A REVIEW OF LE/VENTYX'S COST-BENEFIT ANALYSIS OF MODIFICATION P229

LOT 3 ADDITIONAL ANALYSIS

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1 Introduction and Executive Summary

The Brattle Group has been asked by Ofgem to review the cost-benefit analysis (CBA) commissioned by the Elexon on behalf of the Balancing and Settlement Code (BSC) Modifications Group and carried out by London Economics and Ventyx (LE/Ventyx). The work examined the Balancing and Settlement Code (BSC) Modification P229 and P229 Alternative which proposes the introduction of zonal losses The LE/Ventyx analysis was set out in report (hereafter referred to as the 'LE/Ventyx report')[1] and submitted to the Authority as part of the Final Modification Reports (FMRs) on the proposals.

Ofgem has divided the analysis of the CBA into three parts or Lots:

- Lot 1 High level overview. Lot 1 assesses issues such as the appropriateness of LE's terms of reference, methodology and assumptions, the robustness of the results and the conclusions.
- Lot 2 Additional Scenario analysis. Lot 2 models scenarios which are felt to be important but that were not undertaken in the original LE work.
- Lot 3 Additional Analysis. Lot 3 performs additional analysis of the results of both the original LE work and the new scenarios modelled in Lot 2.

This report summarises the results of the Lot 3 task. Ofgem will publish the results of the Lot 1 and 2 work streams in separate reports.

Ofgem has identified several tasks that we should undertake in Lot 3: Specifically, Ofgem asked *The Brattle Group* to produce as assessment of:

- The impact of P229 on existing and future consumers.
- The impact of P229 on the deployment of renewable generation.
- The impact of P229 on the security of energy supply.
- The impact of DECC's transmission access review. For example, would the implementation of DECC's proposed connect and manage regime[2] have any impact on the costs and benefits associated with P229?
- The effect of P229 on risk and cost of capital in the industry as a whole and in different regions.
- Whether P229 affects renewable generation particularly.
- The impact of P229 on the benefit of embedded generation.

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[1] 'Cost Benefit Analysis of Modification P229: Changing to Zonal-Seasonal Transmission Loss Factors, Report Version 1.0 A report for Elexon by London Economics and Ventyx'.

[2] See http://www.decc.gov.uk/en/content/cms/consultations/improving_grid/improving_grid.aspx for details.

- The effect of P229 on embedded plant, if this plant was treated as generation rather than as negative load.

We address each of these issues in turn. Though we have had limited direct contact with LE/Ventyx, we were able to put written questions to them via Ofgem and Elexon. To reduce the burden on both Ofgem and LE/Ventyx, we did not put questions to LE/Ventyx on issues that did not seem to have a material affect on the outcome of the study.

Results of additional scenarios

Redpoint were asked to model two additional scenarios. One of these scenarios modelled a larger capacity of offshore wind than LE/Ventyx had assumed. The other modelled the impact of the transmission access review, under which generators would be allowed to connect to the grid before the completion of wider network reinforcements.

The additional scenarios modelled by Redpoint give results which are very similar to the scenarios that LE/Ventyx modelled. Both of the new scenarios predict that the costs of generation, including losses, will fall as a result of P229, and the size of the fall in costs is similar to LE/Ventyx's Reference case. Therefore the cost reduction predicted by LE/Ventyx seems robust against both higher levels of offshore wind and any effects of the transmission access review. One of the reasons why Redpoint's additional scenarios might give similar results to those of LE/Ventyx is that the Redpoint scenarios mainly involved the addition of addition aal or accelerated renewable generation, in particular wind power. The despatch of wind power would not be affected significantly by the introduction of zonal losses, and so the change in generating patterns would come mainly from thermal plant, as in the LE/Ventyx scenarios. The results of the additional scenarios are discussed in detail in the Lot 2 report.

Effect on existing and future consumers

P229 will have a number of effects on present and future consumers including:

- Changes in consumer welfare due to changes in the price of electricity as a result of P229;
- Changes in environment and air quality due to reductions in emissions of NOx and SOx, and a reduction in GB's CO2 emissions;
- Increases in security of supply due to less stress on the transmission network and deferred retirements of plant;
- Long-term reductions in transmission use of system charges.

P229 has two separate effects for consumer prices and welfare. First, P229 will change wholesale electricity prices, and these wholesale price changes will be passed onto consumers. Second, to serve a given demand at the point of use (e.g. a house or business), suppliers may have to buy more (or less) electricity under P229 than they currently do. Suppliers would pass on the cost of the change in the gross electricity volumes they need to buy to their customers.

We find that the effect of P229 on consumer benefits is highly sensitive to the predicted change in wholesale electricity prices. We estimate that ignoring price increases P229 results in an increase in benefits for consumers, but that an average price increase of only £0.06/MWh is sufficient to wipe out these benefits. This issue is complicated because predicted wholesale price increases are in turn sensitive to whether one models generators' offers using TLFs or TLMs.[3] LE/Ventyx calculated wholesale prices using TLFs, since this was both more practical and had little effect on the predicted costs. However, we think that modelling generators' offers using TLMs is more likely to reflect generators' actual behaviour under P229. Redpoint estimate that modelling offers using TLFs results in an average wholesale price increase of £0.3/MWh, where as modelling offers using TLMs results in an average price increase of only £0.03/MWh in the reference case.

To reflect the uncertainty in wholesale price increases, we have calculated the change in Consumer Surplus assuming that wholesale prices with and without P229 remain the same, so as to provide an 'upper bound' for consumer benefits. Under this assumption, in the Reference case (LE/Ventyx's change case) the 2009/10 present value of consumer surplus increases by £155 million. In the reference scenario one group of consumers has an increase in surplus of £608 million, and another group has a decrease in surplus of £452 million. The net effect is an increase in surplus of £155 million.

If we use LE/Ventyx's price changes calculated using TLFs, then we find that the net effect of P229 is a decrease in surplus of £524 million for GB consumers in the Reference case, and the effect in other scenarios is similar. The decrease in surplus is caused because of the increase in average prices which LE/Ventyx estimate. We conclude that the effect of P229 on consumers is highly sensitive to prices, but on the basis of Redpoint's analysis there will still be positive consumer benefits assuming that average wholesale price increases are only around £0.03/MWh.

Note that the change in consumer surplus which we calculate as a result of price changes will be approximately offset by a change in generators' profits. In other words, using LE/Ventyx's price changes, there is a transfer from consumers to generators. The total social effect – that is, the combined effect on consumers and generators – should approximately equal the reduction in generating costs predicted by LE/Ventyx.

LE/Ventyx estimate that P229 reduces emissions of NOx by between 2,000 and 7,000 tonnes per year, and SOx emissions by between 3,000 and 25,000 tonnes per year. Both NOx and SOx are responsible for a number of undesirable effects, including acid rain and smog. NOx and SOx are two of the pollutants which contribute toward asthma attacks, which over 5 million people in the UK suffer from. Therefore the reduction in SOx and NOx emissions should benefit GB consumers by increasing air quality. LE/Ventyx also estimates that P229 will reduce GB CO2 emissions by between 1 million and 3 million tonnes per year over the period modelled.

P229 increases security of supply by reducing transmission congestion – which should reduce the vulnerability of the transmission system to failures – and by deferring the retirement of peaking plant. We note that interrupting even 1% of average GB electricity demand for 24 hours would cost around £70 million. This is about double the present value benefits LE/Ventyx estimates for P229 excluding NOx and SOx benefits. We cite these numbers simply to illustrate

[3] TLM =1 +TLF +TLMO. The Transmission Losses Adjustments (TLMO) are calculated separately for suppliers (TLMO-) and for generators (TLMO+).

that even a small reduction in the probability of lost load as a result of P229 could have a material benefit for consumers.

At the margin P229 will make it more likely for plant to locate in the south rather than in the north. This will in turn reduce the costs of the transmission system since NGET will need to install less wires to transit the power. This reduction in transmission costs (TNUoS charges) which P229 realises will eventually be passed on to consumers to their benefit.

Impact on renewable generation

To investigate the effect of P229 on the despatch of renewable generators, we have calculated the average TLM for renewable generators as opposed to non-renewable generators. There is nothing in the P229 proposal which singles out renewable generation for treatment of losses. But because many renewables generators are in the north of GB where losses are higher, there is a possibility that P229 has a larger effect on renewable generators than non-renewable generators.

Our calculations confirm that renewable generators have higher losses on average. For example, in 2011/12 the average non-renewable generator would be credited with 99.8% of their generation, whereas the average renewable generator would only be able to sell 97.8% of its output due to losses. However, the gap between renewable and non-renewable loss factors closes toward 2020. This is because of the location of larger volumes of offshore wind in southern parts of England, which counter-balance onshore and offshore wind in and offshore Scotland.

We do not expect that larger-than-average losses will reduce despatch from a renewable plant under P229. Many renewable technologies such as wind, wave and solar have almost zero marginal costs, and so have an incentive to despatch even if electricity prices are very low or, equivalently, they bear higher-than-average losses. Renewable technologies with higher marginal costs, such as biomass, also have strong incentives to produce even with higher loss factors, because they only receive Renewable Obligation Certificates (ROCs) if they generate electricity. ROCs can represent a significant part of a renewable plant's revenue. Accordingly, high-marginal cost renewable plants that qualify for ROCs will despatch even if they bear they bear higher-than-average losses.

We have also identified an issue whereby ROCs are awarded to generators based on volumes generated *before* losses are taken into account. Similarly, suppliers buy ROCs based on the metered volume delivered to customers, rather that the volumes bought which might be higher or lower depending on the supplier's loss factor. The issue of how ROCs interact with losses would likely be more visible if P229 is introduced, because suppliers and generators would be affected in different ways depending on their location. Ofgem may need to consider modifying the way ROCs are allocated and obligations are set for suppliers to account for losses.

With respect to investment in new renewable generators, we have investigated the profitability of various types of renewable energy under P229. We find that, with the exception of wave power, all forms of renewable energy remain profitable under P229. We estimate that, at the costs used, wave power is unprofitable even without P229. At a discount rate one percentage point higher than used by LE/Ventyx, we find that tidal power would not be profitable offshore Scotland, but could be profitable offshore more southern parts of GB. We conclude that P229 should not make investment in renewables unprofitable.

Security of Supply

We have considered two issues with respect to security of supply – whether P229 could accelerate plant retirements and reduce the capacity margin, and whether P229 could increase congestion thereby making the transmission system less robust against outages.

We broadly agree with LE/Ventyx's conclusions that that P229 is unlikely to have a significant effect on plant retirements, and that other factors would dominate retirement decisions. We have investigated the change in net (post-losses) generation or despatch for the oldest and least efficient/highest marginal cost plant on the system, which is the type of plant that is likely to retire. We find that P229 actually increases despatch from this group of plants. The reason is that many of these plants are in the South and South-East of GB, and will therefore benefit from zonal losses. We conclude that on balance P229 is likely to delay the retirements of oil-fired plant, at least until about 2015, relative to a scenario without P229. After this P229 may slightly accelerate plant retirements but this should not be detrimental to system security, since newer plant will then be on the system.

P229 could also conceivably affect the retirement date of plants that have opted out of the Large Combustion Plant Directive (LCPD 'opt-out' plants). However, Redpoint's modelling actually shows that the despatch of opted out coal plant actually increases with P229. This means that P229 will not accelerate the retirement of opted out coal-plant, and there will be no adverse consequences for security of supply.

Broadly speaking the more heavily congested the network is then the more vulnerable it is to transmission failures. A decrease in congestion under P229 would indicate that the system is more secure and less vulnerable to transmission failures. LE/Ventyx's results indicate that in most scenarios and years P229 reduces congestion and therefore enhances security of supply. There are two scenarios which notably give more congestion in 2015 and beyond – the Low gas scenario and the (increased) Offshore Wind scenario. Both scenarios involve heavier use of the southern part of the transmission system than the reference scenario. Since the effects of P229 is to further shift generation to the south of GB, P229 results in increased congestion and reduced security of supply in the Low Gas Price scenario and the Aggressive Offshore Wind scenario. Nevertheless, on balance across the scenarios modelled P229 appears more likely to increase security of supply by reducing system congestion.

Risk and cost of capital

We find it hard to see any credible arguments that implementing P229 will increase regulatory risk. As far as we are aware the idea of zonal losses was first proposed in 1989 and again in 1995. Any prudent investor considering an investment in the north of GB after these dates should have considered a business case with zonal losses. The approximate size of the loss factors is known from previous public studies.

We estimate that over 55% of GB generating capacity had a final investment decision made after the idea of zonal losses was first mooted in 1989, and about 45% of GB generating capacity made an investment decision after 1995. This still means that about half of GB generating capacity was not aware of the possible introduction of zonal losses at the time they made their investment decision, and that arguably investors in projects in the north of GB would earn less than they originally anticipated if P229 was introduced. But in present value terms – from the perspective of an investor pre-1989 or pre-1995 – the reduction in value that zonal losses would cause from 2011 onward is very small. Moreover it is expected that over the lifetime of a long term investment such as a power plant some changes in the market rules will take place. Investors have a right to expect that these changes take place in an orderly manner and follow a predictable process, but they cannot expect a completely static market. We conclude that the introduction of P229 would not increase regulatory risk.

With respect to the cost of capital, because investors can diversify their holding of plant geographically over GB, P229 should not increase the cost of capital for the GB generation sector in aggregate. However, P229 would increase the cost of capital for projects in the north of GB and reduce it for southern projects. For example, projects in the north would have less revenue with which to support debt, and therefore face higher borrowing costs and/or be able to borrow less. Similarly, because northern generators would be operating more as peak than baseload plant under P229, they would be slightly more susceptible to changes in overall demand correlated to the performance of the economy as a whole. This means that their cost of equity would increase, but we expect the increase to be very slight, and plant developers may not even account for it.

We have also investigated the ability of existing generators in the north of GB to finance their debt under P229. As noted above, the prospect of zonal losses has been advertised for many years, and therefore one might expect that a prudent lender would have accounted for the introduction of zonal losses by demanding higher debt coverage ratios for plant in the north of GB. We conclude that even marginal generating project in the north of GB would still be creditworthy after P229 was introduced. Because projects will typically have more debt in their early years of operation, the highest financing risk of P229 is for non-renewable generating projects commissioned in Scotland between 2010 and 2013 inclusive. However, there are no non-renewable generating projects planned for Scotland in this window. We conclude that P229 will not threaten the financeability of any prospective generating projects.

Impact on embedded benefit

The embedded benefit is understood to be the difference in the overall costs between a situation in which a generator is connected at the transmission level and a situation in which the generator is connected at the distribution level. In this report, we focus on the embedded benefit that relates to losses – that is, the difference in the cost of losses for the generator depending on whether it is distribution or transmission connected. Accordingly, in the context of this report 'embedded benefit' relates only to loss-related embedded benefits. The key issues with respect to losses and embedded generation is that connection at the distribution level means that the generator's output reduces the volume on which the supplier must pay for losses, and this is the route through which the generator affects losses. Connecting at the transmission level means that the generator pays for the losses directly.

We find that that there is a positive embedded benefit with both uniform losses and with P229. However, the embedded benefit is larger with uniform losses, so that the introduction of P229 causes a reduction in the embedded benefit of £67 million in present value terms.

We have also calculated the effect of P229 on the cost of losses for suppliers based on existing embedded generation. Under P229, embedded generation will reduce losses for ‘southern’ suppliers, relative to a situation where the same generation was connected at the transmission level. Conversely, P229 reduces the benefits of embedded generation in ‘northern’ zones. We find that in aggregate P229 increases the cost of losses for suppliers by £34 million in the Reference case. This net increase in the cost of losses for suppliers is that there is more embedded generation in northern zones. There is a reduction in the cost of losses for suppliers in zones like London due to embedded generation and the Southern zone, and there is a increase in the cost of losses in Scotland. The assumption is that ultimately suppliers would pass n the costs or benefits of losses caused by embedded generation to the embedded generators themselves.

