CO_2 impact of Proposed Hunterston Coal/CCS Plant

Revised Final report

for

FoE Scotland
WWF Scotland
and RSPB

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Caveat

While the authors consider that the data and opinions contained in this report are sound, all parties must rely upon their own skill and judgement when using it. The authors do not make any representation or warranty, expressed or implied, as to the accuracy or completeness of the report. There is considerable uncertainty around the development of CCS and the UK power market. The analysis is therefore based around hypothetical scenarios. No detailed location-specific studies have been carried out. The authors assume no liability for any loss or damage arising from decisions made on the basis of this report. The views and judgements expressed here are the opinions of the authors and do not reflect those of FoE Scotland, WWF Scotland or RSPB Scotland.

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Contents

1 Executive Summary

Ayrshire Power's proposal to construct a new coal-fired power station with partial CO_2 capture at Hunterston has attracted considerable interest from a range of stakeholders including leading environmental Non-Governmental Organisations. Friends of the Earth Scotland, WWF Scotland and the Royal Society for the Protection of Birds Scotland were interested to understand quantitatively and qualitatively the impacts of the proposed project.

Therefore, a high level analysis of a new build coal plant with partial CCS was conducted by Element Energy to provide some insights for FoE Scotland and WWF Scotland into the impacts of the Hunterston project going ahead.

A range of plant configurations are possible and lifetime emissions from the proposed project are highly sensitive to the level and timing of CCS retrofit and assumptions on load factor. However, the regulatory and economic mechanisms to drive eventual CCS retrofit and maintain its operation or otherwise limit CO_2 emissions to atmosphere are currently very poorly defined, and there is no clear timetable or process to finalise these.

If CCS is retrofit to the full plant output in 2025, then the CO_2 impacts of the proposed Hunterston project over the whole of its life are likely to be substantially less than the equivalent emissions from new build gas power plants of the same capacity, running at similar load factors for the same period. Another alternative to a new coal-fired power station might be a combination of a gas-fired alternative operating at lower average loads for a shorter period, with electricity demand increasingly met from from renewable sources, coupled with improved interconnection, demand management/reduction and energy storage.

Moreover, if no additional CCS capacity is retrofit at Hunterston, the lifetime CO_2 emissions to atmosphere of the proposed plant would be much greater even than equivalent output from CCGT power generation.

Additional net life cycle CO_2 savings may be possible from co-firing biomass. However at realistic levels of co-firing (e.g. 14% by energy content) these savings are at best modest and highly dependent on assumptions around the carbon intensity of biomass, for which there is significant controversy.[1] As an example of a possible emerging challenge to conventional assumptions about the net emissions from co-firing of biomass, life cycle analysis by the Manomet Centre for Conservation Sciences suggests that use of biomass from Massachussets forests for electricity generation creates an additional carbon emissions burden (or 'carbon debt') in the short term.

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[1] T. Walker *et al*, 2020, Biomass sustainability and Carbon Policy, Manomet Centre for Conservation Sciences, Massachussets USA; http://www.manomet.org/sites/manomet.org/files/Manomet_Biomass_Report_Full_LoRez.pdf; also see Zanchi et al, 2010. The Upfront Carbon debt of Bioenergy. Joanneum Research, Austria http://www.birdlife.org/eu/pdfs/Bioenergy_Joanneum_Research.pdf

The cost of CCS is dominated by the capital costs, ongoing operating and energy costs for capture and costs of financing. It is possible that these costs will decrease over time through innovation, economies of scale and learning-by-doing, although this cannot be guaranteed. Costs passed on to GB electricity consumers to fund CCS demonstration projects will reflect the up-front incremental cost of CCS fitted to part of plant, and an expected value of net present cost of imposing CCS retrofit on full plant capacity. The cost will depend on many variables, including the carbon price and intrinsic cost of CCS. The net present cost of an individual CCS demonstration project has been estimated in the region of £500 m **-** £1 bn, although there is considerable uncertainty on both amount and timing that expenditure is incurred. One study has estimated that the net present cost to consumers of requiring retrofit in 2020 in the region of £80m if CCS is deemed proven. In the event that CCS is not deemed proven, then on the basis that an additional contingency measure would have to be factored into costs, this could increase the net present cost to consumers by an additional £100-£200 m, depending on the timing of the measure.

Published studies suggest a substantial decline in the load factor of unabated fossil fuel plant with increased renewable energy penetration and rising CO_2 prices – this poses a challenge to the economics of new coal plants in particular as these are highly capital intensive and have a higher carbon intensity than gas-fired plant.

Even if fossil power plant is fitted with CCS, there may be times where it is economic to switch off CO_2 capture to enable rapid ramp up/down and/or to match demand, thus temporarily increasing emissions and the carbon intensity of generation. However published simulations suggest this is likely to be limited to only a few hours per year in 2020.

The degree to which transmission of power from a given source is constrained depends on a number of factors. Major investments are underway or being considered for transmission infrastructure in Scotland and England, however there is significant uncertainty over exactly where capacity will be available, when and how much. It is not clear that transmission infrastructure *per se* will pose a material threat to the economics of fossil power generation in Scotland by the time the proposed Hunterston project would be operational. However the prospect cannot be categorically ruled out based on information currently available.

Published reports also provide insufficient evidence to ascertain with confidence if and how investment at Hunterston might impact investment or dispatch from Longannet coal power station in the long term. Dispatch decisions are based on a range of economic criteria as well as overall corporate strategy for portfolio operators. For plants using the same fuel source, typically newer power plant (in this case Hunterston) would benefit from higher efficiencies and be more competitive than older power plant.

2 Terms of Reference

In August 2010, WWF Scotland and Friends of the Earth Scotland contracted Element Energy Ltd. to provide an independent, impartial high level analysis on the costs and CO_2 impacts to support FoE Scotland and WWF Scotland's response to the Consultation on Ayrshire Power's proposed new 1,852 MW coal/CCS plant at Hunterston.

Element Energy's proposal specified provision of impartial quantitative estimates of:

(i) Carbon intensity for the proposed plant under conditions where only part or all of the plant is fitted with CCS.
(ii) Cumulative site lifetime CO_2 emissions under different scenarios (e.g. CCGT with and without CCS, proposed coal plant at Hunterston with different levels of CCS and biomass etc.).
(iii) Impact on overall CO_2 emissions from the Scottish power sector under different scenarios.
(iv) The cost of retro-fitting CCS to the remainder of the power plant between 2020 and 2025 (including considering the costs to energy consumers under a contract-for-difference payment structure).

Additional analysis to be provided on:

(i) The potential to avoid operating the CCS plant, e.g. when spot electricity prices are high.
(ii) Percentage of total emissions from proposed Hunterston plant that will be captured at proposed level of demonstration (327MW).

The proposal specified that where necessary basic models for CCS and coal power plant performance and economics could be used to examine key scenarios, at the level of individual plant operating over 20-40 years. It was agreed that the modelling would not examine overall investment in UK or Scottish generation or transmission capacity, or consider hourly dispatch issues in a quantitative manner.

It was recognised from the outset that only a high level analysis would be feasible within the study timescales and budget.

3 The outlook for fossil/thermal power generation in Scotland and the UK

Following recent consultation, the UK Coalition Government is pushing ahead with proposals developed by the previous Government to demonstrate CCS on power stations in the period up to 2020. The Coalition Government also stands by a decision that new coal fired power stations should capture a proportion of their CO_2 from the date they are commissioned, with the potential to retrofit capture when CCS is deemed 'proven'. The Scottish Government is also firmly behind the development of CCS technologies.

