their own perspective on what constitutes a viable scheme, and the sensitivity analysis illustrates this. For example, a commercial developer may examine more severe discount rates; a farmer may examine the possibility of earning double ROCs; an environmental lobbyist may examine the effect of natural heritage land designations. The effects upon the baseline potential resource are illustrated in ***Figure 1****, though this does not take into account the proportion by which the input parameter was varied.*

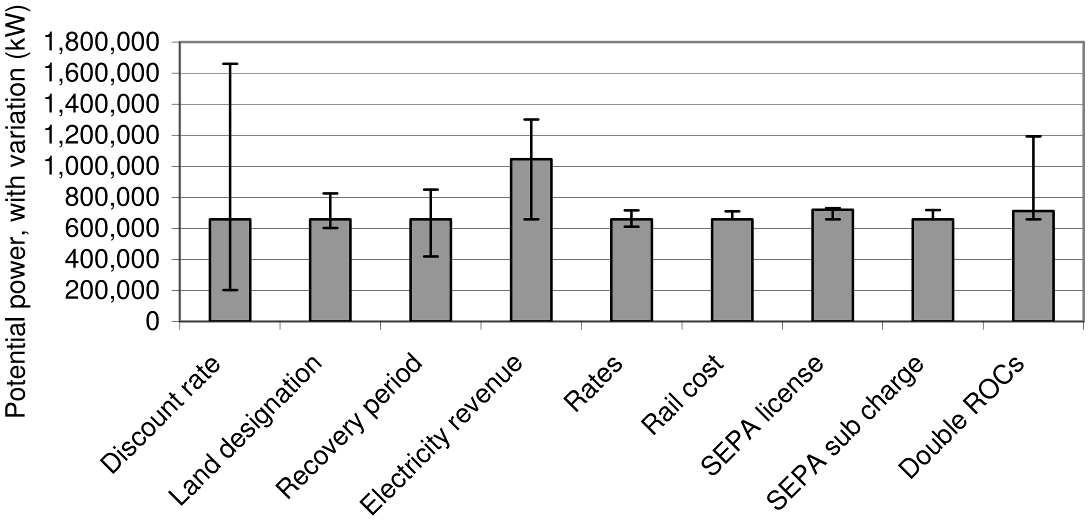

Figure 1. Variation in the Scottish potential hydropower resource as a result of varying certain parameters in the sensitivity analysis. Details of parameters varies are given in Appendix 1. The solid column indicates the middle value (not necessarily the baseline scenario) and the plus and minus bars indicate the change in total potential power with the applied variation. The amount by which parameters are varied is not proportionally equal for all parameters.

Outcomes

The study has demonstrated that not only is there a greater hydro resource in Scotland than has been commonly recognised, but that market forces have a stronger influence on the national hydropower resource than most of the values and thresholds that are within the Government's control. However, market forces can be influenced to some extent by providing a stable support and permitting regime as these affect the investor's perception of risk and hence the discount rate that they will require. Procedural change is worthy of immediate attention, such as removing unnecessary delays and restrictions in the hydro planning process where the impacts are weaker and defensible with simple mitigation measures. This is being addressed through the recent initiatives of the government following the concerns of the FREDS Planning and Consents Sub Group. The Minister for Enterprise, Energy and Tourism already announced the intention that processes related to approvals are to be streamlined and that a target of 9 months has been established as the maximum period for a decision to be reached where no public enquiry is required.

The effect of natural heritage land designations upon the success rate and size of hydro schemes is in need of further research, as are inter-catchment diversions, the impact of offsetting local consumption, and a detailed survey of existing weirs across Scotland.

1 Background and Objectives

This study is being carried out on behalf of the Scottish Government in order to directly assist the Hydro Sub Group of the Forum for Renewable Energy Development in Scotland (FHSG). The study has been carried out by Nick Forrest Associates in close co-operation with the Scottish Institute of Sustainable Technology (SISTech) and the international consultancy, engineering, and construction company Black & Veatch. The study has the overall objective of providing a clear estimate of both the theoretical and the practical potential for expanding hydropower production within Scotland; and so ensuring that this form of energy continues to contribute to Scotland's target of supplying 50% of its electricity demand from renewable sources by 2020. The study provides FHSG with details of the power that can be produced economically; and through the application of a series of sensitivity analyses has the additional objective of defining the effect that certain policy changes might have on the national hydropower resource.

1.1 Introduction to Hydropower

As this report refers in detail to why one particular hydro scheme might be better than another, a brief description of hydropower is necessary. A hydro scheme comprises a system for extracting energy from water as it moves, normally dropping from one elevation to another. Water that is restricted in a sloping pipe will build up a head of pressure at the bottom, which can be used to drive a turbine wheel (or runner). In flatter areas where there is less pressure build-up or no pipe at all, much larger flows are required to compensate for the reduced head, and so larger turbines are used.

In addition to flow and head, a destination or load for the power is needed. In this study, the load is the national grid. As connection and the cost of lines are significant parts of most schemes, distance from the grid may be the deciding factor of whether a scheme is viable. Furthermore, the grid operator must take into account the capacity of the local grid before allowing a scheme to connect. The issue of access to distribution and transmission networks is facing significant change. It is hoped that a relaxation of the distribution network charges and the Transmission Network Use of System (TNUoS) charges (paid by generators and suppliers making direct use of the grid) in the future will make the whole process more attractive to would-be investors in hydropower.

Not all water within a river can be used for generation – a proportion called the "reserve flow" must be left within the river for ecological reasons. Unless there is a storage dam, the usable flow will fluctuate throughout the year, and the system's efficiency will vary as a result. Different turbines have different responses to variations in flow, and this must be taken into account when predicting the available energy.

When a hydro scheme is generating electricity, every unit of electricity exported to the grid brings revenue. In addition, for energy generated the scheme operator will receive Renewable Obligation Certificates (ROCs) which have a market value. Levy Exemption Certificates (LECs) are also a useful support to the small-scale power producer and currently have a value of around £4/MWh. Other smaller revenues or benefits may also be received. As different layouts at a site can cost more or less to construct, but may also generate more or less electricity, the best payback can only be found by examining a number of alternative solutions. This is one reason why hydro site design is complex, and why the tool used in this study is ideal for modelling hydro potential in an area.

1.2 Objectives

The terms of reference indicated that the study needed to provide the FHSG with a total theoretical potential of hydropower within the country as indicated by the average rainfall and the topography of the country's catchments. This was to be modified to take account of actual river flow and constraints imposed by environmental planning, as well as a range of other economic and practical factors.

In the original tender document, the team had provided two main alternatives to the client, the first based on the ordering of the seven phases in accordance with the original terms of reference. The second alternative required a re-ordering of the phases as a result of the application of a computer tool, specifically designed for assessment of hydropower potential. It was agreed that the modified phasing was acceptable and desirable if the benefits of using the modelling tool were to be fully realised. The model used for the study is Hydrobot, (previously known as HELP – Hydro-Electric Location and Planning), as designed by Nick Forrest. This model is able to select the most suitable location for a hydropower unit based on the topography of the site, the river flow, distance to the grid, nature of grid connection, projected unit cost of establishment and maintenance, and revenue as determined by a range of influences.

The work phases to be followed were: -

Definition of Theoretical Potential: The first phase was to determine a theoretical limit to Scotland's hydropower, based on capturing all energy from the total rainfall across the country.

Grid Connection: Connection to the 11kV and 33kV network was to be considered, with distance to the connection and the local grid strength being taken into account.

Practical Potential: Run-of-river schemes were to be modelled using a design flow of 1.5 x mean flow, while storage schemes were to assume 2.5 x mean flow. The resource for each catchment was to be assessed assuming the optimum size and output are achieved, and the results were to be aggregated into 6 bands:

- <100 kW;
- 100kW – 500kW;
- 500kW – 1MW;
- 1MW – 5MW;
- 5MW – 10MW;
- 10MW +

Definition of Economic Potential: In the terms of reference, the technically feasible schemes identified above in *Practical Potential* were then to be filtered using a set of defined economic assumptions. The economically exploitable resource was to be quantified by first generating the following outputs:

- capital cost;
- operating cost;
- average annual energy production of scheme;
- revenue potential;
- cost of mitigation measures;
- cost of development (including administrative costs);
- thresholds of financial acceptability.

Validation: In order for the accuracy of the model to be checked, costs and outputs from real hydro schemes chosen by FHSG were to be compared with Hydrobot's predictions for the same sites or areas. This would allow identification of any bias, and is a means of fine-tuning the model before the final analysis.

Planning and Environmental Constraints: The location of hydropower projects would in practice be limited by planning considerations, which take into account the natural heritage value of the land and other environmental factors. These were to be incorporated in the assessment, and a breakdown of the number/output of sites affected by land designations.

Sensitivity Analysis: In order that the relative importance of various influences could be gauged, a sensitivity analysis was to be conducted, varying agreed parameters in order to measure their effect on the national economically viable resource.

2 Previous Scottish Hydropower Studies

Normally a hydro site assessment begins with a predetermined reach of river and load or grid connection, which are analysed to find the best possible configuration. In cases where the number and location of river reaches and loads is completely unknown, a variety of methods might be employed as found in previous Scottish hydropower studies.

The Salford Study[1], the most widely know early regional study, used a lower threshold of 25kW (or 50kW for remote sites) and an upper threshold of 5MW for convenience. A minimum head of 2m for established weirs, and 3m where there was no weir, was also stipulated for financial reasons, though construction of new dams or weirs was ruled out. Site selection in England and Northern Ireland relied on visual inspection of Ordnance Survey 1:50,000 maps for “weirs, mills, waterfalls and lengths of river with close contours”, as well as consultation with water authorities. These sites were then visited. One third of the sites identified in a previous study of Wales were revisited, and the results were extrapolated across the remainder. Sites in Scotland were rather more arbitrary: electricity generating boards and councils provided information on potential sites, and consulting engineers were asked to comment on suitability. In some cases economic appraisal from elsewhere in the UK was applied to similar Scottish sites. No Scottish sites were visited.

The Salford Study concluded that there was economic potential for the development of some 286MW in Scotland.

The Scottish Study[2] in 1993 redressed the balance of attention to Scottish hydro-potential. The study appears to have considered all sites identified for the Salford Study, but the most promising were visited. This meant the sites were limited to >100kW in the North, and >25kW in the South. The study concluded that 1,000MW was possible at 10p/kWh (£100/MWh), though this could be halved when planning constraints were taken into account. It also assumed an average connection cost for the whole of Scotland, which may not be representative of remote areas.

In 2001 Garrad Hassan[3] was commissioned to update the Scottish Study. Hydroplan revisited the sites identified previously, as well as any new promising sites that had come to light since. There was an additional “commercially sensitive resource, by PA [Planning Authority], for which location could not be specified”, “reflected by factoring up the Salford data by planning authority”. The results of Garrad Hassan’s study were assessed at an 8% discount rate, with cost of energy thresholds of 5p/kWh and 7p/kWh. 270MW were modelled, with the total being reduced during sensitivity analysis.

Other regional studies have been carried out for private developers or landowners, with site identification mainly by examination of maps. A completely automated system has not previously been used.

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[1] Salford Civil Engineering Ltd (1989). *Small Scale Hydroelectric Generation Potential in the UK*. ETSU-SSH-4063 for Department of Energy’s Renewable Energy Research & Development Programme. Department of Energy, London.

[2] Scottish Hydro-Electric Plc, Scottish Power Plc, DTI, The Scottish Office, Scottish Enterprise, Highlands and Islands Enterprise (1993). *An Assessment of the Potential Renewable Energy Resource in Scotland*. Scottish Hydro-Electric Plc, Edinburgh.

[3] Garrad Hassan and Partners Limited (2001). *Scotland’s Renewable Resource 2001 – Volume 1: the analysis*.

3 Methodology for Modelling of Hydro Resources

Hydrobot was devised in 2006 and applied to the catchment of the North and South Esk near Edinburgh, as part of an award-winning MSc dissertation for the University of Edinburgh. Hydrobot remotely identifies likely reaches of river in the area of interest and identifies the closest grid connections to suit a range of generation levels. It then models a range of positions for the turbine, the water intake and the grid/load connection. Energy prices, typical equipment costs and discounting are used to determine the financial viability of each potential solution.

3.1 Calculation of the Full Theoretical Potential (Phase 1)

The first phase was to determine a theoretical limit to Scotland's hydropower based on capturing all energy from the total rainfall across the country, without considering any physical structures or limitations. Scotland was split into 60 rainfall catchments, based on those illustrated in the National River Flow Archive, with some subdivision to reduce size (refer Appendix 1). The rainfall across catchments and gauged streamflow within catchments were used to estimate the proportion of rainfall that should reach the sea as runoff. The potential energy lost by the runoff between its starting point and sea level was calculated, using elevation raster data with cell size 10m x 10m. A typical system efficiency of 70% was used to estimate the maximum theoretical hydro resource for each catchment and for the country. A storage capacity of 100% was also assumed in calculating the annual energy yield of the system.

3.2 Grid Connection Issues

Preparation for Phase 2 began with the costs for grid connection and extension. Data largely derived from Black and Veatch with support from members of FHSG and SSE Power Distribution were used to provide the costs of connecting to the grid for a range of physical conditions. As part of the operation of Hydrobot, these data were incorporated at the beginning since this is an integral part of the selection process.

The 33kV distribution network was plotted in ArcGIS 9.1 mapping software developed by ESRI, and the ratings of substations entered. As it would have taken many weeks to identify and label individual lines, the general minimum rating was determined with the network operators and a blanket rating was taken as 8.8MVA for SSE's region, with 21MVA for Scottish Power's region. According to SSE, a cluster of buildings is likely to have an 11kV supply, so clusters of ten or more buildings were taken to represent an 11kV connection point. In addition, buildings or groups of buildings represent a low-voltage connection to the distribution network for micro-hydro schemes. The number of buildings within a cluster indicates the strength of the local distribution network, and hence the maximum power that can be exported.

Likely reaches of river were selected as those with a minimum slope equivalent to typical viable hydro schemes, taking into account the accuracy of the input elevation data. For the foot of each reach, the closest points on the 11kV and 33kV network were identified. In addition, the foot of each reach was paired with the nearest buildings and cluster of more than ten buildings. Each of these 'turbine-load pairings' was then considered as a potential scheme.