Ofgem has also asked us to consider the case where, for the purposes of calculating losses, embedded generation is treated as transmission connected generation. Since TLFs for generation and load are equal and opposite, then broadly peaking, if embedded generation costs suppliers £34 million while being distribution connected, they will bear the same costs directly when they are transmission connected. There may be slight differences as the TLMO+ and TLMO- factors will differ slightly. However, as the model does not produce these factors, which are determined by Elexon ex post, we cannot make a more accurate assessment of the effect of treating embedded generation as transmission connected.

2 Additional scenarios modelled

2.1 Additional offshore wind scenario

The Lot 1 report described how LE/Ventyx’s assumptions regarding offshore wind capacity are generally lower than those of NGET. Both LE/Ventyx’s reference and aggressive offshore scenarios use 2020 offshore capacities which are around half of the capacity included in National Grid’s 2009 Seven Year Statement (SYS). The SYS contains all connection agreements, and perhaps not all of these will be built. Nevertheless we note that the government’s 2020 renewables target envisages around 20 GW of offshore wind will be required by 2020, where as LE/Ventyx’s aggressive offshore scenario had only 6.3 GW installed by 2020. Moreover, in the analysis undertaken as part of the government’s transmission access review, the assumption under the base case that there would be 13-14 GW of offshore wind by 2020.

Accordingly, the Lot 1 report recommended a sensitivity should be run to investigate the impact of 15 GW of offshore wind by 2020 so that the 2020 capacity is consistent with the offshore wind tenders that have taken place (rounds 1-3) and backing off an equivalent volume of conventional generation, so that the capacity margin is maintained. The new offshore wind would be spread around GB in line with the Round 3 capacity allocations.

2.2 The impact of the transmission access review

In August 2009 the Department of Energy and Climate Change (DECC) began a consultation process on reforms to the transmission access regime. Since LE/Ventyx undertook their analysis in Q1 2009, they could not take into account or investigate the effect of DECC’s proposals on the P229.

The aim of the DECC’s review was to facilitate earlier connection of new generators – in particular renewable generators – to help the UK meet its renewable energy commitments. DECC’s latest consultation document, issued in March last year, indicated that the preferred option is to introduce the current 'connect and manage' regime on an enduring basis.[4] This should result in accelerated connection of new generation, particularly renewable generation, which in turn may affect the impact of P229.

Under 'connect and manage', generators will be allowed to commission their plant and connect to the transmission system before NGET has completed any transmission re-enforcements or 'wider works' that are any required to allow the plant to run without creating congestion. In their modelling, LE/Ventyx added transmission capacity and relaxed transmission constraints in later years to ensure that new generating plants did not face significant local congestion when they come on-stream. However, under a 'connect and manage' regime this may not be realistic. Instead, we would expect that under 'connect and manage' there will be periods of increased congestion between the connection of some new plants and the completion of wider works.

Ignoring a 'connect and manage' scenario now could underestimate the benefits of P229. Zonal losses should reduce any congestion caused by connect and manage, and lower the costs of generation. Since the combined effect of connect and manage and P229 is difficult to predict qualitatively, Ofgem asked the Lot 2 consultants, Redpoint, to model a scenario with the consequences of connect and manage and P229 modelled explicitly.

2.3 Results of all scenarios

A detailed description of the LE/Ventyx CBA results can be found in their report, and Redpoint describe the results of the additional scenarios in the Lot 2 report. However, for ease of reference in Table 1 and Table 2 below we have reproduced the main results from Tables 7-1 and 7-2 of the LE/Ventyx report and also the results of Redpoint's additional scenarios.

Table 1: Summary of the results of the CBA analysis, excluding savings from NOx and SOx, 2009 £ million

	LE/Ventyx scenarios						Redpoint scenarios	
	Reference	High Gas	Low Gas	Fuel Volatility	Aggressive Wind	Alt Nuclear	15 GW Offshore	RES-E Target
2011	2.74	3.69	-1.63	3.76	3.25	2.74	-7.41	-5.13
2012	6.35	11.99	1.83	7.03	6.56	6.35	9.27	6.16
2013	5.47	9.34	-1.04	2.14	5.77	5.47	7.38	8.73
2014	4.06	7.41	0.71	6.04	5.63	4.06	5.74	4.9
2015	2.86	3.98	0.04	1.45	4.12	2.86	4.76	5.37
2016	3.58	4.12	0.55	0.45	3.37	3.52	6.11	6.94
2017	2.55	8.81	-0.25	2.27	3.15	1.33	2.69	6.09
2018	6.19	12.74	1.44	9.87	5.92	1.81	1.36	1.28
2019	5.6	13.54	1.76	0.89	7.03	3.89	2.93	4.58
2020	6.73	22.13	0.88	12.59	7.32	6.73	3.75	2.41
Total	46.13	97.77	4.3	46.48	52.13	38.76	36.58	41.33

4 DECC, Improving Grid Access – Technical consultation on the model for improving grid access Consultation Document, URN 10D/567, 3 March 2010.

Table 2: Summary of the results of the CBA analysis, including savings from NOx and SOx, 2009 £ million

	LE/Ventyx scenarios						Redpoint scenarios	
	Reference	High Gas	Low Gas	Fuel Volatility	Aggressive Wind	Alt Nuclear	15 GW Offshore	RES-E Target
2011	17.2	-1.81	4.58	-1.21	19.04	17.2	13.45	13.15
2012	58.41	-1.74	19.18	63.57	59.03	58.41	12.56	8.59
2013	30.26	-2.09	-5.46	26.53	29.81	30.26	15.72	15.73
2014	28.07	-4.87	0.49	4.41	26.95	28.07	15.18	13.69
2015	33.75	-8.79	-0.83	36.32	30.86	33.75	12.68	14.07
2016	22.05	-1.44	8.59	21.98	20.11	22.06	15.96	16.69
2017	19.05	-1.49	7.94	-0.81	17.81	19.69	12.63	16.4
2018	22.27	1.11	16.36	-3.71	24.17	13.14	12.71	11.03
2019	22.73	2.55	13.54	24.18	20.54	-2.2	14.31	12.86
2020	21.38	-1.39	8.82	1.83	17.63	1.97	10.38	8.86
Total	275.16	-19.97	73.19	172.82	265.94	222.36	135.58	131.07

The Tables above illustrate three main points. First, that in the Reference case and all but one of the scenarios, P229 delivers a net benefit to generators. This is because P229 reduces the overall cost of generation by reducing the volume of losses on the system. Second, the value of the benefits increases substantially when the benefits of reduced SOx and NOx emissions are included. LE/Ventyx estimated the benefit of reduced NOx/SOx based on the cost of abatement, which likely underestimates the actual benefits. Finally, the additional scenarios Redpoint models give a similar level of benefits to the original LE/Ventyx scenarios.[5]

3 Impact on existing and future consumers

3.1 Effect on consumer welfare

3.1.1 Methodology

P229 will have two separate effects for consumer prices and welfare. First, P229 could change the marginal or price setting plant, and therefore change wholesale electricity prices. In a workably competitive market, these wholesale price changes will be passed onto consumers. Second, to serve a given demand at the point of use (e.g. a house or business), suppliers may have to buy more (or less) electricity under P229 than they currently do. Suppliers would pass on the cost of the change in the gross electricity volumes they need to buy to their customers.

LE/Ventyx's terms of reference were to evaluate the impact of P229 on industry, rather than on customers. The LE report did however address the effect that the reaction of customers to changes in prices would have on losses. LE/Ventyx estimated the price effects which we discuss in the paragraph above and the resulting change in demand. LE/Ventyx then estimated the change

[5] The one notable difference is that Redpoint calculate a net disbenefit in 2011, which LE/Ventyx does not find in comparable scenarios such as the Aggressive Wind scenario. The Lot 2 report contains a discussion of why this is the case.

in losses as a result of the change in demand, and the present value of this reduction in losses. However, LE/Ventyx did not report the overall impact of P229 on consumers as this was outside the scope of their analysis.

To estimate the effect of P229 on consumers, we first calculate consumers' electricity costs in each scenario without P229. Specifically, we take LE/Ventyx's wholesale price, which includes generators' uniform losses, and calculate a 'net' price.[6] This is the price of delivered electricity, including the consumer's share of losses. Multiplying this net price by demand gives the total cost. We perform this calculation for each zone and season between 2012 and 2020 inclusive. This provides our baseline consumer cost estimate.

We then repeat the exercise assuming P229 is implemented i.e. using the zonal loss factors and the wholesale prices that result from P229. We calculate the change in demand as a result of the change in prices, using the same demand elasticity of -0.25 as LE/Ventyx used.[7] We calculate the cost of electricity with the P229 net price and demand.

What is most relevant in this case is not the change in costs to consumers, but the change in overall benefits to consumers, as measured by the change in consumer surplus. For example suppose in a given zone and season P229 causes net prices to increase, so that demand falls. P229 has increased electricity costs to consumers, and they have mitigated the increase in costs by slightly reducing demand. But this demand reduction comes at a cost – the consumer is giving up some electricity consumption, and therefore there is a reduction in consumer benefit in addition to the increase in costs. By measuring the change in consumer surplus, rather than costs, we capture the overall change in benefits.

3.1.2 Modelling price changes

The wholesale electricity price change as a result of P229 has a large effect on whether consumers benefit or not from the change. The predicted wholesale price change depends in large part on how one models the way generators account for losses in their offers. Under one methodology the wholesale price change is approximately zero, and under the other the price change is still small in absolute terms, but large enough to create a disbenefit for consumers. Therefore it is important to go into some detail about how wholesale prices are modelled when considering the benefits for consumers.

Because P229 will result in a change in generators' marginal cost, we can expect P229 to result in a change in wholesale prices. P229 will increase the marginal costs of generated in the north of GB, and decrease the marginal costs of generators in the south, resulting in a new merit order. Whether the electricity price under P229 increase or decrease depends on how P229 affects the costs of the marginal or price-setting plant.

To estimate the effect that P229 has on prices, one must make an assumption about how generators will account for zonal losses in their offers. LE/Ventyx has assumed that generators

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[6] LE/Ventyx supplied us with peak and offpeak prices. We then calculated a demand-weighted average price from these two prices.

[7] LE/Ventyx report p.40.

take account of loss factors they face in the offers that they make in the wholesale market.[8] Specifically, LE/Ventyx included generators' TLFs rather than TLMs in generators' offers. The TLMs are derived by making an adjustment to the TLFs so that 45% of actual losses are recovered from generators. Without P229, the TLMs with uniform losses are around 0.6% and the TLFs are zero. Therefore, without P229, modelling generators' offers using TLMs creates prices that are higher than the prices calculated if one models generators' offers using TLFs.

Conversely, with P229 in place, the zonal TLFs are around 0.5% lower than the zonal TLMs. This means that the change in prices with and without P229 is always higher if TLFs rather than TLMs are taken into account in modelling generators offers.

Since it is the TLMs that determine the volumes with which a generator is credited and hence its revenues, it is these, rather than the TLFs, that theoretically should be included in generators' offers. There are two reasons why it is reasonable to model with TLFs rather than TLMs. First, modelling TLMs would require an iterative modelling process, because the TLM for each hour depends on the actual level of losses. This type of modelling would not have been practical because of the length of time that would be involved. Second, there is some question as to how generators would actually account for loss factors in their offers, since they do know what their TLF is before they make an offer, but the TLM is only known with certainty afterwards. The question is to what extent generators would guess their TLM rather than using the known TLF.

We think it is reasonable to suppose that generators would try and make offers including an estimated TLM, since that is what they must do today. Moreover, basing offers on the TLF would consistently over-estimate a generator's costs, and risk making it uncompetitive.

Redpoint estimates that, modelling generators' offers using TLFs in the way that LE/Ventyx did, wholesale prices increase by about £0.3/MWh on average over the period modelled – similar to the price increase of about £0.25/MWh reported by LE/Ventyx. Using an *ex post* adjustment of the model results, Redpoint has estimated that if it had modelled generators' offers using TLMs rather than TLFs, then wholesale prices would rise by only £0.03/MWh or about 10 times less than if one models price changes using TLFs. This issue is discussed in more detail in the Lot 2 report.

We think that modelling generators' offers using estimated TLMs is more likely to reflect reality. Accordingly, we first present the estimated change in consumer surplus assuming that there is no change in wholesale prices with and without P229. Of course, consumers will still experience a price change with P229, because different loss factors will be applied relative to the situation without P229. We have used the same discount rate as LE. Table 3 summarises the change in 2009/10 present value of consumer surplus for the different scenarios.

[8] We understand that in fact most generation is sold under longer term contracts, rather than on the spot market. Nevertheless, spot market prices will ultimately service as a reference point for long term contracts. Therefore the effect of P229 on generators offers and wholesale spot prices will eventually feed into all prices. For convenience we ignore the dynamics of this process.

Table 3: Increase in the 2009/10 present value of consumer surplus for the period 2011 to 2020 inclusive assuming no change in wholesale prices as a result of P229, £ '000

LE/Ventyx Zone	Geographic zone	Reference Scenario	Low Gas Scenario	High Gas Scenario	Fuel Volatility Scenario	Offshore Wind Scenario	Alternate Nuclear Scenario	RE reference	Offshore Wind	Accelerated Renewables
1	Eastern	-34,916	16,068	-62,079	-29,791	-33,816	-20,608	58,001	81,746	77,703
2	East Midlands	32,759	25,097	37,121	33,661	30,117	30,364	89,097	90,188	86,569
3	London	-151,364	-41,291	-204,637	-137,843	-149,352	-149,180	-45,980	-31,746	-35,447
4	North Wales & Mersey	43,770	5,798	58,848	40,482	44,157	28,713	51,061	46,716	45,934
5	Midlands	-9,580	-30,252	-13,859	-12,882	-11,006	-18,008	11,708	10,319	8,047
6	Northern	67,758	20,486	97,001	64,832	66,857	61,936	102,485	95,003	96,859
7	North West	114,886	43,312	156,260	110,769	116,831	104,974	75,998	73,791	74,274
8	Southern	-146,272	-55,482	-208,815	-140,504	-149,040	-132,422	-40,093	-30,000	-33,206
9	South East	-62,441	-5,965	-90,323	-56,441	-63,131	-57,170	16,915	28,242	25,690
10	South Wales	3,587	11,563	-7,393	4,417	1,404	6,624	17,937	18,388	17,290
11	South Western	-47,638	-15,978	-69,975	-45,309	-48,878	-39,020	-3,678	-998	-1,952
12	Yorkshire	77,003	48,692	98,501	79,034	74,670	71,335	142,475	139,441	136,581
13	Southern Scotland	162,034	35,872	248,725	154,392	162,962	155,672	139,533	123,555	137,216
14	Northern Scotland	106,053	39,252	153,788	102,499	117,463	103,668	70,635	51,553	63,655
	Total	155,638	97,174	193,163	167,317	159,236	146,878	686,093	696,198	699,213

Table 3 illustrates that in the Reference case (LE/Ventyx's change case) the 2009/10 present value of consumer surplus increases by £155 million. As one would expect, consumers in northern zones such as Scotland experience an increase in their consumer surplus of £268 million, since they now have to pay less for their electricity. Consumers in London experience a decrease in surplus of £151 million. In the reference scenario one group of consumers has an increase in surplus of £608 million, and another group has a decrease in surplus of £452 million. The net effect is an increase in surplus of £155 million. Table 3 also shows that the increase in consumer surplus is much higher in the three Redpoint scenarios (RE reference, Offshore Wind and Accelerated Renewables). This is presumably because, while Redpoint has calibrated its model to re-produce LE/Ventyx's results as far as possible, the Redpoint model produces different TLFs and therefore the results of the two models will differ.