The purpose of this chapter is to place in context:

- The case for new thermal plant in Scotland
- Estimates of and sensitivities around the load factor for new coal plant
- The choice of the appropriate counterfactual for a new coal plant

3.1 Managing supply in the context of high renewable generation

Studies[2] show that high levels of wind penetration onto networks require greater levels of:

- inter-regional transmission capacity
- energy storage
- demand management
- low load factor dispatchable (thermal) generation.

With sufficient transmission capacity, modelling by Garrad Hassan[3] shows that Scotland is predicted to not require any new thermal plant within its borders to balance even the highest levels of wind penetration. A recent study by AEA has highlighted the potential role that energy storage and management could play in scenarios of high renewable deployment.[4] However it should be noted that thermal plant would be required, even on a very highly integrated, pan European network[5]. The ECF study examined a number of scenarios for renewable energy penetration. With high renewable deployment, ECF

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[2] UK ERC, "Costs and Impacts of Intermittency", 2006.
European Climate Foundation, "Roadmap to 2050 – technical analysis"

[3] Garrad Hassan (2010) Options for coping with high renewables penetration in Scotland, for Friends of the Earth Scotland. *In press.* The Scottish Government's recent Draft Electricity Generation Policy Statement 2010 identifies *inter alia* that up to 2.5 GWe of new build thermal plants (progressively moving towards full CCS) can assist Scotland in achieving a more balanced generation portfolio and can reduce the cost burden that may be pass on to consumers in the absence of these plants. Report available at http://www.scotland.gov.uk/Resource/Doc/331717/0107930.pdf

[4] AEA (2010) Energy Storage and Management Study, available at http://www.scotland.gov.uk/Resource/Doc/328702/0106252.pdf

[5] If this thermal plant is fossil fuelled then other countries are providing balancing and support services and will be responsible for associated emissions. In its fourth budget report, the Committee on Climate Change has identified the need to consider export of CO_2 emissions through import of carbon intensive products (as already required in Scotland under the Climate Change (Scotland) Act 2009 which establishes provisions for parallel consumption based reporting.

concluded that around 15% of total capacity would need to be thermal plant, but this would operate at loads of around 8%, thus delivering much less than 5% of all electricity generated in 2050[6]. Unfortunately, the published data from that study does not allow for a regional disaggregation of these data to estimate the potential requirement for thermal plant in Scotland. In the absence of power market modelling, it is not clear whether these EU-wide proportions can be applied to Scotland directly. However, the Scottish Government's recent Draft Electricity Generating Policy Statement 2010 proposes a level of thermal generation of ca. 2.5 GW in 2030. In one scenario coal provides an overall contribution of 3.1 TWh i.e. 6% of total Scottish generation output in 2030.[7]

3.2 Future load factors for thermal electricity generation plant

Two forecasts for the average load factor for thermal plant which consider the impacts from renewable electricity, CCS and fuel prices have been produced by Redpoint (2009)[8] and Poyry (2009). Approximate load factors for thermal plant in 2020 and 2030 have been collated from these studies and are listed in Table 1 below. The reader is advised to consult the original sources for background assumptions[9].

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[6] The ECF report, under the highest renewables penetration scenario, identifies a requirement for pan-European interconnection, 20% of Europe's energy to be imported from from North Africa, a reliance on "breakthrough technologies" and the remaining thermal peaking plant to be fired on biofuels to limit CO_2 emissions. European Climate Foundation's Roadmap to 2050 available at http://www.roadmap2050.eu/.

[7] Draft Electricity Generation Policy Statement 2010, available at http://www.scotland.gov.uk/Resource/Doc/331717/0107930.pdf

[8] Redpoint (2009) Decarbonising the GB Power Sector – Report to the CCC.

[9] Forecasts in the public domain for load factors for thermal plant in the period 2020 to 2030 and beyond are restricted in the level of detail provided on electricity market modelling, input assumptions for plant cost and performance and fleet breakdown. Typically published outputs are also restricted to a few choice scenarios and variables. Independent verification or scrutiny of these models is outside the scope of the present study. Therefore, published results are taken at face value.

Table 1 Published load factors for thermal plant in 2020 and 2030 (Compiled from Poyry (2009)[10] and Redpoint (2009)).[11]

Thermal plant Type	Average load factor in 2020	Average load factor in 2030
Coal with CCS	75-85%	65-82%
Coal	50-65%	10%[12]
Older CCGT	5-30%	1-25%
New CCGT	50-55%	35%-50%
Biomass	67%	64%

There is a considerable spread in the forecast for the load factor for a new build coal plant with partial CCS and any counterfactual new build gas power plant. A wide range of load factors is possible depending on a complex interplay of capital and operating costs, fuel and CO_2 prices, plant retirements and new investment elsewhere (e.g. in renewables) on the grid.

The load factor for coal could range from very high (ca. baseload levels) if the plant has CCS fitted, to very low if it is run unabated under the scenario of high CO_2 prices. Given the high capital expenditure of coal fired generation, running a new plant at such low load factors would be uneconomic.

Nonetheless, CCS is not a mature technology and it is a reasonable expectation that some thermal plant with CCS could experience, during early years of operation, lower load factors than an equivalent plant without CCS. A demonstration stage is needed to quantify the impact of this. It is not unreasonable to assume that CO_2 injection conditions for geological storage may also require optimisation over time, which may lead to temporary underperformance.

For consistency and simplicity this study has mainly assumed constant lifetimes and load factors for new CCGT and coal plants for the quantitative CO_2 impact analysis. However it should be recognised that gas CCGT and identical load factors/lifetimes may not be the optimal counterfactual, and that actual load factors are likely to vary year to year.

As mentioned above, increased transmission capacity and demand management would reduce the requirement for thermal backup/reserve, and permit backup/reserve generation, operating at very low load factors, to be shared across a wider network.

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[10] Poyry (2009) The impacts of intermittency Summary Report – How wind variability could change the shape of the UK and Irish markets

[11] Redpoint (2009) Decarbonising the GB power sector: evaluating investment pathways, generation patterns and emissions through to 2030.

[12] The more rapid decline in load factor for coal plant relative to gas plant is driven largely through rising CO_2 prices.

4 Methodology for CO_2 impact calculation

CO_2 impacts were calculated using a simplified model developed following literature review, which allowed multiple scenarios to be compared.[13]

4.1 Limitations of published literature on CCS performance

A review of the CCS literature concludes that no single paper provides a comprehensive, consistent, up-to-date and authoritative set of information on the performance for new build/retrofit/capture ready coal and gas plants at the scales relevant for the proposed Hunterston project.

Key engineering variations between reports include plant size, composition of the coal (e.g. moisture level, heavy metal, sulphur content), boiler and turbine configurations, capture technologies, and the degree of capture, clean up and compression. These ‘engineering’ differences impact efficiencies and the requirements for parasitic losses.

In this project the CO_2 impacts were modelled using the latest power plant performance data recently published by DECC[14]. Whilst this excludes consideration of factors such as plant size and dynamics (e.g. reduced economies of scale for demonstration plants and efficiency drops during variable plant output), this reference source does provide transparency. Clearly, in the absence of commercially sensitive detailed data on plant design only a high level analysis is possible, meaning that there are some differences between estimates presented here and the performance data listed in Ayrshire Power’s EIA submission, for example (see Appendix).