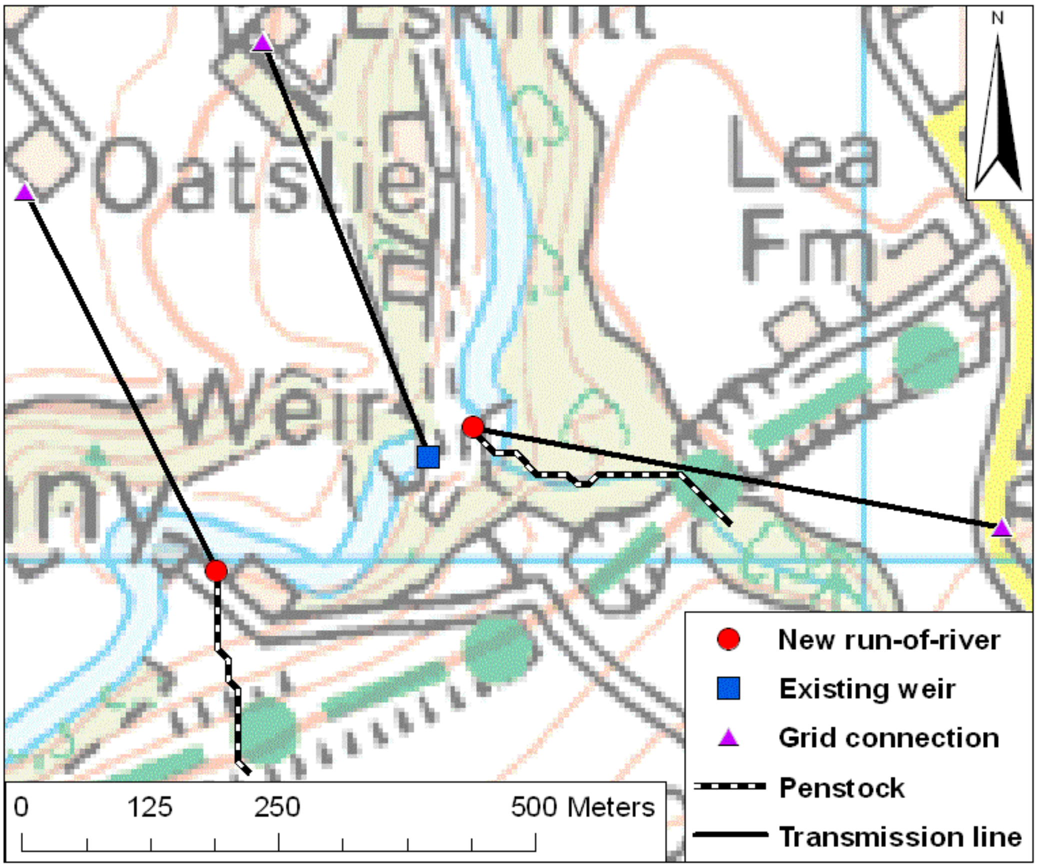

Figure 2. Example of solutions identified by Hydrobot for two new run-of-river schemes and one existing weir. For these small schemes (<100kW), grid connections at low voltage and 11kV were identified, indicated by the straight solid lines. Penstocks are broken lines; turbine locations indicated by circles and square as appropriate.

3.3 River Flow

To allow a catchment-wide analysis with multiple iterations, a simplified flow model was used. Flow data from SEPA gauging stations reveal the proportion of rainfall within a catchment that is not lost through evapotranspiration, and this is quite consistent within and across neighbouring catchments. Elevation data were used to derive the river network within each of sixty catchments, and the catchment area feeding into any point. Combining the above allowed the prediction of the annual mean flow at any point within any catchment.

The Flow Duration Curve (FDC) was also obtained for each gauging station, which allowed the prediction of the FDC for any point within any catchment. Reserve flow to be left in the watercourse was taken to be the Q_{95} flow (the flow that is exceeded for 95% of the year). In real hydro schemes, the reserve flow may be calculated in different ways (often more than Q_{95}), or the allowable abstraction may be a fixed quantity. The Q_{95} flow is a reasonable assumption for the purposes of the study.

This simplified flow model uses surface flow, and does not model infiltration, groundflow and springs. However, any effects on flow from these features will be reflected in the measurements at SEPA gauging stations, and are therefore addressed in Hydrobot so that the overall accuracy is preserved.

Existing hydro schemes are taken into account in the potential for a region. The construction of historical large hydro had less environmental restriction and more non-financial drivers, so the model would not necessarily identify those schemes as financially viable. Therefore, rather than trying to replicate them, the watercourses and weirs already exploited for hydropower are simply excluded from the results.

Other abstractions and existing weirs were also incorporated, as discussed below in *Additional Options*, section 3.9.

3.4 Preliminary Design

For each potential turbine location, many lengths of penstock were modelled at 20m increments, up to 1.5km or the source of the tributary. This led to a different intake elevation and flow curve for each layout. For run-of-river schemes the design flow was initially taken as 1.5 times the annual mean flow.

For storage schemes, the intake positions were taken from the run-of-river results. The terrain around each intake was tested to see if it was suitable for construction for a dam, and if so the design flow starting point was 2.5 times the annual mean flow. Costs for civil engineering were adjusted to take into account dam costs.

Each turbine type was determined by the relationship between flow and head, and the efficiency curve of the appropriate turbine type was selected. Typical values were used for the efficiency of the generator, transformer losses and other parasitic electricity losses. Selection of pipe diameter was designed to minimise cost while ensuring frictional headloss is restricted to 5% of gross head. This allowed calculation of pipe material and thickness for the required strength, with the top section typically being High-Density Polyethylene, and steel in the lower section if necessary.

The instantaneous power was calculated for each exceedence point on the FDC in order to obtain an average power for each period of the year. This was then used to calculate the annual energy generated by each layout.

3.5 Natural Heritage Land Designations

While the presence of natural heritage designation such as SSSIs does not rule out a hydro scheme, it normally implies more environmental studies, a longer planning process, higher mitigation costs, and possibly a smaller scheme than might otherwise be installed. In particular areas protected under the Habitats Directive (Natura 2000 Areas) would be subjected to stringent review and development would only be allowed to go ahead if there are shown to be imperative reasons of over-riding public interest.[4] The requirements will be different for every site, but it was desirable to form a general rule for assessing the effect of land designations. New guidance is being drafted to assist local authorities in evaluating the relative importance of designations, but the most recent grouping suggests that land designations are grouped into three tiers, suggestive of the level of environmental protection that is likely to apply[5].

- Tier 1 (least restrictive): Gardens and Designed Landscapes (GDLs), listed buildings, conservation areas, scheduled ancient monuments

[4] Reference should be made to Scottish Government (2007): *Scottish Planning Policy 6: Renewable Energy*. and to Scottish Government (1999): *National Planning Policy Guideline 14: Natural Heritage*.

[5] Scottish Executive (2000). *National Planning Policy Guideline NPPG6: Renewable Energy Developments*.

- Tier 2: National Scenic Areas, Sites of Special Scientific Interest (SSSIs), Local Nature Reserves (LNRs) and National Nature Reserves (NNRs), National Parks (NPs), National Heritage Areas
- Tier 3: Ramsar wetlands, Natura 2000 Areas - Special Protection Areas (SPAs), Special Areas of Conservation (SACs).

It should be noted that not all land designations are water-related so, although they may include a hydro site, they may not in practice have any impact. At the same time there are other types of planning restriction that have not been incorporated. Data were unavailable for Scotland's three regional parks, though the impact on the national total will be minimal. Fishery and other local amenity/recreational interests may prove the greatest barrier and require the most mitigation in a scheme, though an appropriate way of assessing the impact was not suggested prior to modelling.

The only World Heritage site in Scotland to contain hydro potential is New Lanark, but in fact this has already been developed or would constitute refurbishment of historical sites, thus adding to the heritage value. As such World Heritage sites were not built into the model. Another land classification is 'Wild Places', the subject of a recent policy statement by Scottish Natural Heritage[6]. The quality of 'wildness' may include "natural character, remoteness and the absence of overt human influence". Wild Places are described as those places where wildness is best expressed, and although there is not a definitive list of Wild Places, it is advised in NPPG14[4] that this aspect of landscape character be protected in land-use planning, and also that Councils' protection of such areas be included in their development plans. Many Wild Places are likely to have the climate and topography suited to hydro developments, though they are less likely to have favourable grid connections, so the impact may not be severe. As policy is still being developed Wild Places were not included in the model.

As with impacts of increasing hydro development on the national grid, there will be cumulative impacts upon the environment from each successive hydro scheme within an area. It is difficult to predict how many hydro developments a particular habitat can tolerate, but it seems likely that planning decisions will take into account existing development within the area, and may see this as a reason to restrict development. Because some areas will have a greater density in terms of hydro potential (see Appendix 2), it might not be appropriate to assume a single maximum amount of hydro development per unit area across the whole of Scotland's designated areas. Instead, reducing hydro potential by a predetermined proportion may be a fairer way of countering cumulative impacts while taking a pragmatic approach in areas of high potential.

For a scheme within the least restrictive tier of designation, the design flow was reduced by a small proportion. For each higher tier, the design flow was again reduced by the same proportion (please refer to Appendix 1 for values). For example, when the reduction factor is 0.8, the design flow of sites within Tier 3 is calculated as:

$$\text{Design flow} = 1.5 \times \text{annual mean flow} \times 0.8^3$$

Therefore the design flow is reduced from 1.5 to 0.77 of annual mean flow. In real hydro schemes, an individual scheme size may not actually reduce, but in Tier 3 only half the sites may succeed. Therefore on an aggregated level, the total installed capacity of the region reflected the constraint and deterrent posed

[6] http://www.snh.org.uk/strategy/pd02c.asp

by land designations. These values are arbitrary and are for the purpose of conducting a sensitivity analysis. They are not recommendations.

3.6 Initial Cost and Revenue Analysis

Empirically-derived equations were used to calculate costs for each element of the equipment, installation, specialist services, licensing etc. These were summed to give capital cost and annual operating cost for each layout.

The revenue was based on income from sale of electricity and Renewable Obligation Certificates (ROCs). A constant price was used to reflect the fact that ROC prices should fall as 'grey electricity' revenue prices rise. The revenue was discounted at a predetermined rate to determine the cost of energy and Net Present Value (please refer to Appendix 1 for values).

Together with the installed capacity and capital cost of the layout, the cost of energy was used to evaluate the layout in comparison to all other layouts on that same reach of river. This included comparison of storage schemes that overlapped run-of-river schemes, and the use of multiple intakes *versus* separate small schemes.

3.7 Calibration and Validation

The construction and application of the tool was first calibrated for micro-hydro, in conjunction with Black & Veatch for the costs, then through visits to a sample of run-of-river sites identified throughout the North and South Esk catchments near Edinburgh. Further physical calibration was conducted in the Loch Earn catchment in Perthshire, in collaboration with Black & Veatch, again visiting sites predicted by the model and adjusting the model accordingly.

Thirdly, detailed estimated costs for two further schemes were provided by Black & Veatch, and compared to the outputs of the model. In this case Hydrobot successfully replicated the approximate layout of one scheme so costs could be compared without further intervention. For the second scheme, Hydrobot initially recommended two separate smaller schemes, so its selection criteria were overridden to produce the layout described by Black & Veatch. This allowed comparison and calibration with the second scheme. The costing formulae were adjusted to replicate Black & Veatch's costings, updated to 2008 prices.

Costs and dimensions for an actual hydro scheme were provided by Garbhaig Hydro Power Company, and Hydrobot's prediction for that site was compared to the actual figures, updated to 2008 prices. Results of the comparison are given in section 4.2.

3.8 Sensitivity Analysis

The sensitivity analysis was structured to provide the FHSG with a clearer idea of the relative influence of certain legislative factors on Scotland's economically viable hydro resource. To this end, typical values were selected for the parameters in question and the model was run in its entirety to produce a baseline scenario. Each parameter was then varied separately, and the model was rerun for the whole of Scotland.

The parameters and the values used are detailed in Appendix 1.

3.9 Additional Work

The following additional work inputs were also undertaken: -

- Natural heritage designations (including salmonid rivers) were incorporated into the initial site selection process, rather than being applied subsequent to selection and evaluation of the resource.

- The potential of some sites was improved by simulating multiple intakes. Where two projects were in close proximity, a comparison was made between a combined project and keeping the two separate. Where the site evaluation of the joined schemes was better, this was adopted as the preferred layout.

- A request was made to take account of roads and railways in the selection process, since the presence of a road can increase development costs, and since the railway operator can charge up to 33% of the project's NPV to allow a penstock to pass beneath the railway. OS data were used to fulfil this request.

- The need for additional time inputs for re-runs of the sensitivity analysis were identified as being likely at the time of preparation of the original tender, depending on the number of parameters to be considered. This requirement was agreed and further processing time assigned.

- During tender preparation, discussion was held with SEPA about information regarding existing weirs across Scotland. This dataset was not complete at the time, and when it was delivered it was only partially completed. However, it was possible to adapt the dataset for incorporation into the model, so that the hydro potential from these existing weirs, although often small, could be included in the study. A total of 1951 weirs have been modelled.

- The incorporation of man-made alterations to watercourses was requested and various sources of information on abstractions and discharges were discussed. SEPA supplied a database of abstractions throughout Scotland and, due to the sheer number of abstractions, those equivalent to a mean flow greater than $0.1m^3/s$ were considered. Where an abstraction coincided with a new scheme identified by Hydrobot, and the abstraction was greater than 10% of the mean flow in the river (i.e. enough significantly to affect the hydro scheme), the hydro scheme was removed from the results. This amounted to 5 weirs and 38 run-of-river schemes with a total installed capacity of 10.5 MW.

- For reasons of national security, the location of all drinking water abstractions have not been and cannot be incorporated, but an estimate of the effect was sought. Where drinking water is abstracted from groundwater there is no hydro potential. Where water is abstracted from rivers using an existing weir, the effect upon hydro resources will have been accounted for as described above. The remaining drinking-water abstractions are from reservoirs. It is now possible to install hydro turbines within the potable water system[7], so the existence of a potable water reservoir should not detract from the hydropower potential. For this reason, potential schemes located on reservoirs were not removed.

[7] Rentricity Services Overview (2005). Available online: http://www.rentricity.com/serv_overview.htm

4 Results and Discussion

4.1 Phase 1

Phase 1 demonstrated that the theoretical absolute limit on energy that could be drawn from flowing freshwater in Scotland is 5.4GW. This would imply an annual energy of 47.3 TWh.

These figures do not represent energy that could in reality be harnessed, which would mean using every litre of water that did not evaporate, from where it landed to the sea. As water is required for other purposes, such as drinking and sustaining aquatic life, these figures should be regarded merely as a ceiling that could never be exceeded.

4.2 Validation Results

The actual layouts of many existing schemes were compared to the modelled layout at the same site, as these schemes had to be removed from the results. In general, the modelled layout of schemes with one principal intake was close to the actual layout. Exceptions arose where there were site-specific obstacles or favourable locations that could not be predicted remotely, or incorporated into the current modelling process. Some multiple-intake schemes were modelled as separate smaller schemes, though their combined power was typically similar to the actual scheme. Also, some weir height estimates were sensible but inaccurate. Because there is no better method for estimating weir heights where these are not available, the estimates are acceptable.