Table 4: Increase in the 2009/10 present value of consumer surplus as a result of P229 for the period 2011 to 2020 inclusive, £ '000

LE/Ventyx Zone	Geographic zone	Reference Scenario	Low Gas Scenario	High Gas Scenario	Fuel Volatility Scenario	Offshore Wind Scenario	Alternate Nuclear Scenario	RE reference	Offshore Wind	Accelerated Renewables
1	Eastern	-109,380	-53,141	-142,511	-122,133	-115,131	-95,278	-41,884	-13,488	-43,425
2	East Midlands	-18,425	-22,910	-20,070	-30,013	-26,285	-20,690	19,145	25,337	3,435
3	London	-216,774	-101,761	-273,249	-218,784	-220,323	-215,277	-132,202	-116,448	-142,523
4	North Wales & Mersey	-2,599	-37,390	11,486	-16,852	-5,858	-18,431	-9,754	-14,359	-30,761
5	Midlands	-69,817	-86,667	-79,187	-87,693	-76,912	-78,504	-69,573	-67,199	-90,597
6	Northern	24,477	-19,945	52,134	11,252	20,012	18,070	45,474	38,416	25,489
7	North West	63,873	-4,524	101,965	47,497	61,297	53,539	7,427	7,368	-9,942
8	Southern	-218,759	-122,717	-285,945	-230,334	-227,980	-205,409	-136,346	-123,488	-151,651
9	South East	-111,458	-51,501	-143,263	-117,209	-116,696	-106,358	-48,770	-34,487	-54,046
10	South Wales	-25,847	-15,660	-37,052	-31,946	-30,264	-23,326	-20,336	-20,579	-31,473
11	South Western	-72,617	-39,171	-96,873	-76,285	-76,159	-64,089	-37,012	-33,035	-42,610
12	Yorkshire	23,354	-1,427	41,173	12,515	16,183	17,315	70,794	70,259	48,760
13	Southern Scotland	119,978	-3,853	203,706	102,172	117,117	113,289	82,902	68,955	67,785
14	Northern Scotland	89,513	23,548	136,095	81,948	99,485	87,009	48,134	29,821	36,129
	Total	-524,480	-537,119	-531,590	-675,864	-581,515	-538,140	-222,000	-182,926	-415,429

Table 4 summarises the change in 2009/10 present value of consumer surplus using the wholesale price changes estimated by LE/Ventyx for the different scenarios with equivalent results for the additional Redpoint scenarios. Table 4 illustrates that in the Reference case (LE/Ventyx's change case) the 2009/10 present value of consumer surplus *falls* by £524 million. Consumers in northern zones such as Scotland still experience an increase in their consumer surplus of £209 million, and consumers in London experience a decrease in surplus of £216 million. In the reference scenario one group of consumers has an increase in surplus of £321 million, and another group has a decrease in surplus of £846 million. The net effect is a decrease in surplus of £524 million.

The results for most of the scenarios are broadly similar. In the Fuel Volatility Scenario the reduction in surplus is higher than the Reference case for two reasons. First, wholesale electricity prices increase by more with P229 than they do in the Reference case, and this reduces consumer surplus. Second, consumer loss factors are higher in the Fuel Volatility Scenario than in the Reference case.[9]

The tables above illustrate that the decrease in surplus in the Reference case and other cases is caused because of the increase in average prices which LE/Ventyx estimate. We estimate that an average wholesale price increase of £0.06/MWh under P229 would be sufficient to reduce the consumer benefits of P229 to zero. To make this conclusion more intuitive, consider that in 2011 GB demand is about 335 TWh. An increase of £0.06/MWh therefore represents an increase in costs of £20 million per year. The 2009/10 PV of £20 million over the years studied is £146 million, about the same as the predicted consumer surplus without a price change. This explains why a price increase of £0.06/MWh is sufficient to wipe out any benefits.[10] We conclude that the effect of P229 on consumers is highly sensitive to prices, which seem to dominate the direct effect of losses. However, this also implies that there would still be a positive consumer benefit, if the wholesale prices change was around £0.03/MWh, as implied by Redpoint's analysis when modifying generators' offers using TLMs.

We conclude that modelling price changes using TLMs is more likely to reflect generators' bidding behaviour, and that therefore the price rise of £0.03/MWh implied by Redpoint's analysis is more likely to represent the actual wholesale price increase as a result of P229. This smaller wholesale price increase would still result in an increase in surplus for consumers.

3.2 Emissions

The LE/Ventyx report finds that P229 would reduce emissions of carbon dioxide (CO2) as well as emissions of nitrous oxides and sulphur oxides (NOx and SOx respectively). As we discuss in some more detail in section 4.3, this is mainly because P229 will shift generation away from coal-fired plant in the north of GB to more efficient gas-fired plant in the south.

LE/Ventyx estimate that P229 reduces emissions of NOx by between 2,000 and 7,000 tonnes per year, and SOx emissions by between 3,000 and 25,000 tonnes per year.[11] Both NOx and SOx are responsible for a number of undesirable effects, including acid rain and smog. NOx and SOx are two of the pollutants which contribute toward asthma attacks, which over 5 million people in

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[9] Note that the prices supplied by LE/Ventyx for the Alternative Nuclear Scenario did not seem to be correct. For example the average price increase in the Reference case with P229 is £0.25/MWh. But in the Alternative Nuclear Scenario we see some years where prices increase and decrease by over £7/MWh. Since the Alternative Nuclear Scenario and the Reference case are the same up to and including 2016, we have used the Reference case prices up to this point.

[10] Our actual calculation is more rigorous – these numbers are intended to be illustrative only.

[11] LE/Ventyx report Figure 5-8 and Figure 5-9 pp. 99-100.

the UK suffer from. Therefore the reduction in SOx and NOx emissions should benefit GB consumers by increasing air quality.

LE/Ventyx estimates that P229 will reduce CO2 emissions from GB generators by between 1 million and 3 million tonnes per year. We note that the European Emission Trading Scheme or ETS has capped the total amount of emissions for installations that participate in the scheme, including the GB power sector. The reduction in CO2 emissions from GB generators as a result of P229 will make more emissions certificates available to other emitters within the ETS. Therefore P229 does not reduce CO2 emissions, but rather it lowers the price of meeting the target set by the ETS. We note that since LE/Ventyx has included the price of carbon emissions in plants' costs, then any effect of reduced CO2 emissions on the electricity price will already have been accounted for in the analysis in section 3.1 above.

3.3 Security of Supply

We deal with the effect of P229 on security of supply in detail in section 5. In that section, we conclude that P229 increases security of supply by reducing transmission congestion – which should reduce the vulnerability of the transmission system to failures – and by deferring the retirement of peaking plant. LE/Ventyx has not performed a quantitative estimate of the effect of improved security of supply on consumers, because this was outside of their terms of reference. However, we note that because interruptions of supply security can have very large negative consequences for consumers, even a relatively small reduction in the probability of a supply interruption will have large benefits for consumers.

To illustrate the effect, we note that Ireland's Single Electricity Market proposed a Value of Lost Load – that is the price consumers would be willing to pay to avoid a reduction in electricity supply – of €10,000/MWh, or about £8,000/MWh.[12] At this VOLL, interrupting 1% of average GB electricity demand for 24 hours would cost around £70 million. This is about double the present value benefits LE/Ventyx estimates for P229 excluding NOx and SOx benefits. We cite these numbers simply to illustrate that even a small reduction in the probability of lost load as a result of P229 could have a material benefit for consumers.

3.4 TNUoS charges

NGET applies Transmission Network Use of System (TNUoS) charges to recover the capital or fixed costs of the transmission network. NGET determines TNUoS charges for each zone, based on the long-run marginal cost of expanding the transmission capacity for that zone. Zones in the north of GB have higher TNUoS because NGET would have to invest more money to cope with flows from the north of GB to the larger demand centres in the south of GB. P229 will give a stronger signal to investors to site plants in the south of GB rather than the north, and should therefore reduce transmission investment costs.

The LE/Ventyx report noted that they did not expect P229 to have a significant effect on plant siting decisions, because "other locational charges and location-specific concerns form the

[12] AIP, The Value of Lost Load, the Market Price Cap and the Market Price Floor A Consultation Paper, AIP-SEM-07-381, 2 July 2007.

majority of costs and concerns for plant location decisions".[13] LE/Ventyx noted that many decisions had already been made regarding plant siting, and that TNUoS charges already give a strong locational signal. We broadly agree with LE/Ventyx's analysis, and our own studies of locational signals via electricity transmission tariffs have also confirmed that these signals are often outweighed by the factors cited by LE/Ventyx.[14]

Nevertheless, at the margin P229 will make it more likely for plant to locate in the south rather than in the north. This will in turn reduce the costs of the transmission system since, in basic terms, NGET will need to install less wires to transit the power. In a reasonably competitive electricity market, generators will eventually pass on their costs – including transmission costs – to customers. Therefore any reduction in transmission costs (TNUoS charges) which P229 realises will eventually be passed on to consumers to their benefit.

4 Impact on Generation by Technology Type

Under P229, generators will face higher losses in Scotland, where the majority of wind power will be developed in future. We have investigated whether P229 would adversely affect the attractiveness of investing in renewable forms of energy generation such as wind-power, wave-power and tidal generation. We have also investigated whether P229 might affect one type of generating plant more than another, which could have implications for, among other things, gas transportation costs.

4.1 Effect on incentives to invest in renewable generation

The analysis above assumes that P229 does not reduce investment in renewable energy. This seems likely to be the case. As the LE/Ventyx report points out, the majority of new renewables projects will be in onshore and offshore wind. The local wind resource, the ability to get planning permission (onshore), and access to the grid are likely to have a much greater effect on siting and investment decisions for renewables.[15] On other engagements relating to locational signals in transmission tariffs, we have interviewed plant developers with respect to which factors take priority in their investment and siting decisions, and they have confirmed the list above as being the most important factors. The LE/Ventyx report also notes that embedded generation – which could also make a significant contribution to the total level of renewable energy – will not face the consequences of P229 directly.

To investigate if it is realistic that locational loss-factors could reduce the attractiveness of investing in renewable energy sources, we have set up a simple investment model which calculates the profitability of various types of renewable energy. Our calculations use electricity

[13] LE/Ventyx report p.3.

[14] For example in November 2007 we produced a study for the Dutch Ministry of Economic Affairs 'Locational Signals in Transmission tariffs in North West Europe' which included a study of the effectiveness of transmission tariffs relative to other locational signals for generators, such as gas transport charges, land prices and ease of permitting.

[15] LE/Ventyx report p.48.

prices based on forward prices, and account for income that renewable generators will receive from Renewables Obligation Certificates (ROCs).[16] We have then calculated the minimum TLM that would still allow the project to break even (in other words, reduce the NPV to zero) for several different types of renewable energy. Because the discount factor used by LE/Ventyx was criticised by some parties as being too low, we have performed this calculation using the LE/Ventyx discount factor and a discount factor one percentage point higher.[17] We then compare the minimum TLM that would allow the project to break even with the actual minimum annual average TLM calculated by LE/Ventyx. Table 5 summarises the results of this exercise, while Appendix I provides the detailed calculations.

Table 5: Minimum TLM that would allow project to break even for various types of renewable energy

Technology type	Break-even TLM		Actual lowest TLM	Margin	
	With discount factor 4.42%	With discount factor 5.42%		With discount factor 4.42%	With discount factor 5.42%
Offshore wind	0.865	0.932	0.947	0.081	0.015
Onshore wind	0.602	0.647	0.947	0.345	0.300
Wave	1.102	1.194	0.947	-0.156	-0.247
Tidal	0.888	0.963	0.947	0.058	-0.017
Biomass	0.738	0.764	0.947	0.209	0.183

Table 5 illustrates that, with the LE/Ventyx discount rate, all types of renewable except for Wave power would still be profitable under P229. This is highlighted by the positive margin between the break even TLM and the actual minimum TLM. The exception to this is wave technology, which appears to be unprofitable even if credited with over 100% of the electricity generated.

At a higher discount rate, Tidal would be unprofitable offshore Scotland, but it could still make a profit in most other parts of GB offshore.

4.2 Despatch of existing renewable generation

If renewable generators face higher losses on average, it is possible that P229 could reduce despatch from renewable plant. To investigate whether this could happen we have used the LE/Ventyx report to estimate the weighted-average loss factor for all generation excluding renewables, and the weighted loss factor for renewable generation.[18] We have weighted the loss factors by installed capacity in each zone. Table 6 illustrates that the TLMs for non-renewable generation are between 0.004 and 0.021 higher than for renewable generation. This means that, on average, P229 imposes an extra cost on renewables relative to non-renewable plant. For

[16] Or another form of subsidy that will give the same income as the current ROCs scheme.

[17] Note that we use the LE/Ventyx discount factor to discount real after-tax cash flows.

[18] We include hydro generation and biomass in our calculation, but exclude pumped storage.

example, in 2011/12 the average non-renewable generator would be credited with 99.8% of their generation, whereas the average renewable generator would only be able to sell 97.8% of its output due to losses. However, the gap between renewable and non-renewable loss factors closes toward the end of the period. This is because of the location of larger volumes of offshore wind in southern parts of England, which counter-balances onshore and offshore wind in and offshore Scotland. The result is that by 2020/21 the average non-renewable generator is credited with 99.5% of their generation, and the average renewable generator is credited with 98.8% - one percentage point higher than in 2011/12.

Table 6: Weighted-average loss factors for renewable and non-renewable energy

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Total capacity non renewable	0.998	0.998	0.997	0.996	0.995	0.995	0.995	0.995	0.995	0.995
Total capacity renewable	0.978	0.977	0.982	0.983	0.984	0.987	0.987	0.991	0.988	0.988
Difference	0.020	0.021	0.015	0.013	0.011	0.008	0.008	0.004	0.007	0.007

We have also investigated if this additional cost is likely a) to reduce the volume of renewable energy generated and b) if higher loss factors could reduce the attractiveness of investing in renewable generation.

We would not expect that a larger-than-average TLM would reduce despatch from a renewable plant. Many renewable technologies such as wind, wave and solar have almost zero marginal costs, and so have an incentive to despatch even if electricity prices are very low or, equivalently, they bear higher-than-average losses. Renewable technologies with higher marginal costs, such as biomass, also have strong incentives to produce even with higher loss factors, because they only receive Renewable Obligation Certificates (ROCs) if they generate electricity. ROCs can represent a significant part of a renewable plant's revenue. Accordingly, renewable plants with high marginal costs that qualify for ROCs will despatch even if electricity prices are very low or, equivalently, they bear higher-than-average losses.

For example, suppose that a biomass generator had marginal costs of £45/MWh, the ROC price was £50/MWh and the power price was £40/MWh. The generator would make an operating profit of £45/MWh. Even reducing the volume of power sold by up to 2% would make almost no different to the operating profit, which is still strongly positive. The income from ROCs will offset the marginal costs of wind-powered generators even if electricity prices are negative.

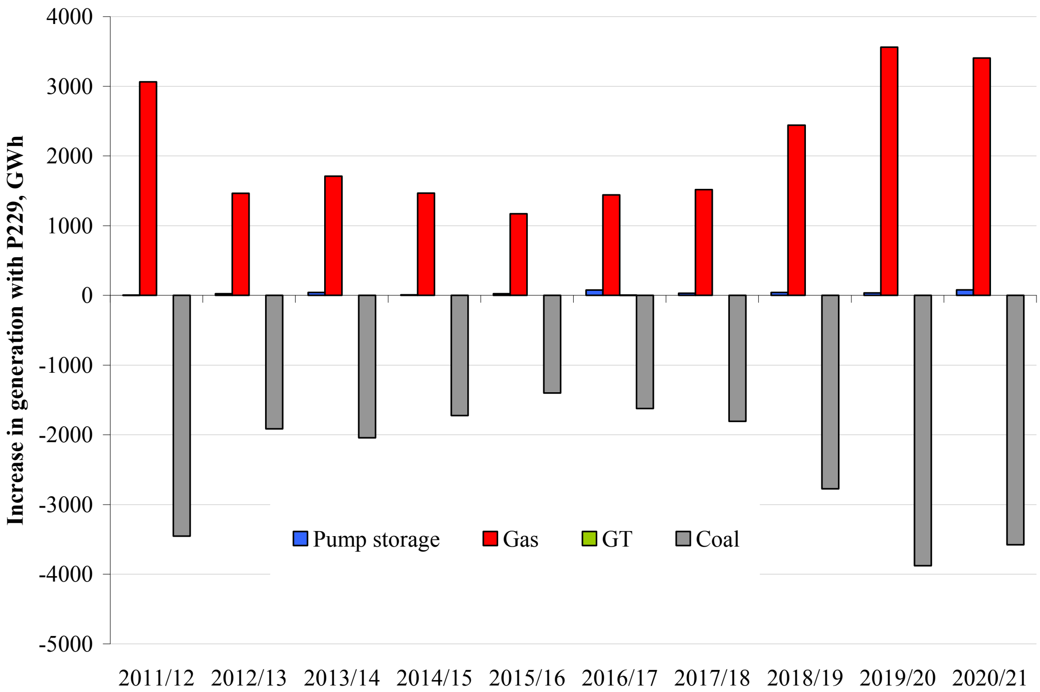
The effect of P229 on renewable generators is further mitigated because ROCs are issued based on the metered volumes without loss-adjustments. Therefore, the introduction of P229 would not change the volume of ROCs that qualifying generators receive. Redpoint have confirmed this conclusion with their quantitative modelling, discussed in the following section.

