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DEPARTMENT OF TRADE AND INDUSTRY

THE IMPACT OF AVERAGE ZONAL TRANSMISSION LOSSES APPLIED THROUGHOUT GREAT BRITAIN

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Executive Summary

OXERA has carried out a study for the Department of Trade and Industry (DTI) to assess the impact of the introduction of average zonal transmission losses (AZTL) applied throughout Great Britain. The study, which combined wholesale market and load-flow modelling, was conducted in conjunction with Professor Janusz Bialek from the University of Edinburgh.

Background

Power losses are incurred when electricity flows through the transmission system, and are measured as the difference between generation and demand. At present, losses in England and Wales are allocated to Balancing and Settlement Code (BSC) parties by scaling the output of generators and the demand attributed to suppliers using Transmission Loss Multipliers (TLMs) which are uniform across the country.[1]

In January, Ofgem approved BSC Modification P82, with an implementation date of April 1st 2004. **This modification will give rise to different TLMs for each Grid Supply Point (GSP) Group**, based on Adjusted Annual Zonal TLFs (ATLFs) calculated using the results of load-flow modelling. ATLFs are fixed annually, and are shifted up and down uniformly to derive TLMs for each settlement period that recover actual losses.

The British Electricity Trading and Transmission Arrangements (BETTA) are due to start in October 2004, or by April 2005 at the latest. In January 2003, the DTI published a consultation on the application of AZTL throughout Great Britain under BETTA.[2]

National resource impacts

OXERA has considered the following national resource impacts which might be relevant to an assessment of AZTL:

- *reduction in losses*—AZTL might be expected to reduce transmission losses compared with the existing uniform charging methodology, by influencing short-run despatch and long-run locational decisions by generators, and possibly consumption and locational decisions by customers;
- *offsetting costs*—the reduction in losses represents a gross rather than a net benefit, and will be partly offset by changes in other costs. For example, where AZTL changes generation despatch, the reduction in losses is likely to be partly offset by an increase in generation fuel costs;
- *reduction in required generation capacity*—this study assumes that the effect of AZTL on generation capacity is captured through the electricity price used to value any loss reduction;

[1] A generator TLM of 0.9, for example, means that, for 100 MW of generation, the company would be attributed 90 MW.

[2] DTI (2003), 'Transmission Losses in a Great Britain Electricity Market: A DTI Consultation Paper', January.

- *reduction in constraint and reinforcement costs*—a reduction in losses stems from a reduction in transmission flows that might lower the level of constraints across parts of the transmission network;
- *increase in perceptions of risk*—it has been argued that, by precipitating large transfers between generating companies, AZTL might increase perceptions of risk and increase the cost of capital for new investments;
- *implementation and operation costs* for both the system operator and market participants.

Summary of findings

The study has found the following.

- OXERA has calculated scenarios of the NPV of the future benefits to 2019/20, net of offsetting cost increases, from the application of AZTL throughout Great Britain (see Table 1). **The figures range from £6.7m in the low scenario to £55.5m in the high scenario, with the key driver of these results being the assumption made regarding long-run benefits**. These figures should be compared to the NPV of implementation and operation costs to give the net national resource benefit. **If implementation costs in England and Wales are included in the analysis, the direction of the net national resource effect is ambiguous, whereas it is likely to be small but positive if these costs are treated as sunk**.

Table 1: Scenarios of future benefits of AZTL (£m)

	High	Medium	Low
Assumed annual benefits			
Generation redespatch	1.29	0.74	0.19
Demand response	0.25	0.19	0.13
Relocation of generation (from 2010/11)	10	4	1
Proportion of above benefits assumed to be offset by change in other costs (%)	25%	25%	25%
NPV of future benefits to 2019/20, net of offsetting cost increases	55.50	24.38	6.67

Source: OXERA.

- **AZTL would lead to transfers of money between different generators and groups of consumers which are likely to be of a greater magnitude than any net efficiency gain**. These would benefit southern generating plant and northern consumers, while leading to a disbenefit for northern generating plant and southern consumers. However, the effect on individual consumers (particularly in the domestic sector) is likely to be very small.

- The study found that the impact of AZTL on renewables projects might be very marginal, due to the high value of Renewables Obligations Certificates (ROCs) relative to the wholesale electricity price. **Hence it seems unlikely that AZTL will materially affect the probability of meeting the government's renewables target**. The net change in emissions is comprised of the following:

  – a reduction in emissions due to reduced losses;

– a change in emissions due to alterations in the generation fuel mix, with the direction of this effect being ambiguous.

The remainder of the Executive Summary outlines the modelling and analysis which supports these findings.

Modelling methodology

The approach taken by OXERA has centred on comparing potential outcomes across Great Britain under zonal and uniform loss charging. To quantify the impact of AZTL, OXERA used two models:

- a full load-flow model of the Great Britain transmission network; and
- OXERA's wholesale market model.

For peak, mid-point and trough snapshot periods in each year, OXERA ran its wholesale market model to determine despatch decisions under uniform loss charging and under AZTL. The generator outputs from the wholesale model were fed into the load-flow model to estimate the level of transmission losses in the snapshot periods and to estimate TLMs for the following year. Once the load-flow modelling had been carried out for all years, OXERA used the estimated TLMs to model wholesale market behaviour across all demand conditions (rather than just the three snapshot periods). This allowed the impact of AZTL on a range of market outcomes to be examined.

While the focus of OXERA's analysis is the impact of AZTL on market outcomes under a base scenario, a number of sensitivity runs have been undertaken to assess how the results might be affected by the base-scenario assumptions.

Modelling Results

Estimated TLMs

Table 2 shows OXERA's estimates of average annual TLMs for generators and suppliers, under the base-scenario assumptions. The results illustrate that:

- **northern generation would be exposed to substantial loss scaling under AZTL**, with generation in Northern Scotland scaled down by an estimated 3.4% in 2005/06 compared with 0.8% under uniform loss charging;
- **generation in the southern zones would tend to benefit**, with output from generation located in London scaled *up* by an estimated 0.5% in 2005/06;
- **northern demand would also tend to benefit**, with demand in Northern Scotland scaled *down* by an estimated 1.9% under AZTL, compared with estimated scaling up of 1% under uniform loss charging;
- **southern demand would see greater loss scaling under AZTL**, with scaling up of 2% for demand in the London region.

The high degree of scaling for generation output in the two Scottish regions is reflective of the inclusion of 132kV lines as part of the transmission network in Scotland[3] as well as the geographical distribution of generation and demand in Great Britain.

Table 2: Estimated average annual TLMs for generators and suppliers

GSP Group		2005/06		2006/07		2007/08		2008/09		2009/10	
		Gen.	**Sup.**	**Gen.**	**Sup.**	**Gen.**	**Sup.**	**Gen.**	**Sup.**	**Gen.**	**Sup.**
14	Northern Scotland	0.966	0.981	0.965	0.982	0.974	0.993	0.974	0.992	0.975	0.993
13	Southern Scotland	0.972	0.987	0.971	0.987	0.981	1.000	0.981	0.999	0.982	1.000
1	Northern	0.986	1.002	0.985	1.002	0.984	1.003	0.983	1.001	0.984	1.002
2	North West	0.991	1.006	0.990	1.007	0.988	1.007	0.988	1.006	0.989	1.007
3	Yorkshire	0.988	1.003	0.987	1.004	0.983	1.002	0.982	1.000	0.982	1.000
4	North Wales and Mersey	1.001	1.016	1.000	1.017	0.995	1.014	0.994	1.012	0.996	1.014
5	East Midlands	0.996	1.011	0.995	1.012	0.990	1.009	0.989	1.008	0.987	1.005
6	Midlands	1.004	1.019	1.003	1.019	1.000	1.019	1.000	1.018	1.002	1.020
7	Eastern	0.996	1.012	0.995	1.012	0.994	1.013	0.996	1.014	0.995	1.013
8	South Wales	1.001	1.017	1.001	1.017	0.997	1.016	1.000	1.018	0.999	1.017
9	South East	0.995	1.011	0.995	1.011	0.995	1.014	0.997	1.015	0.998	1.016
10	London	1.005	1.020	1.004	1.020	1.002	1.021	1.004	1.023	1.004	1.022
11	Southern	1.004	1.019	1.003	1.020	1.000	1.019	1.003	1.021	1.001	1.019
12	South Western	1.004	1.020	1.003	1.020	1.001	1.020	1.004	1.022	1.000	1.018
Estimated uniform TLMs[1]		0.992	1.010	0.991	1.011	0.990	1.012	0.990	1.012	0.990	1.012

Note: [1] These were calculated to recover the same level of total losses as the set of zonal TLMs.
Source: OXERA.

Changes in despatch and losses

Estimates of the net change in annual generation output in each GSP Group from the application of the estimated TLMs are shown in Table 3. **The overall pattern is for small reductions in generation in Scotland and some zones in northern England and for small increases in generation in other zones in England and Wales**.[4] However, the changes are very small compared with the total level of generation—for example, the reduction of 749 GWh in Scottish generation in 2005/06 represents just 0.2% of total generation in Great Britain in that year.

[3] 132kV lines are classified as distribution lines in England and Wales but as transmission lines in Scotland. Losses in these lines tend to be higher than in higher voltage lines, and will affect TLFs in Scotland but not in England and Wales.
[4] There are exceptions to this pattern, such as the reduction in generation in zone 11.

Table 3: Changes in annual output by zone (GWh)

GSP Group		2005/06	2006/07	2007/08	2008/09	2009/10
14	Northern Scotland	–131	–71	–31	–25	–64
13	Southern Scotland	–618	–368	–134	–41	–47
1	Northern	–896	–527	–144	–246	–32
2	North West	108	76	106	112	194
3	Yorkshire	71	91	–369	–522	–400
4	North Wales and Mersey	434	118	162	212	203
5	East Midlands	650	618	380	389	106
6	Midlands	0	0	0	0	0
7	Eastern	414	158	6	93	12
8	South Wales	3	58	123	181	73
9	South East	–93	–156	0	0	0
10	London	2	0	0	0	1
11	Southern	55	–43	–111	–158	–55
12	South Western	2	46	12	5	9
Total output (for comparison)		373,405	379,797	384,271	390,024	395,138

Source: OXERA.

Table 4 shows estimates of annual loss savings resulting from changes in despatch. **The figures suggest that loss reductions may be relatively marginal**, with the highest estimate being a 1.1% reduction in total losses in 2005/06. This compares with modelling work undertaken in the past by NGC, which estimated that taking account of marginal loss impacts in generation despatch decisions could reduce transmission losses by at most 3% in England and Wales. The NGC figure is based on the application of full marginal loss factors, whereas the P82 methodology is likely to lead to lower loss reductions, as it gives less pronounced signals for redespatch.[5] **The average annual loss reductions estimated by the current study might be valued in the range £0.2m to £1.3m per annum.**

[5] Offsetting this is the greater potential for loss reductions from the application of AZTL across Great Britain rather than England and Wales alone.

Table 4: Estimated annual loss savings

	2005/06	2006/07	2007/08	2008/09	2009/10	Average
Annual savings in losses (GWh) [1]						
High figure	90	61	35	38	26	50
Central figure	49	31	20	24	16	28
Low figure	12	6	10	9	11	10
Percentage of total losses						
High figure	1.1	0.7	0.4	0.4	0.3	0.6
Central figure	0.6	0.3	0.2	0.3	0.2	0.3
Low figure	0.2	0.1	0.1	0.1	0.1	0.1
Value of loss reduction (£m)						
High figure[2]	2.05	1.73	0.93	1.03	0.69	1.29
Central figure[3]	0.96	0.70	0.42	0.52	0.34	0.59
Low figure[4]	0.22	0.13	0.20	0.19	0.21	0.19

Note: [1] These estimates are derived from the application of nodal TLFs to the estimated annual change in plant outputs, and may be subject to error due to the volatility of nodal TLFs and the fact that net changes in annual plant output may mask offsetting increases and reductions in output. [2] High loss-saving figure valued using peak price. [3] Central loss-saving figure valued using load-shape price. [4] Low loss-saving figure valued using baseload price.
Source: OXERA.

Fuel mix and emissions

The net change in generation from different types of fuel is shown in Table 5. **The modelling results showed a small net switch from gas to coal in the years 2005/06 to 2008/09**. However, the modelling of snapshot periods also found examples of redespatch occurring from coal to gas, and hence these results do not provide enough evidence to suggest that there will be a systematic shift in favour of any form of generation.

Table 5: Changes in annual output by fuel type (GWh)

	2005/06	2006/07	2007/08	2008/09	2009/10
Coal	20	302	275	209	–5
Gas	–17	–302	–275	–209	6
Nuclear	0	0	0	0	0
Other	–4	0	0	0	–1
Total output (for comparison)	373,405	379,797	384,271	390,024	395,138

Note: The sum of changes may not equal zero due to rounding
Source: OXERA.

Table 6 shows the short-term impact of AZTL on carbon emissions in the base scenario, broken down into the effect due to reduced losses and the effect due to changes in the generation mix. The figures show that:

- **the reduction in losses from generation redespatch will tend to decrease emissions**;
- **the dominant short-term effect of AZTL on emissions was via changes in the generation mix**, with the marginal switch to coal in years 2005/06 to 2008/09

leading to an overall increase in carbon emissions under the base-scenario assumptions. Given that the study did not find conclusive evidence that the direction of the shift in the fuel mix would always be from gas to coal, these results do not provide sufficient evidence to suggest that the overall short-term impact of AZTL on emissions will always be in a particular direction;

- **the short-term impact of AZTL on emissions from generation is very marginal**, with percentage changes of less than 0.1% in all years.

Table 6: Short-term impact of AZTL on emissions under the base scenario (kt CO_2)

	2005/06	2006/07	2007/08	2008/09	2009/10
Impact via loss reduction					
Estimated loss reduction (GWh)	–50	–20	–13	–22	–13
Average unit emissions (kt/GWh)[1]	0.44	0.45	0.44	0.45	0.45
Change	–22	–9	–6	–10	–6
Impact via generation mix					
Uniform loss charging	164,973	168,984	170,028	174,632	176,610
Zonal loss charging	164,989	169,139	170,161	174,736	176,595
Change	16	155	134	104	–15
Overall impact					
Net change in emissions	–6	146	128	94	–21
Percentage change	–0.004%	0.086%	0.075%	0.054%	–0.012%

Note: [1] Calculated by dividing base-scenario emissions with zonal loss charging by total generation.
Source: OXERA.

OXERA has considered the value that might be placed on changes in the level of emissions. There are two possible approaches:

- using estimates of the value at which carbon allowances might trade under the EU Emissions Trading Scheme; and
- applying estimates of carbon damage costs.

OXERA has applied a range of figures from £5 to £70 per tonne of carbon in Table 7 to give estimated monetary values for the change in carbon emissions in the base scenario. **The numbers show the average annual monetary impact of AZTL on carbon emissions varying between –£93,000 and –£1.3m**.

Table 7: Valuation of short-term change in carbon emissions (£)

Value per tonne of carbon	2005/06	2006/07	2007/08	2008/09	2009/10	Average
70	114,000	–2,784,000	–2,447,000	–1,791,000	398,000	–1,302,000
20	33,000	–795,000	–699,000	–512,000	114,000	–372,000
10	16,000	–398,000	–350,000	–256,000	57,000	–186,000
5	8,000	–199,000	–175,000	–128,000	28,000	–93,000

Note: The change in emissions was converted from carbon dioxide to carbon by multiplying by 12/44.
Source: OXERA.

Other modelling results

OXERA has carried out modelling to assess how AZTL, by switching generation from Scotland to England, might alter the estimated cost of constraints across the Scotland–England interconnector. **The modelling found that AZTL might give rise to a very marginal benefit by reducing constraints through its effect on generation despatch**.

The crucial determinant of the impact of AZTL on wholesale prices is the frequency with which the marginal generator, which will determine the wholesale price in a competitive market, is located in different GSP Groups. **The study found that the price impact of AZTL may be small, and that the evidence was not strong enough to suggest a systematic change in either direction.**

The sensitivity runs suggest that the level of TLMs, particularly for Scottish regions, may be influenced by factors such as demand growth, input fuel prices and entry and exit decisions.

Location of generation

The study considered a number of factors that might affect the location of generating plant, including:

- *zonal loss charges*—loss payments tend to be lower (and in some cases negative) for regions further south and west, with OXERA calculations suggesting a maximum differential between zones of £4.9m for a 1 GW plant with an 85% load factor;
- *fuel transportation costs*—Transco's National Transmission System (NTS) exit charges exhibit the opposite trends to those of AZTL loss charges, tending to be higher for more southerly and westerly regions, and differ by up to £2.8m between zones for a 1 GW gas-fired plant. OXERA's estimates of delivered coal prices show maximum differentials equating, under certain assumptions, to a cost difference of around £5.6m per annum for a 1 GW coal plant;[6]

[6] Based on a hypothetical plant with an efficiency of 36% and load factor of 50%.

- *NGC's Transmission Network Use-of-System (TNUoS) charges*—the geographical pattern of TNUoS charges tends to mirror that of zonal loss charges, with southerly zones benefiting relative to northern zones. Annual payments for a hypothetical 1 GW plant vary from a maximum of £8.4m in generation zone 1 to a negative charge (ie, the generator receives money from NGC) of £9.9m in generation zone 15—a total spread of £18.2m;
- *the availability and cost of land*;
- *planning consent for new plant build*.

Table 8 shows how TNUoS charges, NTS exit charges and AZTL payments might vary for three hypothetical baseload CCGT generators located in different areas of the country.

Table 8: Impact on AZTL on regional variations in cost

Hypothetical CCGT plant	GSP Group	Generation tariff zone	Assumed NTS exit charge	TNUoS charge	Regional comparison (before AZTL)	AZTL payments[1]	Regional comparison (after AZTL)
Scotland	14	n/a	0.02	20.45	**20.47**	4.36	**24.83**
Northern	1	1	0.02	8.31	**8.33**	2.30	**10.63**
Mid-England	5	7	0.35	0.34	**0.69**	1.25	**1.93**
Southern	11	13	2.04	–4.76	**–2.72**	–0.30	**–3.02**
Spread	–	–	2.02	25.21	**23.19**	4.66	**27.85**

Note: [1] These figures are the total loss payment under AZTL, rather than the change in loss payments compared with those under a uniform loss charging regime.
Source: OXERA.

Overall, the figures suggest that it is regional variations in TNUoS that are the major cost difference between plant in different regions. To the extent that AZTL reinforces these signals, there may be some impact on long-run decisions by generators, but the size of this effect is uncertain. Non-cost factors, such as planning permission, are also likely to be critical in decisions about the location of new plant, and their impact has not been quantified.

Wholesale electricity prices have fallen by 40% over the last four years, and OXERA has previously suggested that up to 6 GW of capacity in England and Wales might need to be removed from the system for prices to rise to new-entrant levels. If AZTL influences the market's decisions about which plant are closed or mothballed, there may be loss-reduction benefits additional to those arising from potential changes in despatch. Although the potential margin of error is high, the study found that **the closure of a northern plant rather than a power station further south might lead to an estimated reduction of 158 GWh to the annual level of transmission losses, implying a potential**

annual benefit of around £3.2m.[7] However, it is not clear that the current capacity situation will still apply when BETTA goes live in October 2004. Nevertheless, AZTL could create long-run loss-reduction benefits if it leads to more efficient decisions on the return of capacity from mothball if prices rise in the future.

Current levels of capacity in the generation market, alongside the significant volumes of mothballed capacity and the expected growth in renewables generation, may limit new build of gas-fired plant in the near future. Nevertheless, new CCGT entry may be required in the longer term (perhaps post-2010), as the scheduled closure of Great Britain's nuclear generation plant continues. Table 9 shows scenarios of the benefits that AZTL might bring if it leads to the relocation of new CCGT plant build to GSP Groups with more favourable impacts on transmission losses.

Table 9: Scenarios of annual longer-term benefits

GSP Group		Estimated loss reduction (GWh)	Estimated annual benefit per GW relocated (£m)
Original	New		
7	11	100	2.0
3	11	273	5.5
13	11	355	7.1

Note: If a significant volume of generation relocates, the marginal reduction in losses from further relocation is likely to fall.
Source: OXERA.

The figures show a range for the potential long-run benefits of relocating generation, from £2m per annum for each GW of baseload generation relocated from zone 7 to zone 11, to £7.1m per annum for each GW relocated from zone 13 to zone 11. While this range illustrates the uncertainty over the size of these benefits, the results do appear to suggest that **annual benefits from long-run effects could be larger than the short-run benefits from generation redespatch**. Furthermore, the benefits are likely to be greatest the longer the timeframe under consideration, as more plant entry and exit decisions will have been made.

Table 10 shows estimates of the value of carbon savings arising from the long-term relocation of generation. The size of this benefit is crucially dependent on the value placed on carbon. **For each £1m of direct loss-reduction benefit, the estimated carbon savings could be valued in the range £0.03m per annum (using a carbon price of £5/tonne) to £0.42m per annum (using a carbon price of £70/tonne)**.

[7] The estimate is indicative only as it is derived from the loss figure observed using the different closure assumptions for three snapshot periods only. The reduction in losses has been valued using an electricity price of £20/MWh, which is consistent with the average baseload price that emerged from the base scenario.

Table 10: Scenarios of long-term carbon-saving benefits

		Estimated emissions reduction per GW relocated (kt)		Value (£m) per GW relocated at carbon price of			
Original zone	**New zone**	**CO_2**	**Carbon[2]**	**£70/t**	**£20/t**	**£10/t**	**£5/t**
7	11	44	12	0.8	0.2	0.1	0.1
3	11	121	33	2.3	0.7	0.3	0.2
13	11	158	43	3.0	0.9	0.4	0.2

Notes: [1] Calculated using an average of the figures for average unit emissions in kt/GWh shown in Table 6. [2]Converted from CO_2 to carbon by multiplying by 12/44.
Source: OXERA.

The study considered the argument that AZTL might increase the cost of capital for new plant build due to increased perceptions of risk. However:

- **it is not clear that forward-looking perceptions of risk will necessarily increase**, given that changes to the loss-charging regime have been discussed (at least in England and Wales) for a number of years;
- **changes to the loss-charging regime are a diversifiable risk which would not be expected to affect the cost of capital**.

Therefore, OXERA has not considered this issue further.

Renewables

A significant proportion of the UK's onshore wind resource is in Scotland and the North of England. Offshore wind development is anticipated to focus on three strategic regions: the Thames Estuary, the Greater Wash and the North West. It has been argued that applying AZTL across Great Britain might reduce the growth of renewables generation in northern regions and hinder achievement of the government's target of achieving a 10% share of renewables by 2010.

OXERA has developed a financial model to assess how the additional cost or benefit arising from AZTL might affect the economics of a typical new-build project. The marginal impact of AZTL on renewable projects was modelled by calculating the percentage change between the internal rate of return (IRR) under zonal loss charging and that under uniform loss charging. The IRR change calculation can be formally written as:

$$(IRR_{\text{zonal loss charging}} - IRR_{\text{uniform loss charging}}) / IRR_{\text{uniform loss charging}}$$

For example, if the IRR of a renewables project was 10% under uniform loss charging, but only 9% under zonal loss charging, the change in IRR would be –10%.

Table 11: Marginal change (%) in the IRR of offshore wind projects

ROC scenario		Low build rate		Medium built rate		High build rate	
Technology costs		**Low**	**High**	**Low**	**High**	**Low**	**High**
Demand zone (GSP Group)	Northern Scotland	–0.9	–0.9	–1.0	–1.2	–1.1	–1.6
	Southern Scotland	–0.7	–0.6	–0.7	–0.8	–0.8	–1.0
	Northern (1)	–0.2	–0.3	–0.3	–0.4	–0.3	–0.6
	North West (2)	0.0	–0.1	–0.1	–0.1	–0.1	–0.2
	North Wales and Mersey (4)	0.3	0.3	0.3	0.4	0.3	0.5
	East Midlands (5)	0.1	0.0	0.1	0.0	0.1	–0.1
	Eastern (7)	0.2	0.2	0.2	0.3	0.2	0.4
	South Wales (8)	0.4	0.4	0.4	0.5	0.4	0.7
	South East (9)	0.2	0.2	0.2	0.3	0.2	0.5

Source: OXERA.

Table 12: Marginal change (%) in the IRR of onshore wind projects (%)

ROC scenario		Low build rate		Medium built rate		High build rate	
Technology costs		**Low**	**High**	**Low**	**High**	**Low**	**High**
Demand zone (GSP Group)	Northern Scoltland	–0.9	–0.9	–1.0	–1.1	–1.1	–1.5
	Southern Scotland	–0.7	–0.6	–0.7	–0.8	–0.8	–1.0
	Northern (1)	–0.2	–0.3	–0.3	–0.4	–0.3	–0.5
	North West (2)	0.0	–0.1	–0.1	–0.1	–0.1	–0.1
	Yorkshire (3)	–0.2	–0.3	–0.3	–0.4	–0.3	–0.6
	North Wales and Mersey (4)	0.3	0.3	0.3	0.3	0.3	0.4
	East Midlands (5)	0.1	0.0	0.1	0.0	0.1	–0.1
	Eastern (7)	0.2	0.2	0.2	0.2	0.2	0.3
	South Wales (8)	0.4	0.4	0.4	0.5	0.4	0.6
	South Western (12)	0.5	0.5	0.5	0.6	0.6	0.8

Source: OXERA.

Tables 11 and 12 show that **AZTL would have a minor impact on the profitability of renewables projects**, with a percentage impact on the IRR of projects in different regions in the range of about –1.6% to about 0.8%. For a project with gross revenue of about £1.22m, the study estimated that the financial impact of AZTL on the net present value of the generator's expected revenue over 15 years would be in the range of about –£7,400k to £4,200k, depending on location. **These results suggest that zonal loss charging is unlikely to have a significant impact on the growth of renewables generation**.

AZTL may provide marginal locational signals to renewables developers, reinforcing the signals currently provided by NGC's TNUoS charges. Projects located in Northern Scotland would be the most adversely affected, followed by those in Southern Scotland and the North of England. Zonal loss charging would tend to encourage development of new plants in South Western and Wales. Offshore wind farms in two of the strategic regions identified by the DTI in its 'Future Offshore' consultation—Thames Estuary and the Greater Wash—would tend to benefit from AZTL.