The Garbhaig hydro scheme, the case provided by FHSG to validate the model, runs from Loch Garbhaig, south-west of Loch Maree in the north-west of Scotland. The scheme has a gross head of 163 metres from Loch Garbhaig to the power station, which is located a short distance upstream from Victoria Falls, a popular tourist attraction. The turbine is rated at 1000kW, and was installed along with a 1100m penstock in 1993. Since then some of the penstock has been replaced, and a new generator and control system are shortly to be installed. The total capital cost for the scheme was adjusted to take into account installation of these modern components, and updated to 2008 prices using a Producer Price Index for output of manufactured products.

The baseline scenario produced a scheme at the site, incorporating Victoria Falls and stopping short of Loch Garbhaig. The gross head, at 157m, was deemed sufficiently close to the actual site layout. However, the scheme was configured as run-of-river as opposed to storage, because the topography at the intake site would not be suitable for creation of a new reservoir. As a result the installed capacity was only 598kW. To better emulate the existing scheme, the site was remodelled as a storage scheme, and the result had an installed capacity of 998kW.

Actual costs for Garbhaig cannot be listed as these are commercially sensitive, though the modelled scheme had a capital cost that was 6.99% greater than the actual cost. It is worth putting this level of accuracy into context of typical hydropower pre-feasibility studies, to which the outputs of Hydrobot are equivalent. The British Hydropower Association has suggested that a typical pre-feasibility study seeks an accuracy of ±25%. The Canadian hydropower costing software RETScreen was either 11% higher or 9% lower than its validation site's actual cost, depending on certain adjustments to take into account site specifics. In comparison, Hydrobot's simulation of Garbhaig has a high accuracy. Since the purposes of this study are to gauge total capacity (not total cost), and sensitivity of that capacity to certain drivers, this accuracy is appropriate for this study.

While more extensive validation data were sought, FHSG was unable to obtain further examples due to the commercial sensitivity of such data.

4.3 Phase 2

Using data from Scottish Renewables, it was possible to locate all existing schemes with an installed capacity of 700kW or more. It became clear that some of the existing large-scale schemes had been established with less emphasis on their environmental suitability, in that they involved vast civil engineering works in order to transfer water between catchments. Therefore, rather than trying to replicate these schemes using the current model, the watercourses supplying these schemes were identified, so that affected weirs, dams and reaches of river could be excluded. As schemes where water might be diverted from one catchment to another are beyond the scope of the current study they could form the basis of a future study as outlined below.

The baseline scenario produced a total of 36,252 potential schemes across Scotland, including all schemes that were not financially viable (**Table 3**). They represent a total potential of 2,593,317 kW, or 2.59GW. The financially viable potential, defined as schemes which show a positive Net Present Value after the recovery period (25 years in the baseline scenario), was 657,259 kW, or 657 MW, across 1,019 schemes. Together these schemes represent an annual energy output of 2.77 TWh. The full summary of results for each catchment is tabulated in Appendix 4, and the results are mapped as power per unit area in Appendix 2. A breakdown by scheme size is listed in **Table 4** and illustrated in **Figure 3**.

The baseline scenario shows very poor potential for micro-hydro (<100kW) but this should not be taken as an indicator that there is no micro-hydro potential. The baseline scenario represents the investment preferences of a typical hydro developer and, in fact, hydro developers will generally not invest in micro-hydro schemes, tending more towards the 1 MW threshold. An indication of the micro-hydro potential is given in section 4.5 below.

A comparison between the financially viable resource from this study and those of previous studies is given in **Figure 4**. The closest agreement is with the 1 GW predicted by the Scottish Study, conducted in 1993. Further details of these studies can be found in section 2.

Table 3. Summary of total and financially viable potential hydropower schemes in Scotland, using Hydrobot's baseline scenario. For input parameters, see Appendix 1.

Total number of schemes	Total potential power (kW)	Total potential annual energy (MWh)	Financially viable schemes	Financially viable power (kW)	Financially viable annual energy (MWh)	New Dams
36,252	2,593,317	10,644,403	1,019	657,259	2,766,682	128

Table 4. Breakdown of financially viable schemes by scheme size. For each band, the number of financially schemes identified is given, along with the total installed capacity represented by those schemes. These data are illustrated in **Figure 3**.

Power band	< 100kW	100kW - 500kW	500kW - 1MW	1MW - 5MW	5MW - 10MW	> 10MW
Number	6	537	300	170	6	0
Potential power (kW)	450	150,378	193,202	276,640	36,200	0

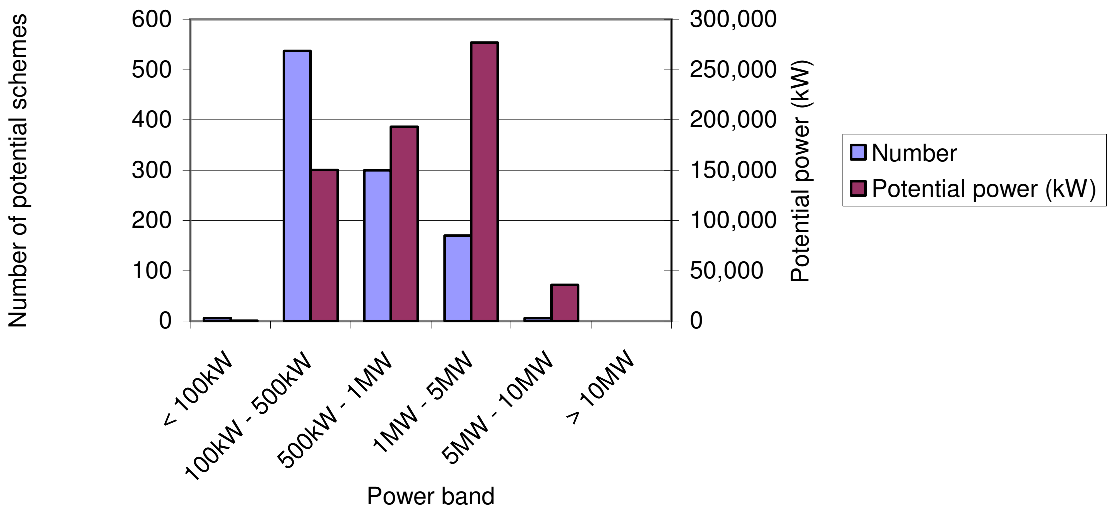

Figure 3. Number of financially viable schemes, and total power represented by these schemes, within each power band, from baseline scenario.

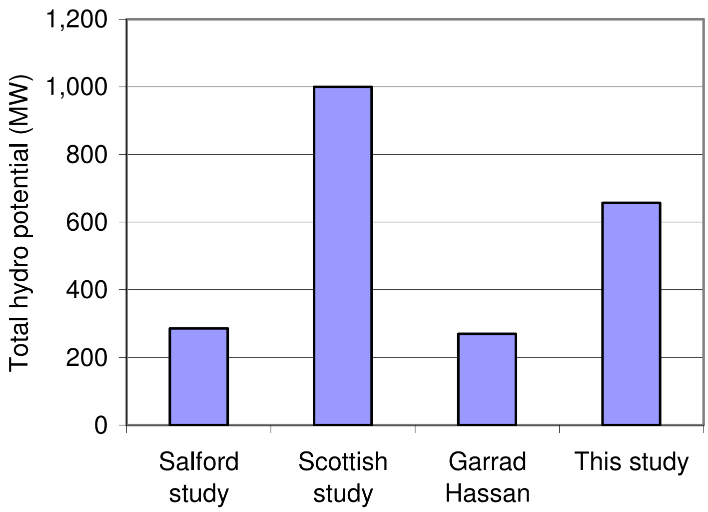

Figure 4. Comparison of results between previous national hydro resource studies and the present study. For details of the previous studies, see Section 2. Parameters used are roughly equivalent to the baseline scenario in this study.

Resource cost curves are a convenient method of showing how the total available power changes as the acceptable lifetime cost of energy changes. This can be interpreted as the amount of hydropower available for development depending on the amount an investor is prepared to spend per unit of power they install. The lifetime cost of energy is not the same as the market price of energy or electricity, which are retail values that change from day to day.

The power cost curve is shown in **Figure 5** and the energy cost curve in **Figure 6**.

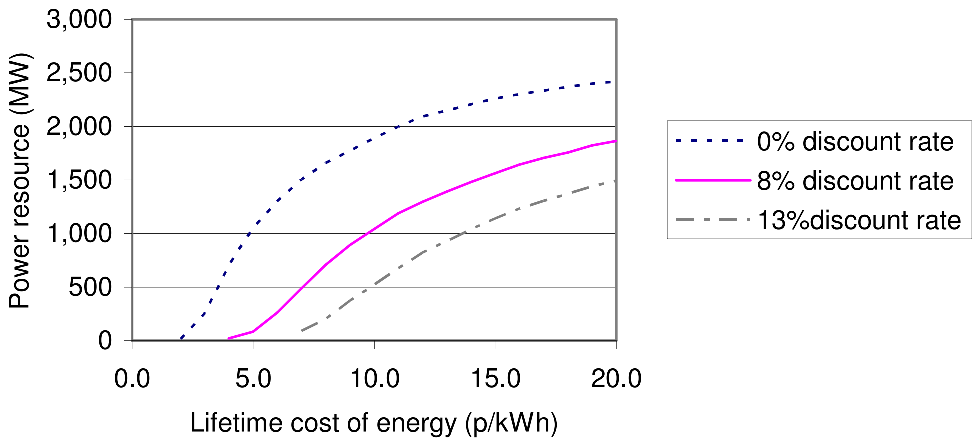

Figure 5. Power-cost curve, showing the increasing hydropower resource available for development as the cost per unit energy that the developer is prepared to pay increases.

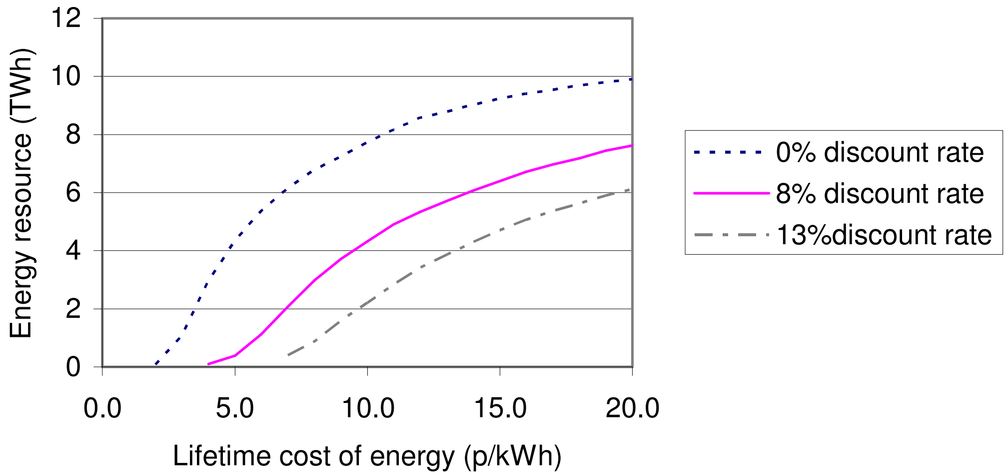

Figure 6. Energy-cost curve, showing the increasing energy available from hydropower as the cost per unit energy that the developer is prepared to pay increases.

4.4 Projects Affected by Each Level of Natural Heritage Designation

To gauge the number and total power of schemes falling within areas protected for their natural heritage value, the model was run with no restriction upon scheme size due to such areas, and also with 0% discount rate. This scenario generated 5,229 viable schemes with a total power of 2.04 GW. **Table 5** shows the number of financially viable schemes within each type of land designation, and the total power represented by the schemes. It should be noted that some areas have more than one natural heritage designation. Where a scheme passes through such an area, it is double-counted in each of the designations that apply – the actual number of schemes within designated areas is 2,153 representing a combined power of 936 MW, though this is less than the sum of the power column in **Table 5.**

The number of projects on a salmonid river is 1,112, representing over 20% of the total schemes from this scenario.

Table 5. Number of viable schemes within each type of area designated for its natural heritage value, as well as the total installed capacity represented by those schemes. Input parameters included no restriction on scheme size and 0% discount rate. Where a scheme falls within more than one designation, it has been counted in each relevant designation. This is not the same scenario as that used in the sensitivity analysis.

Natural Heritage Designation	Number	Total installed power of schemes affected (kW)
Gardens and Designed Landscapes	82	42,929
Sites of Special Scientific Interest	1,076	513,094
National Nature Reserves	1	41
Local Nature Reserves	752	462,100
National Parks	145	75,578
National Scenic Areas	1,253	517,485
Ramsar Wetlands	497	190,250
Special Protection Areas	36	15,478
Special Areas of Conservation	319	87,322

4.5 Sensitivity Analysis

The sensitivity analysis was conducted by re-running the model, varying one parameter at a time. The parameters being tested are listed in Appendix 1.

The sensitivity of the total remaining hydro potential in Scotland to the variation in each parameter was measured using the Sensitivity Index (SI) as described by Haefner (1996)[8]:

$$SI = \frac{\dfrac{R_u - R_l}{R_n}}{\dfrac{P_u - P_l}{P_n}}$$

where R_u , R_l and R_n are upper and lower altered responses and the nominal response respectively, and P_u , P_l and P_n are the upper and lower altered and nominal input parameters respectively.

[8] Haefner, J.W. (1996). *Modelling Biological Systems*. Chapman & Hall, New York.

Table 6. Results of sensitivity analysis.
Each parameter had a lower, medium, and upper value, with the medium value being used in the baseline scenario or when that parameter is not being varied. The exceptions to this are the SEPA license threshold, where the lower value was used in the baseline scenario, and the cost of crossing a railway where the upper value was used. The values listed in columns 2 to 7 are used to calculate Haefner's Sensitivity Index (SI; see above). The magnitude of the SI has been used to rank the parameters, with 1 having the greatest influence on Scotland's total potential hydro resource.

Parameter	Lower value	Normative (or medium) value	Upper value	Lower response (kW)	Normative (or medium) response (kW)	Upper response (kW)	Sensitivity Index	Ranking of SI
Discount rate	0%	8%	13%	1,538,191	657,259	186,957	1.27	1
Land designation multiplier	0.6	0.8	1	557,338	657,259	765,599	0.63	4
Recovery period (years)	15	25	35	387,617	657,259	787,438	0.76	3
Electricity revenue (£/MWh)	35	55	75	657,259	969,269	1,206,179	1.27	2
Business rates (£/kW)	7	9	11	715,103	657,259	703,468	0.04	5
Railway crossing cost limit (% of NPV)	0%	5%	33%	658,529		657,259	0.002	8
SEPA license threshold (MW)	0.1	2	4	657,259	667,456	658,155	0.001	9
SEPA subsistence charge threshold (MW)		2 & 5	4 & 10		657,259	665,718	0.01	7
Double ROCs threshold (MW)	0	0.05	1	657,259	659,685	1,104,942	0.03	6

When referring to **Table 6** it is worth bearing in mind that an SI of zero would mean the parameter had no effect on the total hydropower potential, while an SI of 1 would mean that the total was proportional to that parameter.