4.2 Quantifying the benefits of biomass co-firing

A number of reviews have examined biomass co-firing in the UK and global contexts.[15] As a general conclusion, small amounts (e.g. up to 20% by weight) biomass co-firing can be accommodated with minimal reductions in plant efficiency.

Life cycle CO_2 benefits from biomass co-firing are highly uncertain and subject to wide disagreement. These values depend on assumptions on the nature of the biomass (e.g.

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[13] Calculation using a full market model for investment and dispatch to identify investment decisions and dispatch, and thereby load factors and emissions is time consuming and was agreed as out of the scope of this study.

[14] Mott Macdonald (2010) UK Electricity Generation Costs Update *for DECC*.

[15] The Environment Agency “Biomass: Carbon sink or carbon sinner?”; M. Sami et al. (2001) Co-firing of coal and biomass fuel blends *Progress in Energy and Combustion Science* **27** 171-214; M. Mann and P.L. Spath (2001) A life cycle assessment of biomass cofiring in a coal-fired power plant; *Clean Prod Processes* **3** 81-91; D.A. Tillman (2000) Biomass cofiring: the technology, the experience, the combustion conequences; in *Biomass and Bioenergy* **19** 365-384; A. Dermirbas (2003) Sustainable cofiring of biomass with coal in *Energy Conversion and Management* **44** 1465-1479; S. Patumsawad (2007) Co-firing biomass with coal for power generation at the *Fourth Biomass Asia Workshop “Biomass: Sources of renewable bioenergy and biomaterial”*; Woods *et al.* (2006) Evaluating the sustainability of biomass co-firing in the UK DTI URN06/1960; W. R. Livingston (2007) Advanced Biomass co-firing technologies for coal-fired boilers, published by Doosan Babcock; M. Colechin (2005) Best practice brochure: Co-firing of biomass (main report) Report No. Coal R287 DTI URN 05/160; T. Walker *et al*, 2020, Biomass sustainability and Carbon Policy, Manomet Centre for Conservation Sciences Report NCI-2010-03, Massachussets USA; http://www.manomet.org/sites/manomet.org/files/Manomet_Biomass_Report_Full_LoRez.pdf; also see Zanchi et al, 2010. The Upfront Carbon debt of Bioenergy. Joanneum Research, Austria http://www.birdlife.org/eu/pdfs/Bioenergy_Joanneum_Research.pdf

straw vs. wood chips vs. pellets), its source (e.g. domestic, international supply), potential for CHP, and assumptions on the CO_2 impact of growing, processing and transport of this fuel. As an example, the Environment Agency identifies a range of CO_2 intensities of 0.025–0.130 $kgCO_2$/kWh of energy contained in the fuel for short rotation coppice pellets, with 'good practice' conditions leading to 0.1 $kgCO_2$/kWh of energy According to a study led by AEA for the Environment Agency, "there is no evidence that energy crops are currently being planted directly on permanent grassland in the UK, although anecdotal evidence suggests this is an issue elsewhere." However. displacement of other crops onto permanent grassland would cause the same problem. [16] The Environment Agency estimate does not appear to include emissions from land use change or from carbon debt and therefore actual life cycle carbon impacts could be higher. A study by Walker *et al*. found that it could take several decades of forest regrowth for a carbon neutral system to be achieved, even when the biomass replaced coal combustion, and in the interim the net emissions intensity would be higher from biomass than from coal combustion.

In its Draft Electricity Generation Policy Statement 2010, the Scottish Government has stated that it would prefer to see biomass deployed in heat-only or CHP schemes, off-gas grid, at a scale appropriate to make best use of both the available heat, and of local supply. The Scottish Government implicitly recognises the potential for use of biomass in large power generation may distract focus from meeting Scotland's renewable heat target.

4.3 Key assumptions for CO_2 impact assessment

This section lists the technical assumptions used for plant performance, fuel CO_2 intensity and load factors. For simplicity a single value is used for each parameter. As described above, in reality there may be some variation in these parameters. These values are used as the basis for estimating carbon intensities, annual CO_2 emissions and lifetime CO_2 emissions for different plant configurations.

Table 2: Plant performance assumptions (ref. Mott MacDonald (2010)

Plant type	Gross Efficiency	Auxiliary power	CO_2 removal
CCGT	59%	2.3%	
Pulverised coal	45%	6.5%	
CCGT with CCS	47.5%	11.8%	90%
Pulverised coal with full CCS	35.1%	16.5%	90%

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[16] *AEA (2009) Biomass –carbon sink or carbon sinner?*

Table 3: Fuel CO_2 intensity assumptions (Ref: DUKES 2010 and Environment Agency)[17]

Fuel	kg CO_2/kWh fuel
Natural Gas	0.184
Coal	0.308
Biomass (pellets)	0.1 (good practice, excludes carbon debt and land use change)

Table 4: Load factor assumptions [18]

Scenario	Load factor
High load factor	83%
Low average load factor	50%

4.4 Scenarios for Plant Configuration

Carbon intensities, annual t CO_2 emissions and lifetime CO_2 emissions were calculated for high and low load factor scenarios for eight plant configurations. To enable comparison the gross output was fixed at 1852 MW and plant lifetime set at 40 years. In reality the output and lifetime of gas plant would not necessarily be the same as coal plant.

(1) Unabated new CCGT plant – a counterfactual.
(2) Unabated new supercritical pulverised coal plant
(3) New CCGT plant, initially unabated but retrofit with full CCS in 2025.
(4) Coal plant with 327 MW CCS only for the whole of the plant life
(5) Coal plant with 327 MW CCS only and 14% biomass by energy for the whole of the plant life
(6) Coal plant with 327 MW CCS from start and full CCS retrofit in 2020 and 2025.
(7) Coal plant with 327 MW CCS only and 14% biomass by energy with full CCS retrofit in 2020 and 2025
(8) New unabated CCGT running for only 20 years with the remaining 'demand' assumed to be met through additional renewables or additional energy efficiency and management investment.
(9) New CCGT running for only 20 years, with retrofit in 2020 or 2025. Remaining 'demand' assumed to be met through additional renewables, or additional energy efficiency and management investment.

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[17] N.B. These figures do not take into account plant efficiency.

[18] The load factor assumptions are for illustrative purposes only and do not correspond to a specific scenario of renewable energy deployment. In general it is unlikely that load factors for coal and gas power stations would be similar, except in very specific combinations of gas, coal and carbon price,

For each of configurations (2)-(9), the difference in emissions between the plant and the counterfactual CCGT plant were also calculated. In each case for purposes of quantitative comparison the artificial assumptions of equal load factors and lifespan were imposed.

Issues such as plant degradation, maintenance, outage and repowering have been neglected. Outage (e.g. for maintenance) of the CCS system where the main power station continues operation would clearly result in emissions to the atmosphere close to those of an unabated coal plant. Degradation of the CCS plant performance over time would likely result in reduced efficiencies whereas upgrades would have the opposite effect.[19] Mott MacDonald recently reported that the expected availability of advanced supercritical coal plant with CCS is essentially the same (89%) as the availability of the advanced supercritical coal plant in isolation (90%).