Most renewable power plant are small in comparison with conventional plant and are therefore connected to the lower-voltage distribution networks rather than the high-voltage transmission grid. Distributed plant do not generally see their output scaled to account for transmission losses. In addition, suppliers contracting with distributed generation see the output of these plant netted off against their demand within the same GSP Group. As a result, they avoid transmission losses on the netted-off demand, and this embedded benefit may be shared with the generator.

Introducing zonal loss charging would have an impact on the level of embedded benefits which distributed generators (and suppliers contracting with them) will receive. AZTL would increase the financial benefits received by distributed generation located in zones where supplier TLMs are above their level under uniform loss charging, while reducing the financial benefits received by distributed generation located in demand zones with supplier TLMs below their level under uniform loss charging. **Zonal loss charging would therefore provide price signals encouraging development of distributed generation in southerly zones relative to northern zone**. However, modelling suggests that the marginal impact of AZTL on the IRR of a distributed generation project might be small, ranging between –1.7% and 0.6% for onshore wind projects in different regions.

Impact on consumers

The study examined the potential impact of AZTL on retail prices in different regions, assuming that suppliers pass any effect through to consumers. The analysis found that the application of AZTL throughout Great Britain might tend to give rise to:

- **marginal reductions in domestic electricity prices in Scotland and northern England**, with the largest reduction being around £2.21 per annum in Northern Scotland;
- **marginal increases in domestic electricity prices in the rest of England and Wales**, with the largest change being an estimated cost increase of £0.98 for consumers in London;
- **slightly larger percentage changes in retail prices for industrial and commercial (I&C) consumers, reflecting the higher proportion of wholesale electricity costs in their bills**. AZTL might give rise to an annual benefit of £27,000 for a large industrial consumer in Northern Scotland compared with a cost increase of £12,000 in London.

The study used existing estimates of the elasticity of demand (ie, the percentage change in consumption for a 1% change in price) to estimate the potential impact of these price changes on electricity consumption. Electricity demand is generally perceived to be inelastic (ie, changes in price have a relatively small effect on consumption), and consequently the estimated effect on consumption is very small, particularly in the domestic sector. **The loss-reduction benefits from demand-side response to the application of AZTL across Great Britain might be in the region of £0.13m–£0.25m per annum, and would be partly offset by the value attached to changes in consumption**.

Distributional consequences

Table 13 shows that the **estimated transfers between consumers and generators in each region are substantial** for the base scenario in 2005/06, and appear to be of a higher order of magnitude than the estimated efficiency benefits of AZTL. This arises from the fact that efficiency benefits occur due to the effect of AZTL on marginal generators and consumers, whereas transfer effects also include the impact on infra-marginal generating plant and consumers. **The figures show that in one year alone, AZTL might lead to total gains of approximately £18.5m for Scottish consumers and additional costs of around £19.9m for Scottish generation**. However, it is not possible to ascertain the overall impact of AZTL on different regional economies because the proportion of transfers that will feed into the regional economy is not known.

Table 13: Estimates of potential transfers between regions for 2005/06

GSP Group	Demand (TWh)	Supplier TLMs	Consumer transfers (£m)	Generation (TWh)	Generator TLMs	Generator transfers (£m)	Net transfers (£m)
14 Northern Scotland	10	0.981	5.92	14	0.966	–7.53	–1.61
13 Southern Scotland	27	0.987	12.61	30	0.972	–12.41	0.20
1 Northern	20	1.002	3.53	22	0.986	–2.61	0.92
2 North West	30	1.006	2.21	19	0.991	–0.34	1.86
3 Yorkshire	29	1.003	4.11	63	0.988	–5.51	–1.40
4 North Wales and Mersey	21	1.016	–2.43	27	1.001	4.75	2.33
5 East Midlands	34	1.011	–0.73	46	0.996	3.56	2.83
6 Midlands	33	1.019	–5.65	10	1.004	2.29	–3.36
7 Eastern	42	1.012	–1.20	50	0.996	4.18	2.98
8 South Wales	15	1.017	–1.95	11	1.001	1.97	0.02
9 South East	25	1.011	–0.24	44	0.995	2.87	2.63
10 London	31	1.020	–5.92	0	1.005	0.04	–5.88
11 Southern	39	1.019	–6.81	18	1.004	4.17	–2.64
12 South Western	18	1.020	–3.43	19	1.004	4.56	1.13
Uniform TLM		1.010			0.992		
Sum	373		0.00	373		0.00	0.00

Note: The calculations assume an electricity price of £20/MWh.
Source: OXERA.

Implementation and operation costs

In considering whether to extend AZTL to Scotland, from the starting point of P82 in England and Wales, the following costs are relevant:

- *Implementation costs*—the costs of implementing P82 in England and Wales should be taken into account only if the decision on whether to apply AZTL in England and Wales prior to BETTA depends on the government's decision on whether AZTL should continue to apply under BETTA. The incremental implementation costs of extending the P82 methodology to Scotland are relevant.

- *Operation costs*—the additional annual costs of operating AZTL rather than a system of uniform loss charging should be taken into account.

The central system costs are relatively easy to identify, although costs associated with the Transmission Loss Factor Agent (TLFA) have not been made public. For comparison with the benefits of AZTL, OXERA has assumed that up-front costs would be £0.5m and ongoing costs would be £0.25m per annum, giving an NPV of just under £3m for costs incurred in years until 2019/20.

The costs to market participants are more difficult to ascertain. In its decision letter on P82, Ofgem stated that a significant proportion of respondents suggested that these costs would be minimal. However, other figures put forward for the implementation cost of P82 in England and Wales, would imply an estimate of £31m in NPV terms, as shown in the Table 14. Potentially, survey work could be conducted to generate a precise estimate of implementation costs.

Table 14: NPV cost figures used in scaled cost-benefit analysis of P82 (£m)

Cost element	10 years	20 years	Average
Capital investment in IT			
Central systems (NGC, Elexon, NETA agent)	0.8	0.8	0.8
Market participants	14.9	14.9	14.9
Operational/transactions costs			
Central systems (NGC, Elexon, NETA agent)	1.2	1.8	1.5
Market participants	11	17.1	14.05
Total	27.9	34.6	31.25

Note: OXERA has excluded estimates of the increased cost of capital due to market risks which were in the original figures, for the reasons given in section 1.31.
Source: NERA

Contents

1. Introduction

1.1 Terms of reference

OXERA has carried out a study for the Department of Trade and Industry (DTI) to assess the impact of the introduction of average zonal transmission losses (AZTL) applied throughout Great Britain. The terms of reference for the study required OXERA to examine:

- the national resource costs and benefits;
- the impact on electricity prices;
- distributional consequences for generators and consumers in different regions;
- the impact on renewables development; and
- environmental effects.

OXERA undertook the study in conjunction with academic experts in this field. **Professor Janusz Bialek from the University of Edinburgh carried out the load-flow modelling for the project using software specifically developed for this type of exercise**, and Professor Richard Green from the University of Hull contributed to the economic analysis his expertise in transmission issues.

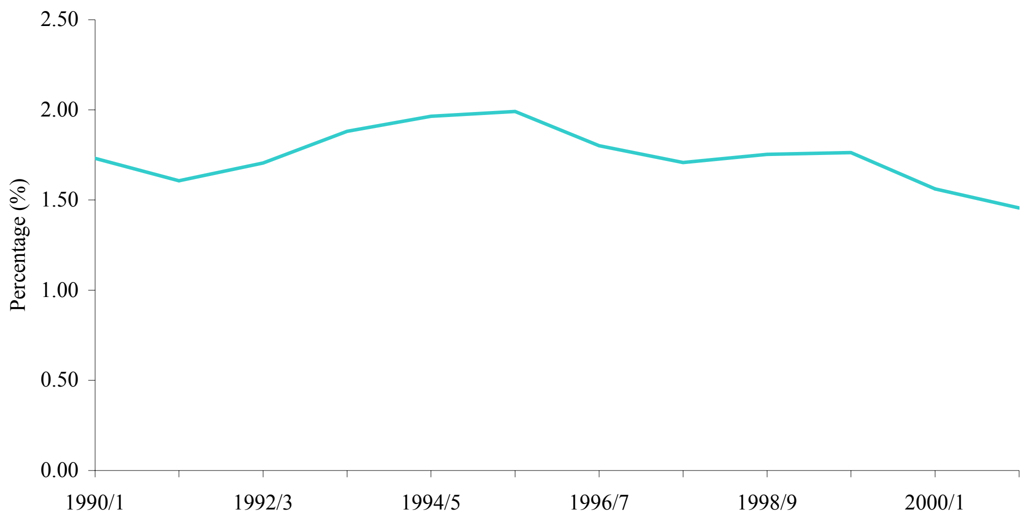
OXERA has also reviewed responses to the DTI consultation on AZTL applied throughout Great Britain.[8] A summary of consultation responses is provided as a separate document. During the course of the project, OXERA also contacted a small number of key stakeholders to request their views on the issues raised by the application of AZTL throughout Great Britain and the proposed methodology for carrying out the analysis.

1.2 Background information

Power losses are incurred when electricity flows through the transmission system, and are measured as the difference between generation and demand. Figure 1.1 shows that, historically, transmission losses have accounted for between 1.5 and 2% of electricity demand.

[8] DTI (2003), 'Transmission Losses in a Great Britain Electricity Market: A DTI Consultation Paper', January.

Figure 1.1: Historical level of transmission losses (%)



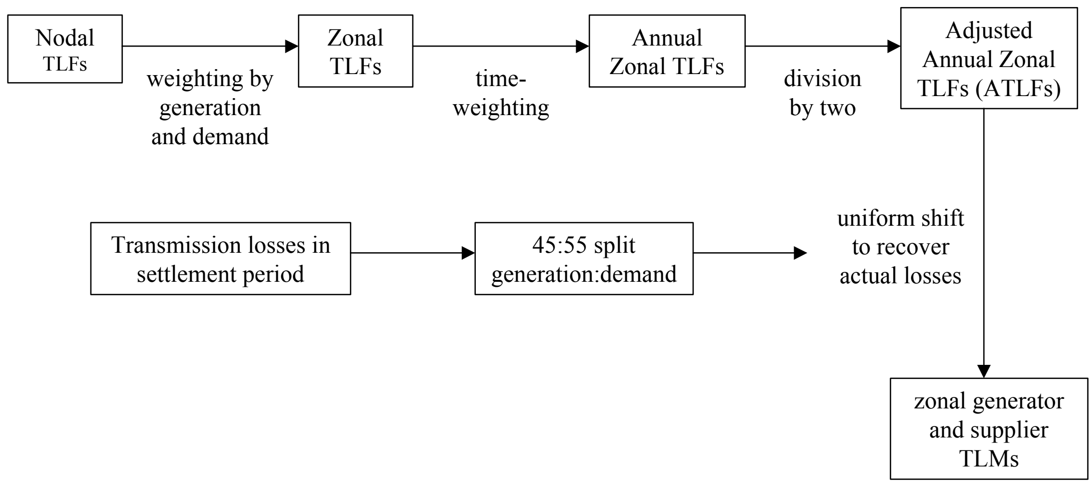
Source: National Grid Company (NGC).

At present, losses in England and Wales are allocated to Balancing and Settlement Code (BSC) parties by scaling the output of generators and the demand attributed to suppliers using Transmission Loss Multipliers (TLMs). A generator TLM of 0.9, for example, means that, for 100 MW of generation, the company would be attributed 90 MW. Likewise, a supplier TLM of 1.1 means that, for 100 MW of actual demand, the supplier would be attributed 110 MW. Total scaling of all generation and demand should exactly recover the level of transmission losses. **Losses are split in the ratio 45:55 between generators and suppliers, and are recovered on a uniform basis across the country**. **In Scotland, transmission losses are recovered from suppliers only**.

BSC Modification P82 was submitted in May 2002, shortly after the submission of an alternative loss-charging proposal Modification P75. The BSC Panel progressed the modifications in parallel with each other, and came to the recommendation in December 2002 that all the proposed modifications relating to losses should be rejected. On January 17th, **Ofgem announced that the Gas and Electricity Markets Authority had decided to direct a modification to the BSC for implementation of P82 to apply from April 1st 2004**.

Under the P82 methodology, TLMs will differ between GSP Groups. (A map of GSP Groups in England and Wales is provided in Appendix 3.) The procedure for calculating zonal TLMs is illustrated in Figure 1.2. Nodal transmission loss factors (TLFs)[9] for historic settlement periods are derived from load-flow modelling, and are converted into Adjusted Annual Zonal TLFs (ATLFs) by weighting across nodes using absolute flows, weighting across different types of settlement period and dividing by two. ATLFs are fixed annually, and give rise to differentials between loss charges in different zones. AZTLs are shifted up and down uniformly to derive TLMs for each settlement period that recover actual losses in the ratio 45:55 between generation and supply.

Figure 1.2: Derivation of ATLFs and TLMs under P82 methodology



Source: OXERA.

The British Electricity Trading and Transmission Arrangements (BETTA) are due to start in October 2004, or by April 2005 at the latest. BETTA will effectively extend to Scotland the New Electricity Trading Arrangements (NETA) that have been introduced in England and Wales. The implementation of BETTA will require primary legislation, and the DTI has published a draft Electricity (Trading and Transmission) Bill to enable pre-legislative scrutiny to be undertaken.

In January 2003, the DTI published a consultation on the application of AZTL throughout Great Britain.[10] Following the consultation, the Secretary of State will reach a conclusion as to whether P82 should be extended across Great Britain under the powers in the Electricity (Trading and Transmission) Bill, or whether the arrangements currently operating in England and Wales (ie, uniform loss charging) should apply under BETTA.

[9] A nodal TLF gives the marginal change in losses for a small change in power flows at a specific node on the network, and will depend on the overall loading conditions of the network.
[10] DTI (2003), 'Transmission Losses in a Great Britain Electricity Market: A DTI Consultation Paper', January.

1.3 Relevant impacts

The application of AZTL throughout Great Britain could affect market outcomes such as the pattern of generation and the financial position of generators. In carrying out the analysis, OXERA has been careful to distinguish between those impacts that represent additional national resource benefits or costs, and those that represent economic transfers between market participants or areas of potential conflict with existing government policy. **OXERA has therefore grouped the impacts of AZTL into three broad categories:**

- **national resource costs and benefits;**
- **transfers between generators and consumers; and**
- **interactions with environmental policy**.

1.3.1 National resource benefits and costs

The following costs and benefits have been identified as potential impacts of AZTL applied throughout Great Britain.

- ***Reduction in losses*—AZTL is expected to reduce transmission losses compared with the existing uniform charging methodology by encouraging market participants to take loss effects into account when making their decisions**. Given that the cost of losses is shared between generators and suppliers, responses to AZTL could occur on both sides of the market. On the generation side, AZTL might affect the despatch decisions of generators as well as longer-term decisions regarding plant closure/mothballing[11] and entry/return of mothballed plant. On the demand side, any response would be through consumers' consumption and locational decisions.

- ***Offsetting costs*—it is important to note that the reduction in losses represents a gross rather than a net benefit, and will be partly offset by changes in other costs**. This can be illustrated by reference to the following examples:

  – *generation redespatch*—suppose AZTL changes despatch in a certain half-hour so that, instead of a northern generator operating, a southern generator is despatched. Since the northern generator would have operated without AZTL, the marginal generation cost (exclusive of the loss impact) of the southern generator must be higher;
  – *location of new entry*—similarly, if AZTL switches the location of new entry, the fact that the plant would otherwise have located elsewhere suggests that other elements of its costs are higher in the new location;

[11] Mothballing refers to the temporary closure of plant with the possibility of returning it to the market if prices rise in the future.

  - *demand-side response*—in regions where AZTL increases consumer costs, any consumption which is deterred, and which leads to loss-reduction benefits, has some value to the consumer which will be forgone. (Conversely, in regions where customers face lower loss charges, any induced consumption will have some additional positive value.)

The existence of these offsetting costs was noted in the cost–benefit analysis of P75.[12] In many cases, the size of these offsetting effects is difficult to estimate. However, they must lie in the range 0–100% of the loss benefit received by market participants responding to the loss pricing signals, since otherwise there would be no incentive to respond. Given that the calculation of TLMs involves dividing annual zonal TLFs in half, it follows that **the offsetting costs would broadly be expected to lie in the range of 0–50% of the physical loss benefits**.[13]

- ***Reduction in required generation capacity*—**lower losses may reduce generation capacity requirements. However, such benefits may only be realisable where the generation capacity margin is tight and loss reductions allow new investment to be avoided, since otherwise capacity costs are largely sunk. **OXERA considers that the effect of AZTL on generation capacity is captured through the electricity price used to value any loss reduction**. In other words, in years when the market is signalling a requirement for new capacity through high prices, the monetary value of loss reductions will be higher.

- ***Reduction in constraint and reinforcement costs*—a reduction in losses stems from a reduction in transmission flows that might lower the level of constraints across parts of the transmission network**, thereby reducing constraint costs and potentially reducing the need for reinforcements of the transmission system. As network investment is driven by peak flows, it is losses during peak periods that are particularly relevant in this regard.

- ***Increase in perceptions of risk*—it has been argued that, by precipitating large transfers between generating companies (see section 3.2), AZTL might increase perceptions of risk and increase the cost of capital for new investments**. With regard to this argument, OXERA notes the following:

  - perceptions of risk are forward-looking. Given that changes to the loss-charging regime, at least in England and Wales, have been mooted since the time of privatisation (and hence past investments have been made in an

[12] NERA (2002), 'Cost Benefit of Transmission Losses Proposal P75: A Report for the P75/P82 TLFMG', October, p. 6.

[13] This may not always hold; the actual physical loss benefit will depend on the node and time at which the response to AZTL occurs, and so may not always be precisely twice the loss benefit accruing to the market participant.

environment of uncertainty), it is not clear that reaching a decision on locational loss charging will necessarily increase the forward-looking risks faced by investors;

- **changes to the loss-charging regime are a diversifiable risk**. An investor holding a balanced portfolio of generator shares would be unaffected by changes to loss-charging arrangements, since costs are simply transferred between different generation companies. As noted in a recent study on the cost of capital,[14] **any regulatory action that has an effect that can be diversified does not affect the cost of capital**;
- if the concern relates to the wider risk of changes to the market arrangements (which in some cases might not be diversifiable), it is not clear that AZTL is as significant as some of the other developments that have occurred in recent years (such as the introduction of NETA).

Consequently, the issue is not addressed further.[15]

- ***Implementation and operation costs*—**these may arise for both the system operator and market participants. Relevant costs include modifying IT systems and the potential legal costs of renegotiating contracts.

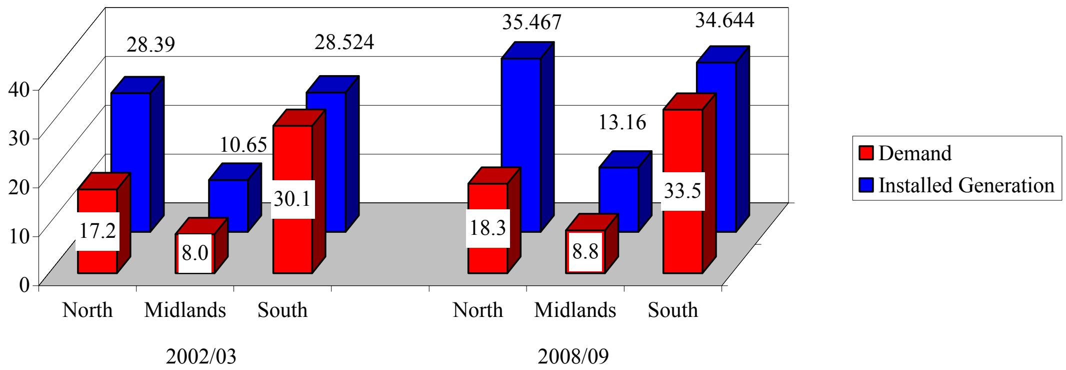
1.3.2 Distributional impacts

Charging for transmission losses on a zonal, rather than a uniform, basis will have a significant effect on how the cost of losses is allocated between market participants. As shown in Figure 1.3, within England and Wales there is a surplus of generation in the north, and the main centre of demand is in the south. This regional comparison is reinforced by the inclusion of Scottish generation and demand. Consequently, **AZTL is expected to adversely affect northern generators and southern consumers, while benefiting southern generators and northern consumers**.

[14] Wright, Mason and Miles (2003), 'A Study into Certain Aspects of the Cost of Capital for Regulated Utilities in the U.K.', February.

[15] In carrying out the modelling, OXERA's estimate of new entry costs assumed that AZTL would have no impact on the cost of capital for new-build projects.

Figure 1.3: North–South plant–demand balance



Note: Based on installed generation.
Source: NGC (2002), 'Ten Year Statement'.

The extent to which there are transfers between consumers as opposed to generating companies is determined by the ratio in which transmission losses are split between suppliers and generators. The current 45:55 split between generators and consumers (which was not affected by the implementation of P82) means that regional transfers will occur on both sides of the market. By contrast, if losses were allocated entirely to generators, the existence of a national wholesale market available to all suppliers would mean that there would be no differential impact on electricity consumers in different regions. Conversely, allocating all losses to suppliers would lead to larger transfers between consumers in different regions, but no regionally differentiated impact on generators.

It is to be expected that the size of transfers between generating plant and consumers in different regions will be of a higher order of magnitude than the net national resource benefit of AZTL. This is because efficiency benefits arise from the effect of zonal loss charging on marginal generators and consumers, whereas transfer effects also include the impact on zonal loss charging on infra-marginal generating plant and consumers.

This study has produced a quantitative estimate (under specific assumptions) of the potential size of transfers compared with the net national resource benefits. However, the weight that should be placed on transfer effects relative to efficiency benefits is ultimately a matter of judgement.

1.3.3 Interaction with environmental policy

The government has a number of environmental targets, including meeting the Kyoto target of reducing greenhouse gas emissions by 12.5% below 1990 levels by 2008–12 and moving towards the domestic goal of a 20% reduction in CO_2 emissions against the same base year by 2010. The government has also set a target that 10% of the UK's electricity should be generated from renewable resources by 2010. The recent Energy White Paper set out the government's ambition to double the share of electricity from renewables to 20% by 2020, and its goal to work towards a 60% cut in carbon emissions by 2050.[16] **Although AZTL is not in itself an environmental policy, the study's terms of reference required consideration of the potential effect on environmental objectives**.

Impact on emissions

AZTL could affect the level of carbon emissions in several ways, and the direction of the net effect is uncertain. **Any reduction in losses decreases the required level of generation, and this may reduce emissions if the marginal generator burns fossil fuels**. **There may also be effects on emissions due to changes in the generation merit order and the level of renewables penetration**. However, in assessing AZTL it should be borne in mind that there are other policy instruments designed specifically to address the issue of carbon emissions. In particular, **the EU Emissions Trading Scheme will control the overall level of emissions in the EU from certain industrial sectors (including generation)**, and is scheduled to take effect from January 2005.

Impact on renewables

One of the concerns about the application of AZTL throughout Great Britain is the potential effect on the government's renewables policy. **Much of the UK's onshore renewable resources are in Scotland and the North of England, and these are the regions where generators are expected to be adversely affected by AZTL**. Set against this is the potential that exists to exploit offshore wind resources in the south of the country. Nevertheless, **it has been argued that applying AZTL across Great Britain may reduce the overall growth of renewables generation and hinder achievement of the government's target of achieving a 10% share of renewables by 2010**.

1.4 Overview of OXERA's approach

The approach taken by OXERA has centred on comparing potential outcomes across Great Britain under zonal and uniform loss charging.

As explained in section 2, **OXERA has conducted full load-flow modelling of the Great Britain transmission networks alongside modelling of the wholesale electricity market for years from 2005/06 to 2009/10**. This enabled the potential level of TLMs to be estimated, if the P82 methodology were to be applied on a Great Britain basis. Modelling the effect of these TLMs on the wholesale market enabled OXERA to analyse the potential impact of AZTL on:

- the financial position of generating plant in different regions;

[16] DTI (2003), 'Our Energy Future—Creating a Low Carbon Economy', February

- the pattern of generation;
- the level of transmission losses;
- the wholesale price;
- the level of emissions; and
- the cost of constraints across the Scotland–England interconnector.

Time constraints required OXERA to focus modelling on a single base scenario. Some sensitivity analysis was carried out to assess how sensitive estimated TLMs might be to the modelling assumptions.

Alongside the modelling analysis, OXERA analysed the relative importance of AZTL compared with other factors that might affect the location of plant entering and exiting the market, such as fuel transportation costs and NGC Transmission Network Use of System (TNUoS) charges. **Scenarios were constructed of how AZTL might affect transmission losses and carbon emissions in the longer term through its effect on the location of plant**.

With regard to renewables, **OXERA analysed how AZTL might affect renewables investment decisions in different regions**, based on estimates of the costs of renewables, coupled with scenarios of future Renewable Obligations Certificate (ROC) prices. Information on the potential resource of different types of renewables in different regions of Great Britain was then used to discuss the potential effect of AZTL on the likely scale of development.

The impact of AZTL on consumers was analysed by considering the link between suppliers' wholesale electricity costs (including loss charges) and retail prices. **This allowed OXERA to estimate the potential effect on end-consumer bills**. Figures for the demand elasticity of different types of consumer were used to calculate the potential size of any demand response.

The final stage of the project involved bringing together the analysis to provide conclusions on the factors that might affect the government's decision. This included consideration of the implementation and operation costs of AZTL, and the potential direction and size of the net national resource benefit.

Table 1.1 summarises the approach taken by OXERA to assess the impacts of AZTL, and provides references to the relevant sections of the report.

Table 1.1: Summary of OXERA approach

Impact	Approach	Report reference (section)
National resource benefits and costs		
Reduced losses		
Generation despatch	Combined market and load-flow modelling	3.4
Longer-term impact on location of generation	Stand-alone scenario analysis	4
Demand response	Use of demand elasticity estimates	6.3
Offsetting increases in other costs	Not assessed	
Lower requirement for generation capacity	Captured in electricity price used to value loss reduction	–
Lower constraint and reinforcement costs	Market modelling	3.7
Carbon emissions		
Lower losses	Combined market and load-flow modelling; stand-alone scenario analysis	3.6
Generation mix	Combined market and load-flow modelling	3.6
Implementation and operating costs	Qualitative analysis; responses to DTI consultation	8
Distributional impacts		
Transfers between generators	Combined market and load-flow modelling	3.2, 7.1
Transfers between consumers	Calculations based on estimated TLMs	6.2, 7.1
Renewables impact		
Penetration with unchanged policy	Internal rate of return analysis combined with data on renewable resources	5

Source: OXERA.