The scenarios listed in **Table 6** will have relevance for different readers. Commercial investors will be interested in the scenarios with 8% and 13% discount rates, and a recovery period of 15 years. These aggressive investment terms take into account the uncertainty of success that an investor must bear when developing a portfolio of projects.

Small landowners may prefer to look at 0% discount on cashflows, the scenario in which double ROCs are available for projects below 50kW, or a longer recovery period before break-even is required. The results for the <100kW band within these scenarios is given in **Table 7**.

The 3 major influences (discounting of cashflows, electricity revenue prices and recovery period) are either market driven or down to the choice of the investor. It can be seen that the multiplier used to reduce the design flow for different degrees of land designation has the next highest SI. The number of schemes within designated areas is significant enough that policy decisions affecting those areas will have a strong effect on the national available resource. The approach taken for this study was to reduce the installed capacity of schemes according to the degree of designation, and this is not necessarily the case. However, this shows how important it will be to establish exactly what impacts land designations have had on the size, cost or success rate of existing schemes. This is discussed further in section 5.

The remaining 4 factors are also within the control of policy-makers, except for the cost of crossing a railway, which has so far been driven by case history. It is worth noting that there is a considerable drop in sensitivity before these policy-driven factors. Therefore the major influences, excepting land designations, are factors that are outwith the control of policy-makers. Industry can, however, take comfort from the fact that, even in the worst of the modelled scenarios, there are still 201 MW of financially viable hydro potential yet to be developed in Scotland.

The slow decision-making process has been an area of contention between the developers and planners. The Electricity Act 1989 specifies that the consent of Scottish Ministers is required for the construction and operation of standard units in excess of 1MW in the case of hydro and marine developments (Section 36) and for most power lines (Section 37). Below this level, applications are processed under a separate planning regime by relevant planning authorities under the Town and Country Planning (Scotland) Act 1997. Following the report of the FREDS Planning and Consenting of Renewables Sub Group at the end of 2007 on their concerns in the delays in reaching a consent on proposals, the Minister formally responded to provide the desired approach to streamlining the process including an undertaking that a decision should be reached within 9 months, where a public inquiry is not being undertaken[9]. The FREDS Sub Group has called for a public enquiry to only be triggered by a material planning consideration and for the subsequent enquiry to focus on that particular issue. A more clearly defined guidance process is being considered by the Government as part of their approach to speeding up and improving the consultation process.

As part of the approach to streamlining the approval process, emphasis is being given for applicants to undertake more extensive scoping and undertake pre-application meetings with future stakeholders in order to minimise later disputes.

4.6 Micro-Hydro

The microgeneration resource, often defined as schemes smaller than 100kW, is commonly overlooked in energy studies, yet would be a significant contribution that can be increased further through grant schemes such as the Scottish Community and Householder Renewables Initiative (SCHRI) or the Scottish Rural Development Programme (SRDP). Also, planning rules whereby such schemes had permitted development status (i.e. planning permission would be granted without having to apply) should further increase the micro-hydro resource.

Table 7. The potential hydro resource comprising schemes smaller than 100kW, in three of the scenarios modelled in the sensitivity analysis. As with the Scottish hydro resource, the discount rate has the greatest impact on the total. These scenarios were modelled separately though there will be duplication of schemes between them.

Scenario	Number of schemes	Financially viable power (kW)
No cashflow discounting	1,422	93,117
Double ROCs for <50kW	70	3,171
35yr recovery period	16	1,216

The totals for three scenarios are given in **Table 7**: 0% discount on cashflows, the scenario in which double ROCs are available for projects below 50kW, and a longer recovery period. These totals for the financially viable micro-hydro resource may still be over-pessimistic for several reasons:

[9] http://openscotland.gov.uk/Topics/Business-Industry/Energy/Energy-Consents/Whatsnew/FREDS-Response

1. The model had to be calibrated to cover in particular the 1MW range, so costs for micro and pico-hydro may be overestimated (especially where the landowner may take on some work themselves, and may be more willing to take risks on cheaper methods or equipment).

2. The above factors were not run in combination, but rather one at a time.

3. Offsetting of onsite consumption was not part of the FREDS study, but would be part of many <100kW schemes, so more schemes would be economical.

4. Grants were not included, but would increase the total.

These four points can be addressed by adjusting Hydrobot's input variables and could comprise the basis of a further study. Analysis of areas using preferences suited to micro-hydro will also be available online from the Hydrobot website.

5 Conclusions and Recommended Follow-up

It has been possible by means of a GIS-based hydrological model to identify, cost and evaluate sites across Scotland where there remains untapped hydropower potential. The total financially viable resource in Scotland was found to be 657 MW installed capacity, the output of which would be 2.98 TWh of electricity per year. **However, grid and environmental constraints (Appendix 5 and Appendix 6) mean that only some of this could be connected.**

Repeated validation of the model at different levels has demonstrated the accuracy of the model. This has given confidence in the model's ability to gauge Scotland's remaining hydro resource under a variety of scenarios. The sensitivity analysis showed that the most influential factors were, in descending order of importance:

1. Discount rate applied to cashflows
2. Electricity revenue price
3. Recovery period
4. Natural heritage land designations
5. Business rates
6. Threshold for earning double ROCs
7. SEPA subsistence charge threshold
8. Cost of crossing a railway
9. SEPA licence threshold

While some of the policy-driven factors at the bottom of the list are of concern to industry and are the subject of research and lobbying, the sensitivity analysis has shown that these factors are not the most significant influences on the national resource. Market forces, which have a stronger effect, can be influenced to some extent by providing a stable support and permitting regime as these affect the investor's perception of risk and hence the discount rate that they will require. However, of the policy-driven influences, business rates are one of the most significant and easy to adjust.

This study is the first automated modelling of a nation's hydro resource, and has led to the development of many novel techniques in order to overcome gaps in current knowledge and data. There are many areas where further research is warranted, and it is possible to highlight some of the more important ones.

In assessing the impacts of protected areas, designated for their natural heritage value, an approach was devised where the level of protection led to a correspondingly severe reduction in the hydro potential of the area. The levels chosen for this study were arbitrary, but do show through sensitivity analysis that such an effect is likely to be significant upon Scotland's total resource. There is scope, then, to conduct a detailed study of existing schemes to determine the effect that local land designations had, upon their cost, installed capacity, or perhaps just on the timescale from inception to commissioning. Such information can then be applied to the results in section 4.4 above, or indeed to a re-run of Hydrobot, accurately to predict the effect of changing planning policy governing designated areas.

The current study has modelled schemes based on the principle that water is returned to the watercourse from which it is abstracted, but in fact larger schemes can be created by diverting water from one catchment to another. This technique was used for many of the well-established and larger scale schemes that were constructed in the 1950s and 1960s. Such schemes can have serious environmental consequences, and identifying opportunities for such diversions is not readily automated. As it is beyond the time and resources available for the current study, this could form the basis of a future project, possibly using the detailed outputs of this study as a starting point.

Many weir heights had to be estimated, as there are no records of heights for most of the weirs around Scotland. At least one local authority is considering a survey of historic mills and weirs to gauge their hydro potential, and such sites can make a contribution to a region's total potential, particularly in flatter regions. It might be affordable for a large number of weirs to be visited and measured if no further site investigation or hydrological knowledge were required, or if an automated data capture and integration system could be used. The results could then be used by Hydrobot to produce a more accurate assessment of the low-head potential. If changes are being considered regarding grants for renovating existing civil works, or regarding planning requirements for historic buildings, such an assessment could be very helpful.

By seeking to quantify Scotland's hydropower potential through cutting-edge modelling techniques, FHSG is helping to fulfil Scotland's ambitions to have 50% of the demand for electricity supplied from renewable resources by 2020. This study has shown that the available and economical hydro resource in Scotland can play a significant role in reaching the Scottish Government's renewable energy targets. It is now evident that factors such as natural heritage designations and business rates will dictate how much of a contribution hydropower will make in practice. Therefore, there is justification to scrutinise the hydro planning process for unnecessary delays and restrictions, particularly where the impacts are weaker and defensible with simple mitigation measures, without sacrificing an appropriate level of environmental conservation.

Appendices

1. Datasets and Parameters
2. Map of Rainfall Catchments
3. Phase 1 – Table of theoretical output by catchments
4. Phase 2 – Potential Production by Catchments
5. Grid Connection Analysis
6. Environmental Factors

Appendix 1: Datasets and Parameters

Environment and Development Datasets

The following datasets were used as inputs to the model: -

- Ordnance Survey Land-Form PROFILE DTM: elevation data
- Ordnance Survey Code-Point: postcode data
- Ordnance Survey Strategi
- Scottish Natural Heritage: Scotland Gardens and Designed Landscapes; Scotland Local Nature Reserves; Scotland NNRs; Scotland National Parks; Scotland SSSIs; National Scenic Areas; Scotland Special Areas of Conservation; Scotland Special Protection Areas; Scotland Wetlands of International Importance (Ramsar)
- National River Flow Archive: flow duration statistics for 1721 gauging stations in UK
- Scottish Power Long-Term Development Statement
- Scottish Hydro-Electric Power Distribution Long-Term Development Statement
- Salmonid Waters: defined using SEPA's baseline digital river network
- Turbine efficiency curves from Newmills
- SEPA Water Environment Charging Calculator

Parameters for Sensitivity Analysis

The following values were used in the baseline (or initial) run of the model, and were varied in the sensitivity analysis. The underlined values were used as the baseline scenario as these reflect a commercial investment. These values are either the current standard, or reflect a consensus of opinion and are open to debate, but in either case are sufficient to allow sensitivity analysis. The effect of any error on the total can then be estimated.

- Discount rate: 0%, <u>8%</u>, 13%
- Reduction in design flow of run-of-river turbines, for different tiers of environmental designation: 0.6^{tier}, <u>0.8^{tier}</u>, 1 (where *tier* is 0 for no designation, to 3 for most restrictive designation)
- Recovery period: 15, <u>25</u>, 35 years
- Electricity revenue: <u>£35/MWh</u>, £55/MWh, £75/MWh (ROCs were held at £45/MWh)
- Business rates: £7/kW, <u>9/kW</u>, 11/kW
- Cost of crossing a railway: 0, <u>33%</u> of NPV
- SEPA license threshold: <u>100kW</u>, 2MW, 4MW
- SEPA subsistence charge thresholds: <u>2 & 5MW</u>, 4 & 10MW
- Threshold for double ROCs: <u>0</u>, <50kW, <1MW

There were a total of 16 sensitivity runs. For the majority it was possible to use the results of the baseline scenario as an input, thereby avoiding complete reruns of the model. However, for variables 2 and 7, the configuration of the site may change as a result of the changed parameters and therefore a full run of the model was necessary for the adjustments of these two variables.

Appendix 2: Map of Rainfall Catchments with Power per Unit Area (Phase 2)

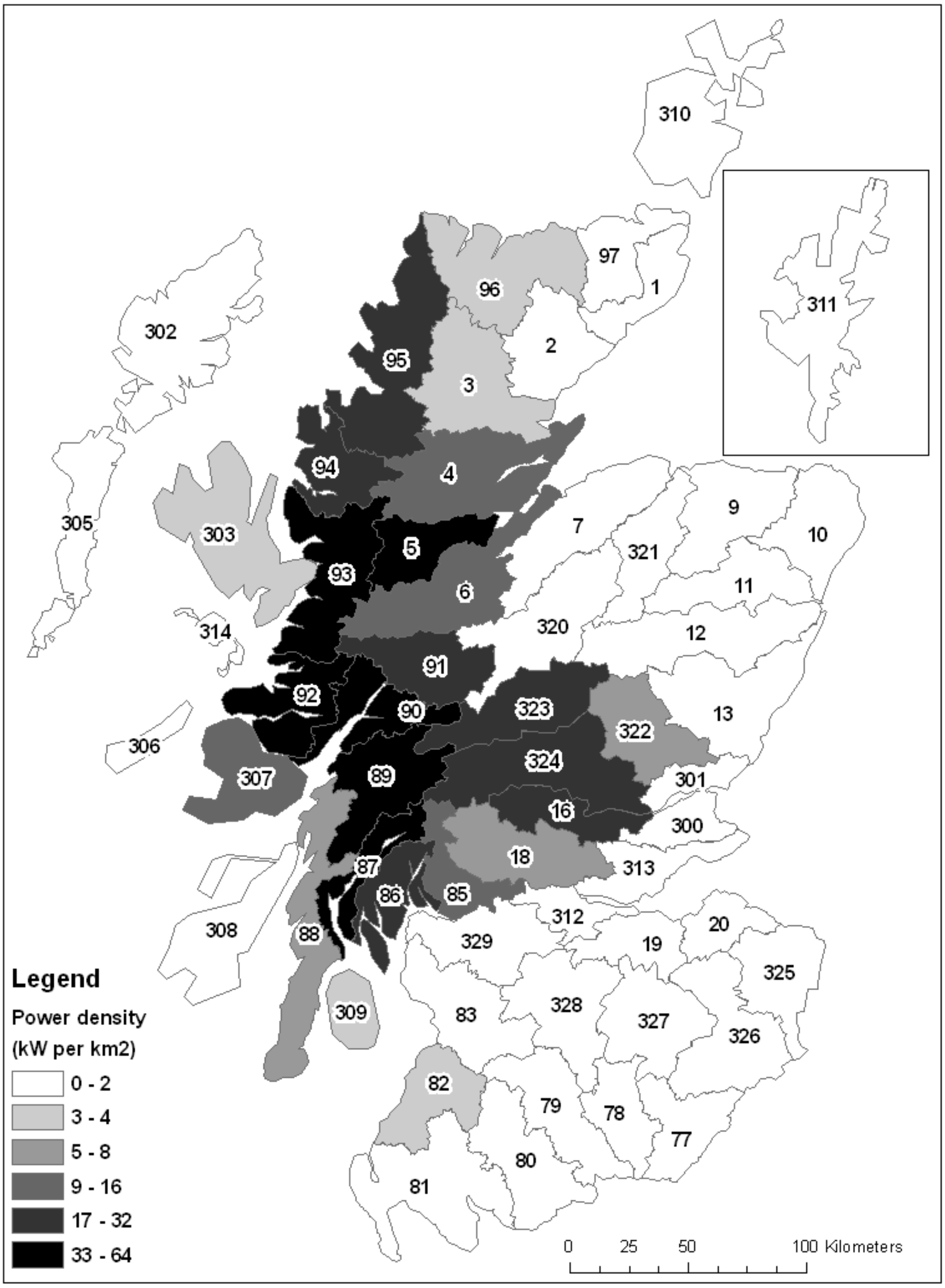

Figure A2.1. Map of Scotland divided into 60 catchments. Numbers within catchments refer to catchment ID, ranging from 1 to 329. Shading indicates potential hydropower within that catchment (produced in Phase 2), divided by the area of the catchment, to give power density.