We have also identified an issue whereby ROCs are awarded to generators based on volumes generated *before* losses are taken into account. For example a generator might produce 1 MWh and be credited with ROCs on this basis, but the generator might only be able to sell 0.98 MWh because of losses under P229. Similarly, suppliers buy ROCs based on the metered volume delivered to customers. So a supplier might have to buy ROCs to cover 1 MWh of demand, but the supplier might actually be buying 1.02 MWh to account for losses under P229. Because generators receive ROCs for more electricity than they actually sell, and (in aggregate) suppliers have to buy ROCs for less power then they actually buy, the effect is to slightly depress ROC prices relative to a situation where ROCs were awarded to generators post-losses, and suppliers had to buy ROCs to cover net demand and losses. In practise we expect the effect to be minor. However, the issue of how ROCs interact with losses would likely be more visible if P229 is introduced, because suppliers and generators would be affected in different ways depending on their location. Ofgem may need to consider modifying the way ROCs are allocated and obligations are set for suppliers to account for losses.

4.3 Impact of P229 on despatch of non-renewable generation

While the LE/Ventyx report provided details on the total change in despatch and emission caused by P229, the results were not broken down by fuel type. However, in their re-creation of LE/Ventyx's Reference case, Redpoint did produce this data, which we summarise below in Figure 1. The figure illustrates that P229 causes a shift from northern coal-fired plant to more widely dispersed gas-fired plant. In percentage terms, electricity from gas-fired generation increases by about 1.5% on average, while coal-fired generation decreases by about 3.5%. Thee total amount of electricity generated in the P229 case is less than without P229, because of the reduction in losses.

Figure 1: Increase in generation by fuel type as a result of P229



As one might expect, there is no change in generation for nuclear, hydro or wind. All of these sources of electricity have very low marginal cost, and so as discussed above we would not expect their despatch to be affected by higher loss factors. P229 slightly increases the despatch of pumped storage.

Redpoint's results are consistent with the findings in the LE/Ventyx report, which calculates that, in the reference case, P229 would reduce emission of carbon-dioxide by between 1 to 3 million tonnes per year.[19] P229 also reduces emissions of NOx and SOx. These figures are consistent with a reduction of generation from coal-fired plants, which emit more carbon dioxide and SOx per kWh of electricity generated than Combined Cycle Gas Turbine (CCGT) plants.

To confirm the Redpoint results, we have calculated the capacity-weighted average TLMs for coal-fired and gas-fired plant, renewable plant (as above) and 'all other plants'. The latter category covers mainly nuclear and oil-fired plants. Table 7 illustrates the results, and confirms that, as we would expect from the Redpoint results, gas-fired plants have lower than average losses, so that they will tend to be despatched more under P229. Conversely, coal-fired plants have higher than average losses, making them more expensive so that they despatch less. Accordingly, one possible effect of P229 is that it will increase the volume of gas transported to power stations, and possibly the capacity required on part of the gas transport network, increasing gas transport costs.

Table 7: Weighted-average loss factors by plant type

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Weighted Average yearly TLM										
All non renewable	99.77%	99.77%	99.66%	99.56%	99.53%	99.49%	99.48%	99.46%	99.49%	99.47%
Gas	99.90%	99.84%	99.71%	99.66%	99.65%	99.64%	99.60%	99.59%	99.60%	99.58%
Coal	99.40%	99.47%	99.39%	99.17%	99.09%	99.15%	99.17%	99.07%	99.04%	99.03%
Non renewable - other	101.93%	101.75%	101.38%	101.26%	101.36%	100.91%	100.59%	101.01%	101.00%	100.99%
Renewable	97.79%	97.68%	98.21%	98.26%	98.40%	98.66%	98.71%	99.10%	98.77%	98.77%
Simple average	99.76%	99.70%	99.67%	99.58%	99.60%	99.57%	99.51%	99.64%	99.58%	99.57%
Differences from average										
All non renewable	0.02%	0.07%	-0.01%	-0.02%	-0.07%	-0.08%	-0.03%	-0.19%	-0.09%	-0.10%
Gas	0.15%	0.14%	0.04%	0.07%	0.04%	0.07%	0.09%	-0.06%	0.02%	0.02%
Coal	-0.36%	-0.23%	-0.28%	-0.41%	-0.52%	-0.42%	-0.34%	-0.57%	-0.53%	-0.54%
Non renewable - other	2.17%	2.05%	1.71%	1.68%	1.75%	1.33%	1.08%	1.37%	1.42%	1.42%
Renewable	-1.97%	-2.02%	-1.46%	-1.32%	-1.20%	-0.91%	-0.80%	-0.55%	-0.81%	-0.80%

5 The impact of P229 on the security of energy supply

P229 could have two potential effects on the security of the electricity supply. First, it could change the capacity of the plant on the system by accelerating or deferring retirement decisions. Second, it could change the way in which the transmission system is used, and therefore change the loss of load resulting from plant outages and transmission line failures. We discuss each effect in turn.

5.1 Plant retirements

Broadly speaking, a generator will decide to retire a plant when the revenue flow for the plant is insufficient to cover the plant's fixed and variable costs and there seems little prospect of this situation changing. Of course, other factors also come into play – for example deferring high site clean-up costs could delay retirement, and an increase in the value of the site could accelerate retirement. But if applying zonal losses significantly reduced the despatch and net generation of

[19] LE/Ventyx report Figure 5-7 p.98.

older 'peaking' plant, then it is possible that P229 could accelerate some plant retirements, and to some extent reduce security of supply. Conversely P229 could increase security of supply, if it increased the revenue of older peaking plant.

The LE/Ventyx report discusses the effect of P229 on plant entry, exit and mothballing.[20] The report concludes that P229 would not affect retirement decisions, which would instead be dominated by factors such as the cost of maintenance and overhaul, supply and demand, and the efficiency of new technology.

We broadly agree that P229 is unlikely to have a significant effect on plant retirements, and that other factors would dominate retirement decisions. Nevertheless to see if the effect of P229 might be material, we have used our simple despatch model to investigate the change in net (post-losses) generation or despatch for the oldest and least efficient/highest marginal cost plant on the system. This is the kind of plant that is likely to retire. A significant reduction in net despatch of older less efficient plant under P229 would indicate a risk of more retirements and some reduction in security of supply.

Table 8 illustrates the percentage change in net despatch for oil-fired plants more than 20 years old, with and without P229, for the reference scenario. The table illustrates that in the first few years at least, P229 actually increases despatch from this group of plants. The reason is that many of these older oil-fired plants are in the South and South-East of GB, and will therefore benefit from zonal losses. From about 2014 onward there is, in any case, a large reduction in the output of this group of plant, as more efficient plant pushes them off the system. In these later years, P229 results in a slight reduction of despatch. But by this time newer plant will have come onto the system and the so there should be sufficient margin even if P229 accelerates the retirements of some older oil-fired plant. We conclude that on balance P229 is likely to delay the retirements of oil-fired plant, at least until about 2015. After this P229 may slightly accelerate plant retirements but this should not be detrimental to system security. Redpoint also estimated the change in despatch for oil-fired plant, but found very little difference in the despatch of oil fired plant with and without P229. However, we note that Redpoint predict much less oil-fired generation than in our simple model, probably due to different input assumptions.

Table 8: Despatch of oil-fired plants older than 20 years as of 2010 with and without P229

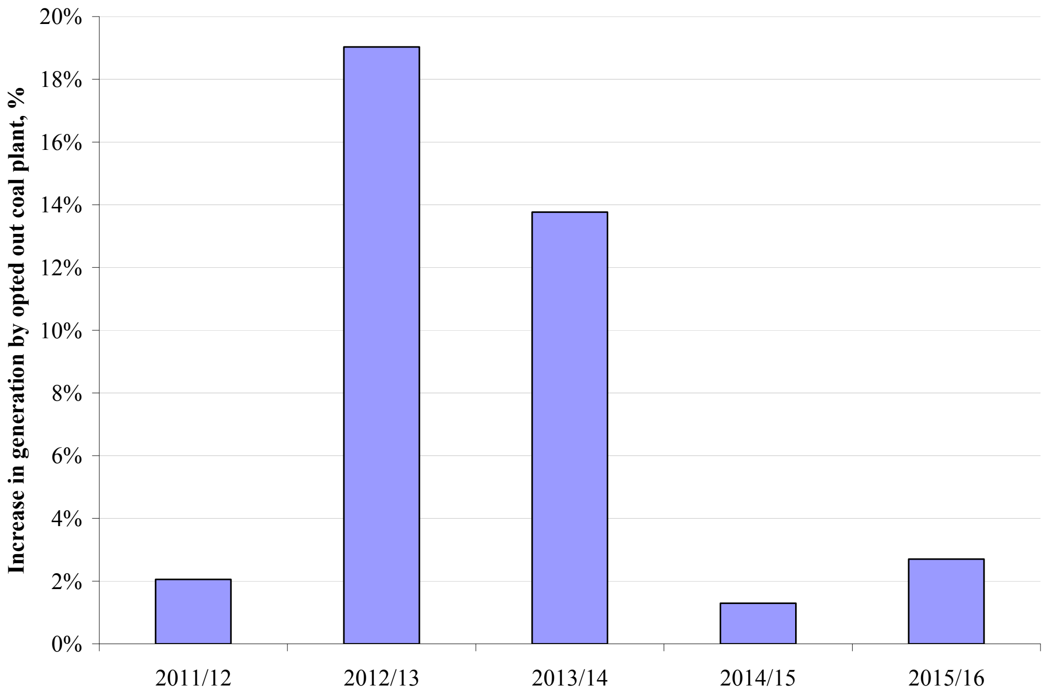
	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Without P229 (TWh)	17.4	14.5	4.8	0.1	1.0	2.1	2.5	2.0	1.8	1.7
With P229 (TWh)	20.2	19.0	10.6	0.2	1.0	2.1	2.2	1.8	1.4	1.5
Increase in despatch with P229, TWh	2.8	4.5	5.9	0.1	0.0	0.0	-0.3	-0.2	-0.4	-0.2
Increase in despatch with P229, %	16%	31%	123%	117%	-4%	-2%	-13%	-8%	-20%	-11%

P229 could also conceivably affect the retirement date of plants that have opted out of the Large Combustion Plant Directive (LCPD 'opt-out' plants). These plants have opted not to install flue-gas desulphurisation equipment, presumably because they are too old and inefficient for such an investment to be economic. As a result, LCPD opt-out plants may only run a total of 20,000

[20] LE/Ventyx report §3.6.3 pp.46-47.

hours and must close by 2015. Because of these restrictions, the LCPD opt-out plants are another group of plants which P229 could cause to retire early.

Figure 2: Percentage change in generation by 'opted out' coal-fired plant with P229



Redpoint has reported the despatch of opted-out coal-fired plant with and without P229 – we summarise the results in Figure 2 above. Redpoint's analysis shows that P229 enables opted out coal-plant to produce more power, and will therefore if anything delay their retirements relative to a scenario without P229. We note that the dominant variable cost for these plants – which are coal-fired and inefficient – is the cost of coal and carbon. Variations in these costs will have a much larger effect than P229 on the retirement decisions of LCPD opt-out plants.

We conclude that P229 will not accelerate the retirement dates of LCPD opt-out plants, and there will be no adverse effect for security of supply.

5.2 Congestion

Broadly speaking, the more heavily congested the network is then the more vulnerable it is to transmission failures. This is because congestion indicates that generators are 'sending' more supply via a particular route, and therefore the loss of load is greater should a congested route fail than if a less congested route failed. We recognise that this is a simplification – some congested routes may have redundancy or almost as much power could flow via an alternative route. Nevertheless, in aggregate if the network was less congested as a result of P229, this would indicate that is more secure and less vulnerable to transmission failures with P229 in place.

LE/Ventyx reported the total hours of congestion with and without P229 for the base case.[21] The results indicated that congestion reduced under P229 in all but the last year, indicating that P229 should improve security of supply. The result is intuitive – P229 should reduce flows from the north to the south of GB, and therefore reduce reliance on the heavily-used north-south transmission lines. LE/Ventyx's results showed a decreasing reduction in congestion over time, and in 2020 there is actually an increase in congestion. However, as LE/Ventyx pointed out in their report, not too much weight should be attached to the results of later years, where it is difficult to anticipate the reinforcement actions that NGET might have taken in response to changes in supply and demand growth. Note that Redpoint did not produce equivalent congestion data in their model, and so we cannot include a congestion analysis of Redpoint's scenarios.

In Table 9 we show the changes in percentage congestion for all the scenarios. We have highlighted cases where P229 increases congestion in red. Table 9 illustrates a number of points. First, in most scenarios and years P229 reduces congestion and therefore enhances security of supply.

Second, the reduction in congestion decreases over time. This is because demand is growing but LE/Ventyx does not make additional transmission investments beyond those described in the SYS. The results of later years should be given little weight, since they are likely to be a result of the difficultly of forecasting transmission investments beyond about 2015.

Third, the decrease in the reduction in congestion does not happen uniformly over time. This is because of additions and retirements in different parts of the grid that affect congestion.

Finally, we note that there are two scenarios which give more congestion in 2015 and beyond – the Low Gas scenario and the Aggressive Offshore Wind scenario. This is explained by the fact that both scenarios involve heavier use of the southern part of the transmission system than the reference scenario. In the low gas case gas-fired plant in the south of GB will run relatively frequently, backing out coal-fired plant in the north of GB. In the offshore wind case, more offshore wind is installed mainly in southern parts of GB, which again increases the load on the southern part of the GB transmission system. Since the effects of P229 is to further shift generation to the south of GB, P229 results in increased congestion and reduced security of supply in the Low Gas and the Offshore Wind scenario. In reality, if either the Low Gas scenario or the Aggressive Offshore Wind scenario materialised in practise, then National Grid would build more transmission capacity to ease the congestion.

[21] LE/Ventyx report Table 5-9 p.95.

Table 9: Changes in congestion for scenarios with and without P229

	Scenario					
	Reference Scenario	High Gas	Low Gas	Fuel Volatility	Offshore Wind	Alternative Nuclear
2011	-33%	-17%	-8%	-12%	-35%	-33%
2012	-13%	-5%	-1%	-16%	-14%	-13%
2013	-8%	-7%	0%	-13%	-5%	-8%
2014	-10%	-7%	-12%	-8%	-6%	-10%
2015	-7%	-9%	**2%**	-9%	**1%**	-7%
2016	-5%	-6%	-1%	-2%	0%	-5%
2017	-6%	-8%	**23%**	-9%	**5%**	-5%
2018	-10%	-8%	**31%**	-5%	**4%**	-9%
2019	-2%	**0%**	**14%**	**75%**	**1%**	-5%
2020	**10%**	-3%	-7%	-1%	**1%**	-42%

6 Effect on risk and cost of capital

In this section we discuss two issues. First, whether the introduction of zonal losses could increase 'regulatory risk'. Second, whether zonal losses would affect the cost of capital.

6.1 Regulatory Risk

All investments carry risks. In energy markets, one of the risks is that the regulator will change the market rules in such as way as to reduce the value of a project once it has been built. Accordingly, investors prefer markets where regulatory changes are predictable and the reasoning behind new rules is transparent. Consultations, impact assessments and explanation about the reasoning behind regulatory decisions all help improve the quality of regulation and reduce regulatory risk.