1.5 Structure of report

This report is structured into sections dealing with different areas of the analysis. Where appropriate, technical details of the modelling work are provided in appendices. The content of each section is as follows:

- section 2 presents the wholesale market and load-flow modelling methodology used by OXERA;
- section 3 presents estimated TLMs for the whole of Great Britain, along with estimated effects on market outcomes;
- section 4 analyses how the estimated TLMs might affect future decisions on generation closure/mothballing, return of mothballed plant and new combined-cycle, gas-turbine (CCGT) entry, with estimates of the potential impact on losses and carbon emissions;
- section 5 sets out scenarios of how AZTL applied throughout Great Britain might affect the growth of renewables under existing government policies;
- section 6 considers the impact of AZTL on demand customers, including the effect on regional demand growth;
- section 7 discusses how distributional consequences and how they might be viewed from an economic and social perspective;
- section 8 discusses the likely scale of implementation and operating costs;

- section 9 draws together some conclusions;
- appendix 1 gives details of the methodology and assumptions used in OXERA's wholesale market modelling;
- appendix 2 provides technical information on the load-flow modelling work;
- appendix 3 is a map of GSP Groups in England and Wales; and
- appendix 4 details assumptions used in the modelling of the profitability of renewables projects.

2. Modelling Methodology

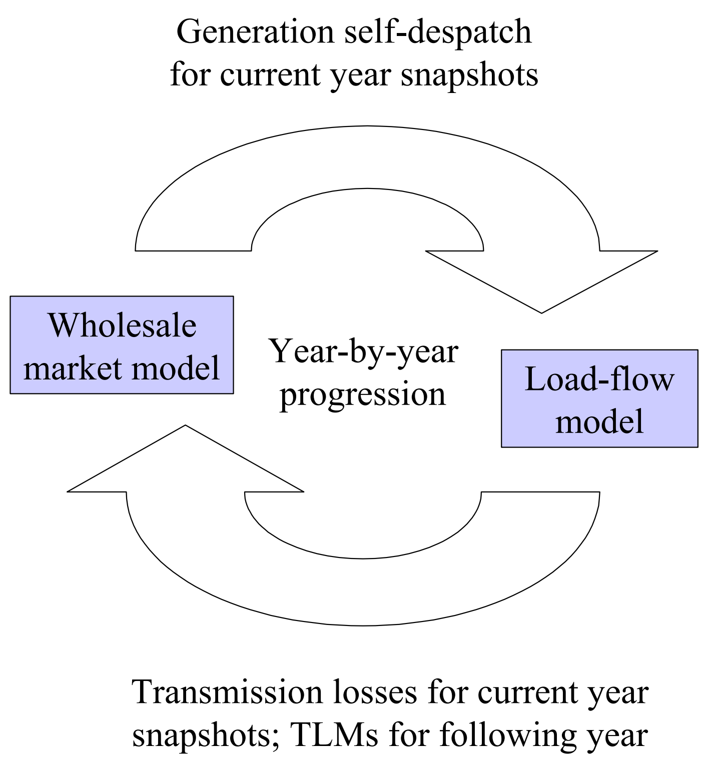
2.1 Basic process

To quantify the impact of AZTL on physical network variables and wholesale market outcomes, OXERA used two models:

- **a full load-flow model of the Great Britain transmission network**, run by Professor Janusz Bialek from the University of Edinburgh. For given generator outputs, this allowed estimates to be made of the level of variable transmission losses, as well as enabling zonal loss factors to be calculated; and
- **OXERA's wholesale market model**, which was used to analyse the impact of zonal loss factors on the self-despatch decisions of generators and on other market outcomes (eg, transfers between generators, level of emissions).

Figure 2.1 illustrates the interaction between the two models.

Figure 2.1: Interaction between wholesale and load-flow model



Source: OXERA.

The modelling process involved the following steps.

- **OXERA's model was run for estimated peak, midpoint and trough demand conditions** in 2004/05, with transmission losses recovered on a uniform basis.[17] Using the generator outputs estimated by OXERA's wholesale market model, the load-flow model was employed to estimate zonal TLMs for 2005/06. This reflects the fact that, under P82, TLFs for any year are calculated on the basis of historic power system conditions during the previous year.

- OXERA's market model was run twice for 2005/06, using:

  – the TLMs calculated from the load-flow modelling exercise;
  – an estimated uniform TLM.

  These model runs allowed estimates to be made of the impact of AZTL on the pattern of generation for the three snapshot periods in that year.

- The generator outputs for 2005/06 under both uniform and zonal loss charging were fed back into the load-flow model to give an estimate of the potential change in transmission losses for the snapshot periods. Zonal transmission loss factors for 2006/07 were calculated.

- This year-by-year process was continued, with OXERA's wholesale market model despatched one year at a time, and the results fed into the load-flow model to give estimated transmission loss factors for the following year.

For the purposes of the modelling, OXERA assumed a BETTA start date of April 2005, as the data required for the model was grouped in financial years. If BETTA goes live in October 2004 as planned, the effects of AZTL applied throughout Great Britain would start to be seen six months earlier. The load-flow simulation was carried out for each of the six years from 2004/05 until 2009/10.

Following the completion of the joint wholesale market/load-flow modelling, OXERA used the estimated TLMs to model wholesale market behaviour across all demand conditions (rather than just the three snapshot periods). The price at which generators were willing to despatch was modelled as being short-run avoidable cost divided by the generator TLM. Intuitively, this reflects the fact that the more output is scaled back, the higher the market price needs to be to allow a generating unit to cover its avoidable costs.

[17] Note that generator outputs in 2004/05 will actually be based on P82 in England and Wales and separate loss charging arrangements in Scotland.

2.2 Derivation of TLFs and TLMs

TLFs for the GB system were calculated using a specialised load-flow package, TRACK/LOFLO. Since its development in the early 1990s, it has been used for a number of projects, funded, among others, by Teesside Power, ScottishPower and Electrical Power Research Institute (EPRI), USA.

Transmission network and demand data to run the simulation studies was gathered from publicly available sources, mainly '2002 Seven Year Statements' published by the three transmission companies: NGC, ScottishPower and Scottish Hydro-Electric Transmission (a subsidiary of Scottish & Southern Energy). These Statements contain predictions up to 2008/09 only, while modelling was carried out for the period up to 2009/10. OXERA was able to obtain pre-publication data for 2009/10 from NGC's 2003 Statement. For ScottishPower and Scottish & Southern Energy, assumptions were made for 2009/10 by extrapolating trends from previous years.

In order to evaluate the zonal TLFs and TLMs according to Modification P82, three load flows were run for each year, for peak, midpoint and trough demand conditions. Individual nodal TLFs were obtained as an output of the load-flow modelling. These were then averaged to obtain zonal TLFs using weights equal to the sum of the absolute value of generation and demand at a given node. The ATLFs were then calculated by halving the zonal TLFs and using time-weighting factors to aggregate the results for the three snapshot periods. These time-weighting factors, shown in Table 2.1, were calculated by taking load-duration curve[18] data from NGC's 'Seven Year Statement', and identifying the proportion of time at which demand was closest to each of the three types of snapshot demand period being modelled.

Table 2.1: Time-weighting coefficients derived from load-duration curve

Snapshot period	Weighting (%)
Peak	10.4
Midpoint	73.8
Trough	15.8

Source: OXERA.

Following the derivation of TLFs, a separate set of TLMs was obtained for each loading condition using the methodology described in section T.2 of the BSC and assuming transmission losses equal to those published in the three 'Seven Year Statements'. Technical details about the methodology of calculating TLFs and ATLFs are contained in appendix 3.

[18] A load-duration curve shows the percentage of time at which demand is at different levels.

The calculation of TLFs required a number of assumptions, the most important of which were the following.

- The current 45:55 split of losses between generators and suppliers in England and Wales reflects the fact that generators' output is measured on the high-voltage side of generator transformers, and hence generators cover generator transformer losses themselves. The situation is different in Scotland, where generators do not cover these losses. While this inconsistency will have to be resolved under BETTA, **OXERA's modelling treats generators in Scotland and in England and Wales in the same way, and assumes a 45:55 split of losses**.

- **TLFs calculated from load flows in any given year were used to derive estimated average TLMs for the following year**. In practice, TLMs are calculated *ex post*, based on the actual amount of losses sustained in a given settlement period.

- The transmission network in England and Wales is defined as that operating at voltages of 275kV and 400kV, while in Scotland it also contains the 132kV level. However, **Scottish & Southern Energy's network also contains a substantial number of lines operating at 33kV and below**. These connections could not be removed from the load-flow model, as this would substantially change the pattern of flows. **This problem was addressed by adjusting resistances and reactances in low-voltage lines so that they did not contribute to the transmission losses or derived TLFs, while the pattern of flows was largely unaffected**.[19]

- OXERA's modelling excluded the proposed new interconnectors to Norway and the Netherlands due to the lack of information about future loading of the interconnectors and uncertainty about their construction.

2.3 Description of scenarios

Due to time constraints, OXERA has focused its analysis on the impact of AZTL on market outcomes under one base scenario. This section sets out the assumptions on fuel prices, demand growth and market entry and exit that were used in this base scenario, and further details are provided in appendix 2. Sensitivities were carried out for one year (2005/06) for some of the variables. Extensions to the modelling work might focus on testing a wider range of sensitivities.

[19] Resistances R in lower-voltage lines and transformers were removed from the model, while the reactances X were increased to the value $\sqrt{R^2 + X^2}$ in order to compensate for the removal of resistances.

2.3.1 Base scenario

Fuel prices

The fuel price assumptions underlying the base scenario are shown in Table 2.2.

Table 2.2: Fuel price assumptions

	Coal (£/tonne)[1]	Gas (p/therm)[2]
2004/05	22	19.8
2005/06	22	19.0
2006/07	22	18.0
2007/08	22	18.0
2008/09	22	18.0
2009/10	22	18.0

Note: [1] ARA coal price. Estimated delivery costs are added on an individual plant basis. [2] NBP gas price.
Source: OXERA.

Coal prices are assumed to be flat across the year, and OXERA has included estimates of transport costs in the delivered coal price for each coal power station. Seasonal shaping factors were applied to the assumed gas price to take account of the variation in gas prices across the year. **These fuel price assumptions result in a tendency for gas to be the more competitive fuel in the trough period, but coal to be more competitive for the peak and midpoint periods**.[20]

Demand growth

The demand assumptions used in the modelling exercise are taken from the 2002 Seven Year Statements of ScottishPower and Scottish & Southern Energy, and advance information provided by NGC from its 2003 Statement. For NGC's region, the demand assumptions were those based on customer projections, as the Statement provided loss figures consistent with this level of demand. However, these figures are higher than NGC's own central estimate of future demand, implying that **the base scenario incorporates a relatively high load-growth assumption**.

Table 2.3 shows the demand figures used for the peak, midpoint and trough demand snapshots in each year. These figures were derived from the load-duration curve in NGC's Statement, which shows that the lowest demand in the year is 37% of peak demand. This percentage was applied to the peak-demand assumptions in Table 2.4 to give annual figures for demand during a 'trough' period. Demand during a 'midpoint' period was calculated by taking an average of peak and trough demand.

[20] Based on plant standard efficiency assumptions of 36% for coal and 50% for gas. Note that OXERA's model includes individual efficiency assumptions for each plant.

Table 2.3: Peak-demand assumptions, inclusive of losses (MW)

	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
Peak	62,840	63,671	64,644	65,395	66,214	67,006
Midpoint	43,086	43,656	44,322	44,837	45,397	45,940
Trough	23,333	23,640	24,001	24,278	24,581	24,874

Note: These figures do not include assumed Moyle Interconnector exports. In the case of Scottish & Southern, the peak-demand figures from the Statement were scaled up to include estimates of transmission losses. Additional loss estimates associated with interconnector flows were added to the figure for total demand. Peak demand in the ScottishPower and Scottish & Southern Energy regions in 2009/10 was estimated by extrapolating trends from previous years.
Source: NGC, ScottishPower, Scottish & Southern Energy, and OXERA calculations.

Market entry and exit

OXERA's modelling took into account the scheduled closure dates for nuclear power stations, shown in Table 2.4, as well as other announced closures prior to 2004/05. The model also assumes that capacity that is uneconomic to run will exit the market.

Table 2.4: Announced closures during the modelling period

Generator	Owner	Type	Closure date	GSP Group	Capacity (MW)
Chapel Cross	BNFL Magnox	Magnox	Mar 2005	13 (SP)	168
Dungeness A	BNFL Magnox	Magnox	Apr 2006	9	450
Sizewell A	BNFL Magnox	Magnox	Apr 2006	7	420
Dungeness B	British Energy	Advanced gas reactor	Apr 2008	9	1,100
Oldbury	BNFL Magnox	Magnox	Oct 2008	6	475

In the modelling, new CCGT entry is assumed to occur when the average market price exceeds the long-run marginal cost of new-entry plant. The new entry that occurred in the base scenario is discussed in section 6.

2.3.2 Sensitivities

OXERA carried out a number of checks to assess how sensitive the results of the load-flow modelling exercise are to the base-scenario assumptions, and to examine whether environmental constraints change the comparison of market outcomes under uniform and zonal loss charging.

To test the assumptions on fuel prices, demand growth and location of closure, the load-flow modelling exercise for 2005/6 was repeated three times using the following assumptions:

- a higher coal price of £26.4/tonne;
- reduced peak demand of 61,910 MW, with correspondingly lower figures for trough and midpoint snapshot periods;
- the closure of around 1 GW of coal-fired capacity in GSP Group 1 (in the North) in March 2005 rather than in GSP Group 7, as occurred in the base scenario.

The sensitivity checks on the load-flow model were restricted to one year and to a limited number of variables, owing to time constraints. The base results presented in section 3 show that outcomes did vary between years, and hence further analysis to assess the robustness of the results for later years would have been desirable.

In carrying out the combined load-flow and market modelling, OXERA did not take explicit account of the Large Combustion Plants Directive (LCPD) and the EU Emissions Trading Scheme. This was because the limits implied by these schemes apply across the year, and it would therefore be difficult to ascertain how generator behaviour in a particular snapshot period might be affected. However, **OXERA tested the sensitivity of the results to stricter environmental controls by running the wholesale market model for 2008/09 and 2009/10 under uniform and zonal loss charging (using the estimated TLMs from the base scenario) with the annual load factors of non-flue-gas desulphurisation coal plant restricted to 28%**. This does not exactly replicate the impact of an emissions trading scheme, however, since it places a physical limit on operation rather than a marginal value on carbon emissions.

3. Modelling Results

This section presents the results of the modelling exercise, which for ease of reference are summarised in Table 3.1. **Overall, the modelling suggests that AZTL may lead to small changes in despatch in favour of southern generation, resulting in small loss reductions, while precipitating large transfers between generators in different regions**. **The short-term effect of AZTL on the fuel mix and emissions would appear to be ambiguous, although the base scenario showed a small switch to coal generation and hence a slight increase in emissions in most of the years**.

Table 3.1: Summary of modelling results

Sub-section		Impact of AZTL
3.1	Loss factors	Generator output would be scaled down the most in Scotland, with the degree of scaling decreasing the further south in Great Britain; the converse holds for suppliers, with demand scaled up the most in the south and the least in the north and Scotland.
3.2	Transfers between generators	There would be significant transfers from generators based in Scotland and North England to generators based in the south.
3.3	Pattern of generation	AZTL would give rise to small changes in despatch from northern to southern generation; the net change in the fuel mix would appear to be ambiguous, although the base scenario showed a small net switch from gas to coal in most years.
3.4	Impact on losses	The reduction in losses from redespatch may be small, and might be valued at £0.2m–£1.3m per annum.
3.5	Wholesale price	The modelling did not find clear evidence of an impact on wholesale prices in either direction.
3.6	Emissions	The emissions impact of small changes in the fuel mix may be more significant than the direct effect on emissions of reduced losses from redespatch. In the base scenario, the small net switch from gas to coal led to a small overall increase in emissions in most years.
3.7	Constraint costs	AZTL might lead to very marginal reductions in constraint costs across the Scotland–England interconnector.
3.8	Sensitivity analysis	Loss factors may be affected by market factors such as demand growth, input fuel prices, and entry and exit decisions.

Source: OXERA.

3.1 Loss factors

3.1.1 Estimated ATLFs

The base-scenario ATLFs calculated from the load-flow modelling are presented in Table 3.2. It is these ATLFs that give rise to zonal variations in TLMs, and it is the differentials in the ATLFs rather than their absolute value that are important. The ATLFs for any given year were calculated from conditions in the previous year.

Table 3.2: Estimated annual ATLFs

GSP Group		2005/06	2006/07	2007/08	2008/09	2009/10
14	Northern Scotland	–0.036	–0.033	–0.024	–0.027	–0.024
13	Southern Scotland	–0.031	–0.026	–0.016	–0.020	–0.017
1	Northern	–0.016	–0.017	–0.014	–0.017	–0.015
2	North West	–0.011	–0.012	–0.009	–0.013	–0.010
3	Yorkshire	–0.014	–0.017	–0.015	–0.019	–0.016
4	North Wales and Mersey	–0.001	–0.002	–0.003	–0.007	–0.003
5	East Midlands	–0.006	–0.009	–0.007	–0.011	–0.012
6	Midlands	0.001	0.001	0.003	–0.001	0.003
7	Eastern	–0.006	–0.006	–0.003	–0.005	–0.003
8	South Wales	–0.001	–0.001	0.000	–0.001	0.000
9	South East	–0.007	–0.005	–0.003	–0.003	0.000
10	London	0.002	0.003	0.005	0.004	0.006
11	Southern	0.002	0.002	0.002	0.003	0.002
12	South Western	0.002	0.002	0.004	0.003	0.001

Note: In line with the BSC methodology, the ATLFs were calculated by dividing annual zonal TLFs by a factor of two. The figures in the table therefore represent the regional variation in loss charges, but are lower than regional differences in marginal loss effects.
Source: OXERA.

Figure 3.1 shows the estimated ATLFs in graphical form. The GSP Groups have been ordered so that moving from left to right across the graph corresponds to moving from northern zones towards southern zones. **The results illustrate that northern generation will be exposed to substantial loss scaling under AZTL, whereas generation in the southern zones will tend to benefit**. Comparison of the results with the map of GSP Groups in appendix 4 also suggests that generation in zones on the east side of the country (1, 3, 5, 7) tends to have a more negative AZTL than corresponding zones on the west side of the country (2, 4, 6, 8). **The effect of these ATLFs on suppliers and consumers in different regions will be the converse of the effect on generators**.

The most negative ATLFs are observed for the two Scottish regions. While this reflects the geographical distribution of demand and generation across Great Britain, it is also **reflective of the inclusion of 132kV lines as part of the transmission network in Scotland**.[21] In general, the 132kV network exhibits higher levels of losses than the 275kV and 400kV networks. Hence, where changes in generation affect flows and losses in 132kV lines, the marginal impact will be included in ATLFs calculated for Scotland but not for England and Wales.

[21] 132kV lines are classified as distribution lines in England and Wales but as transmission lines in Scotland.

The graph also shows that, under the base scenario, the TLFs do change from year to year, particularly for the two Scottish regions. Between the years 2005/06 and 2007/08 the TLFs in Scotland become less punitive for generators, which may reflect changes in power flows due to alterations to generation despatch caused by the assumed increase in the competitiveness of gas relative to coal over this period.

Figure 3.1: Estimated ATLFs

Source: OXERA.

3.1.2 Estimated TLMs

Table 3.3 shows estimated average annual TLMs for generators and suppliers derived from the above ATLF estimates. The estimated uniform factors in the bottom row of the table allows a comparison to be made with the potential level of scaling under a regime of uniform loss charging.

Table 3.3: Estimated average annual TLMs for generators and suppliers

GSP Group		2005/06		2006/07		2007/08		2008/09		2009/10	
		Gen.	Sup.	Gen.	Sup.	Gen.	Sup.	Gen.	Sup.	Gen.	Sup.
14	Northern Scotland	0.966	0.981	0.965	0.982	0.974	0.993	0.974	0.992	0.975	0.993
13	Southern Scotland	0.972	0.987	0.971	0.987	0.981	1.000	0.981	0.999	0.982	1.000
1	Northern	0.986	1.002	0.985	1.002	0.984	1.003	0.983	1.001	0.984	1.002
2	North West	0.991	1.006	0.990	1.007	0.988	1.007	0.988	1.006	0.989	1.007
3	Yorkshire	0.988	1.003	0.987	1.004	0.983	1.002	0.982	1.000	0.982	1.000
4	North Wales and Mersey	1.001	1.016	1.000	1.017	0.995	1.014	0.994	1.012	0.996	1.014
5	East Midlands	0.996	1.011	0.995	1.012	0.990	1.009	0.989	1.008	0.987	1.005
6	Midlands	1.004	1.019	1.003	1.019	1.000	1.019	1.000	1.018	1.002	1.020
7	Eastern	0.996	1.012	0.995	1.012	0.994	1.013	0.996	1.014	0.995	1.013
8	South Wales	1.001	1.017	1.001	1.017	0.997	1.016	1.000	1.018	0.999	1.017
9	South East	0.995	1.011	0.995	1.011	0.995	1.014	0.997	1.015	0.998	1.016
10	London	1.005	1.020	1.004	1.020	1.002	1.021	1.004	1.023	1.004	1.022
11	Southern	1.004	1.019	1.003	1.020	1.000	1.019	1.003	1.021	1.001	1.019
12	South Western	1.004	1.020	1.003	1.020	1.001	1.020	1.004	1.022	1.000	1.018
Estimated uniform TLMs[1]		0.992	1.010	0.991	1.011	0.990	1.012	0.990	1.012	0.990	1.012

Note: [1] These were calculated to recover the same level of total losses as the set of zonal TLMs.
Source: OXERA.

The figures show that, under the base scenario:

- generation in Northern Scotland would be scaled down by an estimated 3.4% in 2005/06, whereas generation in London would be scaled *up* by an estimated 0.5%. Under uniform loss charging, all generation would be scaled down by an estimated 0.8%;
- demand in Northern Scotland would be scaled *down* by an estimated 1.9% under AZTL, whereas demand in the London region would be scaled up by an estimated 2%. By way of comparison, all demand would be scaled up by an estimated 1% under uniform loss charging.

While the table shows that AZTL gives rise to clear regional differences in loss scaling, the spread of these TLMs may not be significant enough to lead to large changes in despatch (see section 3.3). This may reflect the way in which ATLFs are calculated under Modification P82. In particular:

- TLFs are time-averaged, which means that they tend to reflect midpoint loading. At midpoint, variations in marginal loss effects between the GSP Groups 14 and 12 are about half of the variations at peak;
- TLFs are halved in order to derive ATLFs.

3.2 Transfers between generators

In this report, OXERA does not present modelling estimates of the financial impact of AZTL on generating companies. However, Table 3.4 shows figures for the change in total loss payments for hypothetical generation companies with portfolios of four CCGT plant with a capacity of 1 GW operating at load factors of 85%.

Table 3.4: Change in annual loss payments for hypothetical generators (£m)

Hypothetical generator	Location of assumed portfolio of four 1 GW plant	Total loss payments		
		Uniform	Zonal	Change
Northern	14, 13, 1, 2	5.54	11.64	6.10
Southern	9, 10, 11, 12	5.54	–0.65	–6.19
Balanced	13, 1, 10, 11	5.54	4.82	–0.72

Note: For the purpose of this illustrative comparison, losses were valued at an assumed price of £20/MWh.
Source: OXERA.

The figures show that a generator with a 4 GW portfolio located in northern zones would see an increase of £6.1m in annual loss changes from a move to AZTL, whereas a generator with a southern-based portfolio of the same size would benefit to the order of £6.2m. As would be expected, a portfolio of generation distributed more evenly across the country would be less exposed to the transfer effects of AZTL.

These figures relate only to generation businesses, but AZTL will also affect the supply businesses of vertically integrated companies. The extent to which transfers between generation and supply businesses affect company profits will depend on whether they can be passed through in wholesale or retail prices. In this regard, it should be noted that:

- as discussed in section 3.5, in a competitive wholesale market only the impact of AZTL on the marginal generator would feed through into wholesale prices. Hence, transfer effects on infra-marginal generators may not be recoverable through the wholesale market;
- a competitive retail market would tend to force suppliers to pass on any costs or benefits of AZTL to end-consumers. In the case of benefits from AZTL, failing to pass these through might lead to an erosion of retail market share in that region.

The implication is that the impact on generation business might be expected to affect company profits, given the competitiveness of the current wholesale market, whereas the impact on supply business would only affect company profits in the long term if the retail market is *not* competitive.

3.3 Pattern of generation

The impact of AZTL on the pattern of generation has been analysed both for the snapshot demand periods used for the load-flow modelling and for the full wholesale market modelling subsequently undertaken by OXERA.

3.3.1 Snapshot periods

Table 3.5 shows how despatch for the snapshot demand periods changed under AZTL and the size of any consequent reduction in transmission losses for that period.

Table 3.5: Change in despatch and losses for snapshot demand periods

Year	Peak		Midpoint		Trough	
	Redespatch	Loss change (MW)	Redespatch	Loss change (MW)	Redespatch	Loss change (MW)
2005/06	no change	0	219 MW of coal generation in zone 13 replaced with gas generation in zone 8	–13	no change	0
2006/07	no change	0	1,102 MW of gas generation in zone 14 and 40 MW of gas generation in zone 3 replaced with gas generation in zone 11	–84	126 MW of gas generation in zone 3 replaced with gas generation in zone 2	–1
2007/08	no change	0	1,063 MW of gas generation in zone 14 replaced with 861 MW of coal generation in zone 6 and 202 MW of gas generation in zone 8	–80	no change	0
2008/09	no change	0	990 MW of gas generation in zone 14 and 312 MW of gas generation in zone 3 replaced with gas generation in zone 11	–91	no change	0
2009/10	no change	0	582 MW of gas generation in zone 14 replaced with coal generation in zone 6	–30	no change	0

Source: OXERA.

For the snapshot modelling, no changes in despatch occurred for the peak period. This may be a reflection of the fact that a high proportion of generators will be required to operate at such times, and that the fuel price assumptions used in the base scenario imply that coal is significantly more competitive at such times (thus limiting the potential for any redespatch between generators using different fuels). However, it is not clear that this result will hold in all cases, and the discussion of changes in despatch for the full model runs in the following sections includes consideration of the potential value of loss reductions if the redespatch occurs during peak periods. The snapshot modelling showed redespatch in all years for the midpoint period, and in one year for the trough.