4.5 Key Equations for CO_2 impact calculations

Calculation of CO_2 impacts can be broken down into a number of simple equations. For simplicity, a single fixed lifetime of 40 years is assumed. Commissioning in 2017 is assumed, consistent with information in Ayrshire Power's EIA submission.

$$\text{Lifetime CO2 impact (M}t) = \sum_{year\ i=1}^{end\ year=40} \text{emissions } (t) \text{in year } \ i/1{,}000{,}000$$

Here

$$t \text{ emissions in year } i$$
$$= \text{Plant carbon intensity in year } i \ x \text{ Net MWh delivered electricity in year } i$$

Where carbon intensity is defined by:

$$\text{Carbon intensity in year } i \ (\frac{tCO2}{MWh\ net\ electricity}) = \frac{\text{Carbon intensity of fuel } (\frac{tCO2}{MWh} fuel)}{\text{Plant net efficiency } (\%) \text{in year } i}$$

And net delivered electricity is given by:

$$\text{Net electricity delivered } (\frac{MWh}{year}) = \text{Load factor } (\%) \ x \text{ plant net output } (MW) x \ 8760 \ (\frac{hours}{year})$$

Where plant net delivered output to grid is defined by :

$$\text{Plant net output } (MWe) = \text{Gross output } (MWe) - \text{Parasitic load } (MWe)$$

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[19] Degradation estimates are gas (3.5-3.6%), gas with CCS (3.1%), coal (2.9-3%) and coal with CCS (2.4-2.5%), Ref: Mott MacDonald (2010) UK electricity generation costs update.

Plant net efficiency is defined by:

$$\text{Plant net efficiency }\% = \text{Gross efficiency }(\%) * (100\% - \text{auxiliary load}\%)$$

The parasitic load is given by:

$$\text{Parasitic load }(MWe) = \text{Auxiliary load }(\%) x \text{ Gross output}(MWe)$$

4.6 Results

Figure 1 compares the net carbon intensities of seven potential configurations. A key conclusion is that the intensity of the proposed plant is *higher* than unabated gas plant before full CCS retrofit but *lower* after the CCS retrofit (although it remains higher than gas retrofit with CCS).

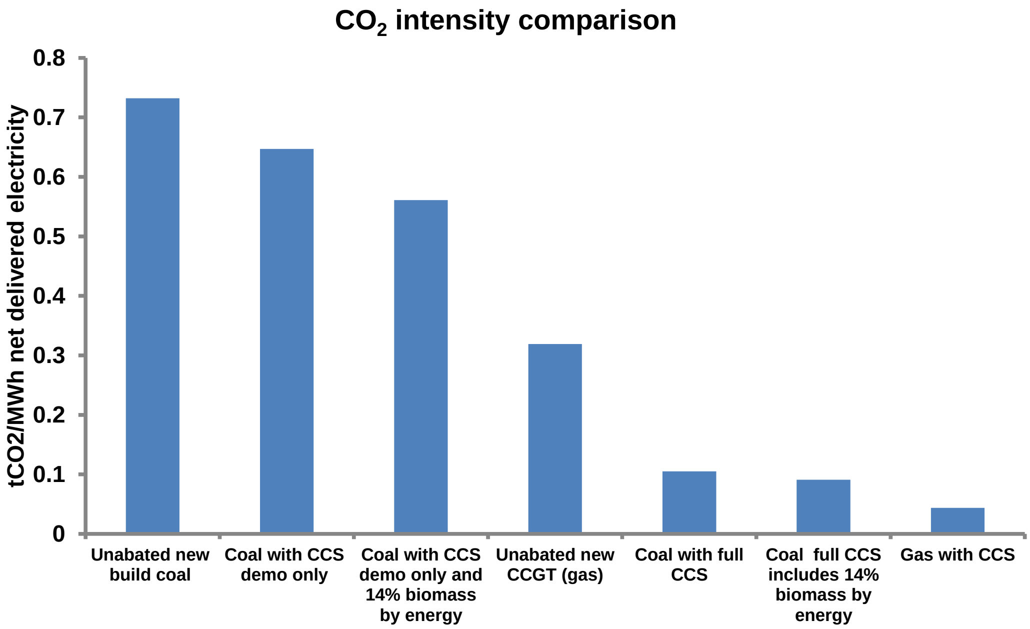

Figure 1 Comparison of CO$_2$ intensities from different plant configurations

The analysis explored the impact on net CO$_2$ emissions over 40 years depending on if and when full CCS retrofit to the whole of plant output occurs. Figure 2 indicates that retrofit before 2025 substantially reduces the lifetime emissions of the plant below those of equivalent CCGT at the same load factor, but leaves them significantly above lifetime emissions from CCGT with retrofit in 2025.

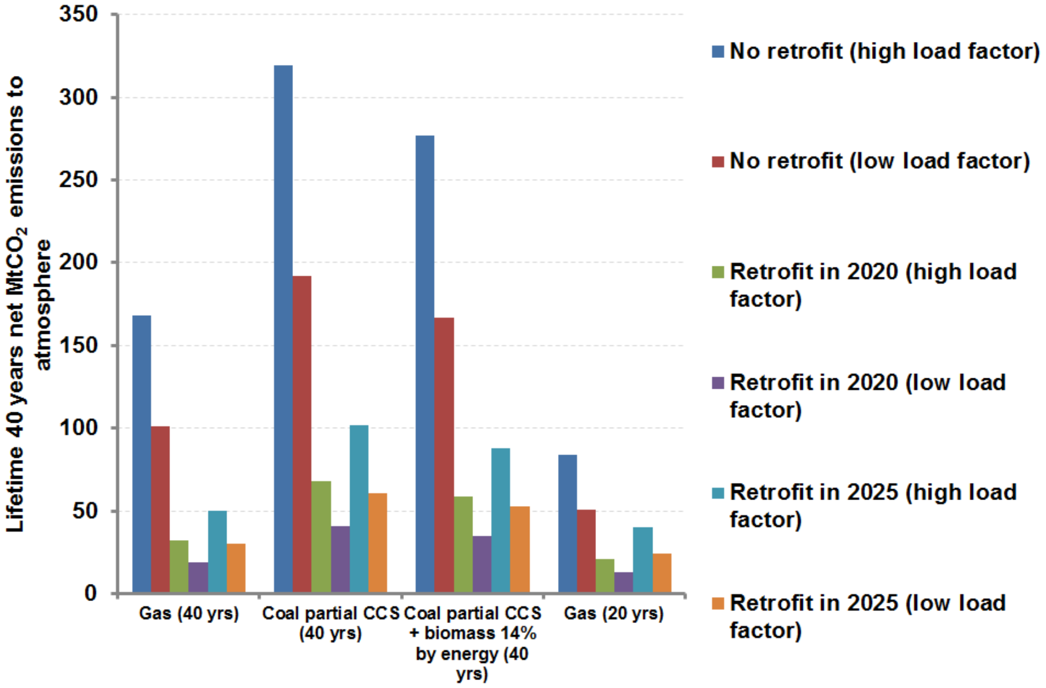

Figure 2 Lifetime net CO$_2$ emissions to atmosphere.

Figure 2 also indicates that the carbon benefits from co-firing biomass, even at 14%, are negligible, even with optimistic assumptions of the carbon benefit. When land-use and carbon debt factors are accounted for, or with pessimistic assumptions, co-firing could raise net emissions over the 40-year lifespan of the plant.

Table 5 presents the carbon intensities and emissions for each plant configuration. Table 6 presents the differences between the intensities and emissions for the coal configuration and the counterfactual gas plant.