Appendix 3: Phase 1 Results

Table A3.1 : Results for phase 1 – the absolute theoretical limits on hydropower for Scotland, based on total rainfall reaching Scotland, less evapotranspiration losses. The potential installed capacities in the table assume that all rainfall could be captured as it hit the land, and stored so that it could be released through hydro power stations at a constant rate, achieving a constant system efficiency of 70%. Calculated using elevation data at a resolution of 10m x 10m, with streamflow data from 314 natural flow gauging stations across Scotland.

Catchment	Potential power (MW)		Catchment	Potential power (MW)		Catchment	Potential power (MW)
1	18.8		81	89.7		305	15.5
2	61.2		82	66.3		306	1.6
3	131		83	60.2		307	85.6
4	181.2		85	83.1		308	48.8
5	137.1		86	92.4		309	26.1
6	175.5		87	88.5		310	9.4
7	88.4		88	91.2		311	31
9	40.2		89	258.2		312	14.5
10	12.7		90	186.4		313	13.2
11	53.3		91	173.1		314	13.8
12	182.3		92	139.2		320	150.5
13	96.5		93	225.1		321	82
16	78.8		94	117		322	87.1
18	129.4		95	191.9		323	253.1
19	21.7		96	114.7		324	302
20	6.9		97	17.3		325	23.2
77	58.8		300	6.2		326	72.7
78	53.4		301	5.6		327	116.5
79	81.9		302	72.8		328	86.8
80	108		303	133.2		329	41

Table A3.1 above shows that the theoretical absolute limit on energy that could be drawn from flowing freshwater in Scotland is 5.4GW. This would imply an annual energy of 47.3 TWh. ***These figures do not represent energy that could in reality be harnessed***, which would mean using every litre of water that did not evaporate, from where it landed to the sea.

Appendix 4: Phase 2 Results

Table A4.1 : Phase 2 Results, showing potential by catchment. These figures are the results of the baseline scenario, using the underlined parameters in Appendix 1. Financial viability is defined as having a positive Net Present Value by the end of the recovery period (the minimum lifespan of 25 years in the baseline scenario). N.B. Area includes a small amount of open sea.

Catchment	Area	Total number of schemes	Total potential power (MW)	Total potential annual energy (GWh)	Financially viable schemes	Financially viable power (MW)	Financially viable annual energy (GWh)	New Dams
1	930	109	5.8	26.3	1	0.2	0.8	0
2	1,406	375	38.4	142.5	6	1.5	6.1	0
3	1,975	649	60.7	237.6	9	7.8	33.8	2
4	2,314	1,014	93.9	351.8	19	18.9	69.5	2
5	1,026	797	98.0	392.3	37	38.7	157.6	4
6	1,999	1,049	119.3	469.0	44	26.9	108.6	5
7	1,890	425	40.9	156.3	3	1.2	4.8	0
9	1,677	231	10.5	37.4	0	0.0	0.0	0
10	1,401	32	1.9	8.3	0	0.0	0.0	0
11	1,316	278	24.9	106.5	0	0.0	0.0	0
12	2,133	719	33.0	166.7	4	1.0	5.5	0
13	2,077	587	35.5	153.9	1	1.2	6.2	0
16	931	616	44.1	184.5	28	14.9	65.4	2
18	1,620	961	48.5	210.3	26	11.2	51.6	4
19	924	179	9.9	39.8	0	0.0	0.0	0
20	710	83	2.6	10.4	0	0.0	0.0	0
77	1,124	494	21.2	82.2	0	0.0	0.0	0
78	968	379	24.2	97.4	3	1.0	3.7	0
79	1,500	638	38.7	148.8	1	0.4	1.8	1
80	1,603	397	32.0	126.7	0	0.0	0.0	0
81	2,268	487	40.6	162.0	8	2.7	12.6	2
82	1,152	468	31.4	124.8	4	3.1	13.1	0
83	1,615	427	27.6	115.4	5	1.5	6.4	1
85	838	675	37.0	163.6	19	10.5	48.0	1
86	836	1,102	50.6	222.4	64	22.6	101.1	6
87	816	1,018	73.4	296.8	55	41.7	167.4	6
88	1,774	1,335	57.5	231.2	29	11.2	46.4	2
89	1,557	2,056	186.0	734.1	84	60.5	239.9	15
90	1,133	1,533	103.9	422.4	64	44.0	186.0	15
91	1,328	900	97.8	405.5	33	30.7	136.0	8
92	1,314	1,683	90.5	374.6	75	40.7	169.0	4
93	1,909	1,978	164.7	639.2	70	59.8	235.9	16
94	1,136	936	76.0	314.3	48	32.2	133.9	4
95	2,466	1,568	126.0	521.4	61	50.4	210.9	10
96	2,144	746	58.3	255.5	11	7.6	37.8	1
97	1,047	63	9.5	43.0	0	0.0	0.0	0
300	655	69	3.1	13.4	0	0.0	0.0	0
301	511	64	2.0	8.2	0	0.0	0.0	0
302	2,694	828	28.8	124.4	6	1.1	5.3	0
303	2,358	1,640	63.6	253.1	26	9.8	41.0	4
305	1,296	23	0.2	0.9	0	0.0	0.0	0
306	342	13	0.1	0.5	0	0.0	0.0	0
307	1,347	1,106	40.2	176.0	32	10.7	47.5	3
308	1,624	573	24.7	102.0	6	1.8	7.6	0
309	581	305	11.2	48.3	7	1.8	8.5	1
310	2,154	68	0.9	4.3	0	0.0	0.0	0
311	2,156	308	6.1	20.2	0	0.0	0.0	0
312	616	118	5.1	20.3	0	0.0	0.0	0
313	955	115	5.6	23.4	0	0.0	0.0	0
314	196	160	3.8	19.3	1	0.1	0.7	0
320	1,983	567	25.2	118.3	3	0.6	3.2	0
321	1,191	433	21.2	96.5	0	0.0	0.0	0
322	1,338	122	24.1	106.9	9	6.8	30.0	0
323	1,541	267	82.9	359.2	38	30.0	139.3	4
324	2,200	379	114.8	497.4	74	48.0	216.0	4
325	1,319	151	18.0	78.1	0	0.0	0.0	0
326	1,855	414	17.9	76.2	0	0.0	0.0	0
327	1,562	747	22.4	94.2	2	0.6	2.8	0
328	1,691	375	24.6	100.9	0	0.0	0.0	0
329	1,323	420	31.9	126.9	3	1.2	4.8	1
		36,252	**2,593**	**10,644**	**1,019**	**657**	**2,767**	**128**

Appendix 5: Grid Connection Issues

This section contains an analysis of the impacts that much wider development of hydropower would have on the transmission and distribution grids in Scotland. To tackle this complicated subject, the analysis has been broken down into the following sections:

- Network description
- Discussion of constraints to embedded generation
- Review of previous studies
- Current, planned and future embedded generation
- Analysis of voltage rise issues
- Analysis of thermal limits and fault levels
- For each constraint, implications for hydropower in Scotland.

Network Description and Development

The UK national grid is divided into the high-voltage bulk power transmission system, and lower voltage distribution systems connecting this to loads. The schematic structure of the UK network is shown in Figure A5.1. In Scotland, 132kV is regarded as the transmission voltage.

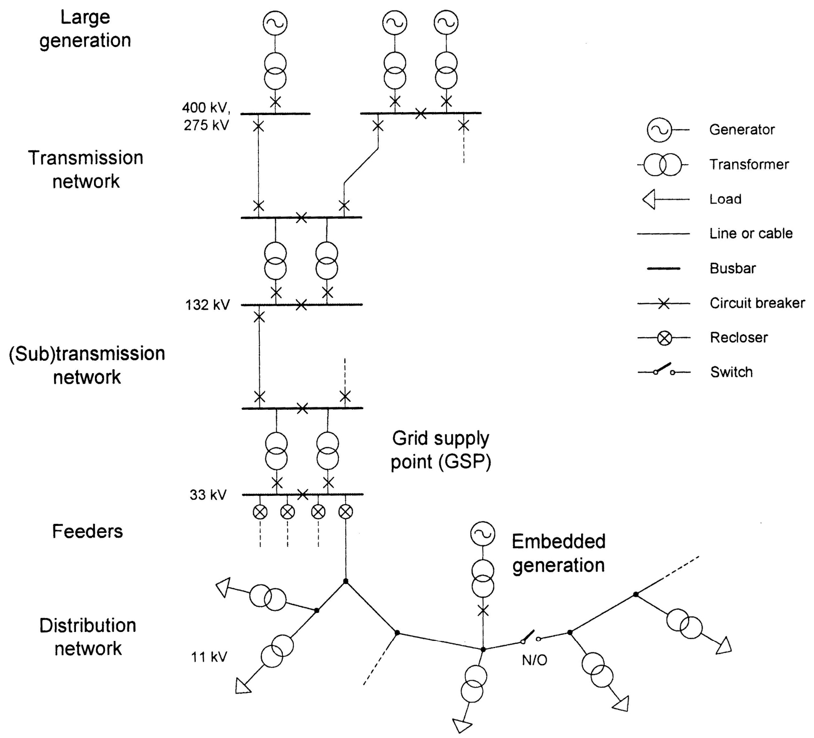

Figure A5.1. Schematic layout of the UK electrical grid [10]

The distribution network in Scotland is divided into two areas operated by two vertically integrated groups. Scottish Power (SP) UK Plc own and operate the network across the central belt, while Scottish and Southern Energy (SSE) UK Plc operate the network north of the central belt, including the islands. Subsidiary companies within the groups hold licenses for generation, transmission, distribution and supply. The two areas are summarised in Table A5.1. SSE operates across a larger area, but with lower population density, and a larger proportion of rural customers. In general, SSE has longer rural distribution lines compared to the rest of UK, and includes some very remote areas, islanded networks, and networks connected by undersea cables. Any embedded generation in these areas will require special consideration before proceeding.

Table A5.1 Characteristics of DNO's areas of operation [11][12]

Group	Area Sq. km	Consumers 000's	Lines Km	Cables Km	Max Demand GW
SSE	51 900	600	31 300	14 500	1.25
SP	20 300	1 600	16 700	14 600	4.00

[10] Boehme T. (2006). Matching Renewable Electricity Generation with Demand in Scotland, Institute of Energy Systems, University of Edinburgh, PhD study.

[11] Scottish Power Distribution Ltd (2006). Distribution Long Term Development Statement for SP Distribution .

[12] SSE Power Distribution (2007). Long-term Development Statement for Scottish Hydro electric Power Distribution plc's Electric Distribution System, Scottish and Southern Energy plc.

The current electricity network was designed to supply power from a relatively small number of large thermal power stations to a geographically dispersed load. Consequently, power flows from generators, through the high-voltage transmission system, to the distribution system, and then to customers.

However, the recent drive for renewables has seen smaller (<100MW) generators seeking to connect to the distribution network – referred to as embedded or distributed generation – since connecting to the transmission network is impractical and uneconomic. This leads to a number of issues which may constrain the amount of generation which can be connected at a particular point, including:

- Fault level limitations;
- Voltage limits;
- Line current ratings;
- Power quality issues (harmonics, flicker etc);
- Transient stability; and
- Transmission constraints.

Fault levels

The fault level is the maximum current that will flow in a particular circuit following a fault, usually a short circuit. The maximum acceptable fault level is determined by the ratings of local circuit breakers, which isolate the circuit following a fault. Any embedded generation on a circuit will add to the fault level; before a generator can connect it must be established whether the circuit breakers have sufficient 'headroom' to accommodate the increase in fault level. The Distribution Network Operator (DNO) can add the cost of an upgrade to the connection charge.

Fault level constraints can be mitigated in a number of ways. There are a number of current-limiting components which could be connected, although these are generally expensive, and would make many generators uneconomic. Network-splitting is sometimes employed as a short-term measure: parallel circuits have reduced fault currents. Network-splitting can be employed at minimal cost, although it reduces the flexibility of the network and will increase losses.

The most common mitigation is to upgrade switchgear to higher ratings. One study put the cost of upgrading 11kV switchgear at £20,000[13], though the complexity involved means upgrading fault ratings may only be an option at 33kV and above[14].

Voltage control

Voltages supplied to customers must be kept within limits, specified by regulation 27 of the Electricity Safety, Quality and Continuity Regulations 2002. These are shown in Table A5.2

[13] Econnect Consulting (2006). Accommodating Distribution Generation. Report for the DTI.
[14] Carbon Trust (2003). Renewables Network Impact Study. Mott MacDonald, Report to the DTI.

Table A5.2 Permitted voltage levels in the UK

Voltage levels	Limits
132 and above	±10%
33	± 6%
11	± 6%
230V single phase 400V three phase	+10†, -6%

† this is likely to revert back to ± 6% following the end of 240/230 V transition period

Figure A5.2 shows a typical voltage profile along an 11kV feeder. The source voltage is set so as to ensure the voltage along the length of the feeder does not drop below the statutory limits under maximum load. Embedding generation will reduce the voltage drop along the feeder, and in situations of low local load and high local generation, could lead to voltage rise at some points which exceeds the statutory limits. Voltages may also rise on LV circuits since they are not usually controlled by on-load tap changers.

Voltage rise is more of an issue on rural radial networks where the supply voltage is set close to maximum permitted to counteract the voltage drop along the feeder.

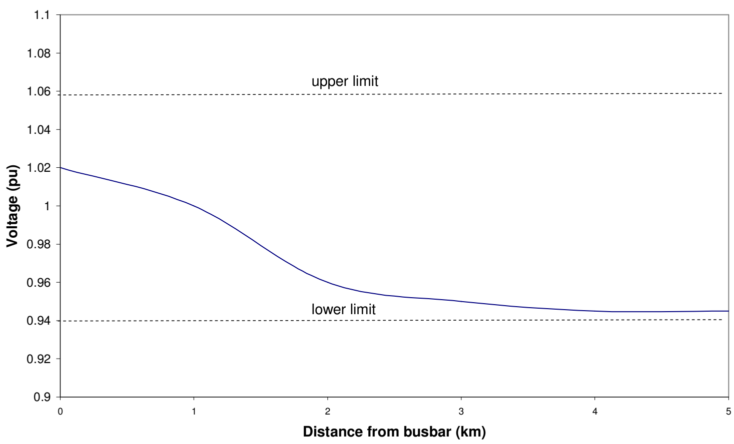

Figure A5.2 – Typical voltage drop along an 11kV feeder

Many DNOs apply line drop compensation (LDC) on rural lines, which boost voltages during times of peak load. Embedded generation on these lines may reduce the voltage boost provided in times of high load, and lead to low-voltage infringements on other adjacent feeders.