As would be expected, **where redespatch occurred, southern generation tended to replace northern generation**. The exception was the redespatch that occurred for the trough period in 2006/07, where generation switched from zone 3 on the east side of the country to zone 2 on the west side. **There appears to be no clear pattern as to how redespatch affects the fuel mix: the above modelling provides examples where redespatch occurred from coal to gas and vice versa, as well as examples of redespatch between gas plant located in different regions**. In line with expectations, the modelling shows that, in general, the larger the redespatch, the greater the reduction in transmission losses.

3.3.2 Full model runs

Table 3.6 shows how the application of estimated zonal TLMs affected the geographical pattern of generation compared with outcomes under uniform loss charging, with OXERA's model run across the whole year rather than for snapshot periods. **The net**

changes in generation across the year for each zone are small compared with the total level of generation. **The overall pattern is for small reductions in generation in Scotland and some zones in northern England (zone 1 for all years, zone 3 for years 2007/08 to 2009/10), and for small increases in generation in other zones in England and Wales**.[22]

Table 3.6: Changes in annual output by zone (GWh)

GSP Group		2005/06	2006/07	2007/08	2008/09	2009/10
14	Northern Scotland	–131	–71	–31	–25	–64
13	Southern Scotland	–618	–368	–134	–41	–47
1	Northern	–896	–527	–144	–246	–32
2	North West	108	76	106	112	194
3	Yorkshire	71	91	–369	–522	–400
4	North Wales and Mersey	434	118	162	212	203
5	East Midlands	650	618	380	389	106
6	Midlands	0	0	0	0	0
7	Eastern	414	158	6	93	12
8	South Wales	3	58	123	181	73
9	South East	–93	–156	0	0	0
10	London	2	0	0	0	1
11	Southern	55	–43	–111	–158	–55
12	South Western	2	46	12	5	9
Total output (for comparison)		373,405	379,797	384,271	390,024	395,138

Source: OXERA.

The net change in generation from different types of fuel is shown in Table 3.7. **The modelling results showed a small net switch from gas to coal in the years 2005/06 to 2008/09**. However, the change in fuel mix is very small compared with total generation—even the largest switch of 302 GWh observed in 2006/07 represented less than 0.1% of total generation. Furthermore, the modelling also showeda net switch from coal to gas in 2009/10, while the snapshot demand modelling found periods in which the switch occurred in the other direction. Hence**, the results may not provide strong enough evidence to suggest that there will be a systematic shift to coal generation**. As expected, the output of nuclear plant was unaffected given that these power stations operate as baseload.

[22] There are exceptions to this pattern—for example, generation fell slightly in zone 11 (Southern) for 2006/07 to 2009/10 due to reduced output from a coal plant. This appears to have been caused by the owner of the plant increasing output in some months of the year from another coal plant in its portfolio with lower fuel transport costs, due to changes in the overall merit order in the generation market following the introduction of AZTL. This required the company to decrease output from the coal-fired plant in zone 11 in other months in order to remain within its overall SO_2 and NOx emissions constraints.

Table 3.7: Changes in annual output by fuel type (GWh)

	2005/06	2006/07	2007/08	2008/09	2009/10
Coal	20	302	275	209	–5
Gas	–17	–302	–275	–209	6
Nuclear	0	0	0	0	0
Other	–4	0	0	0	–1
Total output (for comparison)	373,405	379,797	384,271	390,024	395,138

Note: The sum of changes may not equal zero due to rounding.
Source: OXERA.

3.4 Impact on losses

To provide an accurate figure for the impact of AZTL on transmission losses, full load-flow modelling would have to be carried out for all demand conditions in the year. Given that a modelling exercise on this scale was not possible, **OXERA has employed two separate approaches to provide estimates of how changes in generation despatch due to AZTL might reduce losses**. These are set in Table 3.8, along with the advantages and disadvantages of each method.

Table 3.8: Methods of estimating the loss impact of changes in despatch

Method		Advantage	Disadvantage
1	Multiplication of nodal TLFs[1] from the load-flow modelling to the estimated changes in the output of individual plant produced by running the wholesale market model across the whole year	Relatively realistic assessment of how plant outputs may change across the year as a whole following the application of AZTL	Nodal TLFs are highly volatile—they depend on the specific loading conditions of the network, and are affected by changes in despatch;[23] for some plant, the net change in annual output may aggregate positive and negative changes with separate loss impacts
2	Extrapolation of results from snapshot demand periods using time-weighting factors	For the snapshot periods, the estimates for the change in losses are relatively robust since generated by full load-flow modelling	Three snapshot periods are unlikely to be representative of the year as a whole; time-weighting factors place very high weight on single snapshot period (midpoint)

Note: [1] Nodal TLFs give the marginal change in losses for a change in flows at a node, but are specific to a particular loading condition of the network.
Source: OXERA.

OXERA suggests that more weight should be placed on the estimates generated using method 1, since it was possible to address the main disadvantage (the volatility of nodal TLFs) by producing a range for possible loss reductions from generation

[23] TLFs assess the marginal change in losses due to a small change in output. For large changes in output, the marginal reduction in losses due to further alterations in output is likely to fall.

redespatch. The main problem with method 2 (the fact that results for each year are heavily dependent on a single snapshot period) could not be addressed in this way.

3.4.1 Method 1

The results of applying the first method are shown in Table 3.9. As noted above, **nodal TLFs are highly volatile, and OXERA has explored the effect of using different sets of nodal TLFs** from different snapshot periods to assess the potential loss impact of the redespatch identified in the wholesale market modelling. For the same redespatch figures, **the highest estimated loss effect resulted from using peak nodal TLFs, which suggests that loss savings are highest if redespatch occurs at peak times**. **The lowest loss effect came from using trough nodal TLFs**.

While the table gives an idea of the wide range of estimates due to uncertainty over the actual level of nodal TLFs at the time when redespatch occurred,[24] the figures calculated using method 1 show marginal loss reductions in all cases.

Table 3.9: Method 1: estimated annual loss savings

	2005/06	2006/07	2007/08	2008/09	2009/10	Average
Annual savings in losses (GWh)						
High figure	90	61	35	38	26	50
Central figure	49	31	20	24	16	28
Low figure	12	6	10	9	11	10
Percentage of energy produced						
High figure	0.024	0.016	0.009	0.010	0.007	0.013
Central figure	0.013	0.008	0.005	0.006	0.004	0.007
Low figure	0.003	0.002	0.003	0.002	0.003	0.002
Percentage of total losses						
High figure	1.1	0.7	0.4	0.4	0.3	0.6
Central figure	0.6	0.3	0.2	0.3	0.2	0.3
Low figure	0.2	0.1	0.1	0.1	0.1	0.1

Note: Zonal TLFs were used for a small number of plant for which nodal TLFs were unavailable.
Source: OXERA.

3.4.2 Method 2

Table 3.10 shows estimates of the annual savings in losses derived using the second method. Volatility in the level of savings from year to year seems to be the result of using only three snapshots per year. In order to smooth out that effect, the last column shows the average result across all years. Given that the time-weighting averages place a 73.8%

[24] Moreover, redespatch itself may lead to significant changes in nodal TLFs.

weight on the midpoint snapshot period, which showed redespatch in all years, **these figures may represent relatively high estimates**.[25]

Table 3.10: Method 2: estimated annual loss savings

	2005/06	2006/07	2007/08	2008/09	2009/10	Average
Annual savings in losses (GWh)	84	544	517	588	194	321
Percentage of energy produced	0.02	0.14	0.13	0.15	0.05	0.1
Percentage of total losses	1	6	6	7	2	4

Source: OXERA.

3.4.3 Discussion of loss-reduction estimates

NGC has estimated that taking account of marginal loss impacts in generation despatch decisions could reduce transmission losses by at most 3% in England and Wales. This figure is based on the application of full marginal loss factors, whereas the P82 methodology will give less pronounced signals for redespatch (due to the halving of annual zonal TLFs to obtain AZTLs, as set out in Figure 1.2), and hence might produce loss savings of less than 3%. On the other hand, the application of AZTL across Great Britain rather than on an England and Wales basis only may give greater scope for reducing losses.

Despite the disparity between the numbers produced by the two methods, overall, the reduction in losses due to AZTL's impact on generation despatch would appear to relatively small. Alongside the limited change in despatch identified in the modelling, this may reflect the composition of transmission losses. Table 3.11 shows the breakdown of losses according to NGC's 2003 'Seven Year Statement'.

[25] One of the reasons why the midpoint snapshots consistently showed redespatch in the modelling exercise may have been that assumed gas prices were relatively close to assumed average delivered coal prices for this snapshot period, so that AZTL had the potential to change the ranking of coal and gas stations at the margin.

Table 3.11: System power losses at peak in NGC network

	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
Transmission heating losses excluding GSP transformers (MW)	609	642	629	799	798	807	806
% of total losses	59	60	59	65	65	65	64
Fixed losses (MW)	208	207	208	208	208	208	208
% of total losses	20	19	20	17	17	17	17
GSP transformer heating losses (MW)	110	114	116	121	124	128	133
% of total losses	11	11	11	10	10	10	11
Generator transformer heating losses (MW)	112	113	112	103	102	103	105
% of total losses	11	11	11	8	8	8	8
Total losses	**1,039**	**1,076**	**1,065**	**1,231**	**1,232**	**1,246**	**1,252**

Source: NGC.

Only the first component (transmission heating losses), constituting about 60% of total peak losses, is to be charged on the zonal basis; the remaining components are to be smeared uniformly across all the zones. That first component can be broken down into two further components: losses due to the flow of real power and losses due to the flow of reactive power. OXERA's simulations have shown that the former constitutes about 85–90%, while the latter constitutes about 10–15% of the first row in Table 3.11. Modification P82 stipulates that, when calculating TLFs, reactive power flows should be neglected. Hence, **AZTL addresses only about 85–90% of the 60%—that is 50–55% of the total peak losses (ie, only about 1.1% of power produced at the peak)**. **OXERA's estimates show that this number drops to about 0.8% at midpoint load and 0.7% at trough**. **Taking the time-weighted average, it can be estimated that AZTL charging addresses losses constituting only about 0.8% of energy produced, rather than the headline figure of 2% losses at peak**.

3.4.4 Valuation of loss reductions

OXERA's estimates of the monetary value of potential loss reductions through generation redespatch are shown in Table 3.12. For method 1, **the loss savings calculated using peak nodal TLFs and valued at the peak electricity price from the base scenario are worth around £1.3m per annum**. On the other hand, **if loss savings are calculated using trough nodal TLFs and valued at the baseload price, the benefits are much reduced and are of the order of £0.2m per annum**. The figures produced using method 2 give average annual savings of around £8.4m, although, as discussed, this is likely to be an overestimate.

Table 3.12: Potential loss-reduction benefits from generation redespatch

	2005/06	2006/07	2007/08	2008/09	2009/10	Average
Method 1						
Annual savings in losses (GWh)						
High figure	90	61	35	38	26	50
Central figure	49	31	20	24	16	28
Low figure	12	6	10	9	11	10
Prices generated by base scenario (£/MWh)						
Peak price	22.72	28.62	26.76	27.05	26.94	26.42
Load-shape price	19.45	22.71	21.35	21.42	21.26	21.24
Baseload price	18.72	21.48	20.24	20.23	20.12	20.16
Value of loss reduction (£m)						
High figure	2.05	1.73	0.93	1.03	0.69	1.29
Central figure	0.96	0.70	0.42	0.52	0.34	0.59
Low figure	0.22	0.13	0.20	0.19	0.21	0.19
Method 2 (for comparison)						
Annual savings in losses (GWh)	84	544	517	588	194	385.58
Load-shape price (£/MWh)	19.45	22.71	21.35	21.42	21.26	21.24
Value of loss reduction (£m)	1.63	12.36	11.04	12.60	4.12	8.35

Source: OXERA.

3.5 Wholesale price

In a competitive generation market, the wholesale price in any time period will be determined by the short-run avoidable costs of the marginal generator. The impact of AZTL is to increase the price at which northern generators will tend to self-despatch while reducing the price at which southern generators will do so. **The crucial determinant of the impact of AZTL on wholesale prices is therefore the frequency with which the marginal generator is located in different zones**.

Table 3.13 shows the location of the marginal generator in each of the snapshot demand periods modelled by OXERA. In peak periods in which there were constraints across the Scotland–England interconnector, the marginal generator in both Scotland and England is identified. The table shows that, at different times, **the marginal generator was found to be located in a range of zones, from zone 14 in the North of Scotland to zone 11 in South England**.

Table 3.13: Location of marginal generator in snapshot demand periods

	Peak		Midpoint		Trough	
	Uniform	**Zonal**	**Uniform**	**Zonal**	**Uniform**	**Zonal**
2005/06	14 (Scotland) and 4 (E&W)	no change in despatch	13	13	3	no change in despatch
2006/07	14 (Scotland) and 4 (E&W)	no change in despatch	11	3	3	3
2007/08	14 (Scotland) and 4 (E&W)	no change in despatch	14	11	7	no change in despatch
2008/09	14 (Scotland) and 10 (E&W)	no change in despatch	14	3	7	no change in despatch
2009/10	14 (Scotland) and 4 (E&W)	no change in despatch	14	6	7	no change in despatch

Source: OXERA.

Table 3.14 shows the effect of AZTL on the baseload, load-shape and peak electricity prices in the base scenario. **Overall, the price impact of AZTL appears small, and the evidence is not strong enough to suggest a systematic change in either direction**.

Table 3.14: Effect of AZTL on wholesale price in base scenario

	2005/06	2006/07	2007/08	2008/09	2009/10	Average
Baseload price[1]						
Uniform loss charging	18.68	21.39	20.25	20.21	20.11	0.00
Zonal loss charging	18.72	21.48	20.24	20.23	20.12	0.00
Percentage change	0.21%	0.46%	–0.08%	0.14%	0.09%	0.16%
Load-shape price[2]						
Uniform loss charging	19.41	22.61	21.37	21.40	21.26	0.00
Zonal loss charging	19.45	22.71	21.35	21.42	21.26	0.00
Percentage change	0.20%	0.44%	–0.13%	0.09%	0.03%	0.13%
Peak price[3]						
Uniform loss charging	22.69	28.54	26.85	27.09	27.00	0.00
Zonal loss charging	22.72	28.62	26.76	27.05	26.94	0.00
Percentage change	0.10%	0.26%	–0.37%	–0.13%	–0.23%	–0.07%

Notes: [1] Calculated as a time-weighted average. [2] Calculated as a demand-weighted average. [3] Calculated from the highest 35% of demand periods.
Source: OXERA.

3.6 Emissions

3.6.1 Change in emissions

OXERA has estimated the short-term impact of AZTL on CO_2 emissions under the base scenario. **Table 3.15 breaks down the effect into the change in emissions due to alterations in the fuel mix and the reduction in emissions due to savings in the level of transmission losses from generation redespatch**.

Table 3.15: Short-term impact of AZTL on emissions under the base scenario ($kt\ CO_2$)

	2005/06	2006/07	2007/08	2008/09	2009/10
Impact via generation mix					
Uniform loss charging	164,973	168,984	170,028	174,632	176,610
Zonal loss charging	164,989	169,139	170,161	174,736	176,595
Change	16	155	134	104	–15
Impact via loss reduction					
Estimated loss reduction (GWh)	–50	–20	–13	–22	–13
Average unit emissions (kt/GWh)[1]	0.44	0.45	0.44	0.45	0.45
Change	–22	–9	–6	–10	–6
Overall impact					
Net change in emissions	–6	146	128	94	–21
Percentage change	–0.004%	0.086%	0.075%	0.054%	–0.012%

Note: [1] Calculated by dividing base scenario emissions with zonal loss charging by total generation.
Source: OXERA.

These figures show the expected result that the direct loss-reduction effect of AZTL tends to reduce the level of emissions. However, the table also shows that **the dominant short-term effect of AZTL on emissions was via changes in the generation mix, with the marginal switch to coal in years 2005/06 to 2008/09 (see Table 3.7) tending to increase carbon emissions under the base-scenario assumptions**. As discussed earlier, there does not appear to be any reason to suggest that AZTL will systematically lead to a switch to coal, and the direction of any change in the fuel mix may depend on the assumptions used in the modelling. **The results do not therefore provide strong enough evidence to suggest that the overall impact of AZTL will always be in a particular direction**. Nevertheless, the analysis shows that there will be a direct reduction due to loss savings from generation redespatch, and that this will either be reinforced or offset by alterations in the generation mix, with the latter effect potentially being more significant. The modelling suggests that **the short-term impact on emissions is very marginal, with percentage changes of less than 0.1% in all years**.

AZTL may have further effects on carbon emissions through its impact on the location of generation. This is discussed in section 4.3.2.

3.6.2 Valuation of change in emissions

OXERA has considered the value that might be placed on changes in the level of emissions. **There are two possible approaches:**

- **using estimates of the value at which carbon allowances might trade under the EU Emissions Trading Scheme**. This represents the commercial value placed on carbon, given the global cap on emissions imposed by policy-makers; and
- **applying estimates of carbon damage costs**. This would give a valuation of the potential damage caused by additional carbon emissions, although the damage is unlikely to be specific to the UK.

There have been attempts to place a figure on the damage costs of carbon emissions. The government has estimated such costs at around £70 per tonne carbon,[26] although this figure appears high compared with other estimates. Professor David Pearce, of University College London, has produced estimates for carbon damage costs in the range £2.4–£15 per tonne of carbon.[27] OXERA has applied a range of plausible figures in Table 3.16 to give estimated monetary values for the change in carbon emissions in the base scenario.

Table 3.16: Valuation of change in carbon emissions (£)

Value/tC	2005/06	2006/07	2007/08	2008/09	2009/10	Average
70	114,000	–2,784,000	–2,447,000	–1,791,000	398,000	–1,302,000
20	33,000	–795,000	–699,000	–512,000	114,000	–372,000
10	16,000	–398,000	–350,000	–256,000	57,000	–186,000
5	8,000	–199,000	–175,000	–128,000	28,000	–93,000

Note: The change in emissions was converted from carbon dioxide to carbon by multiplying by 12/44.
Source: OXERA.

The numbers show the short-term monetary impact of AZTL on carbon emissions varying significantly between years, and according to the value placed on unit changes in emissions. The highest estimated impact is £2.8m in 2006/07, if emissions are valued at £70 per tonne of carbon. However, the figure for the same year is reduced to only £0.2m if carbon is valued at £5 per tonne.

Nonetheless, as mentioned in section 1.3.3, the EU Emissions Trading Scheme will give UK generators an incentive to take account of emissions impacts alongside loss effects. Given that the base scenario did not take explicit account of the EU scheme, the above results might be affected.

3.7 Constraint costs

By altering the pattern of flows across the network, AZTL could have an impact on the level of constraints on the system. **OXERA has carried out modelling to assess how AZTL, by switching generation from Scotland to England, might alter the estimated**

[26] Clarkson, R. and Deyes, K. (2002), 'Estimating the Social Cost of Carbon Emissions', Government Economic Service Working Paper 140, January.
[27] Pearce, D. (2002), 'The Social Cost of Carbon and its Policy Implications', October.

cost of constraints across the Scotland–England interconnector. For a given loss-charging regime, OXERA compared the total avoidable costs of generation across the whole of Great Britain with and without a limit of 2,200 MW on flows across the interconnector. This gave an estimate of the resource cost of redespatch due to interconnector constraints. By carrying out this exercise for both uniform and zonal loss charging, OXERA was able to produce an estimate of how AZTL might change these constraint costs. The results are shown in Table 3.17.

Table 3.17: Estimated constraint costs across the Scotland–England interconnector (£)

	2005/06	2006/07	2007/08	2008/09	2009/10
Uniform losses	63,000	341,000	337,000	447,000	405,000
Zonal losses	38,000	317,000	320,000	399,000	367,000
Change	25,000	24,000	17,000	47,000	38,000

Note : The increase in constraint costs in 2006/07 may reflect the relatively high load-growth assumptions used in the base scenario.
Source: OXERA.

The figures show that AZTL might give rise to a very marginal benefit by reducing constraints. Note that these figures only take into account the effect of AZTL on short-run despatch decisions. **If AZTL also has the effect of causing future generation plant to be located in England rather than Scotland, the benefits from reducing constraints might be somewhat larger**. However, based on the above estimates, the benefit of entirely removing constraints across the interconnector would not rise above £0.5m in any of the years.

While the analysis focuses on the Scotland–England interconnector, AZTL might also affect constraints elsewhere on the network. Time constraints prevent a full analysis of all bottlenecks on the Great Britain transmission network, and so no estimates have been derived of the direction or size of any such impacts.

3.8 Sensitivity analysis

3.8.1 Load-flow sensitivity checks

Table 3.18 shows how moving from uniform to zonal loss charging changed despatch in the peak, midpoint and trough periods in 2005/06 for the three sensitivity checks carried out by OXERA. As for the base scenario, the application of AZTL tends to lead to southern generation replacing northern generation. The consequent reductions in losses caused by these changes in despatch are also shown in the table.

Table 3.18: Change in despatch and losses for snapshot demand periods

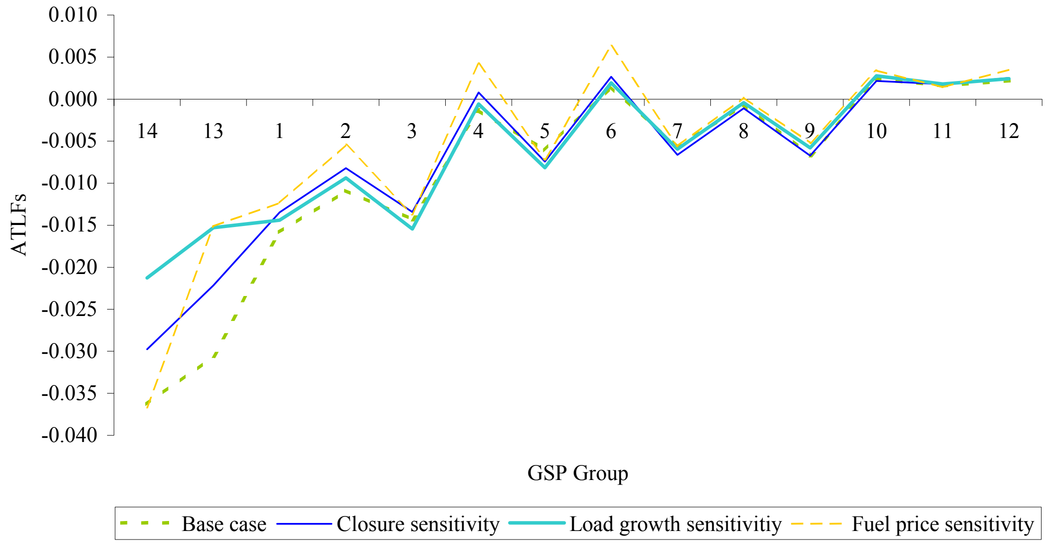
Model run	Peak		Midpoint		Trough		Difference in time-weighted losses compared with base scenario
	Redespatch	Loss change (MW)	Redespatch	Loss change (MW)	Redespatch	Loss change (MW)	
Fuel price	no change	0	857 MW of coal generation in zone 13 and 492MW of coal generation in zone 5 replaced with 1,349 MW of gas generation in zone 4	–62	324MW of gas generation in zone 9 replaced with gas generation in zone 7	–3	+32
Load growth	622 MW of oil generation in zone 14 replaced with oil generation in zone 10	–87	no change	0	no change	0	–34
Closure	no change	0	219 MW of coal generation in zone 13 replaced with gas generation in zone 8	–11	no change	0	–18

Source: OXERA.

The total level of time-weighted losses in the sensitivity runs also differed from that seen in the base scenario, as shown in the final column. **Increases in the coal price relative to the gas price tended to raise the level of transmission losses compared with the base scenario**. **On the other hand, reducing the load growth assumption tended to reduce losses compared with the base scenario, as did closing a northern coal plant instead of a coal generator in zone 7**.

Figure 3.2 shows how the estimated ATLFs changed under the sensitivity runs. For the load-growth and closure sensitivities, the most significant changes were seen in the two Scottish zones (13 and 14). For the fuel price sensitivity, changes were seen for zones 2, 4, 6 and 13.

Figure 3.2: Comparison of ATLFs for sensitivity checks and base scenario



Source: OXERA.

Overall, the sensitivity runs suggest that the level of ATLFs, particularly for Scottish regions, may vary according to the assumptions used in the modelling. This implies that future market outcomes such as demand growth, input fuel prices and entry and exit decisions may lead to changes in ATLFs and hence TLMs.

3.8.2 Environmental constraints

The pattern of results for the wholesale market modelling scenario in which coal plant load factors were restricted to 28% in 2008/09 and 2009/10 was broadly similar to those for the base scenario. In summary, the results of this sensitivity run were:

- a marginal switch from northern to southern generation,[28] leading to a marginal reduction in losses;
- a small net switch from gas to coal generation;
- a small net increase in emissions, with the direct reduction in emissions caused by lower losses offset by increased emissions due to the switch to coal generation.

These results suggest that environmental restrictions on coal plant may not significantly affect the impact that AZTL on market outcomes. However, the methodology of limiting coal load factors may not fully capture the impact of environmental policies. For example, the EU Emissions Trading Scheme would place a value on emissions at the

[28] The reduction in coal generation in zone 11 observed in the base scenario did not occur in this sensitivity run.

margin, rather than a physical restriction on load factor, and this might affect whether a net switch to coal generation is observed.

3.9 Impact of renewables on TLFs

The size and location of new renewable generation may have an impact on the pattern and spread of TLFs across the country. In the base scenario, assumptions about the level of distributed renewables and CHP were embedded in the demand assumptions, which netted off such generation.[29] Apart from existing hydro plants, the base scenario assumed no transmission-connected renewables; the nodes where such generation might connect to the network are uncertain, and the results of the load-flow modelling might be sensitive to assumptions made regarding the point of connection.