Table 5 Modelled carbon intensity and CO$_2$ emissions for plant configurations.

Plant generation scenario (all plants have gross output of 1852 MW, including after retrofit)	CO2 intensity before retrofit (tCO2/MWh)	CO2 intensity after retrofit (t/MWh)	High average load factor scenario (simplifying assumption for low renewables scenario)	Low average load factor (simplifying assumption for high renewables scenario)	Net MW (elec) initially	Net MW (elec) after retrofit if relevant	Annual net tCO2 emissions (high average load factor) BEFORE ANY RETROFIT	Annual net tCO2 emissions (low average load factor) BEFORE ANY RETROFIT	Annual CO2 emissions (high average load factor) AFTER ANY RETROFIT	Annual CO2 emissions (low average load factor) AFTER ANY RETROFIT	Cumulative MtCO2 emissions for 40 years (high average load factor), assume retrofit in 2020 if appropriate	Cumulative MtCO2 emissions for 40 years (low average load factor); assume retrofit in 2020 if appropriate	Cumulative MtCO2 emissions for 40 years (high average load factor), assume retrofit in 2025 if appropriate	Cumulative Mt CO2 emissions for 40 years (low average load factor); assume retrofit in 2025 if appropriate	% annual CO2 emissions captured at start (simplifying assumption)	% annual CO2 emissions captured at end (simplifying assumption)
Unabated new CCGT (gas)	0.32		83%	50%	1810		4,200,000	2,500,000			168	101	168	101	0%	0%
Unabated new build coal	0.73		83%	50%	1730		9,200,000	5,600,000			369	222	369	222	0%	0%
Gas, initially unabated, then CCS retrofit to 100% in 2025	0.32	0.04	83%	50%	1810	1630	4,200,000	2,500,000	520,000	310,000	32	19	50	30	0%	90%
Coal with CCS demo only for whole of plant life	0.65		83%	50%	1700		8,000,000	4,800,000			319	192	319	192	17%	17%
Coal with CCS demo only and 14% biomass by energy for whole of plant life	0.59		83%	50%	1700		7,200,000	4,400,000			289	174	289	174	17%	17%
Coal 327 MW of CCS from start and with full CCS from retrofit date	0.65	0.11	83%	50%	1700	1550	8,000,000	4,800,000	1,180,000	710,000	68	41	102	61	17%	90%
Coal 327 MW of CCS from start and with full CCS from retrofit date includes 14% biomass by energy	0.59	0.10	83%	50%	1700	1550	7,200,000	4,400,000	1,070,000	640,000	61	37	92	55	17%	90%
Unabated CCGT 20 years only	0.32		83%	50%	1810		4,200,000	2,500,000			84	51			0%	0%
CCGT with CCS retrofit, total lifetime of 20 years	0.32	0.04	83%	50%	1810	1630	4,200,000	2,500,000	520,000	310,000	21	13	40	24	0%	90%

Table 6 Differences in carbon intensities and CO_2 emissions for different plant configurations relative to counterfactual unabated new gas plant running for 40 years.

	Difference in CO2 Emissions relative to counterfactual unabated new gas plant running for 40 years									
	Difference in CO2 intensity before retrofit (t/MWh)	Difference in CO2 intensity after retrofit (t/MWh)	Difference in annual t CO2 emissions (high average load factor) BEFORE/ t/yr	Difference in annual t CO2 emissions (low average load factor) BEFORE / t/yr	Difference in annual CO2 emissions (high average load factor) AFTER RETROFIT' t/yr	Difference in annual CO2 emissions (low average load factor) AFTER RETROFIT / t/yr	Difference in Cumulative emissions for 40 years (high average load factor), assume retrofit in 2020 if required/Mt CO2	Difference in Cumulative emissions for 40 years (low average load factor); assume retrofit in 2020 if required/ Mt CO2	Difference in Cumulative emissions for 40 years (high average load factor), assume retrofit in 2025 if required/ Mt CO2	Difference in Cumulative emissions for 40 years (low average load factor); assume retrofit in 2025 if required/ Mt CO2
Unabated new CCGT (40 yrs)	0.00	0.00	-	-	-	-	-	-	-	-
Unabated new build coal (40 yrs)	0.41	-0.32	5,000,000	3,000,000	-	-	201	121	201	121
Gas (40 yrs), initially unabated, then CCS retrofit to 100% in 2025	0.00	-0.28	-	-	500,000	300,000	-136	-82	-118	-71
Coal with CCS demo only for 40 yrs	0.33	-0.32	3,800,000	2,300,000	-	-	151	91	151	91
Coal with CCS demo only and 14% biomass by energy for 40 yrs	0.27	-0.32	3,000,000	1,800,000	-	-	121	73	121	73
Coal 327 MW of CCS from start and with full CCS from retrofit date	0.33	-0.21	3,800,000	2,300,000	1,200,000	700,000	-100	-60	-66	-40
Coal 327 MW of CCS from start and with full CCS from retrofit date includes 14% biomass by energy (40 yrs)	0.27	-0.22	3,000,000	1,800,000	1,100,000	600,000	-107	-64	-76	-46
Unabated CCGT 20 years only	0.00		-	-			-84	-51		
CCGT with CCS retrofit, total lifetime of 20 years	0.00	-0.28	0.00	0.00	500,000	300,000	-147	-88	-128	-77

4.7 Potential to deactivate capture plant

The flexibility of CCS systems is an area of ongoing research and debate[20]. While capture plant would be normally integrated fully with electricity production, there may rational economic incentives for capture equipment to be deactivated temporarily.

To our knowledge a quantitative examination of the required electricity and carbon spot price combinations to encourage deactivation of CCS equipment for coal CCS demonstration has not yet been published. Electricity market simulations suggest that in a high renewables future, short term electricity market prices could fall between *ca.* £100/MWh and £1,300/MWh in 2020 for *ca*. 88 hours per year, and between £150/MWh and £8,000/MWh in 2030 for a similar period, these values potentially guiding an upper limit for the period that capture plant is deactivated for economic reasons[21]. Depending on market arrangements, if the load factor of fossil plant with CCS is low (e.g. as a result of very high renewable energy penetration), and there are significant periods of very high prices, then the fraction that capture equipment is deactivated could become a significant proportion of overall output. [22]

The high electricity price, combined with the drop in efficiency due to capture plant supports the case for decoupling capture during these short duration events, allowing the plant to boost revenues, while increasing direct emissions temporarily and raising the average carbon intensity of the electricity generated.

4.8 Impacts on power sector emissions in Scotland.

Power sector CO_2 emissions are currently dominated by two coal plants (*ca*. 10 Mt/yr from Scottish Power's Longannet and *ca*. 5 Mt/yr at Cockenzie) and *ca*. 3 Mt/yr from SSE's gas power plant at Peterhead[23].

The existing 1152 MW Cockenzie coal power station is expected to close by the end of 2015[24], as a result of the Large Combustion Plant Directive, eliminating CO_2 emissions from this source. Scottish Power has proposed replacing this with a CCGT station.