Voltage rise can be mitigated in a number of ways, including constraining generation and upgrading the capacity of the line. Reinforcing the network is the most commonly applied mitigation since it decreases losses and allows larger power transfers. However, it is expensive and may make a small scheme uneconomic. To upgrade 11kV line from 100mm^2 to 150mm^2 may cost in the region of £30 000 - £40 000 /km.

In future, a change to an active, coordinated system of voltage regulation may allow voltage constraints to be managed more efficiently[15].

Thermal ratings and reverse power flows

If local generation exceeds the local load, reverse power flows occur. Most transformers can accommodate reverse power flows, although some primary transformers have tap-changers with a much lower capacity in the opposite direction, and this may limit the amount of embedded generation which can be connected. If generation minus local load is larger than the peak winter load, then reverse power flows may exceed the thermal capacity of the line.

Power quality issues

Embedded generation may contribute to a number of power quality issues, such as voltage flicker caused by a fluctuating power output, or voltage dips due to a large inrush current when a generator is reconnected to the grid. However, these issues are less problematic for hydropower when compared to wind generation since sudden changes in power output are less frequent. Power quality constraints are unlikely to be encountered before voltage rise or fault level constraints are reached.

Transient stability

Embedded generation can affect the transient stability of a network, i.e. the ability of the system to stay stable following large load changes, switching and faults. For larger generators, or where there may be interaction with customers with large motor drives, steady state and transient stability studies may be needed to ensure the network remains stable following circuit switching or a fault[16]. In general transient stability issues are less of a constraint than fault levels and voltage rise.

Transmission constraints

Some embedded generation may impact on the transmission system, and may be liable for transmission system charges. Typically this will be where the generator is larger than 5MW and/or is more than the minimum demand at the 33kV busbar of the relevant 132/33kV substation. The transmission network in Scotland is already highly constrained, although most hydro schemes will be too small to impact on this.

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[15] ILEX Energy Consulting and G.Strbac (2002). Quantifying the system costs of additional renewables in 2020. Report to the DTI.

[16] SSE Power Distribution (2007). Long Term Development Statement for Scottish Hydro Electric Power Distribution plc's Electricity Distribution System, Scottish and Southern Energy plc.

Review of Previous Studies

As input to the 2003 Energy Review, the Carbon Trust investigated the impacts on distribution networks of meeting Renewable Obligation's 2010 target and 2020 goal, while at the same time expanding CHP to 10GW by 2010[14]

The location and size of new renewable generation was primarily based on real planned projects expected to be completed by 2010. The UK was split into eight regions, and a conservative estimate was made that if the capacity of embedded generation exceeded 20% of the regional load, then there would be areas where the capacity of embedded generation would exceed 100% of local load since generation would tend to cluster in areas of good resource.

The study estimated that in order to accommodate real planned projects in Scotland due for completion before 2010, the network would require immediate investment of £385m, including a significant amount of strategic reinforcing of the 132kV network. In order to fully meet the 2010 target, an additional £138m of investment would be needed.

General limits were proposed on the maximum amount of embedded generation, which might be accommodated at each voltage level. These are given in Table A5.3. The study also presented guidelines regarding fault levels.

Table A5.3 Proposed limits on generation capacity within voltage level[14]

Voltage kV	Maximum generation (MW)	
	On existing circuit	At substation
132	80	200
33	10	20
11	1.8	5
LV	0.2	0.2

A later study[13] assessed the cost of integrating future embedded generation on the UK distribution network, alongside projected growth of large renewables.

The current level of embedded generation was assessed, and scenarios for the future growth of renewables were produced, based on a number of published reports. UK-wide predictions were scaled down to a single section of distribution network supplied from a single Bulk Supply Point (BSP). The case-study network was modelled, with the addition of embedded generation shown in Table A5.4. It was assumed the section of network was in an area where high penetrations of wind and marine projects would occur.

The costs of managing these constraints were calculated under a business-as-usual network reinforcement programme, as well as under more radical approaches aimed to support embedded generation.

Table A5.4 Predicted capacity of embedded generation in the UK and at a single BSP[13].

	2005		2010		2030		2050	
	UK (MW)	BSP (MW)	UK (MW)	BSP (MW)	UK (MW)	BSP (MW)	UK (MW)	BSP (MW)
<11kV								
micro CHP	<50	0	500	0.4	3 000	2.5	9 000	7.8
micro wind	<50	0	<50	0.04	500	0.4	1 400	1.2
PV	<50	0	<50	0.04	250	0.2	1 000	0.9
≥11kV, <33kV								
CHP <10MW	5 000	4.2	8 000	6.8	10 000	8.5	10 000	8.5
Wind <10MW	200	0.2	400	0.3	900	0.8	900	0.8
LFG	600	0.5	600	0.5	300	0.3	300	0.2
Biomass	200	0.2	700	0.6	2 000	1.7	3 000	2.6
Marine	<50	0.4	50	0.04	200	0.2	200	0.2
EfW <10MW	150	0.1	150	0.1	150	0.1	150	0.1
≥33kV								
Onshore wind	1 000	12.8	5 600	71.4	8 100	103	8 100	103
Offshore wind	300	3.8	1 200	15.3	2 500	31.9	2 500	31.9
EfW >10MW	150	1.9	150	19.1	150	19.1	150	19.1
Marine	<50	0.6	50	0.6	2 000	25	2 000	25

Modelling demonstrated that voltage rise and fault levels at 33kV level were the first constraints reached. By 2010, voltage rise was a constraint on three of the nine 33kV busbars, due to the increase in Combined Heat and Power systems (CHP) connecting at this level. Maximum fault levels had been reached on 55% of the high voltage busbars, due to the high penetration of large wind generation. In contrast, thermal limits were not reached until 2030. The cost of clearing the voltage constraints in 2010, mainly by upgrading conductors, was estimated at £5.52M of overhead line and £2.13M of underground cable. The cost of clearing fault constraints in 2010 was put at £300 000 for the replacements of switchgear.

The study highlights the need to consider grid issues in the context of other renewable developments, since connection of generation at 33kV and above can constrain the available capacity at lower voltages.

Future Development in Scotland

The results of the analysis should be taken in the context of a rapidly changing network and generation mix. Table A5.5 shows the current amount of embedded generation in Scotland taken from Long-Term Development Statements (LTDSs), and Table A5.6 shows the capacity of all renewable generators currently operating or planned in Scotland (Scottish Renewables 2008)

Table A5.5 Current Embedded Generation in Scotland

	SSE		SP
Capacity (MW)	11kV	33kV	
Biomass	11.5	0	-
Gas	29.9	43.6	-
Gas (CHP)	8.62	0	-
Hydro	316	173	1.51
Landfill Gas/EfW	6	4	86.5
Wave	7	0	0
Wind	18.7	340	170
Total	**398**	**561**	**258**

Notes – Figures for SP only include renewable generation and do not list CHP. Voltage breakdown was not available for SP

Table A5.6 Operational and planned renewables projects in Scotland (Scottish Renewables)

	Capacity (MW)					
Technology	Operational	Under construction	Consented	Planning	In Appeal	In scoping
Wind	1240	812	1510	2970	1620	2600
Hydro (not PS)	1380	104	5.35	16.1	0	27.2
EfW	99.7	4.23	10.1	4.27	0	4.7
Biomass electricity	78.9	18.2	31.6	71.5	0	54
Wave	0.5	0	3	4	0	0
Tidal	0	0	0	0	0	0
TOTAL	**2800**	**938**	**1560**	**3070**	**1620**	**2680**

Wind is the fastest growing technology and is likely to dominate new renewable generation for the next few years. The British Wind Energy Association, assuming a 50% local planning approval rate and a 36 month delay in obtaining consent, has predicted that Scotland will have 3.4GW of wind installed by 2010[17].

The bulk of the projects in planning, or at least as recorded by the BWEA, are projects over 20MW, which will connect to 132kV and above. However, there are a potential 400MW of projects between 5MW and 20MW in size which may seek to connect to the 33kV system (Table A5.7).

Table A5.7 Predicted voltage connection from new wind power projects

Capacity of wind farm (MW)	**<5**	**≥5, <20**	**≥20**
Predicted connection voltage	**11 kV**	**32 kV**	**≥132 kV**
Operational	8.43	251	912
Construction	0	29.6	802
Consented	4.55	147	1320
Planning	1.47	221	3880
Total	**14.4**	**649**	**6910**

[17] BWEA (2006). Onshore Wind: Powering Ahead, British Wind Energy Association.

Scotland has a long-term target to produce 50% of electricity from renewable sources by 2020, with an interim target of 31% by 2011. According to the Scottish Government these targets would amount to about 5GW of installed capacity by 2011, and over 8GW by 2020.

A University of Edinburgh study for the Scottish Executive[18] looked in detail at the potential for Scotland to meet its (then) target of 40% of electricity from renewable sources by 2020. The study looked at the best mix of technology to achieve matching of supply and demand, but all scenarios showed Scotland would require 6 GW of installed capacity to meet the 40% target.

The studies reviewed above highlight some of the potential constraints to embedded generation. It is impossible to quantify exactly how much this will constrain small-scale hydro development in Scotland since the network and the generation mix are constantly changing. However it is useful to try and estimate to what extent the current network may constrain hydro development.

Assessment Method

As discussed there are a number of issues associated with connection of embedded generation to the distribution system. Detailed network modelling was not possible since data on 11kV circuits and loads are not easily available, and this level of analysis is beyond the time and resources of this study.

To give some idea of the amount of hydro sites that may be connected given network constraints, two particularly binding issues have been investigated; voltage rise on 11 kV lines and thermal limits on 33 kV circuits. These problems are addressed in turn by the following sections.

Analysis was performed on the hydro sites identified for the catchment numbered 86 (see Appendix 2: Map of Rainfall Catchments).

Voltage Rise on 11 kV Lines

Connection of embedded generation to the LV network causes voltage to rise on the line (assuming leading power factor). An embedded generator must not cause the voltage on the line to exceed the +6% limit, constraining the amount of embedded generation that can be connected. Further to this, the reactance and resistance of a line increases with its length, therefore longer lines have greater voltage drops, and also potential for voltage rise.

In rural areas utilities will typically increase the voltage at the 33kV/11kV substations 11kV busbars[19] to allow the permitted voltage drop on long 11kV feeders to be increased. The level of voltage boost varies but can be up to 105% of nominal voltage (Carbon Trust, 2003).

It is therefore necessary to assume that voltage rise on an 11kV line caused by an embedded generator must be limited to 5%. A rise greater than this could cause the voltage at the generator’s end of the line to exceed statutory limits.

[18] Boehme,T, J.Taylor, et al(2006). Matching Renewable Energy Generation with Demand. Scottish Executive.

[19] A conducting bar that carries heavy currents to supply several electric circuits, represents the ‘input’ or ‘output’ to a substation

Voltage rise: methodology

To model the constraints imposed by voltage limits to the level of embedded generation connected to an 11 kV feeder, the maximum allowable power output was calculated for a given line length. As no detailed topography of the 11 kV network is publicly available it was necessary to make assumptions about the typical line length that generators would be connecting to. While it was initially assumed that each Low Voltage (LV) connection would be linked to the 33kV/11kV substation by its own feeder, in reality a number of LV connections would be serviced by a single 11 kV feeder. This approach proved to be too conservative, as these lines provided ample capacity for all the schemes detailed in the catchments to be connected. In order to take into account the number of LV connections serviced by a feeder line, some rough calculations were performed based upon the number of buildings contained within a LV cluster. Based upon the assumption that the typical maximum load for a house is in the region of 1.5 kW, the average number of buildings per LV connection was 15 and that the average load served by an 11 kV line is approximately 1.5 MW, it was possible to calculate that around 65 LV connections are serviced by a single 11 kV feeder.

Furthermore, network modelling of rural areas carried out in the Mott Macdonald SIAM (System Integration of Additional Micro-generation) study[20] suggests 66 transformers per feeder, which is in line with the calculation based on building numbers per LV cluster.

The calculated maximum limits of embedded generation for each LV connection were subsequently divided by 65 to take into account that a single line would supply multiple connections. This is somewhat arbitrary, and will treat a large proportion of sites with capacity greater than 20 kW harshly, but does allow extrapolation across the 11 kV network topology.

Voltage rise: results

Based upon this analysis it was found that 11 kV connections could typically accept between 10 and 1000 kW of new generation (with a median value of 65 kW able to connect at each 11 kV point) depending upon the distance from the nearest 33 kV/11 kV substation (see figure A5.6). It should be noted that this approach will exclude individual schemes larger than the figure allowed for the local connection. In reality it is probable that larger schemes up to around 1.5 – 2 MW would be able to connect, however it is unlikely that a single feeder would be able to accommodate more than 1 scheme of this size.

[20] DTI (2004). System Integration of Additional Microgeneration (SIAM). Mott Macdonald Report to the DTI.