Table 3.19: Estimated net exports by GSP Group in the base scenario (GWh)

GSP Group		2005/06	2006/07	2007/08	2008/09	2009/10
14	Northern Scotland	4,168	4,704	4,374	4,488	4,384
13	Southern Scotland	5,622	4,782	5,019	5,513	5,560
1	Northern	1,690	3,903	3,845	3,721	3,355
2	North West	–11,318	–7,666	–8,068	–7,961	–8,392
3	Yorkshire	34,433	35,521	34,494	34,323	33,715
4	North Wales and Mersey	6,635	7,325	7,067	7,208	6,707
5	East Midlands	11,804	11,982	16,887	24,584	23,567
6	Midlands	–22,845	–23,487	–23,918	–25,288	–27,219
7	Eastern	7,188	4,951	4,107	4,270	3,385
8	South Wales	–4,484	–4,778	–4,975	–4,913	–5,139
9	South East	18,699	15,557	15,354	7,869	7,454
10	London	–30,845	–31,271	–31,676	–31,521	–31,978
11	Southern	–21,063	–21,798	–22,317	–22,153	–14,980
12	South Western	317	275	–194	–139	–417

Notes: Generation output by GSP Group was taken from the full model runs. The total demand assumed for England and Wales in each year was assumed to be distributed between GSP Groups in the same proportion as demand in 2001 (see Table 6.4).
Source: OXERA.

Table 3.19 shows indicative figures for the net exports from each GSP Group under the base scenario. The figures show that the North West, Midlands, South West, London and Southern regions are net importers in all years. The South Western zone is largely in

[29] In submitting their demand projections to NGC, customers in England and Wales are required to net off their own allowance for the output from embedded medium and small power stations. However, they are not required to provide information on their background assumptions, so it is not possible to determine the precise level of assumed renewables and CHP.

balance, while all other zones (including the two Scottish regions) show net exports in all years. Comparing these numbers with the geographical pattern of TLFs suggests that it is not the local balance between generation and demand that determines the TLF for any zone, but rather the broader pattern of flows across the country as a whole.

The shaded rows in Table 3.18 show the regions with significant potential for wind generation (see discussion in section 5). The largest potential for onshore wind development is in Scotland, while the GSP Groups adjacent to the three strategic areas that have been identified for offshore wind are set out in Table 3.20.

Table 3.20: GSP Groups adjacent to strategic areas for offshore wind

Strategic area	GSP Group
North West	2 (North West)
Greater Wash	5 (East Midlands) and 7 (Eastern)
Thames Estuary	7 (Eastern) and 9 (South East)

Source: OXERA.

The connection of significant quantities of onshore wind generation in Scotland, to the extent that it does not displace existing generation in the region, would be expected to increase the spread in TLFs across Great Britain. A recent study suggested that the growth of renewables, if located predominantly in Scotland, could lead to a widening of the spread of TLMs to 0.935 in Northern Scotland compared with 1.025 in Southern England by 2008/09.[30]

On the other hand, the growth of offshore wind, particularly if located in the Greater Wash and Thames Estuary areas, may not increase north–south flows and hence the north–south spread of TLMs in Great Britain to the same extent as the growth of onshore wind in Scotland. However, further load-flow modelling would be required to explore the precise impact of southern offshore generation on the geographical pattern of TLFs.

[30] ILEX (2003), 'Assessing the Introduction of Zonal Charging for Transmission Losses in Great Britain', March.

4. Generation Entry, Exit and Mothballing

This section of the report considers how regional variations in the cost of losses compare with other factors that might affect location, and discusses the implications for long-run entry, exit and mothballing decisions by generators. Although full modelling of future entry and exit decisions was outside the scope of the project, **OXERA has postulated a range of scenarios for the impact of AZTL, along with estimates of the potential impact on transmission losses and carbon emissions**.

4.1 Factors affecting location

The range of factors that might affect the location of generating plant include:

- **zonal loss charges;**
- **fuel transportation costs;**
- **NGC's TNUoS charges;**
- **the availability and cost of land; and**
- **planning consent for new plant build**.

The following sections focus on how the first three of the factors vary between regions.

4.1.1 Zonal loss charges

Table 4.1 gives estimates of annual loss payments for a hypothetical 1 GW plant running at load factors of 40% and 85%. Given the geographical differences in generator TLMs discussed in section 3.1, loss payments tend to be lower (and in some cases negative) for regions further south, and also tend to be lower on the west side of the country. Loss payments depend on the load factor of the plant (since losses are recovered by scaling output), with the calculations below suggesting **a maximum differential between zones of £4.9m per annum for an 85% load factor and £2.3m per annum for a 40% load factor**. For the purpose of comparison, a 1 GW plant running at a load factor of 85% and selling its output at £20/MWh would receive annual revenues of £149m, while a load factor of 40% would give annual revenues of £70m.

Table 4.1: Regional variation in AZTL loss payments

GSP Group		Generator TLM[1]	Estimated annual loss charge (£m)[2]	
			85% load factor	40% load factor
14	Northern Scotland	0.971	4.36	2.05
13	Southern Scotland	0.977	3.38	1.59
1	Northern	0.985	2.30	1.08
2	North West	0.989	1.59	0.75
3	Yorkshire	0.984	2.33	1.10
4	North Wales and Mersey	0.997	0.44	0.21
5	East Midlands	0.992	1.25	0.59
6	Midlands	1.002	–0.25	–0.12
7	Eastern	0.995	0.69	0.32
8	South Wales	1.000	0.07	0.03
9	South East	0.996	0.59	0.28
10	London	1.004	–0.58	–0.27
11	Southern	1.002	–0.30	–0.14
12	South Western	1.002	–0.37	–0.17

Notes: [1] Average estimated TLM for years 2005/06 to 2009/10. [2] Assumes an electricity price of £20/MWh.
Source: OXERA.

4.1.2 Fuel transportation costs

Regional variations in Transco National Transmission System (NTS) exit charges for a hypothetical 1 GW plant are shown in Table 4.2, calculated by averaging, for each GSP Group, the NTS exit charges reported by Transco for gas-fired power stations. For NTS-connected plant buying gas at the National Balancing Point, other elements of gas transportation charges do not vary on a locational basis. **NTS exit charges exhibit the opposite trends to those of AZTL loss charges, tending to be higher for more southerly and westerly regions**. This is likely to be a reflection of the structure of the gas network and the location of beach entry terminals. **The maximum differential in NTS exit charges between zones is around £2.8m per annum**.

Table 4.2: Regional variation in cost of losses and gas transportation costs

GSP Group		Average NTS exit charge[1] (pence per peak day kWh per day)	Estimated annual payment for 1 GW plant[2] (£m)
14	Northern Scotland	0.0001	0.02
13	Southern Scotland	n/a	n/a
1	Northern	0.0001	0.02
2	North West	0.0019	0.30
3	Yorkshire	0.0006	0.09
4	North Wales and Mersey	0.0067	1.07
5	East Midlands	0.0022	0.35
6	Midlands	n/a	n/a
7	Eastern	0.0053	0.85
8	South Wales	0.0174	2.77
9	South East	0.0074	1.18
10	London	0.0128	2.04
11	Southern	0.0128	2.04
12	South Western	0.0118	1.88

Notes: [1] Calculated from those power generator NTS exit charges given in Transco's charging statement. [2] Based on an assumed efficiency of 55%.
Source: Transco; OXERA calculations.

OXERA's modelling of despatch decisions by coal generators takes into account locational variations in delivered coal prices due to transport costs. **OXERA's estimates of delivered prices show maximum differentials equating, under certain assumptions, to a cost difference of around £5.6m per annum for a 1 GW plant**.[31]

4.1.3 TNUoS charges

The geographical pattern of NGC's TNUoS charges for 2002/03 is shown in Table 4.3. While the transmission charging regime that will apply under BETTA has yet to be confirmed, the figures show that the existing Investment Cost Related Pricing (ICRP) methodology gives rise to significant differentials in the level of tariffs across England and Wales. **The geographical pattern of TNUoS charges tends to mirror that of zonal loss charges, with southerly zones benefiting relative to northern zones**. **Annual payments for a hypothetical 1 GW plant vary from a maximum of £8.4m per annum in generation zone 1 to a negative charge (ie, the generator receives money from NGC) of £9.9m per annum in generation zone 15—a total spread of £18.2m per annum**.

[31] Based on a hypothetical plant with an efficiency of 36% and load factor of 50%.

Table 4.3: Regional variation in TNUoS charges in England and Wales

Generation zone	Zone area	Generation tariff (£/kW)	Annual charge for 1 GW plant (£m)
1	North	8.38	8.38
2	Humberside	5.09	5.09
3	North Yorks and North Lancs	4.34	4.34
4	South Yorks and South Lancs	3.78	3.78
5	North Wales	5.61	5.61
6	West Midlands	1.52	1.52
7	Rest of Midlands and Anglia	1.65	1.65
8	South Wales	–4.00	–4.00
9	Wiltshire	–2.28	–2.28
10	Greater London	0.04	0.04
11	Estuary	1.04	1.04
12	Inner London	–9.74	–9.74
13	South Coast	–3.44	–3.44
14	Wessex	–5.57	–5.57
15	Peninsula	–9.86	–9.86

Note: Loss payment figures could not be shown in this table for purposes of comparison because they vary according to GSP Group rather than generation tariff zone.
Source: NGC.

A recent study considered the level of tariffs that might result if ICRP were applied across Great Britain.[32] The results showed a greater spread of charges than currently applies in England and Wales, ranging from £20.45/kW to –£12.21/kW.

The size of regional TNUoS differences would suggest that the effect of the transmission charging methodology on locational decisions is likely to be much greater than the impact of the transmission loss-charging regime and fuel transportation costs. These economic signals imply that the cost of transmitting electricity after generation is significantly greater than the cost of transporting fuel before generation.

4.1.4 Comparison of factors

Table 4.4 shows how TNUoS charges, NTS exit charges and AZTL payments might vary for three hypothetical baseload CCGT generators located in different areas of the country. A full ranking of generation costs by GSP Group was not possible, given that the TNUoS charges are set according to generation tariff zone rather than GSP Group. The table also

[32] ILEX (2003), 'Assessing the Introduction of Zonal Charging for Transmission Losses in Great Britain', March.

excludes other generation costs, such as land rents, which might show significant variations on a regional basis.

Table 4.4: Cost elements that vary on regional basis (£m)

Hypothetical CCGT plant	GSP Group	Generation tariff zone	Assumed NTS exit charge	TNUoS charge[1]	Regional comparison (before AZTL)	AZTL payments[2]	Regional comparison (after AZTL)
Scotland	14	n/a	0.02	20.45	**20.47**	4.36	**24.83**
Northern	1	1	0.02	8.31	**8.33**	2.30	**10.63**
Mid-England	5	7	0.35	0.34	**0.69**	1.25	**1.93**
Southern	11	13	2.04	–4.76	**–2.72**	–0.30	**–3.02**
Spread	–	–	2.02	25.21	**23.19**	4.66	**27.85**

Note: [1] These figures are taken from the study, discussed in section 4.13, which estimated TNUoS charges if ICRP were to be applied across Great Britain, and hence do not match the numbers in Table 4.3. [2] These figures are the total loss payment under AZTL, rather than the change in loss payments compared with those under a uniform loss charging regime.
Source: OXERA.

Overall, the analysis suggests that it is regional variations in TNUoS that are the major cost difference between plant in different regions. **To the extent that AZTL reinforces these signals, there may be some impact on long-run decisions by generators, but the size of this effect is uncertain**. **Non-cost factors, such as planning permission, are also likely to be critical in decisions about the location of new plant, and their impact has not been quantified**.

4.2 Longer-term impact of AZTL

4.2.1 Closure and mothballing

Wholesale electricity prices have fallen by 40% over the last four years, reflecting factors such as deconcentration of the generation sector, the introduction of NETA and the surplus of generation capacity. **Where power stations are failing to recover operating costs, there is an economic incentive for the plant to be closed or mothballed**. This incentive may be increased for portfolio generators if the withdrawal of capacity increases market prices and consequently the revenue obtained by other plant in their portfolio.

In the October 2002 issue of *The Utilities Journal*, **OXERA suggested that up to 6 GW of capacity in England and Wales might need to be removed from the system for prices to rise to new-entrant levels**.[33] The market has already been seen to respond to the current price signals. In October 2002, Powergen announced the mothballing of 1,800 MW of plant, comprising two oil-fired units at its Grain power station and a CCGT

[33] OXERA (2002), 'Something has to Give', October, 22–23.

module at Killingholme. In January 2003, Powergen announced the further closure of two coal-fired power stations, High Marnham and Drakelow C. These plant were acquired by Powergen at the time of its purchase of TXU's retail business, and had available capacity of around 1.4 GW.

If AZTL influences the market's decisions about which plant are closed or mothballed, there may be loss-reduction benefits additional to those arising from potential changes in despatch (see section 3.4). However, in this regard the current study focuses on the application of AZTL across Great Britain under BETTA, which does not go live until October 2004. Given that the market has already responded to low prices by withdrawing plant, it is not necessarily the case that the current capacity situation will still apply by this time.[34]

In the base scenario, OXERA assumed the closure of around 1 GW of coal capacity in GSP Group 7 in March 2005. As discussed in section 3.8, the sensitivity of the modelling results to this assumption was tested by re-running the load-flow model for 2005/06 with an alternative assumption of 1 GW of closure in GSP Group 1. **Although the potential margin of error is high, the closure of a northern plant rather than a power station further south was found to make an estimated difference of 158 GWh to the annual level of transmission losses, which might imply an annual benefit of around £3.2m**.[35]

4.2.2 Return of mothballed plant to market

If prices rise in the future, some of the plant mothballed may be recommissioned. The requirement for capacity to return over time might arise from load growth, the closure of nuclear power stations and environmental constraints on the operation of coal-fired plant (ie, the LCPD and the EU Emissions Trading Scheme). The electricity price at which mothballed plant will be returned is likely to be lower than the price required for new entry, since the capital costs of building the plant have already been sunk. In October 2002 Ofgem quoted a figure of 6% of total generation capacity as the amount of capacity that has been mothballed.[36] **AZTL could create long-run loss-reduction benefits if it leads more efficient decisions on the return of capacity from mothball**.

In carrying out the modelling, OXERA chose to model new capacity requirements as CCGT entry rather than the return of existing mothballed plant (see next section), for the following reasons:

[34] The introduction of AZTL in England and Wales prior to BETTA could lead to benefits through its impact on closure decisions, but this issue is outside the scope of the current study.
[35] This is the time-weighted difference in losses for the closure sensitivity in Table 3.17 multiplied by the number of hours in a year. The estimate is indicative only, as it is derived from modelling results for three snapshot periods only. The reduction in losses has been valued using an electricity price of £20/MWh, which is consistent with the average baseload price that emerged from the base scenario.
[36] Ofgem (2002), 'Electricity Wholesale Market', factsheet, October. The figure quoted may not take into account subsequent announcements by Powergen regarding mothballing.

- the scope for returning coal-fired plant may be restricted by environmental constraints;
- the return of CCGT plant is likely to have a similar effect on the market as the building on new CCGT power stations.[37]

4.2.3 New entry

The potential impact of AZTL on renewables penetration is discussed in section 5. This section looks at the potential for new entry by gas-fired plant, as this is the type of conventional generation considered most likely to be built.

Current levels of capacity in the generation market, alongside the significant volumes of mothballed capacity, might suggest that new build of gas-fired plant may be limited in the near future. The recent Energy White Paper supported this view:

> given current levels of capacity, including mothballed plant, and our expectations of growing renewables generation and energy efficiency improvements over the coming years, we are unlikely to need significant new investment in non-renewable power stations over the next five years or possibly longer.[38]

Nevertheless, new CCGT entry might be required in the longer term (perhaps post-2010), as the scheduled closure of Great Britain's nuclear generation plant continues.

As explained in the previous section, the study modelled new capacity requirements as CCGT entry rather than the return of mothballed capacity. The high load growth assumed in the base scenario, along with the closure of some nuclear generation capacity, created a requirement for significant new CCGT entry over the period to 2009/10. OXERA's assumptions regarding the size and timing of this new build are detailed in Table 4.5. The choice of location for new build was informed by the details of current consented projects in order to ensure a realistic assumption regarding the node where new generation might connect to the transmission network for the load-flow modelling. The choice of location may have affected the total level of transmission losses in the load-flow modelling, but not the assessment of loss reductions from redespatch, since the high assumed efficiency (58%) of the new plant meant that they operated as baseload.

[37] Note, however, that new CCGT plant may have a higher thermal efficiency.
[38] DTI (2003), 'Energy White Paper: Our Energy Future—Creating a Low Carbon Economy', p. 86.

Table 4.5: New-entry assumptions for base scenario

Date of commissioning	Size (MW)
April 2006	500
April 2007	750
April 2008	1,000
April 2009	1,000
April 2010	1,000

Source: OXERA.

AZTL could be one of the factors affecting the location of new plant build. The potential long-run benefits of AZTL through its impact on the location of generation are explored in the following section.

4.3 Scenarios of longer-term benefits

4.3.1 Loss-saving benefits

This part of the report presents scenarios for the potential longer-term benefits of AZTL. As discussed in section 4.1, the marginal impact of AZTL on the long-run location of generation is subject to a large degree of uncertainty. Consequently, **these scenarios are speculative and are only intended to provide rough indications of the potential size of any long-run benefit under specific assumptions**.

As discussed in section 4.2.3, the base scenario resulted in new CCGT entry of 4,250 MW before 2010, due to the high load-growth assumption. Previous modelling work by OXERA with lower load-growth assumptions has suggested new entry (or, alternatively, the return of mothballed plant) in the range 2,250–2,750 MW over the same period. Given these figures for the volume of new capacity that might be commissioned (or returned from mothball) in the years to 2010, OXERA has constructed scenarios based on AZTL influencing the location of 1 GW, 2 GW, 3 GW and 4 GW respectively of generation capacity.

The scenarios assume that it is the location of *baseload* capacity that is altered over time. This might reflect a situation where AZTL changes decisions about the siting of new CCGT build (which is likely to have a high efficiency and might be expected to operate as baseload). If AZTL primarily affects decisions on closure and the return of mothballed capacity rather than new entry, it might be more appropriate to consider scenarios where the location of mid-merit or peaking plant (ie, plant with a lower load factor) is affected.

Table 4.6 shows the geographical distribution by GSP Group of major CCGT plant. Currently, the GSP Groups with the most CCGT plant are 7, 3 and 5, which are all located on the east of the country. Zones 11 and 4 also contain more than two such plant. There is only one CCGT power station in Scotland, located in Scottish & Southern Energy's region.

Table 4.6: Location of CCGT plant

GSP Group		Number of CCGT plants
13	Southern Scotland	1
1	Northern	1
2	North West	2
3	Yorkshire	6
4	North Wales and Mersey	3
5	East Midlands	5
7	Eastern	8
8	South Wales	2
9	South East	2
11	Southern	3
12	South Western	2

Source: OXERA.

The choice of scenarios was informed by these historical siting decisions of CCGT entrants. The scenarios consider the potential value of loss savings if AZTL shifts the location of plant southwards from:

- zone 7 to zone 11;
- zone 3 to zone 11;
- zone 13 to zone 11 (for the 1 GW case only).

The last case was included to show the potential effect of relocating baseload plant from Scotland to southern England. However, OXERA is not aware of any planned new CCGT build in Scotland, and only the relocation of 1 GW was considered.

Rough approximations for loss reductions from these changes in location were calculated by multiplying the annual output of the relocated plant (calculated using an assumed load factor of 85%) by the difference between the annual zonal TLFs[39] for the original and new zone. As discussed in section 3.4, the use of TLFs in this way may not provide accurate estimates, as TLFs vary significantly according to network loading conditions. The change in losses was converted into an annual monetary benefit using an assumed electricity price of £20/MWh.

The final scenarios are shown in Table 4.7. OXERA has not attached probabilities to these scenarios, but notes that some of them might be considered more unrealistic than others. For example, the last scenario could be regarded as implausible, as it suggests that, in the absence of AZTL, 4 GW of new plant would be built in northern zone 3, and that,

[39] With reference to Figure 1.1, the number used was the annual zonal TLF prior to division by two to obtain ATLFs, as the calculation concerns the physical change in losses for a change in generation in a zone, whereas the division by two is an adjustment used to derive loss charges.

following the application of AZTL throughout Great Britain, all four new-build projects are relocated to southern zone 11.

Table 4.7: Scenarios of annual longer-term benefits

GW relocated	GSP Groups		Estimated loss reduction (GWh)	Estimated annual benefit (£m)
	Original	New		
1	7	11	100	2.0
1	3	11	273	5.5
1	13	11	355	7.1
2	7	11	199	4.0
2	3	11	546	10.9
3	7	11	299	6.0
3	3	11	819	16.4
4	7	11	399	8.0
4	3	11	1,092	21.8

Source: OXERA.

The figures show a wide range for the potential long-run benefits of AZTL, from £2m per annum from the relocation of 1 GW of baseload generation from zone 7 to zone 11, to a figure of £21.8m obtained from the relocation of 4 GW from zone 3 to zone 11. While this is reflective of the uncertainty over the size of these benefits, the results do appear to suggest that annual benefits from long-run effects could be larger than the short-run benefits from generation redespatch identified in section 3.4. Furthermore, the benefits are likely to be greatest the longer the timeframe under consideration, as more plant entry and exit decisions will have been made.

OXERA considers that it would be prudent to take the lower end of the range for estimated benefits as being more realistic, for the following reasons.

- The discussion in section 4.1 highlighted the fact that **AZTL is only one of the factors that might affect the location of generation plant**, and that other factors, such as TNUoS charging (and planning permission in the case of new build), may exert a greater influence.
- The scenarios are based on the relocation of baseload plant, which would change flow patterns with potential beneficial effects on losses during all time periods. However, **if AZTL changes the location of mid-merit or peaking plant, loss reductions would only occur during periods of higher demand**.
- The methodology of **using estimated zonal TLFs to calculate potential loss reductions will systematically tend to overestimate the effect on losses**. This is because as generation is switched between zones, the marginal loss benefit of switching further generation will tend to fall. Hence, multiplying by TLFs calculated using the initial pattern of generation will overstate the final impact.

For these reasons, **OXERA used a range of £1m–£10m per annum for the level of longer-term benefits in constructing the scenarios of national resource benefits presented in section 9.2.2**.

As discussed in section 1.3.1, **where generation does relocate as a result of AZTL, the loss-reduction benefits will be partly offset by increases in other project costs**. The precise size of these offsetting cost increases is not known, but, as explained in section 1.3.1, would be expected to lie in the range 0–50% of the loss-reduction benefit.

4.3.2 Carbon-saving benefits

Table 4.8 shows indicative calculations for the potential reduction in carbon emissions for each of the scenarios shown in Table 4.7. The potential monetary value of these carbon savings is also given, using the four carbon price figures used to value changes in emissions in Table 3.16.

Table 4.8: Scenarios of long-term carbon-saving benefits

			Estimated emissions reduction per annum (kt)		Annual value (£m) at carbon price of			
GW relocated	Original zone	New zone	CO_2[1]	Carbon[2]	£70/t	£20/t	£10/t	£5/t
1	7	11	44	12	0.8	0.2	0.1	0.1
1	3	11	121	33	2.3	0.7	0.3	0.2
1	13	11	158	43	3.0	0.9	0.4	0.2
2	7	11	89	24	1.7	0.5	0.2	0.1
2	3	11	243	66	4.6	1.3	0.7	0.3
3	7	11	133	36	2.5	0.7	0.4	0.2
3	3	11	364	99	7.0	2.0	1.0	0.5
4	7	11	178	48	3.4	1.0	0.5	0.2
4	3	11	486	133	9.3	2.7	1.3	0.7

Notes: [1] Calculated using an average of the figures for average unit emissions in kt/GWh shown in Table 3.15. [2] Converted from CO_2 to carbon by multiplying by 12/44.
Source: OXERA.

The size of the long-run carbon-savings benefit is crucially dependent on the value placed on carbon. In conjunction with Table 4.7, the figures suggest that **for each £1m of loss-reduction benefit, the estimated carbon savings could be valued in the range £0.03m per annum (using a carbon price of £5/tonne) to £0.42m per annum (using a carbon price of £70/tonne)**.

Potentially, AZTL could have a long-run effect on the fuel mix if it affects the type of power station closed, mothballed or returned from mothball. It seems less likely that there would be an impact on the fuel type for new plant build, which in a market environment is most likely to be gas-fired.

5. Renewables Penetration

A significant proportion of the UK's onshore renewables resource is in Scotland and the North of England, which are the regions where generators are expected to be adversely affected by the introduction of AZTL. **Following the introduction of AZTL in England and Wales, it has been argued that applying this methodology across Great Britain might reduce the growth of renewables generation and hinder achievement of the government's target of achieving a 10% share of renewables by 2010**. To address this issue, OXERA has developed a simple model to assess how AZTL might affect investment decisions in renewable technologies such as offshore and onshore wind. Drawing on this analysis, the impact of AZTL on the likely scale and location of new renewables plant connected to the transmission and distribution networks is assessed. This analysis is preceded by a review of regional renewable resources, which seeks to identify regions that are of relevance to the assessment.

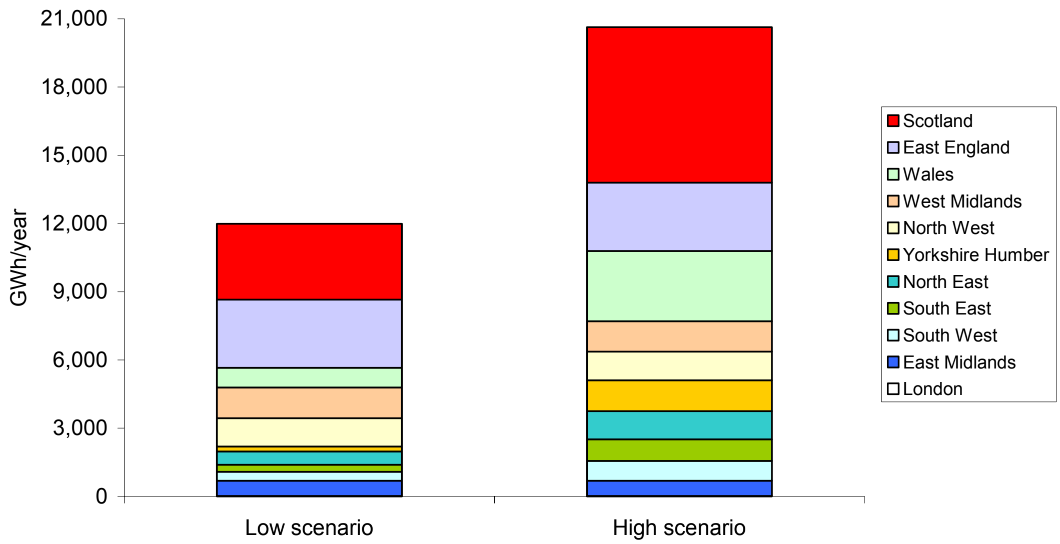
5.1 Regional renewable resources

Onshore and offshore wind generation are likely to be the largest contributors to the renewables generation mix in the future. OXERA modelling suggests that the installed capacity of onshore wind in the UK could rise to at least 4.3 GW in 2010, and possibly 7.5 GW in 2020 if 20% of electricity supply from renewable sources is achieved. Although only 4 MW has been installed so far, offshore wind capacity is also expected to increase in light of the government's strategy, and consent has been given for wind farms around the UK coast with a total capacity of at least 1.4 GW. The offshore wind industry considers that a further 3–4 GW could be built by 2010.[40]

Figure 5.1 shows forecasts for the location of wind generation in the UK regional renewable energy assessments, which were undertaken mostly during 2001 by the planning community.[41] The relative importance of regions within Great Britain for wind generation development is shown in the figure, which also **identifies Scotland, the East and North West of England, and the West Midlands as significant contributors**.