In the case of P229, we find it hard to see any credible arguments that implementing the proposal will increase regulatory risk. Consultants for Ofgem have documented the history of zonal losses proposals, and noted that the issue of zonal losses was first mentioned in the 1990 Pooling & Settlement Agreement.[22] Accordingly the idea of zonal losses has been around for at least 20 years. Any prudent investor considering an investment in the north of GB – where TLMs for generators will be lower – should have considered a business case with zonal losses. The approximate size of the loss factors is known from previous public studies.

We estimate that over 55% of GB generating capacity had a final investment decision made *after* the idea of zonal losses was first mooted in 1989. If one consider 1995 as the date that investors should first have taken the prospect of zonal losses seriously then about 45% of GB

[22] See 'Zonal Transmission Losses in the GB Electricity Market A Review of Statements by Ofgem and Others' 31 July 2006. Available from www.ofgem.gov.uk.

generating capacity made an investment decision after this date.[23] This still means that about half of GB generating capacity was not aware of the possible introduction of zonal losses at the time they made their investment decision, and that arguably investors in projects in the north of GB would earn less than they originally anticipated if P229 was introduced. But in present value terms – from the perspective of an investor pre-1989 or pre-1995 – the reduction in value that zonal losses would cause from 2011 onward is very small. Moreover it is expected that over the lifetime of a long term investment such as a power plant some changes in the market rules will take place. Investors have a right to expect that these changes take place in an orderly manner and follow a predictable process, but they cannot expect a completely static market. We conclude that the introduction of P229 would not increase regulatory risk.

6.2 Cost of Capital

The cost of capital refers to the return on their investment that firms must give their shareholders and the interest they need to pay on their debts. Ofgem have asked us to consider if P229 could have any affect on the cost of capital for generation.

6.2.1 Existing generators

In the discussion, it is important to distinguish between the effect on existing generators and those about to build plants. For existing plants, P229 will increase revenues for generators in the south and decrease them for plants in the north. Probably the most pressing issue is whether the change in revenue P229 realises is sufficient to affect the ability of generators that had planned their borrowing before P229 was introduced to repay their debts.

To investigate this issue, we made a simple financial model of a CCGT plant, financed 40% by debt, and assuming that the plant's loss factor (paid via BSUoS charges) is 99.5%. Appendix shows the details of the model. We set up the project so that without P229, the project's shareholders earn exactly their cost of equity – in other words, the Net Present Value of the project is zero. We calculate that the project has a minimum ratio of EBITDA to principal and interest payments (debt commitments) of 2.11. We then modify the project so that it has the highest level of losses LE/Ventyx predict under P229, and we also increase the electricity price by 0.3 £/MWh which is roughly in line with the increase in prices due to P229 foreseen by the LE/Ventyx report. Our model indicates that the minimum ratio of EBITDA/debt commitments falls to 1.79, which still represents a credit worthy project and does not present a risk of bankruptcy. Even if the project's borrowing costs were to increase by 50 basis points as a result of the fall in EBITDA/debt commitments, this ratio would only drop to 1.74. Coincidentally, assuming no increase in the wholesale electricity price under P229 also reduces the EBITDA/debt commitments ratio to 1.74.

We also note that the point of highest financial risk is the first two years of the project, when debt commitments are at their highest level. This means that the relevant time window is non-renewable plants being commissioned between now and 2013 inclusive. Plants commissioned after 2013 would only be finalising their loans at the end of 2011 or later, by which time the

[23] Note that we anticipate a lead time between the final investment decision and the plant commissioning date – so that for example a CCGT commissioned in 1990 would have had a final investment decision in 1988.

outcome of the zonal losses proposal would be known. Lenders could make therefore make adjustments to the loans to account for the effect of P229. Our assumption is generous, in the sense that, in the previous section we argue that the prospect of zonal losses has been advertised for about 20 years. Therefore one might expect that, even before the outcome of P229 is known, a prudent lender would have accounted for the possibility of zonal losses by demanding higher coverage ratios for plant in the north of GB. Projects commissioned in 2009 would be in the third year of operation when P229 came into effect, and so would not face any problems repaying debt under P229, even in Scotland.

According to our data base, there are no non-renewable plants being commissioned in Scotland or the North West zone between 2010 and 2013. These are the zones with the highest loss factors according to LE/Ventyx. A CCGT is planned for the Yorkshire zone in 2011 – this zone has the fourth highest loss factor. However, our model indicates that applying the average 2012 Yorkshire loss factor of 98.86% to the plant in our simple financial model does not cause any financial distress. In fact the overall effect of P229 is to increase the profitability of the project, because of the small increase in average electricity prices which LE/Ventyx predict. We conclude that P229 will not threaten the financeability of any prospective generating projects.

6.2.2 Cost of Capital for new projects

In terms of new generating projects, we do not think the P229 will systematically increase the cost of capital for generation in GB. The borrowing costs for projects in the north of GB will increase – or equivalently the projects will be able to borrow less – since these projects will now earn less revenue. This could mean that some marginal projects planned in the north of GB do not get built. Equally projects in the south of GB will be able to borrow more cheaply. This effect should simply encourage more plant to locate in the south of GB.

Many analysts use the Capital Asset Pricing Model or CAPM to measure the cost of equity, and LE/Ventyx refer to this model in their report.[24] The CAPM measures the non-diversifiable risk of a line of business – that is, the risk that cannot be dissipated by holding a broad portfolio of different assets. But investors could diversify the risk of P229 by investing in generation projects in both the north and south of GB.

The CAPM – and in particular the beta parameter – essentially reflects the correlation between the returns to equity holders from a particular line of business (in this case, electricity generation) and the performance of the economy as a whole. P229 will modify the revenues that all generators receive via the electricity price – LE/Ventyx estimates that P229 will increase electricity prices by a bit less than 0.3 £/MWh on average. P229 will also in effect change generators' costs. However, there seems no reason why this change will be at all correlated with changes in the market as a whole. So P229 would not change the cost of capital for generation in GB in aggregate.

To the extent that P229 makes northern generators more expensive and more likely to be used only at 'peak' demand, then northern generators will be more exposed to reduced demand due to downturns in the economy as a whole. Therefore the beta and cost of equity could increase

[24] See LE/Ventyx report §3.2.2.

slightly for projects in the north of GB. Similar, southern generating projects would become more 'baseload' and less exposed to economic downturn – their beta would decrease and the cost of capital for these projects should fall slightly. This effect on the cost of equity would 'compliment' the changes in the cost of debt described above and reduce the cost of capital for southern generating projects.

However, we also note that the theory outlined above also indicates that investors and developers should use different costs of capital for different types of generating project. For example a gas-fired CCGT should have a different cost of capital from a peaking plant. In practice conversations with plant developers indicate that they do not use separate costs of capital for different types of generating projects. Therefore it seems unlikely that the theoretical effect we describe above would affect any investment decisions in practise. The effect on a projects present value is also likely to be very small compared to the much more direct effect of P229 on a project's revenues.

We note that in practise some analysts increase or decrease the cost of capital to account for project-specific risk. First, as we explain above, we think it is not credible that implementing P229 has increased risk, because various proposals on zonal losses have been around for so many years. Any prudent investor should already have factored in the costs or benefits of zonal losses. Second, even if the introduction of P229 does change risks for certain generation projects, it is not correct to account for this change in project-specific risk in the cost of capital. Instead, the risk should be reflected by adjusting the project's cash flows. A leading textbook on corporate finance notes that 'bad' project outcomes, such as the introduction of a disadvantageous TLM, "reflect unique (i.e., diversifiable) risks which would not affect the expected rate of return demanded by investors. The need for a discount rate adjustment usually arises because managers fail to give bad outcomes their due weight in cash-flow forecasts. The managers then try to offset that mistake by adding a fudge factor to the discount rate."[25] We conclude that the introduction of P229 will not affect the cost of capital for GB electricity generators in aggregate, but will increase the cost of capital for generating projects in the north of GB and reduce the cost of capital for projects in the south.

7 Impact on embedded generation

We have examined two issues with respect to 'embedded' generation – which we define as generation connected to the distribution network, rather than the higher-voltage transmission network. First, how would P229 affect the benefits of embedded generation? And second, how would this benefit change if embedded generation were treated as generation rather than negative load. We discuss these issues below.

7.1 Effect of P229 on the embedded benefit

The embedded benefit is understood to be the difference in the overall cost of losses between a situation in which a generator is connected at the transmission level and a situation in which the generator is connected at the distribution level. Connection at the distribution level means that the

[25] Brealey and Myers, Principles of Corporate Finance, Fifth International Edition, p.220.

generator's output reduces the volume on which the supplier must pay for losses, and this is the route through which the generator affects losses. Connecting at the transmission level means that the generator pays for the losses directly.

To calculate the embedded benefit in monetary terms, we need to first make an estimate of the volume of embedded generation by zone. In the 2010 Seven Year Statement (SYS), NGET published data on embedded generation broken down by zone and plant-type for 2010/11. The 2009 SYS gives the contribution of embedded generation at the time of system peak for 2009/10 to 2015/16 inclusive. We calculate the ratio between installed embedded capacity and contribution to peak load in 2009/10 for each zone using the 2009 SYS data. We use this ratio – which we assume is fixed – to calculate the installed embedded capacity up to 2015/16. Although we use the embedded forecast from the 2009 SYS, we make an adjustment for the change in embedded capacity that results from the 2010 SYS. Beyond the forecast of the 2009 SYS (from 2016/17 to 2020/21) we assume that embedded generation remains constant in each zone. In practice, NGET does not forecast much growth in embedded generation between 2009/10 and 2015/16 so assuming constant embedded capacity post 2015/16 seems reasonable.

Finally, we estimate the electricity generated in GWh by embedded generation in each zone. The 2010 SYS contains the capacity and plant-type of embedded generation by zone in 2010/11. Therefore we are able to estimate a load factor for each type of embedded generation (onshore wind, waste gas etc.) and then calculate the average embedded-generation load factor by zone. For example, zones with a large capacity of embedded onshore wind will have a relatively low load factor, whereas zones with a large capacity of embedded CHP plant will have a high load factor. Multiplying the load factor by the installed capacity gives an estimate of embedded-generation output (GWh) by zone. We assume that the load-factor remains the same for each zone, which seems reasonable as long as the mix of embedded capacity in each zone remains similar in future as it was in 2010/11. Given the slow growth of embedded generation foreseen by NGET, this seems likely to be the case.

Suppliers pay for losses associated with the power supplied from the transmission network to the distribution network. Generation embedded within the distribution network reduces the amount of power suppliers need to draw from the transmission network. So embedded generation reduces the volumes of which suppliers are charged (or credited) with losses, relative to a situation where the same generation was connected at the transmission level. For example, suppose a supplier was in a zone with a TLM of 1.01. Absent embedded generation they would need to buy 101 MWh for every 100 MWh delivered to the distribution network. If an embedded generator produces the power rather than a transmission-connected plant, the supplier only needs to buy 100 MWh, and saves 1 MWh of costs.

We calculate the value of the losses which embedded generation saves suppliers under uniform losses – the assumption being that this benefit will ultimately be passed onto the embedded generators themselves. We then calculate the cost of the losses that embedded generators would face if they were transmission connected. The difference between these two numbers, illustrated in Table 10, is the embedded benefit. The size of the embedded benefit by zone is driven by the volume of embedded generation in each zone.

Mathematically, and referring to the definition given in footnote 3 on page 4, the embedded benefit is the difference between the loss factor for suppliers, given by 1+TLF+TLMO-, and the loss factor for generators, 1+TLF+TLMO+. Since the TLF is zero under uniform losses, the above reduces to (TLMO-)-(TLMO+), so the difference in the TLMO factors for generators and suppliers. These are the same throughout GB, and so the embedded benefit on a per MWh basis is also uniform throughout GB.

Under uniform losses the embedded benefit is clearly positive, since the distributed generator is always saving the supplier money and would have to pay for losses if it was transmission connected. Specificaally, the TLMO- is calculated sso that demand (suppliers) pay for 55% of total losses and generation pays for 45% of total losses. So if losses were 2% of total demand, then TLMO- would be about 1.1% and TLMO+ would be about -0.9%. This gives the embedded benefits equal to 1.1%-(-0.9%) = 2% of its output volume.

Table 10: NPV of the embedded benefit under uniform losses

LE/Ventyx Zone	Zone Name		Reference Scenario	Low Gas Scenario	High Gas Scenario	Fuel Volatility Scenario	Offshore Wind Scenario	Alternate Nuclear Scenario	RE reference	Offshore Wind	Accelerated Renewables
1	Eastern		25,009	19,282	34,886	26,418	26,133	24,592	27,759	27,416	28,927
2	East Midlands		9,602	7,380	13,409	10,187	10,029	9,444	10,629	10,497	11,068
3	London		8,332	6,402	11,636	8,844	8,702	8,195	9,221	9,106	9,601
4	North Wales & Mersey		19,058	14,643	26,616	20,228	19,903	18,745	21,090	20,827	21,959
5	Midlands		10,246	7,873	14,309	10,875	10,700	10,078	11,338	11,197	11,806
6	Northern		15,822	12,157	22,096	16,793	16,523	15,562	17,509	17,291	18,230
7	North West		17,121	13,155	23,911	18,172	17,881	16,840	18,947	18,711	19,728
8	Southern		12,746	9,797	17,797	13,522	13,312	12,536	14,110	13,935	14,694
9	South East		16,783	12,895	23,438	17,813	17,527	16,507	18,572	18,341	19,338
10	South Wales		7,123	5,473	9,948	7,560	7,439	7,006	7,883	7,785	8,208
11	South Western		5,151	3,958	7,194	5,467	5,379	5,066	5,700	5,629	5,935
12	Yorkshire		16,108	12,377	22,497	17,097	16,823	15,844	17,826	17,604	18,561
13	Southern Scotland		9,650	7,458	13,436	10,196	10,090	9,484	10,745	10,619	11,215
14	Northern Scotland		4,500	3,459	6,284	4,774	4,700	4,426	4,981	4,919	5,187
	Total	#	177,251	136,310	247,458	187,946	185,140	174,325	196,309	193,877	204,456

We then repeat the exercise, but this time applying the zonal loss factors that would apply under P229. Under zonal losses, the embedded benefit is mathematically calculated in the same way, but the intuition is different than under uniform loses. For example in Scotland, under P229, a supplier actually benefits by being credited with more power than it actually pays for since it is savings the system money by reducing north-to-south power flows. So in Scotland distributed generation reduces the amount of power the supplier takes from the transmission grid and actually increases north-to-south flows and losses. In Scotland distributed generators actually cost the supplier money by reducing its loss-related benefits, and again we assume that this cost is passed onto the distributed generator. But if the distributed generator was transmission connected it would also pay for losses. The embedded benefit is again the difference between these two scenarios.

Mathematically, the embedded benefit is given by the expression (TLFg + TLMO-) - (TLFs + TLMO+), where TLFg is the zonal TLF for generators and TLFs is the zonal TLF for suppliers (offtake). Since TLFg is the equal and opposite to TLFs, the embedded benefit again reduces to (TLMO-)-(TLMO+). Since these factors are the same throughout GB, the embedded benefit on a per MWh basis is also uniform throughout GB under P229. However, since zonally varying TLFs recover some of the losses locationally, the magnitude of both TLMO+ and TLMO- is smaller, as is the difference between them. For this reason under P229 the embedded benefit is smaller under P229. Table 12 illustrates that P229 causes a reduction in the embedded benefit of about £67 million in present value terms.