Scottish Power's Longannet power station (2,400 MW) is currently the only candidate for the UK Government's CCS competition for a 300 MW post-combustion capture plant, and if funding is confirmed this project would likely be operational by 2015

The SSE-owned 2200 MW dual fuel Peterhead power station[25] is primarily gas powered. SSE recently announced their intention to retrofit CO_2 capture facilities at this plant if they

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[20] See for example IEA GHG (2010) Workshop on the operating flexibility of power plants with CCS. http://www.co2captureandstorage.info/docs/flexibility%20workshop/2010-1%20(Without%20Presentations).pdf

[21] To our knowledge, an analysis of the required electricity price for deactivating capture from new supercritical coal power stations in the UK has not been published. By way of comparison, a recent study for the Committee on Climate Change estimates the minimum price for deactivating capture facilities for gas power plant is £75/MWh in 2030 or £122/MWh in 2050, although it should be noted that the economics of coal and gas plant will differ. See Element Energy (2010) Potential for the application of CCS to UK industry and natural gas power generation.

[22] Poyry (2009) Impact of intermittency - Summary Report. Note that the technical assumptions (prices) are not explicitly defined in this report.

[23] See for example, Opportunities for CO_2 storage around Scotland – an integrated strategic research study. In addition there are small generators such as the 120 MW CCGT plant in Fife and industrial CHP plants.

[24] See for example, Redpoint (2009) Decarbonising the GB power sector: evaluating investment pathways, generation patterns and emissions through to 2030 - A Report to the Committee on Climate Change.

[25] Output from Peterhead power station is currently transmission constrained to 1180 MW.

are able to attract public-funding for CCS demonstration which has recently been extended to the gas power sector.[26]

These changes are not accounted for in the figures below.

Ayrshire Power's proposed 1852 MW coal power station with partial CCS would generate a new point source of CO_2 emissions at Hunterston. The impact on overall CO_2 emissions in Scotland will depend on the precise configuration and load factor, and how investment at Hunterston impacts investments and dispatch elsewhere. If there were no other changes in capacity or operating loads, and if the new Hunterston coal plant were to operate at a high load factor, this plant would add *ca* 8 Mt/yr to Scottish annual power sector emissions, i.e. 44% of 2009 emissions from the power sector. Assuming no additional CCS capacity is fitted and the plant operates at high load factor, in 2020 this is equivalent to *ca*. 20% of the allowable total Scottish emissions under the Climate Change (Scotland) Act. In the absence of any CCS retrofit or restriction on output in 2050 (i.e.If the plant load factor were to remain at *ca* 83%), then annual emissions of 8 Mt would correspond to 57% of the national permitted emissions.

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[26] See for example http://www.bbc.co.uk/news/10552954. The Peterhead site was the proposed location for the BP/SSE DF1 project in 2006.

5 Costs of CCS retrofit[27]

The underlying costs for capture facilities and operation will be driven largely by progress in capture technology development, energy prices, engineering sector supply chain costs, and costs of financing.

In addition to the costs for any new underlying power station, expected *annual* project costs for the CCS component of a new coal plant with CCS at demo scale are in the region of tens of millions of pounds during pre-development for FEED studies, rising to hundreds of millions per year during construction, which would likely last up to four years. [28] The uncertainties in costs are currently large. In general terms, costs are uncertain partly because the CCS at the proposed scale is still in demonstration phase implying high levels of contingency requirement, but also because there are alternative design options that allow for different levels of current and future performance.

Liabilities are incurred:

1) Pre-development, to understand storage requirements in detail[29], in Front-End Engineering Design, and in obtaining necessary permits.
2) For construction of capture, compression, transport and storage physical facilities. For transport and storage the timing of expenditure will be dictated by whether initial infrastructure is sized to accommodate initial throughput of CO_2 or the throughput after any eventual retrofit.
3) During operation for routine management, maintenance and for the energy required to operate the capture and compression facilities, and in monitoring the storage site. Energy costs for capture are clearly linked to the fossil fuel prices and the efficiency penalty associated with capture. Critically the actual ongoing cost will reflect the difference between these costs, the carbon price, and revenue from electricity sales, so that if the external carbon price is low, then the project would continue to require public support (potentially this could amount to several millions of pounds each year). Economic decisions for coal plants often consider that these are long-lived plants, with lifespan of up to 30 and 40 years, although it is conceivable that individual elements of the CCS system may require overhaul before the end of life.
4) At the end of life, to continue to monitor the storage site integrity[29] and to decommission equipment. Storage monitoring technologies and costs would be site dependent, but it is conceivable that these costs could amount to millions of pounds each year until regulators are satisfied that the CO_2 storage conditions are satisfactory.

From a calculation of the levelised cost of electricity of CCS plant with the price required to make the plant economic, Redpoint (2009) identified the ‘incremental funding gap’ for full

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[27] A discussion of transport and storage issues was out of the scope of the present study, but will affect costs and risks for CCS projects, and the potential for a CCS demonstrate project to nucleate CCS transport and storage infrastructure and thereby facilitate the uptake of capture activities elsewhere, for example from industrial CO_2 emitters.

[28] DECC’s impact assessment accompanying its proposal for a contract-for-difference mechanism to support for four CCS demonstration projects estimates a cumulative resource cost of £8.7-£10.3 bn, See http://www.decc.gov.uk/assets/decc/Consultations/A%20framework%20for%20the%20development%20of%20clean%20coal/1_20090623122727_e_@@_cleancoalia.pdf

[29] See http://www.decc.gov.uk/en/content/cms/news/pn10_97/pn10_97.aspx

retrofit on coal plant with partial capture in 2020, 2025 and 2030[30]. Imposing full retrofit in 2020 on a supercritical coal power station with gross output of 1,600 MW with 400 MW gross capacity fitted for CCS would requires an additional *ca*. £82 m in net present cost if CCS is proven under a scenario of investor-expected commodity prices. These costs would be proportionate to scale and would therefore be up to 20% higher for the larger Hunterston power station (overall size 1852 MW), subject to potential benefits from economies of scale. DECC expects that the costs of CCS demonstration would likely be passed on to consumers through a levy although details are still under discussion[31].

The higher the carbon price, the poorer the economics of the baseline coal plant but the more favourable the economics for CCS retrofit. The overall investment decision will reflect an interplay of these drivers and the level of associated uncertainty. Redpoint modelling suggests that the sensitivity is limited - an increase in the carbon price by 1% results in only a 0.1% change in the project net present value, assuming retrofit in 2025.

The impacts of discount rate reflect a complex interplay between the up-front expenditure and the future costs (e.g. carbon and energy prices) and future revenues (e.g. electricity prices). Redpoint's modelling suggests that an increase in hurdle rate by 0.1% from the baseline value of 10% results in a 2.5% decrease in project net present value, assuming retrofit in 2025.

Redpoint conclude that the cost to consumers of CCS retrofit in 2025 may not be substantial[32], largely because:

- Capital costs incurred from 2025 are in any case heavily discounted.
- CCS may become commercially viable by 2025 through the interplay of 'learning' and rising CO_2 prices.

Under the commodity prices and CCS conditions in their model, an equivalent retrofit in 2030 would be economically beneficial (i.e. no additional costs would be passed to consumers).

Higher costs for CCS retrofit may be passed to suppliers (and therefore consumers) in the expectation of:

- Requirements for extensive storage site maturation.
- Construction cost over-runs
- Higher operating costs (e.g. through lower efficiencies and/or higher energy prices)
- Reduced plant load factor
- Lower CO_2 prices
- Underperformance or outright failure of any key elements particularly CO_2 storage operation[33].
- Delays to permitting and build times

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[30] Redpoint (2009) Carbon capture and storage : analysis of policies on coal/CCS and financial incentive schemes. This assumes a linear rising CO_2 price between 2020 and 2030 from 30-80/t CO_2 (central case) and discount rate of 10%.