[40] See DTI (2003), 'Energy White Paper; Our Energy Future—Creating a Low Carbon Economy', February, paragraph 4.45; and DTI (2002), 'Future Offshore', November, section 1.1.
[41] See OXERA and Arup Economics & Planning (2002), 'A Report to the DTI and the DTLR: Regional Renewable Energy Assessments', February.

Figure 5.1: Contribution of regions to wind generation in 2010



Note: An adjustment was made for Scotland, where the renewable assessment did not take into account offshore wind; under the high scenario, 3.5 TWh of offshore wind electricity have been added.
Source: Regional renewable energy assessments; Scottish Executive, Garrad Hassan & Partners (2001), 'Renewable Energy Study—Volume I: The Analysis, and Volume 2: The Context', November.

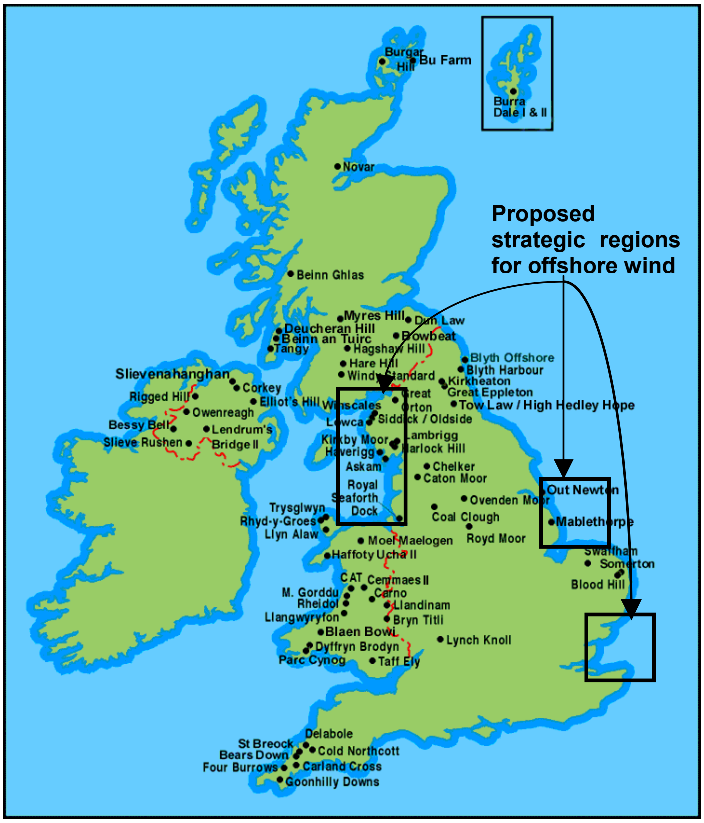
About 1.4 GW of wind generation capacity has been installed in Great Britain to date. As illustrated in Figure 5.2, wind farms have been developed in Scotland and along the Scottish coast, the North West, Wales, and on the east coast of England (ie, East Midlands, Eastern England, and the South East). Offshore wind farms are expected to connect mainly to the national grid, while onshore wind farms can connect to either the transmission or the distribution networks, depending on their scale. As other renewables technologies—which will also contribute to meeting the government's target—are likely to be developed as small-scale plant connected to distribution networks, the focus in this assessment is on wind farms.[42]

Since the regional renewable energy assessments were completed, **the government has proposed a strategic planning framework aimed at facilitating offshore wind development**. Following the Crown Estate invitation in 2000 to developers to apply for site leases for the development of offshore wind farms within territorial waters, there are now 18 offshore wind farms planned for commissioning across Great Britain by around summer 2005, with capacity of 1.2 GWh. The government is now developing a framework to enable more ambitious plant build in the future, both within and beyond territorial waters. The government's 'Future Offshore' consultation proposes a strategic planning framework as a basis for expanding the offshore wind industry.[43] **Analysis of**

[42] The potential impact of AZTL on distributed generation is discussed in section 5.3.2.
[43] DTI (2002), 'Future Offshore', November.

the regional distribution of potentially suitable sites and provisional indications of interest from the industry suggest that development interest is likely to be clustered in three general regions: the Thames Estuary, the Greater Wash (with substantial grid capacity available in both regions), and the North West. The proposed strategic regions for offshore wind are identified in Figure 5.2, together with actual wind generation sites.

Figure 5.2: Actual wind-farm development and potential for offshore wind in the UK



Source: British Wind Energy Association website, and DTI (2002), 'Future Offshore', November.

5.2 Impact of AZTL on the profitability of renewables generation projects

OXERA has developed a financial model to assess how the additional cost or benefit arising from AZTL might affect the economics of a typical new-build project. The remainder of this section provides an overview of the modelling methodology and of the costs and funding assumptions. It also discusses the results of the model.

5.2.1 Modelling methodology

Figure 5.3 illustrates the methodology adopted for the modelling. The OXERA model considers how AZTL might affect the IRR of typical renewables projects connected to the high-voltage transmission network. **The profitability of projects is calculated over a lifetime of 15 years from 2005/06, based on the following inputs:**

- **the estimates of TLMs obtained in the main modelling exercise;**
- **assumed capital and operational costs of renewables projects;**

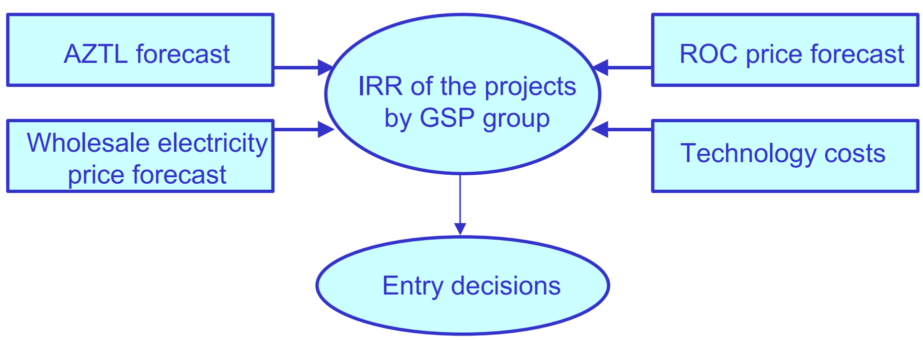
- **assumed revenue from electricity sales;**
- **scenarios of future ROC prices**.

It is assumed that capital costs are incurred in full in the first year of the investment appraisal period, while operational and maintenance (O&M) costs are proportional to generation. All monetary values in the model are in 2005/06 prices, assuming an inflation rate of 2% per annum.

The model considers offshore and large-scale onshore wind farms, as these technologies are expected to connect at the transmission level. It provides the IRR of typical projects in different demand zones, in order to assess both whether AZTL may deter entry of the technologies in question, and whether there may be an impact on the location of new plants. OXERA's analysis focuses on GSP Groups that are most relevant to wind generation development—ie, GSP Groups 2 (North West), 1 (Northern), 3 (Yorkshire), 5 (East Midlands), 7 (Eastern), 9 (South East), 4 (North Wales and Mersey), 8 (South Wales), 12 (South Western), as well as Scotland.

Technologies, such as smaller-scale onshore wind, biomass, energy from biodegradable waste, landfill gas, waste and tidal, and photovoltaics, are likely to connect to distribution networks rather than to the national grid. The impact of AZTL on distributed generation is discussed in section 5.3.2, with reference to the modelling results.

Figure 5.3: Modelling methodology



Low- and high-technology-cost scenarios have been provided for offshore and onshore wind farms. In addition, several scenarios of future ROC prices have been considered in the modelling so as to assess the significance of the loss-charging impact compared with other elements of investment decisions. The range of cost assumptions used in the model is presented in Appendix 4, together with assumptions on wholesale electricity prices and ROC scenarios.

As the model seeks to assess the *marginal* impact of AZTL on renewable projects—ie, by how much it affects the rate of return earned by investors and hence whether it is likely to affect investment decisions—charges for connection, network use of system, and market balancing have not been included in the model. Introducing these charges—for which future values are difficult to forecast due to the uncertainty surrounding investment plans and the operation of the GB-wide electricity market—is likely to have only a small effect on the marginal impact of AZTL.

5.2.2 Results of the model

The impact of AZTL on renewable projects is measured by the percentage change between the IRR under zonal loss charging and that under uniform loss charging. The IRR change calculation can be formally written as:

$$(IRR_{\text{zonal loss charging}} - IRR_{\text{uniform loss charging}}) / IRR_{\text{uniform loss charging}}$$

For example, if the IRR of a renewables project was 10% under uniform loss charging, but only 9% under zonal loss charging, the change in IRR would be –10%.

Tables 5.1 and 5.2 summarise the change in the IRR of offshore and onshore wind farms by GSP Group between uniform and zonal loss charging. The results are only reported for areas with significant potential for wind generation.

Table 5.1: Marginal change (%) in the IRR of offshore wind projects

ROC scenario		Low build rate		Medium built rate		High build rate	
Technology costs		Low	High	Low	High	Low	High
Demand zone (GSP Group)	Northern Scotland	–0.9	–0.9	–1.0	–1.2	–1.1	–1.6
	Southern Scotland	–0.7	–0.6	–0.7	–0.8	–0.8	–1.0
	Northern (1)	–0.2	–0.3	–0.3	–0.4	–0.3	–0.6
	North West (2)	0.0	–0.1	–0.1	–0.1	–0.1	–0.2
	North Wales and Mersey (4)	0.3	0.3	0.3	0.4	0.3	0.5
	East Midlands (5)	0.1	0.0	0.1	0.0	0.1	–0.1
	Eastern (7)	0.2	0.2	0.2	0.3	0.2	0.4
	South Wales (8)	0.4	0.4	0.4	0.5	0.4	0.7
	South East (9)	0.2	0.2	0.2	0.3	0.2	0.5

Source: OXERA.

Table 5.2: Marginal change (%) in the IRR of onshore wind projects

ROC scenario		Low build rate		Medium built rate		High build rate	
Technology costs		Low	High	Low	High	Low	High
Demand zone (GSP Group)	Northern Scotland	–0.9	–0.9	–1.0	–1.1	–1.1	–1.5
	Southern Scotland	–0.7	–0.6	–0.7	–0.8	–0.8	–1.0
	Northern (1)	–0.2	–0.3	–0.3	–0.4	–0.3	–0.5
	North West (2)	0.0	–0.1	–0.1	–0.1	–0.1	–0.1
	Yorkshire (3)	–0.2	–0.3	–0.3	–0.4	–0.3	–0.6
	North Wales and Mersey (4)	0.3	0.3	0.3	0.3	0.3	0.4
	East Midlands (5)	0.1	0.0	0.1	0.0	0.1	–0.1
	Eastern (7)	0.2	0.2	0.2	0.2	0.2	0.3
	South Wales (8)	0.4	0.4	0.4	0.5	0.4	0.6
	South Western (12)	0.5	0.5	0.5	0.6	0.6	0.8

Source: OXERA.

These results from the financial modelling suggest that zonal loss charging would have a marginal impact on the profitability of wind generation projects connecting to the transmission grid, and hence is unlikely to prevent generation entry. The limited impact of AZTL on the profitability of the projects reflects the relatively narrow spread in TLMs expected from 2005/06 to 2009/10, and the fact that the ROC revenue received by renewables is unaffected (see Appendix 4). Key features of the results are outlined below.

- **AZTL would have a minor impact on the profitability of renewables projects**. The financial model suggests that the impact on project's IRR will be in the range of about −1.6% to about 0.8%—ie, assuming that the IRR under uniform loss charging were 10%, the IRR of a wind generation project would be between 9.84% and 10.12% under AZTL.

  The assessment of the direct financial impact of AZTL can also focus on generators' gross revenue—ie, the sum of their revenue from electricity sales, appropriately scaled for losses, and support from ROCs.[44] Based on the assumptions presented in Appendix 4, **zonal loss charging would impose a reduction in gross revenue of at most 0.6%, or increase gross revenue by up to 0.3%, depending on the generator's location and the ROC scenario chosen**. **The financial impact of AZTL would be in the range of about –£7.4k to £4.2k on the net present value of the generator's expected revenue over 15 years, for a project with gross revenue of about £1.22m**.

- In the worst-case scenario, the IRR of an offshore wind generation project is reduced by 1.6%. **Projects located in Northern Scotland are most adversely affected, followed by those in Southern Scotland** (reduction in the project's IRR of up to 1%) **and the North of England, in particular the Northern region** (where the project's IRR is reduced by up to 0.6%).

  The effect is similar with respect to onshore wind. In the worst-case scenario, the IRR of a project is reduced by 1.5%. Projects located in Northern Scotland are most adversely affected, followed by those in Southern Scotland (reduction of the project's IRR of up to 1%) and the North of England, in particular Yorkshire and Northern (reduction of the project's IRR of up to 0.6% and 0.5%, respectively).

- In contrast, **zonal loss charging would provide financial benefits to projects located in South Wales**, and to a lesser extent to those in North Wales and Mersey, South East, South Western, and Eastern. Offshore projects located in South Wales would be most affected, where the project's IRR would be uplifted by up to 0.7%, followed by those in the South East, North Wales and Eastern (increase in the project's IRR of up to 0.4–0.5%).

  With respect to **onshore, wind generation projects located in South Western will be most advantaged by AZTL**, their IRR being increased by 0.8% by zonal

[44] As all costs borne by generators are not taken into account, assessing the impact of AZTL on gross profits would not be relevant.

loss charging. Projects located in South Wales, North Wales, and Eastern will also benefit from AZTL, with uplift of the IRR of wind generation projects of up to 0.6%, 0.4% and 0.3%, respectively.

The modelling results are discussed further in section 5.3, together with their implications for other renewables investment projects connecting to distribution networks.

5.3 Impact of AZTL on renewable penetration

5.3.1 Generation connecting to the transmission network

The results of the financial model suggest that AZTL would reduce the IRR of renewables projects in regions most adversely affected by zonal loss charging, such as Scotland and the North of England, by no more than 1–2%. Projects located in Northern Scotland would be most affected, followed by those in Southern Scotland; however, financial penalties would only be a reduction in the project's rate of return of up to 1.6% and 1%, respectively. Any adverse impact on the gross revenue of a renewables generator would be limited to 0.6% in the worst-case scenario. Such an impact appears **unlikely to have any significant effect on investment in new wind generating capacity**.

Although AZTL would be unlikely to deter renewables entry, **it may provide locational signals to renewables developers, reinforcing the signals currently provided by generation transportation charges**. Zonal loss charging would:

- have an adverse financial impact on wind generation projects located in the Scotland, the North East of England and Yorkshire and, to a lesser extent, those located in the North West of England and East Midlands;
- provide benefits to projects located in South Wales, and to a lesser extent to those in North Wales and Mersey, South East, South Western, and Eastern.

Renewables developers would be expected to locate their generation units so as to maximise their profits. The impact of AZTL on a generator's gross revenue, based on the methodology presented above and the assumptions set in Appendix 4, range from –0.6% to 0.3% for both offshore and onshore wind. For instance, an offshore wind developer deciding where to locate new investment, within geographical constraints, would expect AZTL to have the following impact on the revenue generated by the plant:

- an uplift of 0.2–0.3% in South Wales, 0.2% in South East, 0.1–0.2% in North Wales, and 0.1% in Eastern;
- a reduction of 0.5–0.6% in Northern Scotland, 0.3–0.4% in Southern Scotland, and 0.2% in Northern;
- under the high-build ROC scenario (ie, low ROC prices), a reduction 0.1% in the North West and East Midlands; otherwise no impact.

All other things being held constant, **AZTL would provide signals encouraging the development of offshore wind farms in Wales, as well as in two of the proposed strategic regions identified by the DTI in its 'Future Offshore' consultation: Thames Estuary and the Greater Wash**. In the latter, however, the projects connected to the transmission network in East Midlands would be adversely affected, although by only –0.1% of the generator's gross revenue. **Development in the third proposed strategic region, North West England, may be subject to the same marginal adverse impact under zonal loss charging**.

With respect to onshore wind generation, a developer deciding where to locate new investment, within geographical constraints, would expect AZTL to have the following impact on the revenue generated by the plant:

- an uplift of 0.3% in South Western, 0.2–0.3% in South Wales, 0.1–0.2% in North Wales, and 0.1% in Eastern;
- a reduction of 0.5–0.6% in Northern Scotland, 0.3–0.4% in Southern Scotland, 0.2–0.3% in Yorkshire, and 0.2% in Northern;
- under the high-build ROC scenario, a reduction of 0.1% in the North West and East Midlands; otherwise no impact.

As a result, **zonal loss charging would encourage development of new plant in South Western and Wales, and where abundant resources are available**. **However, all other costs being deemed constant, it would render investment in Scotland and the North of England less attractive**.

However, **the extent to which the locational decisions of new generation might be influenced by AZTL will depend on how significant the loss-charging impact is likely to be compared with other elements of the cost of a new power plant, which might also vary on a regional basis** (eg, land costs, difficulty in obtaining planning permission, environmental concerns, and transmission charges).

The analysis in this report focuses on transmission network charges, as these are readily quantifiable. As discussed in section 4.1.3, under the current transmission charging regime, there are differentials in the level of tariffs across England and Wales of much higher magnitude than the differential expected in loss charges across Great Britain. While in England and Wales the impact of 2003/04 TNUoS charges on generators' revenue ranges from –16.8% in generation zone 1 to 19.5% in generation zone 12, the impact of GB-wide zonal loss-charging on generators' gross revenue would be expected to be limited to –0.6% to 0.3%.

A recent study considering the application of this methodology across Great Britain suggests that the spread of charges could be greater under BETTA. This would suggest that **the effect of the transmission charging methodology on renewables projects' profitability is likely to be of greater magnitude than the impact of the transmission loss-charging regime**. However, should the geographical pattern of TNUoS charges continue broadly to mirror that of zonal loss charges, with southerly zones benefiting relative to northern zones, AZTL would reinforce the signals provided by transmission charges.

5.3.2 Distributed generation

Most renewable power plant are small in comparison with conventional plant and are therefore connected to the lower-voltage distribution networks rather than the high-voltage transmission grid. This section discusses whether AZTL could have an impact on distributed generation, notably on entry decision and location of plant.

Impact of AZTL on embedded benefits

Unlike generators connected to the national grid, **distributed plant do not generally see their output scaled to account for transmission losses**. Entry costs are similar to those of generators connecting to the high-voltage transmission network, except that distributed generators pay 'deep' connection charges (ie, the full cost of connection to the system), which includes the cost of any network reinforcement, and, potentially, any marginal change in maintenance cost; however, they do not pay use-of-system charges. A review of the structure of electricity distribution charges is under way, which is considering whether to move towards a shallower-connection charging regime supplemented by a transportation charge.[45]

Avoiding losses is only one of the 'embedded benefits' which enhance the revenue of distributed generators. Distributed plant can also benefit from not being subject to TNUoS and balancing services use-of-system charges (BSUoS), and, if they are not directly trading in the wholesale electricity market, trading and BSC membership charges. **A second aspect of embedded benefits relates to benefits enjoyed by electricity suppliers contracting with distributed generators**. **Suppliers see the output of these plant netted off against their demand within the same GSP Group**. **As a result, they avoid TNUoS charges and transmission losses on the netted-off demand**.

At present, this benefit is shared between the supplier and the distributed generator, the latter's proportion of this value being typically in the range 50–90% of the total.[46] Recent changes have been introduced in order to increase competition in the embedded benefit market and thereby maximise the share of benefits captured by generators.[47] However, this change will mainly affect large distributed plant, as the possibility for a generator directly to receive demand TNUoS charges is subject to being registered with the Central Meter Registration Service, which requires a Central Volume Allocation to meter imports/exports on a half-hourly basis. As a result, smaller generators are likely to have to negotiate with a supplier their share of the benefits arising from avoiding demand charges, and may not capture full embedded benefits.

Embedded benefits occur as a result of the BSC rules and the transmission charging rules in England and Wales. The analysis in this report assumes that, with the introduction of BETTA, distributed generators in England and Wales and Scotland should become eligible for such benefits under similar terms.

Introducing zonal loss charging would have an impact on the level of embedded benefits which distributed generators (and suppliers contracting with them) will receive. Compared with uniform loss charging, the expected impact of AZTL on distributed generation would be twofold.

[45] See Ofgem (2002), 'The Structure of Electricity Distribution Charges: Update Document', October.
[46] Larger embedded generators could expect to receive the higher end of this range. See DTI (2001), 'The Consolidation of Small Generators under NETA: A Scoping Study', ETSU K/EL/00243/REP, DTI/Pub URN 01/685.

[47] From April 2003, distributed generators will have the opportunity to be paid directly by the national grid operator for the benefit of reducing demand on the transmission system, rather than these benefits going to suppliers. In addition, from November 2003, they will have the opportunity to receive directly from NGC the benefit of reducing the costs of energy balancing services. This results from modifications to the BSC (Modification Proposal P100), and of NGC's use-of-system charging methodology (UoSCM-M-07) announced by Ofgem on March 28th 2003.

- **AZTL would increase the financial benefits received by distributed generation located in demand zones where demand TLMs are above their level under uniform loss charging**. OXERA's estimates of TLMs suggest that this would be the case in South Western, South and North Wales, and South East. This additional benefit will originate from the increased financial impact of avoiding the requirement to scale up netted-off demand by TLMs, compared with that under uniform demand loss charges.

- **In contrast, AZTL would be expected to reduce the financial benefits received by distributed generation located in demand zones that are below their level under uniform loss charging**. OXERA's estimates of TLMs suggest that this would include Scotland, the North of England and East Midlands. In these regions, netting off demand would create fewer benefits for transmission losses than under uniform loss charging.

As a result, AZTL would make contracting with distributed generation more attractive in regions such as Wales, South Western and the South East coast of England, where zonal demand TLMs are above their level under uniform loss charging. On the other hand, it would make it less attractive to contract with distributed generators in regions where demand TLMs are above their level under uniform loss charging, such as the North of England.

OXERA's modelling suggests that, under AZTL, Scotland would have demand TLMs of less than 1, so that the suppliers' demand in the region would be scaled down (whereas demand would be scaled up in England and Wales). As a result, **AZTL may make it less attractive for suppliers to contract with distributed generators located in Scotland, as this would prevent the capture of benefits through demand scaling down**, and would therefore affect the revenue of these generators.

The financial impact of AZTL on embedded benefits is difficult to assess, as these benefits will vary according to the size and activity of the generator (including its intermittency, and the time at which it generates), the generation and demand charges in the GSP Group in which the generator is located, and the TLMs. To inform the analysis, the financial model was used to assess the magnitude of the impact of demand TLMs on generation projects connected at the distribution level.

Including the embedded benefit gained from the avoidance of supplier transmission losses in the rate-of-return calculation suggests that **the marginal impact of AZTL on the IRR of a distributed generation project would range between –1.7% and 0.6% for onshore wind projects** (assuming that the distributed generator obtains 100% of the supplier's embedded benefits, and that the costs are similar to those incurred for larger-scale plant connecting to the high-voltage grid). As for transmission-connected generation, the impact of AZTL would be twofold.

- **Distributed generation located in Northern Scotland is at the lower end of this range, followed by that located in Southern Scotland**. A project's IRR would be reduced by 1–1.7% in the former, and 0.7–1.2% in the latter. **Distributed plant located in Yorkshire, Northern, and the North West of England would also be adversely affected by AZTL**, which would reduce their IRR by 0.3–0.8%, 0.4–0.7%, and 0.2–0.3%, respectively. In some cases, projects located in East Midlands would be adversely affected, albeit in the range of –0.1% to –0.3% of their IRR.

- In contrast, **distributed plant located in South Western would receive the highest benefits**, raising projects' IRR by between 0.4% to 0.6%, **together with those in Wales**, for which embedded benefits increase their IRR by 0.2– 0.4%. Distributed generation located in Eastern would also receive benefits, although the uplift on projects' rate of return would only be 0.1%.

Zonal loss charging would therefore provide price signals encouraging development of distributed generation in southerly zones relative to zones in the North. However, as for transmission, these price signals would be of lower magnitude than other locational signals, such as embedded benefits from avoided TNUoS or connection charges.

Distributed plant subject to transmission losses

Distributed plant that are capable of exporting 100 MW or more to the transmission system, as agreed with the high-voltage grid transmission operator, are liable to pay TNUoS, and, being registered as a Balancing Mechanism Unit, see their output scaled to reflect transmission losses. Distributed generators that participate in the Balancing Mechanism also pay BSUoS charges, and other relevant membership charges. AZTL would be expected to have an impact on such generators—ie, large-scale distributed generation designed to export output—which may represent a significant share of onshore wind new build.

Where distributed generators pay for losses, the effect of zonal loss-charging arrangements on generators in different regions is likely to follow the same patterns as for generation connected to the high-voltage grid. However, the relative impact is likely to be smaller if the cost base of the generator is larger (eg, due to deep-connection charges).