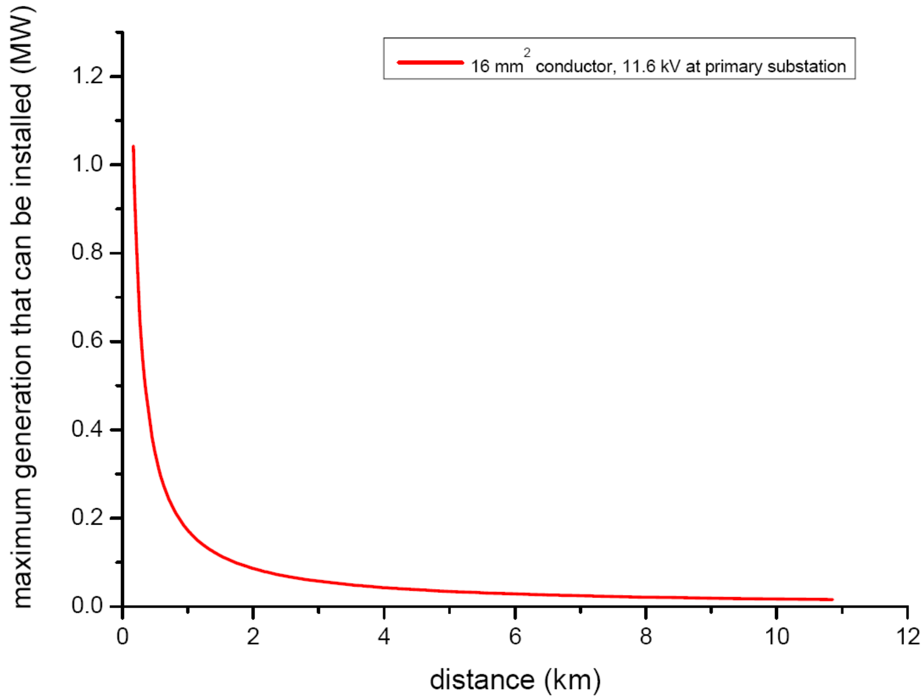

Figure A5.6 Calculated maximum new generation at a postcode by distance from primary substation

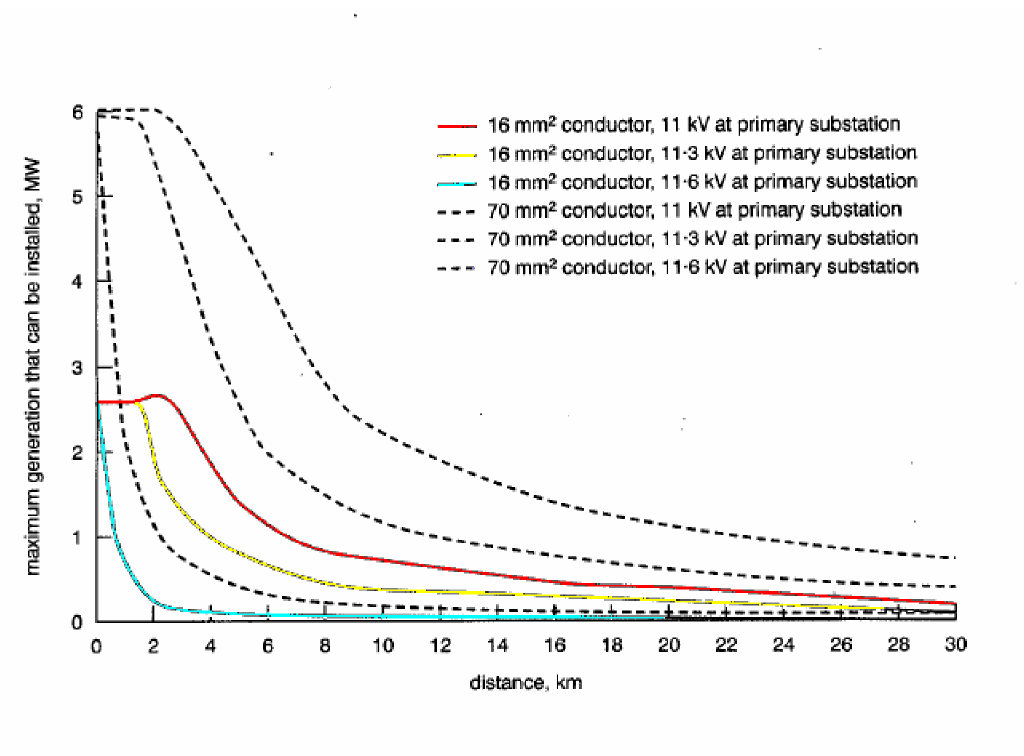

Figure A5.7. A guide to levels of embedded generation that may be connected at different lengths along 11kV line (Masters, 2002)[21]

[21] Masters (2002). Masters C.L. Voltage Rise the big issues when connection embedded generation to long 11kv Overhead Lines. IEE Power Engineering Journal. February 2002.

These results are comparable with other published results for the maximum capacities of embedded generation that can be connected to 11 kV lines based upon the distance from the 11 kV busbar (see figure A5.7).

The amount of generation that could connect at each 11 kV point was totalled and compared with the limits imposed by voltage constraints. The total generation unable to connect was then summed for the catchment. Out of 13.5 MW to be connected at 11 kV approximately 9 MW (66%) could not be connected.

Thermal Limits and Fault Levels

For generators connecting at 33 kV voltage rise becomes less important; the most onerous constraints are thermal limits and fault level ratings of distribution equipment. A value of 20-30 MVA can be connected to a primary substation before fault level problems are encountered. It was found when investigating the SSE data that thermal limits of circuits would be encountered first (based upon the conservative estimate of thermal limits used). Therefore this section will focus on understanding the constraints introduced by thermal limits.

Thermal limits and fault levels: methodology

Thermal limits were calculated for each substation using the following assumption: Total connected generation capacity *minus* the summer load must remain below the peak load supplied by the substation (Carbon Trust, 2003).

Detailed load data are provided by SSE as part of its Long Term Development Statement SHEPD (2007). From this it is possible to determine the peak and summer load at each 33 kV/ 11 kV substation, and consequently the likely maximum thermal limit to new embedded generation based on the following:

total embedded generation – summer load < winter peak load

=> total embedded generation < winter peak load + summer load

The maximum generation values ranged from 0.49 MVA to 8.89 MVA in the study area.

Thermal limits and fault levels: results

The total generation available to connect to each substation (including via the 11 kV network) was totalled and compared to the calculated thermal limits. Based upon this analysis it was found that 33% of identified hydro capacity could not be accommodated on the grid due to thermal limits. Fault level constraints were disregarded as thermal limits were reached first at all substations under study.

To take into account that a large proportion of 11 kV connected generators would not be allowed to connect due to voltage constraints the analysis was repeated excluding 2/3 of 11 kV generation. It was found that this reduced the amount of generation unable to connect by a small amount; 27% of total generation capacity.

This simple analysis shows that grid constraints are much worse for schemes connecting at 11 kV, whilst the situation is much better for schemes connecting at 33 kV. It should be noted that this analysis proceeds on the assumption that all schemes will be connected at the same time. In reality connection would occur on a piecemeal basis with individual schemes applying for connection over a period of time. As more generators are connected, less room remains for new capacity, effectively penalising late entrants. This could, of course, be mitigated if network upgrades are undertaken.

Appendix 6: Environmental Impacts

Environmental Impact of Hydro Power

Hydropower has huge potential to help Scotland reduce its emissions by meeting its energy needs from renewable energy generation. However, deciding whether or not to permit a new development requires taking into account local environmental concerns. Scotland is home to large areas of undeveloped land, many of which are environmentally sensitive. Although the impacts of potential Scottish hydropower schemes are much smaller in scope and scale compared to the massive engineering projects in places such as China they still pose risks, particularly to sensitive species such as salmonids and crayfish. These need to be considered when making recommendations for or against granting planning permission and abstraction licences.

Hydropower is the most significant cause of water abstraction and flow regulation impacts on Scottish waters. More than 15% of rivers and 40% of lochs are at risk of failing to meet environmental objectives under the Water Framework Directive. This amounts to 1,451km of rivers, covering 130 water bodies, and 279km^2 of lochs, covering 45 water bodies.

Although the full details of implementation of the Water Framework Directive (WFD) were not available at the time of this report it is possible to estimate the impact on hydropower potential of excluding designated environmentally sensitive areas, as shown in Table A6.1.

The location of protected areas, grouped into 3 tiers of sensitivity, is shown in Figure A6.1. As indicated by Table 3 in Section 4.4 of the main report, SSSIs and NSAs are of particular interest in that they cover much of the country and would have the greatest effect in reducing the potential hydro resource. Local Nature Reserves (LNR) and Ramsar sites also would greatly reduce hydro potential, if developments were to be excluded from such areas. Special Areas of Conservation (SACs) and Special Protection Areas (SPAs) are linked to Ramsar wetland areas as tier 3 areas and hence controlled by the most stringent conservation restrictions.

The locations of separate designated areas are available through Scottish Natural Heritage, where the Sitelink page provides an online search function[22].

[22] http://www.snh.org.uk/snhi

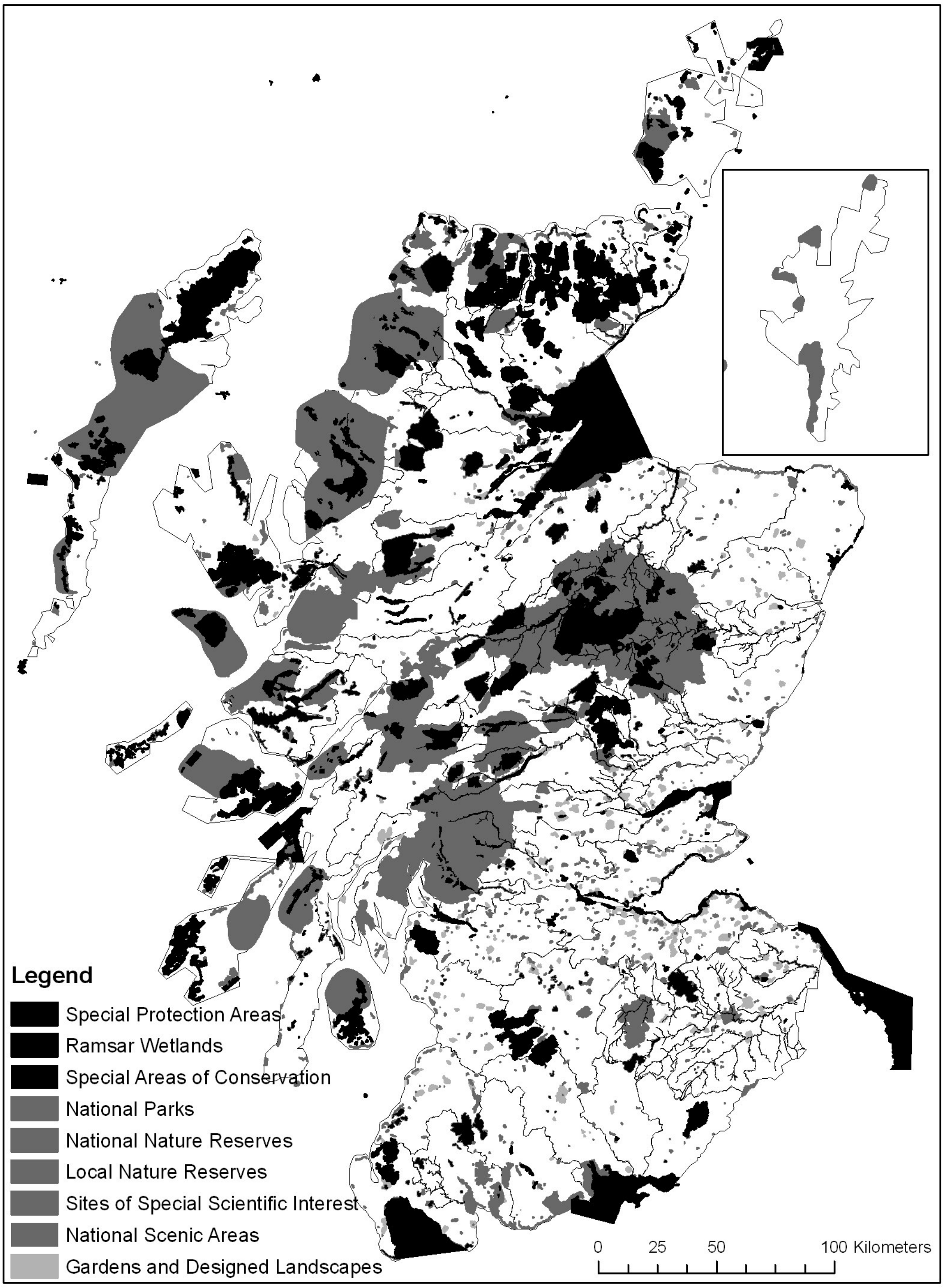

Figure A6.1. Map of Scotland showing areas designated for their natural heritage value. Designations are classed into three tiers depending on the level of protection applied; the most protective tier is indicated by the darkest shading.

Impact of Level of Restriction on Potential Power Generation

As discussed in section 4.4 above, the maximum number of schemes within designated areas was modelled using a scenario where there was no reduction in scheme size due to level of protection and with 0% discount rate. This scenario produced 5,229 schemes with a total power of 2.02 GW.

To test the sensitivity of the Scottish hydro resource, three new scenarios were used: no planning restrictions (Light), the most severe restriction (Severe) and an intermediate 'baseline' scenario[23]. For each of these scenarios, the baseline discount rate of 8% was used. The baseline scenario modelled a total of 657 MW of financially viable installed capacity producing 2.77 TWh per annum, reducing to 557 MW for 'Severe'. In comparison the viable power for 'Light' was estimated to be 766 MW of installed capacity.

Table A6.1 provides a comparison of the number and potential power of financially viable schemes aggregated into size bands. This shows that, as the level of restriction increases from Light to Severe, the number of small schemes increases and the number of larger schemes decreases. This is intuitively correct as the increasing levels of environmental protection are taken into account by reducing the size of each scheme.

There is one exception to this trend in Table A6.1, which is the 100-500kW band when moving from the Light to the Baseline scenario. A similar exception to the rule appears in Table A6.2, in the SPA category. In these cases the national total increases with the severity of the size restriction. This happens because, when the restriction on a scheme's flow is lifted, the cost of the turbine increases. High flow turbines are generally more expensive per unit power than high head turbines, so even though there will be an increase in power, a scheme that is only just financially viable can become unviable with this increase of flow. Normally there is enough growth among the viable schemes, or alternative schemes at the same site, to bring about an overall increase in the national total. However, if a large proportion of the viable schemes within a catchment are on the borderline, the schemes that become unviable can outweigh the size increase of the viable schemes.

Table A6.1 Effect of levels of size restriction on number and total power (kW) of potential sites, aggregated by size. For MW, divide kW by 1000.

Size band	Light		Baseline		Severe	
	Number	Power (kW)	Number	Power (kW)	Number	Power (kW)
<100kW	0	0	6	450	50	3,591
100-500kW	416	127,632	537	150,467	474	127,074
500kW-1MW	329	213,015	300	193,316	248	159,691
1-5 MW	208	339,932	170	276,804	152	256,966
5-10MW	9	56,602	6	36,222	2	10,017
10MW+	2	27,518	0	0	0	0
Total	965	765,599	1,019	657,259	926	557,338

[23] In the 'Light' scenario there are no restrictions on the scheme size due to natural heritage land designations and therefore design flow equals 1.5 x annual mean flow in run-of-river schemes, and 2.5 x annual mean flow in storage schemes. The 'Baseline' scenario assumes that each tier is reduced by a factor of 0.8, hence Tier 1 areas (Gardens and Designated Landscapes) have a design flow of 1.2 x annual flow; this is reduced to 0.96 for Tier 2 areas (SSSIs, National and Local Nature Reserves, National Parks, National Scenic Areas) and to 0.77 for Tier 3 areas (Ramsar, SPAs and SACs). The 'Severe' scenario uses a reduction factor of 0.6, rather than 0.8; hence the multiples for design flow are 0.9 for Tier 1, 0.54 for Tier 2 and 0.33 for Tier 3.