[31] See for example, http://www.decc.gov.uk/en/content/cms/consultations/emr/emr.aspx

[32] Redpoint's modelling concludes that the difference in funding gap between supporting a demonstration project only and a demonstration project with retrofit in 2025 is £3m if CCS is proven. The discounted costs to consumers could rise to £124 m if a contingency scenario is included (where CCS is not proven and plant output would need to be curtailed), In principle contingency measures could also be applied to existing plant, i.e. not simply new coal fired power station.

[33] In extremis, though very unlikely, a catastrophic failure of storage site could require the storage operator to pay the carbon price for cumulative CO_2 stored as well as any remediation requirements.

- Pessimistic investor perceptions of (or simply very large uncertainty in) risks and prices, resulting in higher risk premia.

It is standard practice within the energy industry to use probabilistic tools, for example Monte Carlo simulation[34], to derive expectations for costs (most likely and best and worst cases at different levels of probability).Typically investors would then set a price that would result in a low probability of making a loss. Quantifying these impacts through a combination of Monte-Carlo simulation is outside the scope of this study. The UK Government's CCS demonstration programme envisages payment in the form of a contract-for-difference (CfD). In this approach the difference in costs from application of CCS and a pre-determined CO_2 'strike' price are expected to be met by a GB-wide levy on suppliers that would be passed on to electricity consumers, although the Government is considering large scale electricity market reform[35].

In the event that CCS is not proven – and plant emissions are instead controlled through contingency measures such as a restriction on emissions, this would add significantly to the investor expectations of the required CO_2 price within a CfD structure. Redpoint modelled the change in net present cost and strike price for contingency measures equivalent to an annual limit set equal to the emissions of a typical CCGT plant of the same gross capacity running at a load factor of 80%. Depending on when the contingency is imposed, the change in net present cost amounts to between £80m (if imposed in 2030) and £200m if imposed in 2020. Whilst this appears a moderate change, it is important to remember that this is *in addition to* a demonstration only net present cost of ca. £500m.

In the CfD scheme modelled by Redpoint, the lifetime costs of CCS equipment (potentially running for up to 40 years) are paid back within the first 20 Mt of CO_2 stored (or a 15 year horizon), using a formula where the payments are made on the product of the difference between the strike price and the outturn carbon price and the emissions abated relative to an appropriate counterfactual and with future cashflows discounted back to 2010 at 10%[36]. The corresponding strike prices for bids quoted for CCS demonstration would then be between £118 (contingency imposed in 2030) and £137/tCO_2 (contingency imposed in 2020). A contingency measure imposed in 2025 could cost £131 m.[37]

Redpoint's modelling identifies that investor expectations of commodity prices have a substantial impact on the expected bids under a contract for difference incentive scheme. Under DECC's low commodity price scenario, the CfD required rises to £191-£201/tCO_2 whereas DECC's 'high-high' scenario no additional project subsidy is required.

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[34] C. Harris (2006) *Electricity Markets: Pricing, structures and economics* (Wiley & Sons, West Sussex).

[35] It is likely that a number of performance guarantees would be put in place to limit the exposure of either the public sector or electricity consumers to cost escalation, however this may in turn drive up the costs of CCS. See also Redpoint (2009) Carbon Capture and Storage demonstration: analysis of policies on coal/CCS and financial incentive schemes

[36] As an example, if a demonstration project abates 2 Mt/yr relative Redpoint (2009) Carbon Capture and storage demonstration: analysis of policies on coal/CCS and financial incentive schemes.

[37] Whilst these costs appear higher than McKinsey's estimates for 2030 CO_2 reduction costs (see for example http://climatechange.cbi.org.uk/uploaded/climatereport2007mckinseyapp.pdf), it should be noted that these carbon prices refer to investors' requirements during the early CCS demonstration. For an example of the possible relative cost of CCS within a marginal abatement cost curve for 2020, see The Committee on Climate Change (2009) The costs of decarbonising electricity generation (Chapter 5 technical appendix). For a comparison of the current and predicted levelised costs of electricity generation from different sources, see Mott MacDonald (2010) UK Electricity Generation Costs Update

6 Transmission constraints on output from Hunterston

The transmission infrastructure in Scotland is heavily constrained already, and this is an important constraint on the development of new generation capacity[38]. FoE Scotland and WWF Scotland are keen to understand whether transmission constraints could result in reduced load factor for the Hunterston plant, or other fossil generators in Scotland, in particular the Longannet plant (for which CCS is also proposed).

To examine this possibility fully requires a quantitative grid modelling exercise which is outside of the scope of the study. Instead publicly available literature has been reviewed.

The published literature is **inconclusive** as to whether transmission constraints are likely to impose a material reduction on load factors at Longannet power station in the event that the Hunterston coal/CCS plant is built. Neither, however, can we rule out the prospect that such an impact might arise. More detailed analysis of the likely scenarios for upgrades is needed to address this issue.

6.1 Current capacity constraints

National Grid's analysis shows there is currently 'Very Low' opportunity for new generation connections across Scotland and in the North of England, as shown in Figure 3 below, because existing capacity is already fully committed.

It is possible that some local capacity would become available to the proposed coal plant when the existing nuclear power generation site at Hunterston is closed, although the level to which this existing capacity is contractually committed to others requires more detailed examination.

Similarly, planned upgrades of transmission capacity between Scotland and England and Wales may make additional capacity available at Hunterson, if the total exceeds the additional capacity required for export of renewable generation from Scotland.

Ayrshire Power's EIA states that National Grid's planned transmission infrastructure upgrade, supported by Ofgem, will eliminate the constraints. However the analysis does not specify which upgrades are most critical here, and the associated likelihood of these upgrades going ahead, nor does it take account of the growth in renewables generation with first call on that new capacity[39]. The EIA supporting information does not provide significant detail on these dimensions.

For the hypothetical scenario that the Hunterston coal power station is built but output is constrained because of limited transmission capacity, the impact on overall generation costs would depend on the details any power purchase agreements and the impact of operation at partial load on efficiency (of either the generating unit or the CCS unit) and ability to capture CO_2. In the absence of a detailed investment model for the plant, it is challenging to anticipate the scale of impacts. In general terms, variable costs would be reduced, but it is possible that efficiency is reduced for partial operation. If either efficiency or ability to capture CO_2 are reduced, then the costs of the CCS unit would be expected to rise on a £/tCO_2 basis and £/MWh basis. Alternatively if the CCS unit collects a higher proportion of the plant's emissions without any reduction in performance, the impact on

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[38] National Grid (2010) Seven Year Statement

[39] A capacity constraint payment model is out of the scope of the present study.

cost as expressed on a £/tCO_2 basis may be reduced or unchanged, whereas the £/MWh may rise as the output in MWh is reduced.