5.3.3 Conclusion

The analysis has shown that applying AZTL across Great Britain would have a marginal impact on the profitability of renewables projects connected to transmission networks and large distributed generators. It would adversely affect projects located in Scotland and, to a lesser extent, in the North of England, while providing some benefits to those located in Wales, South Western, South East and Eastern demand zones. In the latter areas, AZTL would provide increased financial benefits to smaller-scale distributed plant. **Given the marginal financial effect on renewables, it seems unlikely that AZTL will materially affect the probability of meeting the government's renewables target**. As it is unlikely that policy would need to be adjusted to offset any adverse impact of AZTL on renewables entry, the implications of such a policy change have not been considered.

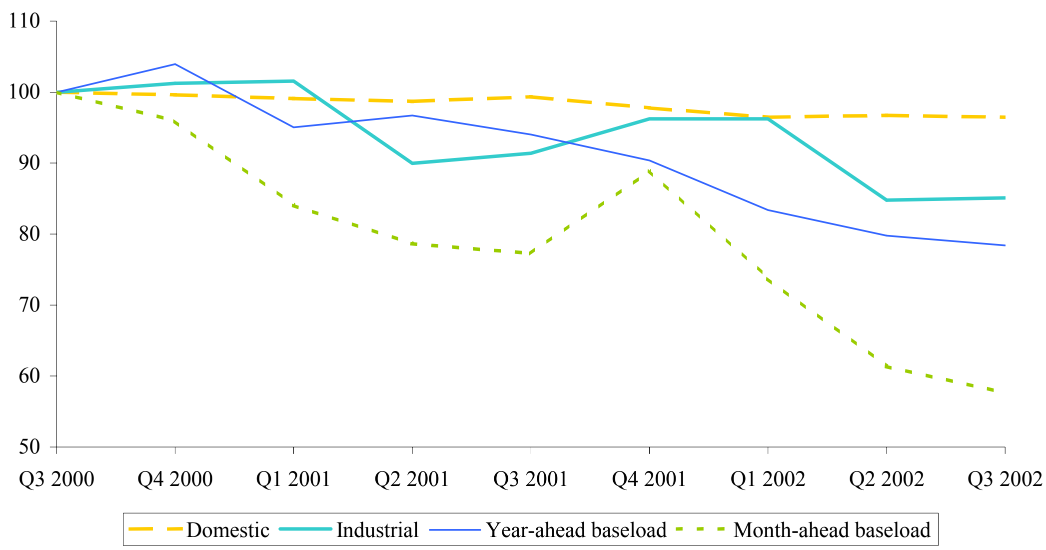
6. Impact on Customers

6.1 The link between wholesale and retail prices

In order to understand how AZTL might affect consumers, assumptions have to be made about the link between wholesale costs and retail prices. This sub-section briefly explores the issue and sets out the approach that has been adopted.

Figure 6.1 shows wholesale and retail price movements since the third quarter of 2000. Wholesale prices are represented by average reported prices for month-ahead and year-ahead Electricity Forward Agreement (EFA) contracts across each quarter. Data on retail prices for the industrial and commercial (I&C) and domestic sectors is taken from the DTI's *Energy Prices* publication.[48]

Figure 6.1: Comparison of wholesale and retail price movements (Q3 2000=100)



Source: Energy Argus, and DTI (2002), *Energy Prices*, December 2002.

In comparing movements in wholesale and retail prices for each market segment, a range of factors might be relevant (eg, costs associated with environmental policies such as the RO and Energy Efficiency Commitment).[49] Nonetheless, the graph would suggest that **changes in wholesale costs are more quickly reflected in I&C retail prices than domestic retail prices**. By the end of the period, the reduction in wholesale prices has led to a 15% fall in I&C prices, but only a 4% reduction in prices for domestic consumers.

[48] DTI (2002), *Energy Prices*, December.

[49] For a discussion of electricity supply competition, see Ofgem (2002), 'Electricity Supply Competition: An Ofgem Occasional Paper', December.

Alongside different levels of switching in the two markets, **one of the reasons behind this is likely to be the different proportion of retail bills accounted for by wholesale costs in each of the sectors**.

Table 6.1 gives figures on wholesale costs as a proportion of retail bills. These can be used to provide an estimate of the change in retail prices if competition is effective and cost or benefit to suppliers from AZTL is passed through in full to consumers. For example, **since 39% of domestic retail bills are made up of wholesale costs, in the long run, in a fully competitive market, a 1% change in wholesale electricity costs might be expected to change retail prices by approximately 0.39%**.[50] These figures form the basis of the analysis of the consumer impact of AZTL in the following section.

Table 6.1: Wholesale costs as a proportion of retail bills

	Wholesale costs as a proportion of retail bills	Implied % change in retail price with a 1% change in wholesale cost
Domestic	39	0.39
I&C	67	0.67

Source: Ofgem, and OXERA.

6.2 Financial impact on consumers

Table 6.2 shows OXERA estimates of the impact of AZTL on consumer prices in different regions. The figures are based on a comparison of zonal TLMs with a uniform TLM calculated to recover the same level of total losses. The analysis does not take into account existing differentials in retail tariffs across the country, and AZTL is assumed to have no impact on the underlying wholesale price of electricity.

[50] For large changes in wholesale costs, this approximation might become less valid, since the proportion of wholesale costs in final bills would itself be significantly affected.

Table 6.2: Impact of AZTL on consumers in different regions

GSP Group		TLM	% change in retail prices		Estimated absolute change in retail bills (£)			
			Domestic	I&C	Domestic[2]	Small industrial[3]	Medium industrial[4]	Large industrial[5]
14	Northern Scotland	0.981	–0.89	–1.71	–2.21	–940	–13,000	–27,000
13	Southern Scotland	0.987	–0.63	–1.22	–1.58	–670	–10,000	–20,000
1	Northern	1.002	–0.35	–0.68	–0.88	–370	–5,000	–11,000
2	North West	1.006	–0.17	–0.33	–0.42	–180	–3,000	–5,000
3	Yorkshire	1.003	–0.36	–0.70	–0.90	–380	–6,000	–11,000
4	North Wales and Mersey	1.016	0.13	0.25	0.32	140	2,000	4,000
5	East Midlands	1.011	–0.08	–0.15	–0.20	–90	–1,000	–2,000
6	Midlands	1.019	0.31	0.59	0.76	320	5,000	9,000
7	Eastern	1.012	0.06	0.12	0.16	70	1,000	2,000
8	South Wales	1.017	0.23	0.43	0.56	240	3,000	7,000
9	South East	1.011	0.09	0.17	0.22	100	1,000	3,000
10	London	1.02	0.39	0.75	0.98	410	6,000	12,000
11	Southern	1.019	0.32	0.61	0.80	340	5,000	10,000
12	South Western	1.02	0.34	0.65	0.84	360	5,000	10,000

Note: [1] Average TLM for years 2005/06 to 2009/10 calculated from the load-flow modelling. [2] Based on an average annual standard credit bill of £249 in 2002. [3] Consumption of 1.25 GWh per annum. [4] Consumption of 24 GWh per annum. [4] Consumption of 50 GWh per annum.
Source: OXERA, and DTI (2003), *Energy Prices*, March.

The results show that, under the base scenario and compared with a system of uniform pricing, **the application of AZTL throughout Great Britain would tend to give rise to marginal reductions in retail electricity prices in Scotland and Northern zones 1–3 and 5 in England, while leading to marginal increases in retail electricity prices in the rest of England and Wales**. The percentage change in retail prices is more pronounced for I&C consumers, reflecting the higher proportion of wholesale electricity costs in their bills. **In absolute terms, the estimated financial effect on domestic customers appears minimal, ranging from an annual benefit of £2.21 in Scottish & Southern Energy's region to an additional annual cost of £0.98 in GSP Group 10**. **The estimated absolute impact on industrial customers is larger, with an annual benefit of £27,000 for a hypothetical large industrial consumer in Scottish & Southern Energy's region compared with a cost increase of £12,000 in GSP Group 10**.

6.3 Potential demand-side response

The potential impact of retail price changes on consumption has been estimated by applying existing estimates of the elasticity of demand, which give the percentage change in consumption for a 1% change in price.[51] While **electricity demand is generally perceived to be relatively inelastic (ie, changes in price have a relatively small effect on consumption)**, a range of figures has been put forward for the precise level of demand elasticity. For example, for the domestic sector, Miller (2001) produced an estimate of –0.37,[52] while the UK Treasury has used a figure of –0.187 in the past to analyse the impact of tax changes.[53] Past modelling work by OXERA has produced an estimate of long-run price elasticity for the domestic sector of –0.33. Elasticity estimates for I&C customers tend to be slightly higher. For example, a recent study for the Australian market which estimated domestic elasticity as –0.25 produced figures of –0.35 and –0.38 respectively for the industrial and commercial sectors.[54]

Based on the range of existing estimates, the high and low figures set out in Table 6.3 were used to assess the potential impact of AZTL on consumption. The high figures are more likely to apply in the long run, when consumers have the greatest scope to respond to price changes.

Table 6.3: Assumptions on electricity price elasticity

	Low scenario	High scenario
Domestic	–0.15	–0.35
I&C	–0.25	–0.45

Source: OXERA.

Table 6.4 gives estimates of the potential annual change in consumption by domestic and industrial customers in different GSP Groups, calculated from the application of the elasticity assumptions to data on consumption broken down by GSP Groups. Note that OXERA did not have information on the precise breakdown between domestic and I&C consumption in each region, and the figures have therefore been calculated using an assumed volume split of 33:67 for all zones. The table also provides estimates of the potential impact on transmission losses, based on the use of annual zonal TLFs. As discussed earlier in the report, this approach provides only very approximate estimates, since actual loss impacts will vary between nodes on the network and between time periods. The final column values the loss savings using an assumed electricity price of £20/MWh.

[51] For example, a demand elasticity of –0.3 means that, for a 1% increase in price, consumption would fall by 0.3%.
[52] Miller (2001), 'Modelling Residential Demand for Electricity in the U.S.: A Semiparametric Panel Data Approach', November.
[53] http://www.parliament.the-stationery-office.co.uk/pa/cm199798/cmhansrd/vo980210/text/80210w09.htm
[54] http://www.nemmco.com.au/publications/soo/410-0023.pdf

Table 6.4: Potential annual benefits from demand-side response to AZTL

GSP Group		Consumption (GWh)[1]	Estimated change in consumption (MWh)[2]				Estimated impact on losses (MWh)[3]		Estimated value of change in losses(£)[4]	
			Low scenario		High scenario		Low scenario	High scenario	Low scenario	High scenario
			Dom	I&C	Dom	I&C				
14	Northern Scotland	8,000	3,735	23,940	8,714	43,092	–1,589	–2,974	32,000	59,000
13	Southern Scotland	22,000	7,089	45,442	16,541	81,795	–2,289	–4,284	46,000	86,000
1	Northern	17,000	2,998	19,219	6,996	34,594	–703	–1,315	14,000	26,000
2	North West	25,000	2,099	13,458	4,899	24,225	–339	–634	7,000	13,000
3	Yorkshire	24,000	4,319	27,689	10,079	49,840	–1,042	–1,951	21,000	39,000
4	North Wales and Mersey	17,000	–1,103	–7,073	–2,574	–12,731	52	97	–1,000	–2,000
5	East Midlands	28,000	1,137	7,287	2,653	13,117	–151	–282	3,000	6,000
6	Midlands	27,000	–4,136	–26,512	–9,651	–47,722	–92	–172	2,000	3,000
7	Eastern	35,000	–1,126	–7,219	–2,628	–12,994	78	145	–2,000	–3,000
8	South Wales	12,000	–1,392	–8,921	–3,247	–16,058	14	25	0	–1,000
9	South East	21,000	–934	–5,986	–2,179	–10,774	51	96	–1,000	–2,000
10	London	25,000	–4,993	–32,010	–11,651	–57,617	–294	–551	6,000	11,000
11	Southern	32,000	–5,135	–32,917	–11,982	–59,250	–156	–293	3,000	6,000
12	South Western	15,000	–2,558	–16,398	–5,969	–29,516	–94	–176	2,000	4,000
Total		**308,000**	**0**	**0**	**0**	**0**	**–6,555**	**–12,270**	**132,000**	**245,000**

Notes: [1] Figures for 2001 taken from returns to the DTI. [2] Assumes a standard volume split between domestic and I&C customers of 33:67 for all GSP Groups. [3] Calculated by multiplying the change in consumption by annual zonal TLFs (prior to division by two to obtain ATLFs). [4] Valued using an assumed electricity price of £20/MWh.
Source: OXERA.

The figures show that the estimated effect of AZTL on consumption in different regions is likely to be very small, particularly in the domestic sector. This result is a consequence of the marginal changes to retail bills estimated in Table 6.2 and the inelasticity of demand. The final row of the table suggests that **the loss-reduction benefits from demand-side response to the application of AZTL across Great Britain might be in the region of £0.13m–£0.25m per annum**.[55] **This benefit will be partly offset by the value attached to changes in consumption**. This follows from the fact that consumption valued above the original retail price will be deterred in regions where

[55] Demand growth might marginally increase this benefit.

prices increase, whereas consumption valued below the original retail price will be induced in regions where prices fall. Hence, the net value attached to changes in consumption will be negative.

7. Distributional Consequences

The potential effects of AZTL for hypothetical generating companies were discussed in section 3.2, and the potential impact on individual consumers in section 6. This part of the report discusses estimates of overall transfers of money between regions of the country, and how these might be viewed from an economic and social perspective.

7.1 Size of transfers

Table 7.1 shows estimates of potential transfers between regions based on the TLMs calculated for 2005/06. The figures for generation in each zone are based on the results of the base scenario for that year. Demand figures were calculated by scaling up the GSP demand figures in Table 6.4 to match the total level of demand in 2005/06 assumed in the base scenario. The transfers are calculated by comparing loss payments that would occur for generators and consumers in each region under AZTL and under uniform loss charging, with uniform factors calculated so that total loss payments across the country remain the same.

Table 7.1: Estimates of potential transfers between regions for 2005/06

GSP Group	Demand (TWh)	Supplier TLMs	Consumer transfers (£m)	Generation (TWh)	Generator TLMs	Generator transfers (£m)	Net transfers (£m)
14 Northern Scotland	10	0.981	5.92	14	0.966	–7.53	–1.61
13 Southern Scotland	27	0.987	12.61	30	0.972	–12.41	0.20
1 Northern	20	1.002	3.53	22	0.986	–2.61	0.92
2 North West	30	1.006	2.21	19	0.991	–0.34	1.86
3 Yorkshire	29	1.003	4.11	63	0.988	–5.51	–1.40
4 North Wales and Mersey	21	1.016	–2.43	27	1.001	4.75	2.33
5 East Midlands	34	1.011	–0.73	46	0.996	3.56	2.83
6 Midlands	33	1.019	–5.65	10	1.004	2.29	–3.36
7 Eastern	42	1.012	–1.20	50	0.996	4.18	2.98
8 South Wales	15	1.017	–1.95	11	1.001	1.97	0.02
9 South East	25	1.011	–0.24	44	0.995	2.87	2.63
10 London	31	1.020	–5.92	0	1.005	0.04	–5.88
11 Southern	39	1.019	–6.81	18	1.004	4.17	–2.64
12 South Western	18	1.020	–3.43	19	1.004	4.56	1.13
Uniform TLM		1.010			0.992		
Sum	373		0.00	373		0.00	0.00

Note: The calculations assume an electricity price of £20/MWh.
Source: OXERA.

The calculations show that the potential transfers between consumers and generators in each region are substantial for the base scenario in this year, and may be significantly larger than estimated efficiency gains from AZTL. On the demand side, the figures suggest that Scottish electricity consumers might receive total benefits of approximately £18.5m, while consumers in the Northern English zones 1–3 might receive total benefits in the region of £9.8m. Consumers in the rest of England and Wales would see an equivalent disbenefit of around £28.4m. The transfers between generating plant in different regions are also large. The calculations suggest that generators in Scotland might lose around £19.9m; generators in the Northern English zones 1–3 might lose £8.5m; while generators in the rest of England and Wales might see equivalent gains in the order of £28.4m.

The final column of the table shows net transfers for each region, taking into account the impact on both consumers and generators. The direction and size of these transfers are determined by the volume of generation relative to demand and marginal loss effects captured by the TLMs. For Scotland, the positive impact on consumers largely balances out the negative impact on generators, and the overall net transfer suggested by the figures is around £1m. Within England and Wales, there does not appear to be a clear geographical pattern as to which zones see net gains or losses. As discussed in the next sub-section, the net transfer should not be interpreted as a proxy for the impact on regional economies.

These calculations are presented for one year and scenario only, and it is possible that the transfer effects (particularly the figures for net transfers) might vary between years and according to the assumptions used in the calculations.

7.2 Economic and social factors

Information on economic and social conditions in different regions may help provide guidance as to whether the transfer effects might be viewed in a positive or negative light. Table 7.2 shows selected economic and social statistics broken down by region.

Table 7.2: Selected economic and social statistics broken down by region

		Weekly household income[1] (£)	Households in receipt of benefits[2] (%)		Unemployment rate (%)	
			Family Credit/WFTC or Income Support	Housing benefit	Claimant count[3]	International Labour Organisation[4]
UK[6]		480	16	21	3.2	5.2
England		496	16	20	3.0	4.9
	North East	380	21	23	5.5	6.9
	North West	430	19	18	3.7	5.5
	Yorkshire and the Humber	432	19	19	4.0	5.4
	East Midlands	449	15	14	3.2	4.2
	West Midlands	462	18	17	3.7	5.5
	East	510	11	11	2.1	3.5
	London	615	16	20	3.3	6.6
	South East	586	10	10	1.6	4.0
	South West	449	14	13	2.1	3.6
Wales		376	20	19	3.9	6.1
Scotland		419	19	23	4.2	6.8

Notes: [1] Average gross weekly household income, based on combined data from 1998/99, 1999/2000 and 2000/01 surveys. [2] 2000/01. [3] Seasonally adjusted annual average, 2001. [4] Spring 2002. [5] 2001. [6] Includes Northern Ireland.
Source: Office of National Statistics, *Regional Trends*, **37**.

The statistics provide a mixed picture of economic and social conditions in different regions. **Household income appears to be highest in the South and East of the country**, although, ideally, the figures would be adjusted to take account of variations in the cost of living.[56] The geographical pattern for the proportion of households in receipt of benefits (focusing on benefits aimed primarily at those on low incomes) and the rate of unemployment appears broadly similar. However, there are exceptions to the general pattern—for example, although London has the highest household income, it also has an above-average unemployment rate on the ILO figures.

If it is accepted that consumers in the South of the country tend to be better off than those in the North, the distributional consequences of AZTL between domestic consumers in the North and South might be viewed in a positive light. However, the conclusion is not clear-cut—for example, the above figures suggest that the lowest average household income is to be found in Wales, where consumers suffer a disbenefit

[56] The distribution of income within each region may also be relevant.

from the application of AZTL across Great Britain. Moreover, the analysis in section 6 suggested that the impact on an individual domestic consumer is likely to be negligible.

It is not possible to ascertain the overall impact of AZTL on different regional economies. This is because the proportion of transfers to generating companies and I&C consumers that will feed into the regional economy is not known. To take an illustrative example, if generators in a particular region gain from AZTL and these benefits accrue to shareholders, it is not clear that the transfers to generating plant in this region would necessarily benefit the local economy.

8. Implementation and Operation Costs

This section considers the direct costs that might arise from the extension of AZTL from England and Wales to Scotland under BETTA. In analysing this issue, it is useful to consider three categories of cost.

- *Implementation costs of introducing P82 in England and Wales*—with regard to these costs, it should be noted that:

  – **if P82 is introduced in England and Wales regardless of the governments decision in relation to AZTL under BETTA, then these costs are unaffected by the government's decision and should be treated as sunk**. However, this would imply that the fallback position, if the decision were taken not to apply AZTL throughout Great Britain, would be charging losses according to the P82 methodology for six months or a year from April 2004 (depending on the start date of BETTA), and then reverting to uniform loss charging across Great Britain. This fallback position would see the costs of implementing P82 incurred even though benefits would only be gained for a short period of time, and is therefore unlikely to be optimal;

  – **alternatively, the introduction of P82 in England and Wales might be dependent on whether the government decides to extend AZTL throughout Great Britain under BETTA**. In other words, *if* a decision were taken not to apply AZTL under BETTA, then P82 would not be introduced in England and Wales prior to BETTA either. In this case, whether or not the industry incurs the implementation costs in England and Wales depends on the government's decision, and these costs would therefore become relevant to the analysis.

- *Incremental implementation costs arising from the extension of the P82 methodology to Scotland*—costs that will be incurred anyway as part of the BETTA programme regardless of the decision on AZTL are irrelevant for this analysis.

- *Operation costs*—the additional annual costs of operating AZTL rather than a system of uniform loss charging should be taken into account.

The following sub-sections discuss the implementation and operation costs that might be incurred in relation to central systems and individual market players.

8.1 Central systems costs

Elexon has estimated that the capital costs of changing central systems to accommodate P82 in England and Wales would be £110,000 plus costs associated with the Transmission Loss Factor Agent (TLFA). BSCCo costs were estimated to be 500 days. OXERA has made assumptions to translate the latter figure into an indicative monetary value of £38,000.[57]

Elexon would incur certain additional implementation costs if the P82 methodology were to be extended to Scotland. Elexon highlighted three such costs in its response to the DTI consultation, as summarised in Table 8.1. Elexon was not able to provide quantitative estimates of the size of these costs, but suggested that they would not be expected to be a material proportion of the overall BETTA programme.

Table 8.1: Additional central systems costs

Cost	Impact	Separable from BETTA?
Obtaining historic Scottish metered volumes for the load-flow model	Potentially high, since no existing requirement to establish such data	Yes
Obtaining Scottish network data for the load-flow model	Low, assuming data is readily available from the Scottish transmission companies	Yes
Amendment to core P82 documentation	Low	Yes

Source: Elexon.

Elexon has estimated the ongoing operation/maintenance costs of AZTL to be £17,000 per annum, plus costs associated with the Transmission Loss Factor Agent.

The costs incurred by NGC in providing one intact network for the year for the load-flow modelling have been estimated as a set up cost of £10,000–£20,000 plus an annual cost of £10,000–£20,000.

Given that TLFA costs remain confidential, **OXERA has assumed, for the purpose of comparison with the benefits of AZTL, that total up-front costs for central systems would be £0.5m and that ongoing costs would be £0.25m per annum**. **Discounting these operation costs for years to 2019/20 at a discount rate of 6% would give a total NPV for central system costs of just under £3m**.

8.2 Costs to market participants

Generators, suppliers and possibly large consumers may incur costs associated with modifying internal systems (eg, IT systems) and renegotiating contracts in preparation for

[57] 500 days is assumed to be equivalent to one and a half years' work, and this has been valued at an assumed salary of £25,000.

the introduction of P82 in England and Wales. However, there appear to be varying views on the likely scale of these costs.

In its decision letter on P82, Ofgem stated that:

> Ofgem has given careful consideration to respondents' views on the cost impact on their internal systems and process. Overall, respondents indicated that they would be much lower than those for Modification Proposal P75. Further, 6 out of the 18 respondents said that the costs would be minimal or zero.

On the other hand, some individual participants have put forward significantly higher figures. There were responses to the DTI consultation which gave company-specific estimates for the cost of implementation of £0.25m, £0.5m and £0.1m. One respondent suggested that overall implementation costs for the industry might be between £1m and £2m, with further operation costs of £1m per year. **Table 8.2 shows NPV cost figures quoted in a scaled cost-benefit analysis of the introduction of P82 in England and Wales**.[58] **The average NPV figure (which would roughly equate to costs going out to 2019/20) is £31m**, the majority of which comprises capital investment in IT and transactions costs for market participants. In all these cases, it is difficult to evaluate the estimates without more detailed information.

Table 8.2: NPV cost figures used in scaled cost-benefit analysis of P82 (£m)

Cost element	10 years	20 years	Average
Capital investment in IT			
Central systems (NGC, Elexon, NETA agent)	0.8	0.8	0.8
Market participants	14.9	14.9	14.9
Operational/transactions costs			
Central systems (NGC, Elexon, NETA agent)	1.2	1.8	1.5
Market participants	11	17.1	14.05
Total	27.9	34.6	31.25

Note: OXERA has excluded estimates of the increased cost of capital due to market risks which were in the original figures, for the reasons given in section 1.31.
Source: NERA

Incremental implementation costs may mostly concern companies that operate only in Scotland at present, and any legal costs associated with renegotiating contracts that relate exclusively to Scotland. It is not clear what any ongoing operation costs of AZTL to market participants would comprise. **Many respondents to the DTI consultation indicated that such costs might be minimal**.

In conclusion, an important issue to resolve is if the decision on whether to apply AZTL throughout Great Britain under BETTA will affect whether it is implemented in England

[58] NERA (2002), Memo on Scaled Cost Benefit Analysis submitted to the P82 Assessment Consultation, November

and Wales prior to BETTA, as this determines whether England and Wales implementation costs should be included in the analysis. The central system costs (both capital and ongoing) are relatively straightforward to identify, and might equate to around £3m in NPV terms. However, the costs incurred by market participants are more uncertain, with some estimates suggesting that the costs are minimal, while other estimates suggest that they are significant, perhaps giving rise to total costs as high as £31m in NPV terms.

9. Conclusions

The study has provided an assessment of the impact of AZTL in the following areas:

- interactions with environmental policy;
- national resource costs and benefits;
- transfers between generators and consumers.

9.1 Interaction with environmental policy

- The study found that the effect of AZTL on the financial viability of renewables projects is likely to be very small. The key driver of this result is the high value of ROCs relative to the wholesale electricity price. **Given the marginal financial impact on renewables, it seems unlikely that AZTL will materially affect the probability of meeting the government's renewables target**.

- **The study found that the effect on emissions over the period 2005/06 to 2009/10 resulting from changes in the generation mix caused by AZTL had the potential to be of a greater magnitude than any direct emissions benefit from decreased losses resulting from redespatch, although the direction of the effect is ambiguous**. Under the base-scenario assumptions, AZTL led to a very small switch from gas to coal generation in most of the years, leading to a marginal overall increase in emissions. However, the base scenario and subsequent sensitivity analysis did not fully reflect the potential impact of the EU Emissions Trading Scheme, which might have affected this result.

- There might be further carbon-saving benefits if AZTL affects the location of generation in the long run. The value of these savings depends crucially on the assumed carbon price, with **each £1m of direct loss-reduction benefit from generation relocation being associated with an additional carbon-saving benefit of between £0.03m and £0.42m, based on a carbon price in the range £5–£70/t**.