Table 11: NPV of the embedded benefit under P229

LE/Ventyx Zone	Geographic zone	Reference Scenario	Low Gas Scenario	High Gas Scenario	Fuel Volatility Scenario	Offshore Wind Scenario	Alternate Nuclear Scenario	RE reference	Offshore Wind	Accelerated Renewables
1	Eastern	15,529	15,522	20,890	18,094	16,772	15,937	7,066	7,254	8,682
2	East Midlands	5,950	5,941	8,036	6,961	6,421	6,105	2,763	2,773	3,314
3	London	5,162	5,153	6,974	6,042	5,570	5,296	2,347	2,405	2,874
4	North Wales & Mersey	11,807	11,787	15,952	13,819	12,740	12,113	5,484	5,502	6,574
5	Midlands	6,347	6,337	8,576	7,429	6,849	6,512	2,946	2,958	3,534
6	Northern	9,802	9,786	13,243	11,472	10,576	10,056	4,624	4,567	5,457
7	North West	10,607	10,590	14,331	12,415	11,445	10,882	5,031	4,942	5,905
8	Southern	7,898	7,886	10,665	9,241	8,524	8,104	3,602	3,682	4,400
9	South East	10,397	10,380	14,047	12,169	11,219	10,667	4,727	4,845	5,789
10	South Wales	4,413	4,406	5,962	5,165	4,762	4,527	1,993	2,056	2,457
11	South Western	3,191	3,186	4,311	3,735	3,443	3,274	1,438	1,487	1,777
12	Yorkshire	9,979	9,963	13,483	11,680	10,768	10,238	4,674	4,650	5,556
13	Southern Scotland	6,003	5,999	8,040	7,003	6,489	6,165	2,913	2,822	3,386
14	Northern Scotland	2,788	2,784	3,766	3,262	3,009	2,861	1,297	1,300	1,553
	Total #	109,872	109,721	148,276	128,489	118,587	112,738	50,905	51,243	61,258

Table 12: Change in the NPV of the embedded benefit as a result of introducing P229

LE/Ventyx Zone	Geographic zone	Reference Scenario	Low Gas Scenario	High Gas Scenario	Fuel Volatility Scenario	Offshore Wind Scenario	Alternate Nuclear Scenario	RE reference	Offshore Wind	Accelerated Renewables
1	Eastern	-9,481	-3,760	-13,996	-8,323	-9,361	-8,655	-20,693	-20,163	-20,245
2	East Midlands	-3,652	-1,439	-5,373	-3,226	-3,608	-3,340	-7,866	-7,724	-7,754
3	London	-3,170	-1,249	-4,662	-2,802	-3,132	-2,899	-6,873	-6,700	-6,727
4	North Wales & Mersey	-7,251	-2,856	-10,664	-6,409	-7,163	-6,632	-15,606	-15,326	-15,386
5	Midlands	-3,898	-1,535	-5,733	-3,445	-3,851	-3,565	-8,393	-8,239	-8,272
6	Northern	-6,020	-2,371	-8,853	-5,320	-5,947	-5,506	-12,885	-12,723	-12,773
7	North West	-6,514	-2,566	-9,580	-5,757	-6,435	-5,958	-13,916	-13,768	-13,822
8	Southern	-4,847	-1,911	-7,132	-4,281	-4,788	-4,432	-10,508	-10,253	-10,293
9	South East	-6,386	-2,515	-9,391	-5,644	-6,308	-5,840	-13,846	-13,496	-13,549
10	South Wales	-2,710	-1,067	-3,986	-2,395	-2,677	-2,479	-5,890	-5,728	-5,751
11	South Western	-1,960	-772	-2,882	-1,732	-1,936	-1,792	-4,262	-4,142	-4,159
12	Yorkshire	-6,129	-2,414	-9,014	-5,417	-6,055	-5,605	-13,152	-12,954	-13,005
13	Southern Scotland	-3,647	-1,460	-5,395	-3,193	-3,600	-3,319	-7,832	-7,797	-7,829
14	Northern Scotland	-1,712	-675	-2,518	-1,512	-1,691	-1,565	-3,684	-3,620	-3,634
	Total	-67,379	-26,589	-99,181	-59,457	-66,552	-61,587	-145,404	-142,634	-143,197

7.2 Effects of embedded generation on suppliers' losses under P229

We have estimated the difference in the cost of losses for suppliers with and without P229. We calculate the difference between the value of the avoided losses due to embedded generation in the reference case and with P229 in place. Table 13 summarises the results. As one would expect, with P229 embedded generation reduces the cost of losses for suppliers in zones like London and the Southern zone, but increases the cost of losses in Scotland and other northern zones. The overall effect of embedded generation with P229 is to increase the cost of losses for suppliers. This is because there is a relative large amount of embedded generation in northern zones. In these zones the more power that the supplier takes from transmission connected generators the lower the cost of the supplier's losses. Embedded generation in northern zones actually costs the supplier money. In aggregate the combination of P229 and embedded generation increases the cost of losses to suppliers by £34 million in the Reference case. However, we assume that the additional cost of these losses (or the benefits in some zones) would be passed through to the embedded generators by the supplier. Hence this can also be read as the overall effect on embedded generators of introducing P229.

Table 13: Increase in NPV of cost of losses to suppliers by zone due to embedded generation, P229 compared to uniform losses, embedded generation treated as negative demand£ '000

LE/Ventyx Zone	Zone Name	Reference Scenario	Low Gas Scenario	High Gas Scenario	Fuel Volatility Scenario	Offshore Wind Scenario	Alternate Nuclear Scenario	RE reference	Offshore Wind	Accelerated Renewables
1	Eastern	9,675	-1,383	16,891	8,966	9,604	6,820	-9,835	-14,575	-13,592
2	East Midlands	-2,755	-2,125	-2,887	-2,786	-2,473	-2,566	-8,655	-8,746	-8,351
3	London	10,937	3,083	14,763	10,063	10,788	10,775	3,453	2,467	2,755
4	North Wales & Mersey	-8,585	687	-11,370	-7,565	-8,555	-4,828	-10,194	-9,093	-8,738
5	Midlands	1,459	3,437	2,108	1,874	1,629	2,173	-318	-217	28
6	Northern	-13,250	-3,075	-19,010	-12,514	-12,966	-12,035	-20,645	-19,006	-19,301
7	North West	-21,026	-6,996	-28,707	-20,194	-21,302	-19,208	-12,592	-12,216	-12,172
8	Southern	14,809	5,834	21,369	14,425	15,128	13,505	4,420	3,432	3,803
9	South East	14,573	2,326	21,559	13,636	14,819	13,480	-2,486	-4,821	-4,180
10	South Wales	165	-1,133	1,849	52	497	-257	-1,782	-1,846	-1,662
11	South Western	5,767	2,060	8,609	5,597	5,935	4,835	634	326	459
12	Yorkshire	-11,877	-7,303	-15,023	-12,176	-11,413	-10,988	-23,139	-22,627	-22,045
13	Southern Scotland	-18,915	-3,572	-30,235	-18,166	-18,981	-18,158	-15,795	-13,787	-15,486
14	Northern Scotland	-15,133	-5,293	-22,451	-14,776	-16,793	-14,810	-9,570	-6,703	-8,466
	Total	-34,158	-13,454	-42,536	-33,564	-34,084	-31,260	-106,504	-107,411	-106,948

The other LE/Ventyx scenarios show a similar level of change in benefits, with the largest differences caused by the high and low gas case scenarios. The reason for this is that in the low gas case, there is more southern gas-fired generation running without P229. When P229 is introduced, the marginal cost of losses from the north is lower in the Low Gas Scenario than in the Reference case, because there is less northern plant dispatching in the Low Gas Scenario. This means that the suppliers in northern zones do not lose quite so much by taking power from embedded generation as they do in the Reference case, and so the reduction in embedded benefit is less in the Low Gas Scenario. The opposite arguments hold for the High Gas Scenario.

Note that this analysis also misses the ‘dynamic’ element of the issue – if, under P229 there is greater benefit to southern embedded generation, then one would expect suppliers to take measures to shift projects from north to south. This change is not reflected in National Grid’s forecast of embedded generation, which was undertaken assuming no zonal losses.

7.3 Treating distribution connected plant as transmission connected generation

As mentioned above, embedded generation is currently treated as ‘negative load’. Ofgem has also asked us to consider the case where, for the purposes of calculating losses, embedded generation is treated as transmission connected generation. That is, suppliers would also have to compensate for losses on volumes supplied by embedded generation. Clearly in this case there would be no embedded benefit, in the sense described in section 7.1, since there would be no difference between transmission connected and distribution connected generation from the point of view of losses. All distributed generation would be transmission connected for the purpose of calculating losses.

In the section above, we calculated that under P229 embedded generators would cost suppliers, in aggregate, an additional £34 million in losses, and these costs would be passed on to embedded generators. We also noted that TLFs for generation and load are equal and opposite. Therefore, broadly peaking, if embedded generation costs suppliers £34 million while being distribution connected, they will bear the same costs directly when they are transmission connected. There may be slight differences as the TLMO+ and TLMO- factors will differ slightly. However, as the model does not produce these factors, which are determined by Elexon ex post, we cannot make a more accurate assessment.

8 Conclusions

- Assuming no changes in wholesale prices as a result of P229, in the Reference case the 2009/10 present value of consumer surplus increases by £155 million.
- If we use LE/Ventyx's price changes calculated using TLFs, then we find that the net effect of P229 is a *decrease* in surplus of £524 million for GB consumers in the Reference case, and the effect in other scenarios is similar.
- We conclude that the effect of P229 on consumers is highly sensitive to prices, but on the basis of Redpoint's analysis it seems most likely that price rises will be much more limited than predicted by LE/Ventyx, and that there will still be some increase in consumer surplus as a result of P229.
- At the margin P229 will make it more likely for plant to locate in the south rather than in the north. This will in turn reduce the costs of the transmission system since NGET will need to install less wires to transit the power.
- Renewable generators have higher losses on average under P229 than non-renewable generators, but we do not expect that larger-than-average losses will reduce despatch from a renewable plant under P229. Many renewable technologies such as wind, wave and solar have almost zero marginal costs, and so have an incentive to despatch even if electricity prices are very low or, equivalently, they bear higher-than-average losses.
- We find that, with the exception of wave power, all forms of renewable energy remain profitable under P229. We estimate that, at the costs used, wave power is unprofitable even without P229.
- We conclude that on balance P229 is likely to delay the retirements of oil-fired plant, at least until about 2015, relative to a scenario without P229, and so this should improve security of supply.
- P229 will not accelerate the retirement of opted out coal-plant.
- On balance across the scenarios modelled P229 appears more likely to increase security of supply by reducing system congestion.
- We find it hard to see any credible arguments that implementing P229 will increase regulatory risk. P229 would increase the cost of capital for projects in the north of GB and reduce it for southern projects, but we conclude that even marginal generating project in the north of GB would still be creditworthy after P229 was introduced.
- P229 causes a reduction in the embedded benefit of about £67 million in present value terms.
- If embedded generators are treated as being transmission connected and P229 is introduced, the net effect is that embedded generation is worse off by £34 million in aggregate.

Appendix I : NPV of renewable energy projects

Table 14: Net Present Value for Tidal

			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Inputs																						
Load factor	[1]	See note	35%																			
Installed capital cost, £/kW	[2]	See note	3,800																			
Discount rate (after-tax real)	[3]	LE/Ventyx Report	4.42%																			
Corporate tax rate	[4]	LE/Ventyx Report	28%																			
Assumed depreciation period	[5]	Assumed	20																			
TLM	[6]	See note	89%																			
			Year																			
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Revenues																						
Electricity price, £/MWh	[7]	See note		49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0
ROC Price, £/ROC	[8]	See note		52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9
ROCs/MWh	[9]	See note		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Total revenue, £/MWh	[10]	[7] + ([8] x [9])		154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7
Gross generation, MWh/MW	[11]	8760 x [1]		3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066
Loss-factor	[12]	= [6]		89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%
Net generation, MWh/MW	[13]	[11] x [12]		2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724
Total revenue, £/MW	[14]	[13] x [10]		421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486
			Year																			
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Costs																						
Investment, £/MW	[15]	See note	- 3,800,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating costs, £/MWh	[16]	[17]/[11]		25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8
Operating costs, £/MW	[17]	See note		79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065
Tax																						
Depreciation, £/MW	[18]	-[16]/[5]		190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000
Taxable income, £/MW	[19]	[14]-[17]-[18]		152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421
Tax, £/MW	[20]	[19] x [4]		42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678
After-tax cash flow, £/MW	[21]	[14]-[17]-[20]	- 3,800,000	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743
Net Present Value																						
Discount factor	[22]	[1/(1+[3])^(Year-2010.	98%	94%	90%	86%	82%	79%	75%	72%	69%	66%	63%	61%	58%	56%	53%	51%	49%	47%	45%	43%
Discounted cash flow, £/MW	[23]	[22] x [21]	- 3,718,705	280,914	269,023	257,636	246,730	236,286	226,284	216,706	207,533	198,748	190,336	182,279	174,563	167,174	160,098	153,321	146,831	140,616	134,664	128,963
Net Present Value, £/MW	[24]	sum([23])	-																			

Notes and sources:
Calculations done per MW of installed capacity. All numbers in 2009 real terms.
[1]: From Impact of banding the Renewables Obligation - Cost of electricity production; DTI; April 2007.
[2],[15]: From Project Discovery Energy Market Scenarios, the value refers to tidal range
[6]: The TLM that sets the Net Present Value to 0
[7]: Electricity prices are based on assessment of current forward prices
[8]: ROC prices forecasted based on the historic ratio between average ROC prices and buy out prices
[9]: Renewables Obligations, Guidance for generators; 2010; Ofgem
[17]: From Impact of banding the Renewables Obligation - Cost of electricity production; DTI, April 2007. We used the figure for 2010 in 2006 real prices and inflated to 2009 prices. The inflation rate used: 8.31% from CPI figures provided by ONS

Table 15: Net Present Value for Offshore Wind

Inputs																						
Load factor	[1]	See note	35%																			
Installed capital cost, £/kW	[2]	See note	2,800																			
Discount rate (after-tax real)	[3]	LE/Ventyx Report	4.42%																			
Corporate tax rate	[4]	LE/Ventyx Report	28%																			
Assumed depreciation period	[5]	Assumed	20																			
Offshore loss factor	[6]	Assumed	2%																			
TLM	[7]	See note	87%																			
												Year										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Revenues																						
Electricity price, £/MWh	[8]	See note		49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0
ROC Price, £/ROC	[9]	See note		52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9
ROCs/MWh	[10]	See note		1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Total revenue, £/MWh	[11]	[8] + ([9] x [10])		128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3
Gross generation, MWh/MW	[12]	8760 x [1]		3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066
Loss-factor	[13]	[7] - [6]		85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Net generation, MWh/MW	[14]	[12] x [13]		2,591	2,591	2,591	2,591	2,591	2,591	2,591	2,591	2,591	2,591	2,591	2,591	2,591	2,591	2,591	2,591	2,591	2,591	2,591
Total revenue, £/MW	[15]	[14] x [11]		332,458	332,458	332,458	332,458	332,458	332,458	332,458	332,458	332,458	332,458	332,458	332,458	332,458	332,458	332,458	332,458	332,458	332,458	332,458
												Year										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Costs																						
Investment, £/MW	[16]	See note	- 2,800,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating costs, £/MWh	[17]	[18]/[12]		26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1
Operating costs, £/MW	[18]	See note		80,149	80,149	80,149	80,149	80,149	80,149	80,149	80,149	80,149	80,149	80,149	80,149	80,149	80,149	80,149	80,149	80,149	80,149	80,149
Tax																						
Depreciation, £/MW	[19]	-[16]/[5]		140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000	140,000
Taxable income, £/MW	[20]	[15]-[18]-[19]		112,310	112,310	112,310	112,310	112,310	112,310	112,310	112,310	112,310	112,310	112,310	112,310	112,310	112,310	112,310	112,310	112,310	112,310	112,310
Tax, £/MW	[21]	[20] x [4]		31,447	31,447	31,447	31,447	31,447	31,447	31,447	31,447	31,447	31,447	31,447	31,447	31,447	31,447	31,447	31,447	31,447	31,447	31,447
After-tax cash flow, £/MW	[22]	[15]-[18]-[21]	- 2,800,000	220,863	220,863	220,863	220,863	220,863	220,863	220,863	220,863	220,863	220,863	220,863	220,863	220,863	220,863	220,863	220,863	220,863	220,863	220,863
Net Present Value																						
Discount factor	[23]	[1/(1+[3])^(Year-2010.5)	98%	94%	90%	86%	82%	79%	75%	72%	69%	66%	63%	61%	58%	56%	53%	51%	49%	47%	45%	43%
Discounted cash flow, £/MW	[24]	[23] x [22]	- 2,740,099	206,989	198,228	189,837	181,801	174,106	166,736	159,678	152,919	146,446	140,247	134,311	128,625	123,181	117,967	112,973	108,191	103,612	99,226	95,026
Net Present Value, £/MW	[25]	sum([24])	- 0																			