Table A6.2 and Figure A6.2 show the potential power falling within each type of land designation. SSSIs and Local Nature Reserves contain the greatest number of sites and power, and both are Tier 2 in terms of the level of protection. Taking into account that the remaining hydro resource is 657 MW under the baseline scenario, the treatment of applications for schemes within these designations will have a significant impact on Scotland's hydro resource.

Table A6.2 Summary of number of potential sites and total power of schemes falling within areas designated for their natural heritage value, under three scenarios of environmental protection: light, baseline (intermediate) and severe protection. Note that schemes may fall within more than one designation, so the figures below include double-counting, and add up to more than the totals.

	Light		Baseline		Severe	
	Number	**Power (kW)**	**Number**	**Power (kW)**	**Number**	**Power (kW)**
GDLs	20	20,793	22	13,829	19	7,682
SSSIs	210	234,549	228	143,214	154	54,766
NNRs	0	0	0	0	0	0
LNRs	149	190,895	149	111,406	102	37,305
NPs	18	30,543	21	22,356	14	7,798
NSAs	266	237,079	275	205,013	239	163,016
Ramsar	89	66,882	104	48,215	90	23,973
SPAs	4	3,998	7	5,255	2	668
SACs	27	15,522	36	13,127	18	2,342
Total	518	356,901	549	227,230	447	93,755

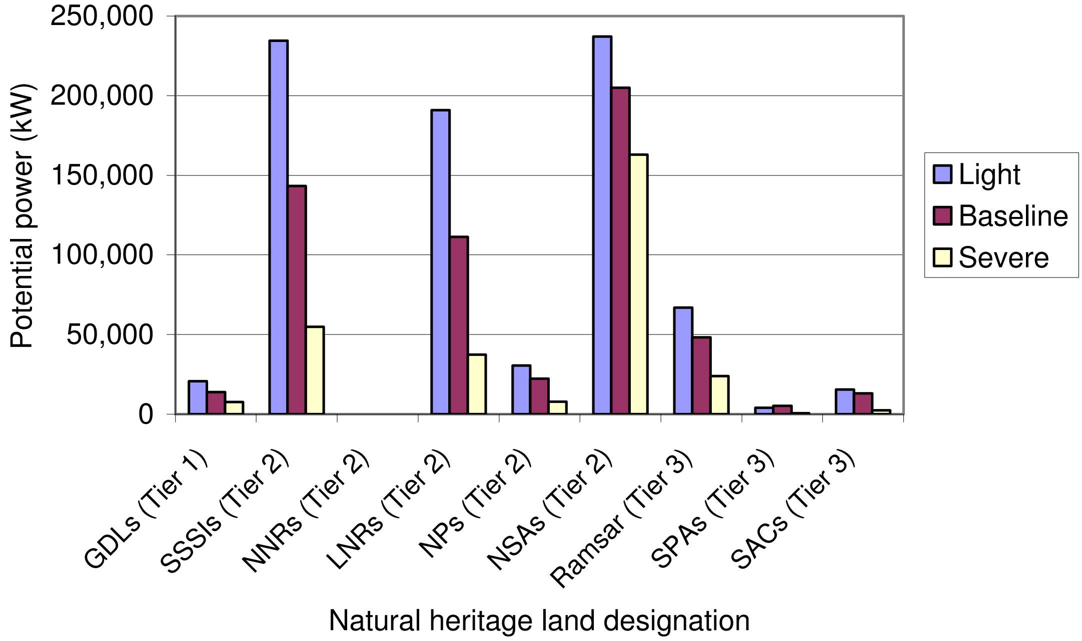

Figure A6.2. Potential power of schemes falling within each level of land designation. Note that in some cases, the total power available within areas of a particular designation can actually reduce when the restrictions are lifted. This is because smaller but more profitable schemes may be selected over the larger schemes, where the smaller schemes are not considered under the 'Severe' or 'Baseline' scenarios.

As is shown by Figure A6.2 the potential generation from Tier 1 and Tier 3 sites is relatively small, and approximately one third of the potential is lost as the restrictions are stepped up. The Tier 2 sites have the greatest generation potential, and benefit the most in relative terms from removing restrictions on scheme size. Therefore when considered along with the other factors of meeting renewables targets and economic benefit there may be a case for considering a low level of restriction for Tier 2 sites, as a trade-off against more severe restrictions for Tier 3 sites.

This raises questions over what could be done to improve the economic viability of sites in non-designated areas and what could be done to facilitate the use of sites in designated areas. The latter could be achieved by developing proposals for those sites that demonstrate how mitigation measures will be employed so as not to contravene the guidelines set by SNH and SEPA's Conservation and River Basin Management Strategies. A possible option for the future would be for SNH and SEPA to be directly involved with a small number of pilot developments in designated areas; conduct in-depth environmental impact assessments, and use the results to inform guidance for future projects and make them publicly available as case studies for potential developers to learn from.

Mitigation Options

The Water Framework Directive (2000/60/EC) (WFD) is a wide-ranging and ambitious piece of European environmental legislation that became law in Scotland at the end of 2003 through the Water Environment and Water Services (Scotland) Act 2003 (WEWS Act). The WEWS Act gave Scottish Ministers powers to introduce regulatory controls over activities in order to protect and improve Scotland's water environment. That is, wetlands, rivers, lochs, transitional waters (estuaries and saline lagoons), coastal waters and water under the ground (groundwater). The Scottish Environment Protection Agency (SEPA) is tasked with carrying out and implementing these regulatory controls.

The Act outlines SEPA's duties to:

- protect and improve the water environment;
- promote efficient water use;
- have regard to the social and economic impacts of exercising its functions;
- act in the best way to contribute to the achievement of sustainable development;
- promote sustainable flood management; and
- co-ordinate the delivery of its functions with others.

In fulfilling these duties, SEPA will regulate activities such as abstraction, impoundment and engineering activities, as well as pollution, from 1 April 2006 under The Water Environment (Controlled Activities) (Scotland) Regulations 2005 (CAR).

Since 1 April 2006 it has been an offence to undertake the following activities without a CAR authorisation:

- discharges of polluting matter to all wetlands, surface waters and groundwaters
- abstractions from all wetlands, surface waters and groundwaters;
- impoundments (dams and weirs) of rivers, lochs, wetlands and transitional waters;
- engineering works in inland waters and wetlands.

This means that authorisation under CAR is required for any abstractions or impoundments associated with a hydropower scheme. Authorisation may also be required for any engineering works that impact on inland waters that are not directly associated with the abstraction or impoundment (e.g. bridges, bank reinforcements)

The River Basin Management Planning process aims to improve and support sound and sustainable water management to deliver the requirements of the Water Framework Directive. River basin management planning also tries to balance environmental, social and economic needs within the River Basin District (RBD).

River Basin Management Plans are the output from each six-year cycle of the river basin planning process. The contents of a RBMP include:

- identification of responsible authorities;
- characterisation of the RBD;
- monitoring networks;
- environmental objectives;
- a Programme of Measures for the RBD;
- identification of heavily modified and artificial water bodies;
- a Register of Protected Areas;
- summary of consultative and participative activities undertaken to support RBMP production and the outcome of these exercises.

The RBMP will indicate what improvements will be necessary and when these improvements are required.

The principal environmental concerns over micro hydro schemes relate to their impact on fish populations, particularly in salmonid rivers. The Fisheries (Electricity) Committee within the Scottish Government has the statutory function of advising on impacts of hydro-electric schemes on fish populations[24]. In addition SEPA have produced a guidance document that highlights best practice in conserving fish habitats around all projects being planned for Scottish rivers[25]. The key point from the current legislation (Schedule 9 of the 1989 Electricity Act) states that electricity generators are to:

> "avoid, so far as possible, causing injury to fisheries or to the stocks of fish in any waters"

Obstructions

The primary concern here is obstructing or blocking migratory routes for salmonid species, however cumulative impacts that restrict movement over long stretches of river risk impacting on genetic health and diversity of all species, and may also restrict movement away from pollution incidents. Weirs and impounding dams can obstruct the passage of fish unless an effective fish pass (also known as fish ladders) is provided, for example the one at Pitlochry Dam. In addition, construction of hydro sites may cause temporary obstructions so this needs to be managed to mitigate the impact on fish movement, particularly around migratory periods.

The Salmon (Fish Passes and Screens) (Scotland) Regulations 1994 require dams to have an adequate fish pass and all off-takes, whether or not associated with a dam, to be screened to protect the passage of salmon (and sea trout). The Scottish Office Agriculture and Fisheries Department issued non-statutory guidance notes, to accompany the Fish Pass Regulations, to assist owners of dams and weirs on the practical aspects of their implementation. It should be noted that while the Regulations apply to proposals dealt with by planning authorities, they do not apply to dams or off-takes which are authorised by the Scottish Ministers under Acts which provide that they can have regard to the arrangements for the safe passage of salmon and sea trout when authorising the scheme e.g. under the Electricity Act 1989.[26]

In addition to fish passes a range of measures can be employed to mitigate impacts on salmonid populations, based on sound knowledge of their lifecycles. Screens can be used to minimise fatalities at weirs, smolt traps can be used to prevent juveniles entering turbines, and where necessary on larger projects compensation flows may be employed. Fish counters can be used to monitor changes in populations and adult salmonids can be radio-tagged for tracking. This latter option may be particularly valuable for monitoring populations in water bodies in which several projects have been installed for cumulative impacts.[27]

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[24] http://www.scotland.gov.uk/Topics/Fisheries/Salmon-Trout-Coarse/17604/9136

[25] SEPA, 'Managing River Habitats for Fisheries: A guide to best practice.' Available at: http://www.scotland.gov.uk/Resource/Doc/47133/0009767.pdf

[26] "The Salmon (Fish Passes and Screens) (Scotland) Regulations 1994". SI 1994/2524.

[27] SNH / SSE Joint Seminar. 'Hydro Developments and the Environment.' Thurs 2nd May 2002, Battleby, Redgorton, Perth.

More innovative measures for diverting fish that do not entail physical screens, which invariably clog with debris over time and require cleaning, are under development. These include bubble curtains and sound and electric barriers, but none has yet received approval from SEPA.

Turbines and tailrace

Depending on the design of a turbine, fish passing through it may be killed or injured from changes in pressure or by being struck by turbine blades. This can be mitigated by providing screens upstream and downstream to prevent fish entering the turbine and tailrace.

Pollution

Pollution incidents are a concern under operational conditions, but particularly around construction and maintenance periods. Strict standards are in place to prevent pollution incidents occurring but these cannot be entirely ruled out.

Catchment transfer

The tunnels used to transfer water around sites can provide fish with access to previously inaccessible water bodies, along with carrying infections and parasites. Salmonids are known to follow chemical signals along migratory routes and tunnels can confuse the transmission of these signals and misdirect fish into other water bodies. However, micro hydro projects rarely involve diverting water from one body to another so catchment transfer risks only apply to a small number of projects, and therefore this has a very limited impact on micro hydro potential. Furthermore, if those projects and associated mitigation options are risk assessed on a case by case basis these risks should not be a barrier to increased use of micro hydro.

Changes in hydrology

Hydro schemes change the local water body environment, and can also impact on those beyond them.

Flow reduction is a major issue, the largest is the temporary reduction at the point of the plant but reductions in downstream flows can significantly reduce fish stocks and restrict migratory routes. Schemes that require dams pose serious risks to salmonids but can create new habitats for non-migratory species, and fluctuations in water levels can also harm populations. Catchment transfers can cause changes in flows that can affect habitats far away from the site, and changes in flow patterns and strengths can alter sediment deposition and harm species that feed and spawn in sediments. However, for micro hydro, particularly at the small end of the scale, well-managed projects often have a net benefit on water quality through increased oxygenation and removal of litter and other debris.[28]

Despite all of these risks well-managed micro-hydro schemes can benefit fish populations through their emphasis on careful management of the environment, and in the case of non-migratory species they can create new spawning areas. As the environmental impacts of micro hydro are vastly outweighed by its substitution of conventional generation it would seem to be overly cautious to reject all schemes where concerns are raised regarding fish stocks alone.

[28] Environment Agency, 2003. 'Hydropower: A Handbook for Agency staff.'

Where proposed sites have been identified for protected areas, the resultant EIA can still allow the proposal to go ahead subject to specific restrictions with respect to the design or method of construction. For example, the Loch Poll scheme in the Highlands was for the development of a 0.24 MW scheme. It was approved by the Highland Council in 1999 and commissioned in 2000. The Loch is part of an SPA linked to protected birds (Black-throated Divers) and the Freshwater Pearl Mussel. Agreement to operate the scheme within existing high and low water limits, to a comprehensive set of rules; provision of a floating raft and a reduced length of the original designed tailrace allowed the scheme to go ahead. At the other end of the size spectrum, a 100 MW scheme at Glendoe, near Fort Augustus initially had major problems since it involved the construction of a new dam that would infringe on an SPA and SSSI. Following a detailed EIA, specific measures were identified with respect to the method and timing of construction and the need for bird monitoring. Following agreement to these modifications, approval for the scheme was given.

In general the impacts of micro hydro schemes on organisms other than fish and water birds should be negligible; however in the event of any environmental concerns arising it can do no harm to conduct simple population surveys in advance. Where threatened or endangered species are resident in the area, e.g. invertebrates such as whiteclawed crayfish or mammals such as otters and water voles, any potential impacts should be considered and documented. Simple population surveys conducted pre and post-construction are advisable for sites in designated areas and on salmonid rivers. The Environment Agency's Hydropower Handbook for Staff contains the necessary details of species that may be affected and the appropriate organisations to consult regarding surveys.

Implications of Findings

Under the strict interpretations of the natural heritage land designations and using the reduction factors to restrict flow as described in this study, most of the economically viable potential power that could be generated from micro-hydro would be lost, and even the more relaxed interpretations exclude a significant amount of potential.

Given the wider benefits of micro-hydro and the range of mitigation options available it seems unnecessary to apply the strictest restrictions to all designated areas, perhaps even to Tier 3 sites. There is also a clear case for differentiating the degree of relaxation based on site category (e.g. applying stricter interpretations for Tier 3 sites and the more relaxed interpretations for Tier 1 and 2 sites).

It seems advisable to treat proposals for the most sensitive sites on a case-by-case basis to ensure that all and any mitigation measures are investigated and impacts on hydrology, and species populations are fully assessed and accounted for. However, because of the benefits of micro-hydro there is also a clear case for a less restrictive planning application process to encourage developments where these impacts are weaker and defensible with simple mitigation measures.