In principle, if plant output is constrained below any contractually agreed transmission capacity there may be a requirement to compensate plant operators. A detailed quantitative analysis of the likelihood or the amount of compensation were out of scope of this study. Although the impact of the proposed Hunterston coal plant is not clearly described, the recent Scottish draft electricity generation policy statement 2010 states that "the scheduled closure of existing plants and the construction of a minimum of 2.5 GW of new efficient thermal electricity generation would satisfy all security of supply concerns and operate within the current and proposed transmission constraints delivering large amounts of electricity exports".[40]

The recent AEA study[41] examines the requirement for energy storage and management under different scenarios of renewable energy deployment and interconnection. The scenarios do not specifically examine the impacts of a new coal plant at Hunterston but do identify that the capacity for interconnection to England is critical for accommodating planned and ambitious levels of renewable electricity generation in Scotland. For extremely high levels of renewable generation, the AEA study highlights an additional requirement for energy storage and management.

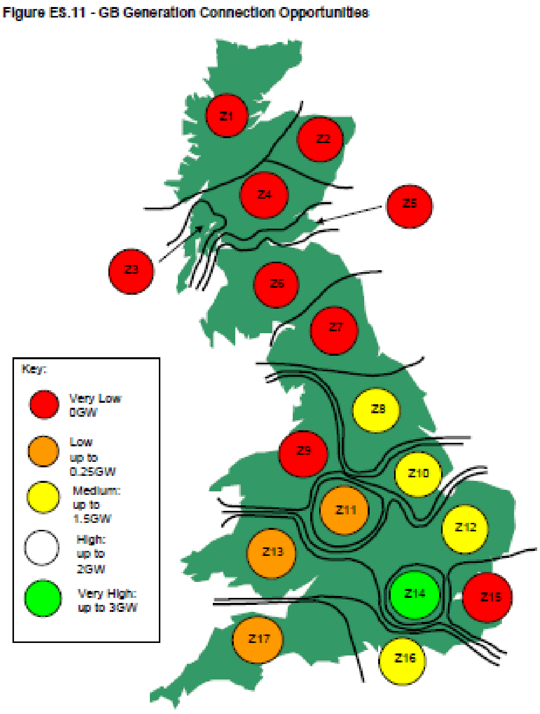

Figure 3 Opportunity for new generation connections (Ref: National Grid's 2010 Seven Year Statement). Each circle corresponds to a zone, colour coded to indicate spare capacity.

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[40] Draft Electricity Generation Policy Statement 2010 Scotland – a low carbon society; available at http://www.scotland.gov.uk/Resource/Doc/331717/0107930.pdf

[41] AEA (2010) Energy Storage and Management Study, for the Scottish Government, available at http://www.scotland.gov.uk/Resource/Doc/328702/0106252.pdf

6.2 Dispatch from Hunterston

The Hunterston coal plant would be expected to operate within the GB BETTA market, so that output will depend on decisions in the GB market, not just Scottish market. Published reports provide insufficient evidence to ascertain with confidence if and how investment at Hunterston might impact investment or dispatch from existing British power stations such as the Longannet coal power station in the long term. Dispatch decisions are based on a range of economic criteria as well as overall corporate strategy for portfolio operators. For plants using the same fuel source typically, newer power plant (in this case Hunterston) would benefit from higher efficiencies and be more competitive than older power plant.

Detailed market modelling would be required to model the likely interdependencies of investment and dispatch at Hunterston on investments in and dispatch from other Scottish fossil power stations This is out of scope of the present study.

7 Appendix– Comparison of modelled data with Eunomia projections

Table 7 Comparison of plant assumptions

Assumptions	Eunomia	Element Energy	Comment
Coal plant lifetime	40 years	40 years	Consistent
High load factor	100%	83%	100% load factor is optimistic - assumes no downtime for maintenance or low demand.
Partial load factor	60%	50%	Both choices reflect arbitrary modelling assumptions. In reality load factors will change over time.
Gross output at full load	1852 MW	1852 MW	Baseline assumption
Net output at full load, coal no CCS	1724 MW	1732 MW	Consistent
Parasitic load - demo scale CCS	99MW likely additional to the 128 MW baseline plant.	35 MW in addition to 120 MW required for baseline plant.	Eunomia assumption appears realistic. EE assumption is optimistic, assumes linear scaling of parasitic load.
Parasitic load - full scale CCS unit	492 MW – not specified if this is additional to the baseline plant	185 MW in addition to 120 MW required for baseline plant	Detailed description of scope of parasitic load would be useful.
t CO_2/t coal input	2.3 tCO_2/t coal	2.3 tCO_2/t coal	Consistent

Table 8 Comparison of carbon intensity models (tCO_2/MWh)

Configuration	Eunomia	Element Energy	Comment
Coal, Demo CCS, full load	0.587	0.65 (without biomass)	Eunomia assumes higher electrical generation efficiency
Coal, Demo CCS, partial load	0.528	Not calculated[42]-	Eunomia assumes ability to capture higher proportion of flue gas at partial load
Coal, Full scale CCS, full load	0.102	0.1-0.11	Consistent
Coal, Full scale CCS, partial load	0.106	Not calculated[42]	Eunomia assumes reduced efficiency at partial load
Combined Cycle Gas Turbine plant	0.33	0.32	Consistent

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[42] Low load factor operation may involve operation at full load factor for a reduced time or operation at partial load factor for a longer period. In the former, the carbon intensity would approximate that of the baseline system. In the latter case, both the efficiency of the power station itself and the demonstration scale CO_2 capture equipment may be compromised, dependent on plant design (including modularity, thermal integration, and oversizing of capacity). An Aspen-Hisys type process simulation would be required to quantify the capture potential. However at least conceptually, if the capacity and efficiency of the demonstration scale CO_2 capture system can be sustained, then there is a potential for the demonstration system to capture a larger fraction of total CO_2 emissions when operating at partial load. In the extreme limit, if the power station operates at only 25% output, it may be possible for the demonstration scale capture equipment to capture 90% of these emissions (rather than 90% of 25% of the output of a full scale plant). Thus carbon intensities could fall in the range ca. 0.1-0.65t/MWh.

Table 9 Comparison of plant emissions

Result	Eunomia	Element Energy	Comment
40 years CO_2 impact over lifetime assuming full load, full scale CCS coal plant,	42 Mt	59-102 Mt CO_2 depending on whether retrofit is in 2020 or 2025 and use of biomass (assumes higher load factor)	Eunomia assumption considers 40 years with full CCS, i.e. does not factor initial CO_2 emissions when plant is operating with CCS at demo scale only.
CCGT, 40 years over lifetime	135 Mt	101-Mt (assumes 50% load factor for 40 years) 168 Mt (assumes 83% load factor for 40 years)	Consistent (assuming intermediate load factor)
Hunterston impact by 2050	Ca. 90 Mt (assumes retrofit in 2024, load factor not specified) [43]	88 Mt (assumes retrofit in 2024, 83% load factor)	Consistent
Unabated CCGT impact by 2050	Ca. 115 Mt (load factor unspecified)[43]	Ca. 86 Mt (assumes 50% load factor) Ca. 143 Mt (assumes 83% load factor)	Consistent (depends on load factor assumptions).

8 Acknowledgements

The authors wish to thank Poyry Energy Consulting and Garrad Hassan for discussions and FoE Scotland, WWF Scotland, WWF UK, and RSBP for valuable feedback received during the course of this study.

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[43] Estimated from Figure 4-2 in Eunomia (2010) Analysis of CO2 emissons from Hunterston – Report on behalf of Ayrshire Power Ltd.

9 Abbreviations

CCGT – Combined Cycle Gas Turbine

CCS – Carbon dioxide capture and storage

GW – Gigawatt

HVDC – High Voltage Direct Current

Mt – Million tonnes

MW – Megawatt