Notes and sources:
Calculations done per MW of installed capacity. All numbers in 2009 real terms.
[1]: From Impact of banding the Renewables Obligation - Cost of electricity production; DTI; April 2007.
[2],[16]: From Project Discovery Energy Market Scenarios
[7]: The TLM that sets the Net Present Value to 0
[8]: Electricity prices are based on assessment of current forward prices
[9]: ROC prices forecasted based on the average ratio between average ROC prices and buy out prices
[10]: Renewables Obligations, Guidance for generators; 2010; Ofgem
[18]: From Impact of banding the Renewables Obligation - Cost of electricity production; DTI, April 2007. We used the figure for 2010 in 2006 real prices and inflated to 2009 prices. The inflation rate used: 8.31% from CPI figures provided by ONS

Table 16: Net Present Value for Onshore Wind

Inputs																						
Load factor	[1]	See note	28%																			
Installed capital cost, £/kW	[2]	See note	1,200																			
Discount rate (after-tax real)	[3]	LE/Ventyx Report	4.42%																			
Corporate tax rate	[4]	LE/Ventyx Report	28%																			
Assumed depreciation period	[5]	Assumed	20																			
TLM	[6]	See note	60%																			
												Year										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Revenues																						
Electricity price, £/MWh	[7]	See note		49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0
ROC Price, £/ROC	[8]	See note		52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9
ROCs/MWh	[9]	See note		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Total revenue, £/MWh	[10]	[7] + ([8] x [9])		101.9	101.9	101.9	101.9	101.9	101.9	101.9	101.9	101.9	101.9	101.9	101.9	101.9	101.9	101.9	101.9	101.9	101.9	101.9
Gross generation, MWh/MW	[11]	8760 x [1]		2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453
Loss-factor	[12]	= [6]		60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%
Net generation, MWh/MW	[13]	[11] x [12]		1,476	1,476	1,476	1,476	1,476	1,476	1,476	1,476	1,476	1,476	1,476	1,476	1,476	1,476	1,476	1,476	1,476	1,476	1,476
Total revenue, £/MW	[14]	[13] x [10]		150,373	150,373	150,373	150,373	150,373	150,373	150,373	150,373	150,373	150,373	150,373	150,373	150,373	150,373	150,373	150,373	150,373	150,373	150,373
												Year										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Costs																						
Investment, £/MW	[15]	See note	- 1,200,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating costs, £/MWh	[16]	[17]/[11]		17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2	17.2
Operating costs, £/MW	[17]	See note		42,240	42,240	42,240	42,240	42,240	42,240	42,240	42,240	42,240	42,240	42,240	42,240	42,240	42,240	42,240	42,240	42,240	42,240	42,240
Tax																						
Depreciation, £/MW	[18]	-[16]/[5]		60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000
Taxable income, £/MW	[19]	[14]-[17]-[18]		48,133	48,133	48,133	48,133	48,133	48,133	48,133	48,133	48,133	48,133	48,133	48,133	48,133	48,133	48,133	48,133	48,133	48,133	48,133
Tax, £/MW	[20]	[19] x [4]		13,477	13,477	13,477	13,477	13,477	13,477	13,477	13,477	13,477	13,477	13,477	13,477	13,477	13,477	13,477	13,477	13,477	13,477	13,477
After-tax cash flow, £/MW	[21]	[14]-[17]-[20]	- 1,200,000	94,656	94,656	94,656	94,656	94,656	94,656	94,656	94,656	94,656	94,656	94,656	94,656	94,656	94,656	94,656	94,656	94,656	94,656	94,656
Net Present Value																						
Discount factor	[22]	[1/(1+[3])^(Year-2010.	98%	94%	90%	86%	82%	79%	75%	72%	69%	66%	63%	61%	58%	56%	53%	51%	49%	47%	45%	43%
Discounted cash flow, £/MW	[23]	[22] x [21]	- 1,174,328	88,710	84,955	81,359	77,915	74,617	71,458	68,433	65,537	62,763	60,106	57,562	55,125	52,792	50,557	48,417	46,368	44,405	42,525	40,725
Net Present Value, £/MW	[24]	sum([23])	- 0																			

Notes and sources:
Calculations done per MW of installed capacity. All numbers in 2009 real terms.
[1]: From Impact of banding the Renewables Obligation - Cost of electricity production; DTI; April 2007.
[2],[15]: From From Project Discovery Energy Market Scenarios
[6]: The TLM that sets the Net Present Value to 0
[7]: Electricity prices are based on assessment of current forward prices
[8]: ROC prices forecasted based on the historic ratio between average ROC prices and buy out prices
[9]: Renewables Obligations, Guidance for generators; 2010; Ofgem
[17]: From Impact of banding the Renewables Obligation - Cost of electricity production; DTI, April 2007. We used the figure for 2010 in 2006 real prices and inflated to 2009 prices. The inflation rate used: 8.31% from CPI figures provided by ONS

Table 17: Net Present Value for Wave

Inputs																						
Load factor	[1]	See note	30%																			
Installed capital cost, £/kW	[2]	See note	4,000																			
Discount rate (after-tax real)	[3]	LE/Ventyx Report	4.42%																			
Corporate tax rate	[4]	LE/Ventyx Report	28%																			
Assumed depreciation period	[5]	Assumed	20																			
TLM	[6]	See note	110%																			
												Year										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Revenues																						
Electricity price, £/MWh	[7]	See note		49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0
ROC Price, £/ROC	[8]	See note		52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9
ROCs/MWh	[9]	See note		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Total revenue, £/MWh	[10]	[7] + ([8] x [9])		154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7
Gross generation, MWh/MW	[11]	8760 x [1]		2,628	2,628	2,628	2,628	2,628	2,628	2,628	2,628	2,628	2,628	2,628	2,628	2,628	2,628	2,628	2,628	2,628	2,628	2,628
Loss-factor	[12]	= [6]		110%	110%	110%	110%	110%	110%	110%	110%	110%	110%	110%	110%	110%	110%	110%	110%	110%	110%	110%
Net generation, MWh/MW	[13]	[11] x [12]		2,897	2,897	2,897	2,897	2,897	2,897	2,897	2,897	2,897	2,897	2,897	2,897	2,897	2,897	2,897	2,897	2,897	2,897	2,897
Total revenue, £/MW	[14]	[13] x [10]		448,173	448,173	448,173	448,173	448,173	448,173	448,173	448,173	448,173	448,173	448,173	448,173	448,173	448,173	448,173	448,173	448,173	448,173	448,173
												Year										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Costs																						
Investment, £/MW	[15]	See note	- 4,000,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating costs, £/MWh	[16]	[17]/[11]		33.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4
Operating costs, £/MW	[17]	See note		87,730	87,730	87,730	87,730	87,730	87,730	87,730	87,730	87,730	87,730	87,730	87,730	87,730	87,730	87,730	87,730	87,730	87,730	87,730
Tax																						
Depreciation, £/MW	[18]	-[16]/[5]		200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
Taxable income, £/MW	[19]	[14]-[17]-[18]		160,443	160,443	160,443	160,443	160,443	160,443	160,443	160,443	160,443	160,443	160,443	160,443	160,443	160,443	160,443	160,443	160,443	160,443	160,443
Tax, £/MW	[20]	[19] x [4]		44,924	44,924	44,924	44,924	44,924	44,924	44,924	44,924	44,924	44,924	44,924	44,924	44,924	44,924	44,924	44,924	44,924	44,924	44,924
After-tax cash flow, £/MW	[21]	[14]-[17]-[20]	- 4,000,000	315,519	315,519	315,519	315,519	315,519	315,519	315,519	315,519	315,519	315,519	315,519	315,519	315,519	315,519	315,519	315,519	315,519	315,519	315,519
Net Present Value																						
Discount factor	[22]	[1/(1+[3])^(Year-2010.	98%	94%	90%	86%	82%	79%	75%	72%	69%	66%	63%	61%	58%	56%	53%	51%	49%	47%	45%	43%
Discounted cash flow, £/MW	[23]	[22] x [21]	- 3,914,427	295,699	283,182	271,195	259,716	248,722	238,194	228,112	218,456	209,209	200,353	191,872	183,751	175,973	168,524	161,390	154,559	148,017	141,751	135,751
Net Present Value, £/MW	[24]	sum([23])	0																			

Notes and sources:
Calculations done per MW of installed capacity. All numbers in 2009 real terms.
[1]: From Impact of banding the Renewables Obligation - Cost of electricity production; DTI; April 2007.
[2],[15]: From Project Discovery Energy Market Scenarios
[6]: The TLM that sets the Net Present Value to 0
[7]: Electricity prices are based on assessment of current forward prices
[8]: ROC prices forecasted based on the historic ratio between average ROC prices and buy out prices
[9]: Renewables Obligations, Guidance for generators; 2010; Ofgem
[17]: From Impact of banding the Renewables Obligation - Cost of electricity production; DTI, April 2007. We used the figure for 2010 in 2006 real prices and inflated to 2009 prices. The inflation rate used: 8.31% from CPI figures provided by ONS

Table 18: Net Present Value for Tidal

			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Inputs																						
Load factor	[1]	See note	35%																			
Installed capital cost, £/kW	[2]	See note	3,800																			
Discount rate (after-tax real)	[3]	LE/Ventyx Report	4.42%																			
Corporate tax rate	[4]	LE/Ventyx Report	28%																			
Assumed depreciation period	[5]	Assumed	20																			
TLM	[6]	See note	89%																			
												Year										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Revenues																						
Electricity price, £/MWh	[7]	See note		49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0
ROC Price, £/ROC	[8]	See note		52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9
ROCs/MWh	[9]	See note		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Total revenue, £/MWh	[10]	[7] + ([8] x [9])		154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7	154.7
Gross generation, MWh/MW	[11]	8760 x [1]		3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066
Loss-factor	[12]	= [6]		89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%
Net generation, MWh/MW	[13]	[11] x [12]		2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724	2,724
Total revenue, £/MW	[14]	[13] x [10]		421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486	421,486
												Year										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Costs																						
Investment, £/MW	[15]	See note	- 3,800,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating costs, £/MWh	[16]	[17]/[11]		25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8	25.8
Operating costs, £/MW	[17]	See note		79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065	79,065
Tax																						
Depreciation, £/MW	[18]	-[16]/[5]		190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000	190,000
Taxable income, £/MW	[19]	[14]-[17]-[18]		152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421	152,421
Tax, £/MW	[20]	[19] x [4]		42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678	42,678
After-tax cash flow, £/MW	[21]	[14]-[17]-[20]	- 3,800,000	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743	299,743
Net Present Value																						
Discount factor	[22]	[1/(1+[3])^(Year-2010.	98%	94%	90%	86%	82%	79%	75%	72%	69%	66%	63%	61%	58%	56%	53%	51%	49%	47%	45%	43%
Discounted cash flow, £/MW	[23]	[22] x [21]	- 3,718,705	280,914	269,023	257,636	246,730	236,286	226,284	216,706	207,533	198,748	190,336	182,279	174,563	167,174	160,098	153,321	146,831	140,616	134,664	128,963
Net Present Value, £/MW	[24]	sum([23])	-																			

Notes and sources:
Calculations done per MW of installed capacity. All numbers in 2009 real terms.
[1]: From Impact of banding the Renewables Obligation - Cost of electricity production; DTI; April 2007.
[2],[15]: From Project Discovery Energy Market Scenarios, the value refers to tidal range
[6]: The TLM that sets the Net Present Value to 0
[7]: Electricity prices are based on assessment of current forward prices
[8]: ROC prices forecasted based on the historic ratio between average ROC prices and buy out prices
[9]: Renewables Obligations, Guidance for generators; 2010; Ofgem
[17]: From Impact of banding the Renewables Obligation - Cost of electricity production; DTI, April 2007. We used the figure for 2010 in 2006 real prices and inflated to 2009 prices. The inflation rate used: 8.31% from CPI figures provided by ONS

Table 19: Net Present Value for Biomass

Inputs																						
Load factor	[1]	See note	80%																			
Installed capital cost, £/kW	[2]	See note	2,500																			
Discount rate (after-tax real)	[3]	LE/Ventyx Report	4.42%																			
Corporate tax rate	[4]	LE/Ventyx Report	28%																			
Assumed depreciation period	[5]	Assumed	20																			
TLM	[6]	See note	74%																			
												Year										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Revenues																						
Electricity price, £/MWh	[7]	See note		49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0	49.0
ROC Price, £/ROC	[8]	See note		52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9
ROCs/MWh	[9]	See note		1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Total revenue, £/MWh	[10]	[7] + ([8] x [9])		128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3	128.3
Gross generation, MWh/MW	[11]	8760 x [1]		7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008
Loss-factor	[12]	= [6]		74%	74%	74%	74%	74%	74%	74%	74%	74%	74%	74%	74%	74%	74%	74%	74%	74%	74%	74%
Net generation, MWh/MW	[13]	[11] x [12]		5,170	5,170	5,170	5,170	5,170	5,170	5,170	5,170	5,170	5,170	5,170	5,170	5,170	5,170	5,170	5,170	5,170	5,170	5,170
Total revenue, £/MW	[14]	[13] x [10]		663,269	663,269	663,269	663,269	663,269	663,269	663,269	663,269	663,269	663,269	663,269	663,269	663,269	663,269	663,269	663,269	663,269	663,269	663,269
												Year										
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Costs																						
Investment, £/MW	[15]	See note	- 2,500,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating costs, £/MWh	[16]	[17]/[11]		9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
Operating costs, £/MW	[17]	See note		66,068	66,068	66,068	66,068	66,068	66,068	66,068	66,068	66,068	66,068	66,068	66,068	66,068	66,068	66,068	66,068	66,068	66,068	66,068
Fuel costs, £/MW	[18]	See note		371,924	371,924	371,924	371,924	371,924	371,924	371,924	371,924	371,924	371,924	371,924	371,924	371,924	371,924	371,924	371,924	371,924	371,924	371,924
Tax																						
Depreciation, £/MW	[19]	-[16]/[5]		125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000	125,000
Taxable income, £/MW	[20]	[14]-[17]-[19]		100,277	100,277	100,277	100,277	100,277	100,277	100,277	100,277	100,277	100,277	100,277	100,277	100,277	100,277	100,277	100,277	100,277	100,277	100,277
Tax, £/MW	[21]	[20] x [4]		28,077	28,077	28,077	28,077	28,077	28,077	28,077	28,077	28,077	28,077	28,077	28,077	28,077	28,077	28,077	28,077	28,077	28,077	28,077
After-tax cash flow, £/MW	[22]	[14]-[17]-[21]	- 2,500,000	197,199	197,199	197,199	197,199	197,199	197,199	197,199	197,199	197,199	197,199	197,199	197,199	197,199	197,199	197,199	197,199	197,199	197,199	197,199
Net Present Value																						
Discount factor	[23]	[1/(1+[3])^(Year-2010.	98%	94%	90%	86%	82%	79%	75%	72%	69%	66%	63%	61%	58%	56%	53%	51%	49%	47%	45%	43%
Discounted cash flow, £/MW	[24]	[23] x [22]	- 2,446,517	184,812	176,989	169,497	162,322	155,451	148,871	142,570	136,535	130,756	125,221	119,920	114,844	109,983	105,327	100,869	96,599	92,510	88,595	84,844
Net Present Value, £/MW	[25]	sum([24])	-																			

Notes and sources:
Calculations done per MW of installed capacity. All numbers in 2009 real terms.
[1]: From Impact of banding the Renewables Obligation - Cost of electricity production; DTI; April 2007.
[2],[15]: From Project Discovery Energy Market Scenarios. The value refers to biomass regular
[6]: The TLM that sets the Net Present Value to 0
[7]: Electricity prices are based on assessment of current forward prices
[8]: ROC prices forecasted based on the historic ratio between average ROC prices and buy out prices
[9]: Renewables Obligations, Guidance for generators; 2010; Ofgem
[17],[18]: From Impact of banding the Renewables Obligation - Cost of electricity production; DTI, April 2007. We used the figure for 2010 in 2006 real prices and inflated to 2009 prices. The inflation rate used: 8.31% from CPI figures provided by ONS

Appendix II : CCGT project model

Table 20: Breakeven CCGT project with P229

Inputs			
Load factor	[1]	Assumed	60%
2009 Installed capital cost, £/kW	[2]	See note	600
Inflation, 2009 - 2011	[3]	See note	6.2%
2011 Installed capital cost, £/kW	[4]	(1 + [3]) x [2]	637
Unlevered cost of equity	[5]	Assumed	7.92%
Debt rate	[6]	See note	5.50%
Corporate tax rate	[7]	LE/Ventyx Report	28%
Assumed depreciation period	[8]	Assumed	20
TLM	[9]	LE/Ventyx Report	99.45%
Gas price and carbon price, £/MWh	[10]	See note	14.63
Efficiency	[11]	Assumed	56%
Leverage in first year	[12]	Assumed	40%
Loan term	[13]	Assumed	12
2011 electricity price, £/MWh	[14]	See note	41.0
Annual Inflation	[15]	Assumed	2%

			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Year 2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Revenues																								
Inflation factor from 2011	[16]	(1+[15]) ^ (Year - 2011)		1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24	1.27	1.29	1.32	1.35	1.37	1.40	1.43	1.46	1.49	1.52
Electricity price, £/MWh	[17]	[14] x [16]		41.8	42.7	43.5	44.4	45.3	46.2	47.1	48.0	49.0	50.0	51.0	52.0	53.0	54.1	55.2	56.3	57.4	58.6	59.7	60.9	62.1
Gross generation, MWh/MW	[18]	8,760 x [1]		5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256
Loss-factor	[19]	[9]		99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%
Net generation, MWh/MW	[20]	[18] x [19]		5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227
Total revenue, £/MW	[21]	[17] x [20]		218,597	222,969	227,428	231,977	236,616	241,349	246,176	251,099	256,121	261,244	266,469	271,798	277,234	282,779	288,434	294,203	300,087	306,089	312,210	318,455	324,824
Costs																								
Investment, £/MW	[22]	- [4] x 1000	- 637,297	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	2
Operating costs, £/MWh	[23]	{([10] / [11]) + 3} x [16]		29.7	30.3	30.9	31.5	32.1	32.8	33.4	34.1	34.8	35.5	36.2	36.9	37.7	38.4	39.2	40.0	40.8	41.6	42.4	43.3	44.1
Operating costs, £/MW	[24]	[18] x [23]		156,112	159,234	162,419	165,667	168,980	172,360	175,807	179,323	182,910	186,568	190,299	194,105	197,987	201,947	205,986	210,106	214,308	218,594	222,966	227,425	231,974
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Year 2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Debt																								
Opening balance	[25]	See note		254,919	239,361	222,948	205,632	187,364	168,091	147,758	126,307	103,675	79,800	54,611	28,036									
Principal and interest	[26]	PMT([6],[13],[22] in 2011)		29,578	29,578	29,578	29,578	29,578	29,578	29,578	29,578	29,578	29,578	29,578	29,578									
Interest	[27]	[6] x [25]		14,021	13,165	12,262	11,310	10,305	9,245	8,127	6,947	5,702	4,389	3,004	1,542									
Principal repayment	[28]	[26] - [27]		15,558	16,413	17,316	18,268	19,273	20,333	21,451	22,631	23,876	25,189	26,574	28,036									
Cumulative repayment	[29]	See note		15,558	31,971	49,287	67,555	86,828	107,161	128,612	151,243	175,119	200,308	226,883	254,919									
Closing balance	[30]	[25](in 2012)- [29]		239,361	222,948	205,632	187,364	168,091	147,758	126,307	103,675	79,800	54,611	28,036	- 0									
All Equity Taxes																								
Depreciation, £/MW	[31]	- ([22] / [8])		31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	-
Taxable income, £/MW	[32]	[21] - [24] - [31]		30,620	31,870	33,145	34,445	35,771	37,124	38,504	39,911	41,347	42,811	44,304	45,828	47,382	48,967	50,583	52,232	53,914	55,630	57,380	59,164	92,850
Tax, £/MW	[33]	[7] x [32]		8,574	8,924	9,281	9,645	10,016	10,395	10,781	11,175	11,577	11,987	12,405	12,832	13,267	13,711	14,163	14,625	15,096	15,576	16,066	16,566	25,998
After-tax cash flow, £/MW	[34]	[21] - [24] - [33]		53,912	54,811	55,729	56,665	57,620	58,594	59,588	60,601	61,634	62,689	63,764	64,861	65,980	67,121	68,285	69,472	70,683	71,918	73,178	74,463	66,852
Value of debt tax-shield	[35]	[7] x [27]		3,926	3,686	3,433	3,167	2,885	2,589	2,275	1,945	1,597	1,229	841	432	-	-	-	-	-	-	-	-	-

														Year											
				2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Project cash flows																									
All equity cash flow	[36]	See note	-	637,297	53,912	54,811	55,729	56,665	57,620	58,594	59,588	60,601	61,634	62,689	63,764	64,861	65,980	67,121	68,285	69,472	70,683	71,918	73,178	74,463	66,852
Discount factor	[37]	1 / (1 + [5]) ^ (Year-2011)		100%	93%	86%	80%	74%	68%	63%	59%	54%	50%	47%	43%	40%	37%	34%	32%	30%	27%	25%	23%	22%	20%
Discounted cash flow, £/MW	[38]	[36] x [37]	-	637,297	49,953	47,058	44,333	41,768	39,354	37,080	34,940	32,926	31,028	29,242	27,560	25,976	24,484	23,078	21,755	20,508	19,333	18,227	17,184	16,202	13,478
NPV, £/MW	[39]	Sum([38])	-	21,829																					
Discount Rate	[40]	[6]		5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%
Discount Factor	[41]	1 / (1 + [40]) ^ (Year-2011)		100%	95%	90%	85%	81%	77%	73%	69%	65%	62%	59%	55%	53%	50%	47%	45%	42%	40%	38%	36%	34%	32%
NPV of Interest Tax shield	[42]	See note		21,829	3,721	3,312	2,924	2,556	2,208	1,877	1,564	1,267	986	719	467	227	-	-	-	-	-	-	-	-	-
Total Project NPV	[43]	[39] + [42]	-	0																					
Debt statistics																									
EBITDA	[44]	[21] - [24]			62,485	63,735	65,010	66,310	67,636	68,989	70,369	71,776	73,211	74,676	76,169	77,693									
Principal and interest	[45]	[26]			29,578	29,578	29,578	29,578	29,578	29,578	29,578	29,578	29,578	29,578	29,578	29,578									
Ratio EBITDA/(principal + interest)	[46]	[44] / [45]			2.11	2.15	2.20	2.24	2.29	2.33	2.38	2.43	2.48	2.52	2.58	2.63									
Ratio EBITDA/(interest)	[47]	[44] / [27]			4.46	4.84	5.30	5.86	6.56	7.46	8.66	10.33	12.84	17.01	25.36	50.38									
Debt discount factor	[48]	[41]			95%	90%	85%	81%	77%	73%	69%	65%	62%	59%	55%	53%									
PV	[49]	[45] x [48]			28,036	26,574	25,189	23,876	22,631	21,451	20,333	19,273	18,268	17,316	16,413	15,558									
PV of debt year 1	[50]	Sum([49])		254,919																					
PV of project	[51]	[43]	-	0																					
Difference	[52]	[50] - [51]		254,919																					

Notes and sources:
[2]: From Project Discovery Energy Market Scenarios
[3]: 2009, Office for National statistics, 2010 – 2011, HM Treasury, Forecasts for the UK economy, May 2010. 2012 onward – 2% per year assumed.
[6]: Assumed to be the risk free rate plus 2%
[10]: Gas + carbon price is set so as to give a zero PV without P229.
[14]: Nominal prices, based on prevailing forward prices.
[23]: The extra £3 are assumed in order to cover some non-fuel wear and tear costs.
[25]: In 2011, [4] x [12] x 1000. Thereafter [30] from Year-1
[29]: In 2011, [28]. Thereafter [28] + [29](Year-1)
[36]: In 2011, [22]. Thereafter [21] - [24] - [33]
[42]: In 2011, sum of [42]. Thereafter [41] x [35]

Table 21: Breakeven CCGT project without P229

Inputs			
Load factor	[1]	Assumed	60%
2009 Installed capital cost, £/kW	[2]	See note	600
Inflation, 2009 - 2011	[3]	See note	6.2%
2011 Installed capital cost, £/kW	[4]	(1 + [3]) x [2]	637
Unlevered cost of equity	[5]	Assumed	7.92%
Debt rate	[6]	See note	5.50%
Corporate tax rate	[7]	LE/Ventyx Report	28%
Assumed depreciation period	[8]	Assumed	20
TLM	[9]	LE/Ventyx Report	99.45%
Gas price and carbon price, £/MWh	[10]	See note	14.63
Efficiency	[11]	Assumed	56%
Leverage in first year	[12]	Assumed	40%
Loan term	[13]	Assumed	12
2011 electricity price, £/MWh	[14]	See note	41.0
Annual Inflation	[15]	Assumed	2%

													Year											
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Revenues																								
Inflation factor from 2011	[16]	(1+[15]) ^ (Year - 2011)		1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24	1.27	1.29	1.32	1.35	1.37	1.40	1.43	1.46	1.49	1.52
Electricity price, £/MWh	[17]	[14] x [16]		41.8	42.7	43.5	44.4	45.3	46.2	47.1	48.0	49.0	50.0	51.0	52.0	53.0	54.1	55.2	56.3	57.4	58.6	59.7	60.9	62.1
Gross generation, MWh/MW	[18]	8,760 x [1]		5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256	5,256
Loss-factor	[19]	[9]		99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%	99.45%
Net generation, MWh/MW	[20]	[18] x [19]		5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227	5,227
Total revenue, £/MW	[21]	[17] x [20]		218,597	222,969	227,428	231,977	236,616	241,349	246,176	251,099	256,121	261,244	266,469	271,798	277,234	282,779	288,434	294,203	300,087	306,089	312,210	318,455	324,824
Costs																								
Investment, £/MW	[22]	- [4] x 1000	- 637,297	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	2
Operating costs, £/MWh	[23]	{([10] / [11]) + 3} x [16]		29.7	30.3	30.9	31.5	32.1	32.8	33.4	34.1	34.8	35.5	36.2	36.9	37.7	38.4	39.2	40.0	40.8	41.6	42.4	43.3	44.1
Operating costs, £/MW	[24]	[18] x [23]		156,112	159,234	162,419	165,667	168,980	172,360	175,807	179,323	182,910	186,568	190,299	194,105	197,987	201,947	205,986	210,106	214,308	218,594	222,966	227,425	231,974

													Year											
			2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Debt																								
Opening balance	[25]	See note		254,919	239,361	222,948	205,632	187,364	168,091	147,758	126,307	103,675	79,800	54,611	28,036									
Principal and interest	[26]	PMT([6],[13],[22] in 2011)		29,578	29,578	29,578	29,578	29,578	29,578	29,578	29,578	29,578	29,578	29,578	29,578									
Interest	[27]	[6] x [25]		14,021	13,165	12,262	11,310	10,305	9,245	8,127	6,947	5,702	4,389	3,004	1,542									
Principal repayment	[28]	[26] - [27]		15,558	16,413	17,316	18,268	19,273	20,333	21,451	22,631	23,876	25,189	26,574	28,036									
Cumulative repayment	[29]	See note		15,558	31,971	49,287	67,555	86,828	107,161	128,612	151,243	175,119	200,308	226,883	254,919									
Closing balance	[30]	[25](in 2012)- [29]		239,361	222,948	205,632	187,364	168,091	147,758	126,307	103,675	79,800	54,611	28,036	- 0									
All Equity Taxes																								
Depreciation, £/MW	[31]	- ([22] / [8])		31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	31,865	-
Taxable income, £/MW	[32]	[21] - [24] - [31]		30,620	31,870	33,145	34,445	35,771	37,124	38,504	39,911	41,347	42,811	44,304	45,828	47,382	48,967	50,583	52,232	53,914	55,630	57,380	59,164	92,850
Tax, £/MW	[33]	[7] x [32]		8,574	8,924	9,281	9,645	10,016	10,395	10,781	11,175	11,577	11,987	12,405	12,832	13,267	13,711	14,163	14,625	15,096	15,576	16,066	16,566	25,998
After-tax cash flow, £/MW	[34]	[21] - [24] - [33]		53,912	54,811	55,729	56,665	57,620	58,594	59,588	60,601	61,634	62,689	63,764	64,861	65,980	67,121	68,285	69,472	70,683	71,918	73,178	74,463	66,852
Value of debt tax-shield	[35]	[7] x [27]		3,926	3,686	3,433	3,167	2,885	2,589	2,275	1,945	1,597	1,229	841	432	-	-	-	-	-	-	-	-	-

Project cash flows

All equity cash flow	[36]	See note	-	637,297	53,912	54,811	55,729	56,665	57,620	58,594	59,588	60,601	61,634	62,689	63,764	64,861	65,980	67,121	68,285	69,472	70,683	71,918	73,178	74,463	66,852
Discount factor	[37]	1 / (1 + [5]) ^ (Year-2011)		100%	93%	86%	80%	74%	68%	63%	59%	54%	50%	47%	43%	40%	37%	34%	32%	30%	27%	25%	23%	22%	20%
Discounted cash flow, £/MW	[38]	[36] x [37]	-	637,297	49,953	47,058	44,333	41,768	39,354	37,080	34,940	32,926	31,028	29,242	27,560	25,976	24,484	23,078	21,755	20,508	19,333	18,227	17,184	16,202	13,478
NPV, £/MW	[39]	Sum([38])	-	21,829																					
Discount Rate	[40]	[6]		5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%
Discount Factor	[41]	1 / (1 + [40]) ^ (Year-2011)		100%	95%	90%	85%	81%	77%	73%	69%	65%	62%	59%	55%	53%	50%	47%	45%	42%	40%	38%	36%	34%	32%
NPV of Interest Tax shield	[42]	See note		21,829	3,721	3,312	2,924	2,556	2,208	1,877	1,564	1,267	986	719	467	227	-	-	-	-	-	-	-	-	-
Total Project NPV	[43]	[39] + [42]	-	0																					

Debt statistics

EBITDA	[44]	[21] - [24]			62,485	63,735	65,010	66,310	67,636	68,989	70,369	71,776	73,211	74,676	76,169	77,693
Principal and interest	[45]	[26]			29,578	29,578	29,578	29,578	29,578	29,578	29,578	29,578	29,578	29,578	29,578	29,578
Ratio EBITDA/(principal + interest)	[46]	[44] / [45]			2.11	2.15	2.20	2.24	2.29	2.33	2.38	2.43	2.48	2.52	2.58	2.63
Ratio EBITDA/(interest)	[47]	[44] / [27]			4.46	4.84	5.30	5.86	6.56	7.46	8.66	10.33	12.84	17.01	25.36	50.38
Debt discount factor	[48]	[41]			95%	90%	85%	81%	77%	73%	69%	65%	62%	59%	55%	53%
PV	[49]	[45] x [48]			28,036	26,574	25,189	23,876	22,631	21,451	20,333	19,273	18,268	17,316	16,413	15,558
PV of debt year 1	[50]	Sum([49])		254,919												
PV of project	[51]	[43]	-	0												
Difference	[52]	[50] - [51]		254,919												

Notes and sources:
[2]: From Project Discovery Energy Market Scenarios
[3]: 2009, Office for National statistics, 2010 – 2011, HM Treasury, Forecasts for the UK economy, May 2010. 2012 onward – 2% per year assumed.
[6]: Assumed to be the risk free rate plus 2%
[10]: Gas + carbon price is set so as to give a zero PV without P229.
[14]: Nominal prices, based on prevailing forward prices.
[23]: The extra £3 are assumed in order to cover some non-fuel wear and tear costs.
[25]: In 2011, [4] x [12] x 1000. Thereafter [30] from Year-1
[29]: In 2011, [28]. Thereafter [28] + [29](Year-1)
[36]: In 2011, [22]. Thereafter [21] - [24] - [33]
[42]: In 2011, sum of [42]. Thereafter [41] x [35]