9.2 National resource costs and benefits

9.2.1 Summary of report findings

- The modelling results suggest that AZTL might lead to small changes in despatch from northern to southern generators. **These would lead to marginal reductions in losses, which might be valued at approximately £0.19m–£1.29m per**

annum.[59] **These benefits are likely to be offset to some extent by increases in avoidable generation costs (eg, fuel costs)**.

- There would be limited demand-side response to AZTL, as the expected impact on final retail bills is small and electricity demand is generally perceived as inelastic. **This report gives estimates of the loss-reduction benefits from changes in the pattern of consumption in the range of £0.13m–£0.25m per annum**. **These benefits are likely to be partly offset by the value that consumers place on changes in consumption**.

- In the longer term, **AZTL has the potential to give rise to larger reductions in losses if it results in a significant impact on generators' decisions regarding exit/mothballing and entry/return from mothballing**. However, **the size of these benefits is highly uncertain—**this report has presented specific examples of potential long-run benefits ranging from £2m to £22.8m per annum, although the lower end of this range might be considered more prudent. **Longer-term benefits are likely to be partly offset by increases in other generation costs that may arise from changing the location of generating plant**.

- The modelling results suggest that **AZTL might lead to very marginal reductions in the cost of constraints across the Scotland–England interconnector**.

- **The costs of implementing P82 in England and Wales are relevant if the government's decision on AZTL under BETTA affects whether or not P82 is actually implemented prior to BETTA**. **Additionally, the incremental implementation costs of extending the P82 methodology to Scotland and the additional annual costs of operating AZTL rather than a system of uniform loss charging should be taken into account**. While central system costs are relatively easy to identify, there is insufficient information to draw definite conclusions on implementation costs incurred by market participants. While some have suggested that these costs are minimal, others have put forward relatively high figures, such as the estimate of £31m derived from a cost-benefit analysis of P82 in England and Wales.

- **The argument that applying AZTL across Great Britain may increase the cost of capital would appear questionable**. It is not clear that forward-looking perceptions of risk will be increased, given that the issue of loss charging has been subject to debate (at least in England and Wales) for some time. Moreover, any risk that relates specifically to the loss-charging regime would appear to be

[59] As discussed in section 3.4, using an alternative methodology to calculate the value of loss reductions produced an estimate of £8.4m per annum. However, this figure is highly dependent on load-flow modelling results for a single snapshot period, and is likely to be an overestimate.

diversifiable and hence would not be expected to have an impact on the cost of capital.

9.2.2 Comparison of benefits and costs

- In order to compare potential benefits and costs while taking into account the uncertainty surrounding some of the impacts of AZTL, OXERA has constructed three scenarios of the future benefits that might arise from applying AZTL throughout Great Britain. These scenarios *exclude* implementation and operation costs. Therefore, if implementation and operation costs are less than the estimates of the NPV of benefits, the implication is that there might be a net positive benefit from AZTL. Conversely, if implementation and operation costs are greater than these estimated benefits, the net benefit might be negative. The assumptions and estimated benefits for each scenario are shown in Table 9.1.

Table 9.1: Scenarios of future benefits of AZTL (£m)

	High	Medium	Low
Assumed annual benefits			
Generation redespatch	1.29	0.74	0.19
Demand response	0.25	0.19	0.13
Relocation of generation (from 20010/11)	10	4	1
Proportion of above benefits assumed to be offset by change in other costs (%)	25%	25%	25%
NPV of future benefits to 2019/20, net of offsetting cost increases	55.50	24.38	6.67

Source: OXERA.

- The scenarios are indicative only, and have been constructed as follows:
  - assumed benefits and costs have been calculated for all years until 2019/20 and then discounted back to 2003/04, the year in which implementation costs from the introduction of P82 in England and Wales are expected to be incurred. A discount rate of 6% has been used;[60]
  - BETTA is assumed to start in 2005/06. For 2004/05, when AZTL may apply in England and Wales alone, only the benefits from generation redespatch have been included;[61]

[60] This is the figure that has been recommended in the past by the Treasury (Green Book: Appraisal and Evaluation in Central Government, Treasury Guidance, 1997). In the latest 2003 edition of the Green Book, the Treasury recommends the use of a rate of 3.5%, with adjustments in the appraisal for risk and optimism bias. OXERA has chosen to use the 6% figure as this appraisal of AZTL has not been adjusted for risk, and also to ensure consistency with the approach used by NERA to derive the cost figures in Table 8.2.

[61] OXERA has not explicitly taken into account of the fact that the benefits from redespatch within England and Wales alone are likely to be less than those obtained from redespatch across the whole of Great Britain. However, this is offset by the exclusion of benefits from demand-side response in 2004/05.

- the assumed annual benefits from generation redespatch and demand response are based on the ranges calculated during the study;
- the assumptions regarding annual long-run benefits from generation relocation are more subjective. The low scenario assumption reflects a situation in which AZTL has very little impact on locational decisions due to the greater importance of other factors. The high scenario assumes that AZTL does have an impact on the location of generation, and is broadly consistent with the suggestion in Ofgem's response to the DTI consultation[62] that long-run benefits might actually be twice the figure of £5.3m per annum quoted in their decision letter on P82;[63]
- to reflect the fact that long-run benefits are expected to rise through time as more locational decisions are affected by AZTL, 50% of the annual benefits in Table 9.1 were assumed to be obtained annually from the third year of BETTA until 2009/10, with the full 100% obtained every year thereafter;

given that it was not possible to quantify the size of the costs that were identified as offsetting the benefits of AZTL, and the fact (explained in section 1.3.1) that these costs would be expected to lie somewhere in the range of 0–50% of the physical loss benefits, an assumption was made that these offsetting costs were 25% of the benefits.

- The scenarios of national resource benefits in Table 9.1 do not include the monetary value attached to the changes in emissions discussed in section 9.1. OXERA considers it appropriate to structure the analysis so that national resource effects are considered separately from environmental impacts, for the following reasons:

  - AZTL is primarily a method of allocating losses in a more cost-reflective manner, and it would therefore seem appropriate to analyse the efficiency costs and benefits separately from other impacts, such as those on the environment;
  - a reduction in carbon emissions cannot be classified as a national resource benefit, as the benefits would accrue at a global level. Indeed, without carrying out climate modelling, it would not be possible to say what impact a reduction in UK emissions might have on the future costs faced by the UK as a result of changing climate.

- Based on the above assumptions and methodology, **the NPV of the future benefits to 2019/20, net of offsetting cost increases, from the application of AZTL throughout Great Britain, ranges from £6.7m in the low scenario to £55.5m in the high scenario. The key driver of these results is the assumption**

[62] Ofgem (2003), 'Transmission Losses in a Great Britain Market: Ofgem's Response to the DTI', March

[63] Ofgem (2003), 'Modification to the Balancing and Settlement Code—Decision and Direction in Relation to Modification Proposal P82: Introduction of Zonal Transmission Losses on an Average Basis', January

made regarding long-run benefits, which as discussed in section 4 is an area of uncertainty because of the large number of other factors affecting locational decisions. These figures should be compared to the NPV of implementation and operation costs to give the net national resource benefit. In this regard:

- **If implementation costs in England and Wales are treated as sunk (because P82 is implemented prior to BETTA whatever the government's decision about AZTL under BETTA), then it would appear reasonable to suggest that the net national resource benefit is likely to be positive**. This is based on the assumption, supported by many responses to the DTI consultation, that the incremental costs of extending the P82 methodology to Scotland are likely to be minimal.

- **If England and Wales implementation costs are taken into consideration (because the government's decision affects whether P82 is implemented in England and Wales prior to BETTA), then the net national resource effect of applying AZTL throughout Great Britain becomes ambiguous**. On the assumption that the NPV of central system costs is £3m (see section 8.1), the implementation and operation costs for market participants would have to be very minimal to yield a net positive benefit if AZTL does not have much impact on the location of generation (ie, under the low scenario). On the other hand, if the NPV of all implementation and operation costs is as significant as the figure of £31m discussed in section 8.2, then AZTL would have to have a significant impact on locational decisions in order to yield a positive benefit.

- Potentially, survey work could be conducted to generate a precise estimate of implementation costs, especially given that market participants are likely to be incurring these costs in the near future if P82 is implemented from April 2004.

- It is likely to remain very difficult to generate a precise estimate of long-term benefits, due to the uncertainties involved.[64] Nevertheless, the high scenario would appear least consistent with responses to the DTI consultation which generally suggested that, although there might be a marginal shift in plant location, other factors were likely to be more important determinants.

9.3 Transfers between generators and consumers

- **This study has found that AZTL would lead to transfers between different generators and groups of consumers of a much greater magnitude than any net efficiency gain**. **These transfers would benefit southern generators and**

[64] An interesting question is whether it might be possible to obtain any long-run benefits through adjustments by marginally increasing locational differentials in TNUoS charges to reflect loss impacts, without incurring the implementation and operation costs associated with AZTL.

northern consumers, while leading to a disbenefit for northern generators and southern consumers.

- OXERA produced indicative calculations for potential transfer effects in 2005/06. For that year alone, the figures suggested that:
  - Scottish generators might lose around £19.9m, generators in North England might lose an estimated £8.5m, and generators in the rest of England and Wales might see gains of approximately £28.4m;
  - on the consumer side, potential gains to Scottish electricity consumers might be around £18.5m, gains to consumers in North England might be £9.8m, and consumers in the rest of England and Wales might see a disbenefit of £28.4m.

- **The impact of this redistribution on regional economies is difficult to determine since it is unknown what proportion of the transfers will feed through into the local economy**.

- **The effect on individual domestic consumers is likely to be very small**. Estimates presented in this report show that, if suppliers pass through the impact of AZTL on consumers in full, domestic retail bills might fall by a maximum of £2.21 per annum in Scottish & Southern Energy's region and rise by a maximum of £0.98 per annum in London.

- **Industrial and commercial customers might see slightly larger effects than domestic consumers, as wholesale costs form a larger proportion of their bills**. If the impact of AZTL was passed through in full, a large industrial customer[65] in Scottish & Southern Energy's region might see a reduction of £27,000 in electricity costs, whereas an equivalent customer in London might see a cost increase of £12,000 per year.

- **The study did not find any significant effects on the wholesale electricity price**.

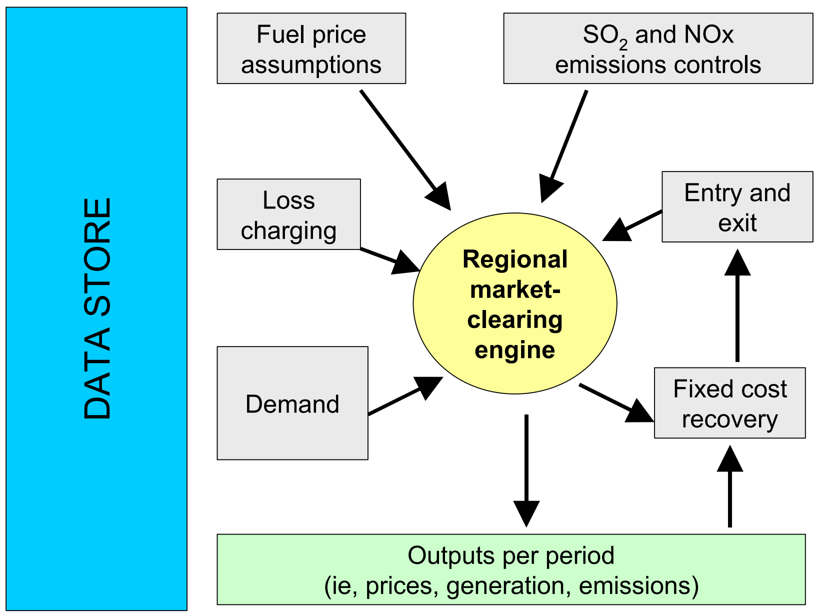
[65] Based on an electricity bill of £1.6m.

Appendix 1: Wholesale Market Modelling

A1.1 OXERA wholesale model

The OXERA wholesale electricity market model is a production cost model, with the facility for assessing the impact of zonal TLMs on generation despatch. Figure A1.1 displays the various interactions in the model.

Figure A1.1: OXERA's electricity wholesale model



Source: OXERA.

For each time period, the model ranks the available generation on the basis of short-run marginal costs, reflecting:

- input fuel costs;
- plant efficiencies;
- loss charges;
- variable operating and maintenance costs;
- the variable costs of operating emissions-abatement equipment.

The ranked generators are then despatched against total demand. This calculation is performed simultaneously for all periods being modelled, thereby allowing the model to restrict SO_2 and NOx emissions (either individually or at a company level) for annual runs. The model allows transmission constraints across zones of the network to be taken into account—in particular, across the Scotland–England interconnector.

The model assumes that plant exit the market when their lifetime expires or when they are no longer economic to run. OXERA assumes that the published lifetimes of nuclear stations are adhered to, and that the lifetime of other plant can be extended, at least to 2015. New CCGT entry is assumed to occur when the average market price exceeds the long-run marginal cost of new-entry plant.

The model generates values for the following variables for each period:

- wholesale electricity prices;
- electricity generation;
- load factors of each plant;
- emissions.

For this project, OXERA ran its wholesale market model in two modes:

- *snapshot demand mode*—for selected demand conditions, OXERA ran its model to simulate despatch decisions under uniform and zonal loss charging, to provide inputs into the load-flow modelling exercise;
- *full load-duration curve mode*—once the load-flow modelling had produced estimates of TLMs for all years, OXERA re-ran its model using monthly load-duration curves for both uniform and zonal loss charging. This allowed the impact of AZTL on a range of market outcomes to be examined.

A1.2 Further information on modelling assumptions

The information provided below on the assumptions OXERA used for the base scenario is additional to that contained in section 2.3.1 of the report.

Sulphur constraints

When run in full load-duration curve mode, the OXERA model takes explicit account of Environment Agency limits for the production of SO_2 from large coal- and oil-fired stations. The total limits used in the model (for April–March years) are reproduced in Table A1.1. The base scenario did not take account of the restrictions imposed by the LCPD or the EU Emissions Trading Scheme, although, as discussed in section 3.8, some limited sensitivity analysis was carried out to explore the effect of these policies on the results of the modelling.

Table A1.1: Total national B limit allocations (kte SO_2)

Year	2004/05	2005/06	2006/07 and thereafter
Kte SO_2	417	398.5	398

Source: Environment Agency.

Interconnectors

The following assumptions were made with regard to interconnector flows:

- baseload imports of 1,798 MW were assumed across the UK–France interconnector;[66]
- peak exports of 450 MW were assumed across the Moyle Interconnector, with an load-duration curve used to derive flows at other times;
- the proposed Norwegian and Netherlands interconnectors were assumed not to come on stream.

Plant availability

In carrying out the modelling, it was necessary to make some assumptions about the availability of plant for the three levels of snapshot demand that were modelled. OXERA assumed that a high proportion of plant would be available for generation during peak periods. For the off-peak and trough periods, two modelling options were considered: taking individual plant off-line; or scaling back the capacity of all plants of a given type to reflect overall availability. With regard to the first approach, OXERA concluded that the assumption as to which individual plant might be off-line during a particular demand period was too discretionary, and that the assumption might have a significant impact on flows. Therefore, OXERA adopted the second option, while recognising that, in practice, this pattern of plant availability is unlikely.

[66] OXERA notes that imports across the UK–France interconnector have declined recently. To the extent that this is caused by the level of wholesale electricity prices in the UK at present, flows might be expected to increase in the future if wholesale prices rise.

Appendix 2: Derivation of TLFs and TLMs

A2.1 Assumptions

The calculation of TLFs required a number of assumptions to be made.

- At present, generators' output is measured on the high-voltage side of generator transformers in England and Wales, which means that losses sustained on the generator transformers are effectively covered by the generators themselves. On the other hand, demand is measured on the low-voltage side of grid supply point (GSP) transformers, which means that GSP transformer losses are not covered by the loads. To take this into account, the BSC for NGC stipulates that total transmission losses to be covered are split 45:55 between generators and loads. The situation is different in Scotland, where generation is measured at generator voltage, so generators do not cover losses on generator transformers. This inconsistency will have to be resolved under BETTA. In OXERA's modelling, the generators in Scotland and England and Wales are treated identically, assuming a 45:55 split of losses.

- TLFs calculated from load flows in any given year were used to derive TLMs for the following year. In practice, TLMs are calculated *ex post* to reconcile the difference between the amount charged for losses and the actual amount of losses sustained in a given settlement period. However, based on historical experience and published values of TLFs, it is expected that generators will be able to predict the actual values of TLMs and modify their self-despatch, and OXERA's methodology reflects this.

- The transmission network in England and Wales is defined as that operating at voltages of 275kV and 400kV, while in Scotland it also contains the 132kV level. However, Scottish & Southern Energy's network also contains a substantial number of lines operating at 33kV and below. These connections could not be removed from the load-flow model, as this would substantially change the pattern of flows. To address this problem, a solution was devised whereby resistances R in lower-voltage lines and transformers were removed from the model, while the reactances X were increased to the value $\sqrt{R^2 + X^2}$ in order to compensate for the removal of resistances. Consequently, as losses arise on the resistance but not reactance, low-voltage lines did not contribute to the transmission losses or derived TLFs, while the pattern of flows was largely unaffected.

- NGC's 2002 'Seven Year Statement' contains predictions about the commissioning of new interconnectors to Norway and the Netherlands. Owing to the lack of information about future loading of the interconnectors and uncertainty about their construction, the interconnectors have not been included in the OXERA network models.

- The load-flow program used was alternating current (AC)—ie, it included resistances and reactive power flows. As Modification P82 specifies that reactive power flows should be neglected, reactive power demands at all GSP transformers were set to zero and voltages set equal to 1.01 per unit at all network nodes.

Consequently, reactive power flows corresponded only to reactive losses on network reactances caused by real power flows.

- Only the real power part of the load-flow program was activated, while all the reactive power equations were relaxed. This again had an effect of minimising the influence of reactive power flows.

- The TLFs were calculated directly from the Jacobian matrix evaluated at a given operating point. Sensitivity analysis was undertaken by disturbing the solution around the solved operating point, allowing all of the TLFs to be calculated at once using appropriate elements of the Jacobian and inverse Jacobian matrices.

- Network data often did not contain information about busbar connections in substations with transformers (GSP, generator and network transformers). Hence, it was necessary to assume certain substation connections. This was done using engineering judgement in such a way as not to overload transformers and lines. While care was taken to do this as accurately as possible, connections in some substations might be different to the actual ones. However, this is a local problem that should not affect either losses or derived TLF values in any significant way.

A2.2 Simulation steps

The simulation involved the following main steps.

- An overall level of demand was assumed for all three networks following demand and loss predictions from the three 'Seven Year Statements'. Table A2.1 contains predictions for the peak demand.

Table A2.1: Assumptions on peak demand and losses (MW)

	2004/5	2005/6	2006/7	2007/8	2008/9	2009/10
NGC Statement gross demand	56,938	57,761	58,783	59,529	60,353	61,151
NGC Statement losses	1,076	1,065	1,231	1,232	1,246	1,252
Net demand	55,862	56,696	57,552	58,297	59,107	59,899
Scottish & Southern Energy Statement net demand	1,674	1,684	1,694	1,704	1,714	1,724
Losses assumed by OXERA	44	44	44	44	45	45
Scaled-up demand	1,718	1,728	1,738	1,748	1,759	1,769
ScottishPower Statement gross demand	4,102	4,100	4,041	4,036	4,020	4,004
Losses assumed by OXERA	86	86	85	85	84	84
Net demand	4,016	4,014	3,956	3,951	3,936	3,920
Exports to NGC assumed by OXERA	2,200	2,200	2,200	2,200	2,200	2,200
Export to NIE assumed by OXERA	450	450	450	450	450	450
Losses on exports assumed by OXERA	82	82	82	82	82	82
Total losses	168	168	167	167	167	166
Statement gross demand + export losses	4,184	4,182	4,123	4,118	4,102	4,086
Total losses	**1,288**	**1,277**	**1,442**	**1,443**	**1,458**	**1,463**
Total generation	**62,840**	**63,671**	**64,644**	**65,395**	**66,214**	**67,006**

Source: NGC; ScottishPower, Scottish & Southern Energy; OXERA assumptions and calculations.

- OXERA's wholesale model was then run to produce the merit order of power stations in two versions: assuming uniform loss charging and AZTL charging. It was assumed that the maximum export from Scotland to NGC was 2,200 MW. Hence, under peak-demand conditions, the most expensive in-merit power stations in Scotland tended to be constrained off, while the most economical off-merit power stations in England and Wales tended to be constrained on. The resulting despatch was used as the generation input for the load-flow program.

- For the load-flow program, the distribution of overall demand between individual GSP transformers was assumed to follow information published in the three Statements and was scaled up and down proportionally to generation. The load-flow program was then run and the resulting imbalance appearing in the slack node was distributed evenly among all the loads. In other words, demand was adjusted to match generation assumed and losses. The program calculates real power losses only on resistances that are in the network model. This means that fixed losses, losses on GSP and generator transformers, and losses due to reactive power demands were not modelled. Their effect was spread evenly on the demand nodes.

- Based on the load-flow results, individual TLFs for each network node were calculated, halved, and averaged into GSP Groups using weights equal to the sum of absolute values of generation and demand at a given node.

- The simulation was repeated for three loading levels corresponding to the peak demand, trough and midpoint demand. The annual average TLFs were calculated for each year using weights derived from the load-duration curve taken from NGC's Statement.

  The annual average TLFs were then used to calculate generation and demand TLMs for the three load flows, following the procedure described in Section T.2 of BSC. To calculate TLMs it is necessary to know the total losses for a given settlement period. Total peak losses were taken from Table A2.1. For the midpoint and trough, estimates of total losses have been derived using the losses calculated by the program and shown in Table A2.2. The losses that were not modelled (ie, fixed losses, losses due to reactive power flows and GSP and generator transformers) are equal at peak to the difference between the 'Total losses' row in Table A2.1 and the 'Peak' row in Table A2.2. It was assumed that these losses were not constant but they decreased slightly with the load. Note that these losses are spread uniformly among all generators and suppliers, so the above assumptions did not affect despatch or the estimates of savings due to AZTL.

Table A2.2: Losses calculated by the load-flow program (MW)

	2005/06	2006/07	2007/08	2008/09	2009/10
Peak	740	771	807	849	829
Minimum	161	162	165	165	168
Midpoint	364	344	367	383	390

Source: OXERA.

- The load-flow program was also run using despatch results under uniform loss charging. The difference between losses under uniform and AZTL despatch was used to estimate the impact of introducing AZTL charging.

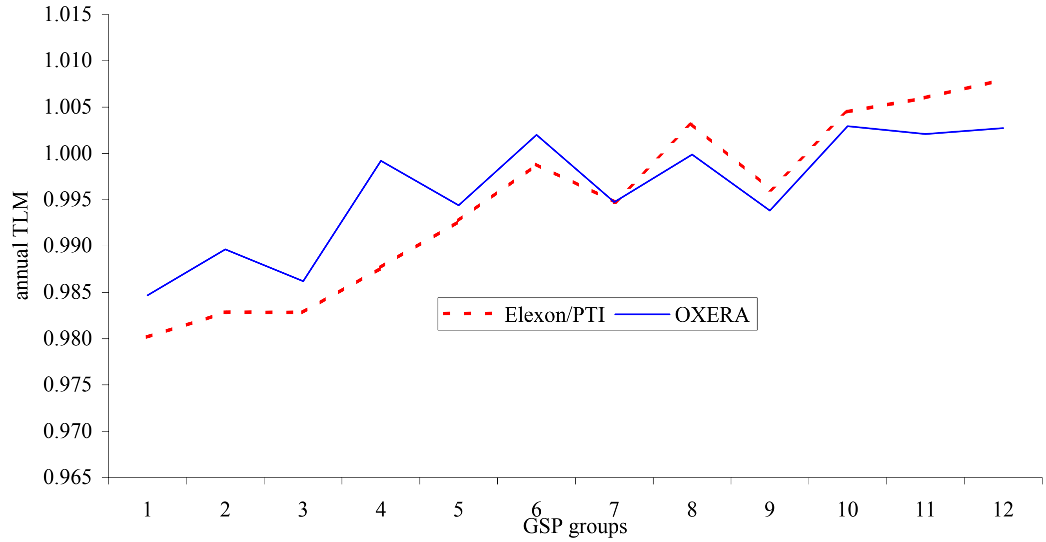
A2.3 Validation of simulation results

To validate the simulation results, the overall level of calculated losses was checked and compared with NGC predictions. NGC transmission losses calculated during the study tended to be about 15% lower than NGC's own prediction of peak losses (see the first row in Table 3.11). This effect was largely due to neglecting the influence of reactive power demands in the OXERA model, which was done according to Modification P82. In fact, transmission losses arise from both real and reactive power flows, and the losses due to real power flows are approximately proportional to the square of the power factor. As an example, consider the year 2004/05. The calculated level of transmission heating losses in the study's modelling was 543 MW at the peak, while NGC's estimate was 642 MW (see the first row in Table 3.11). If it is assumed that the average power factor of network flows was 0.9, then $0.9^2 \times 642 = 520$ MW is due to real power flows only, which is very close to the calculated value of 543 MW. Losses due to reactive power flows would not influence the TLFs according to P82 (they would be smeared uniformly among all the generators due to using TLM^+ adjustment factors) and hence would not influence shifts in despatch.

The calculated values of TLFs and TLMs were validated using the PTI/Elexon October 2002 study, 'A Load Flow Modelling Service'. This used the 2001/02 NGC network model and actual values of demand and generation in the 2001/02 season, while OXERA used 2004/5 predicted data. Moreover, Elexon/PTI used AC load flow and included reactive power demands in its model while the current study did not.

Figure A2.1 compares the TLM factors obtained by Elexon and OXERA. Due to differences in modelling assumptions, the absolute values of TLMs are slightly different. However, from the point of view of affecting short- and long-term behaviour of generators and suppliers, it is not the absolute level of TLMs that is important but their geographical differences. To account for this, PTI/Elexon TLMs have been shifted so that both graphs start with the same value for GSP Group 7. Both graphs show similar patterns (with the exception of zone 4), but OXERA's graph is slightly flatter, giving a lower South–North difference.

Figure A2.1: Comparison of OXERA and Elexon/PTI results



Source: OXERA.

There seem to be a number of reasons for differences between the graphs.

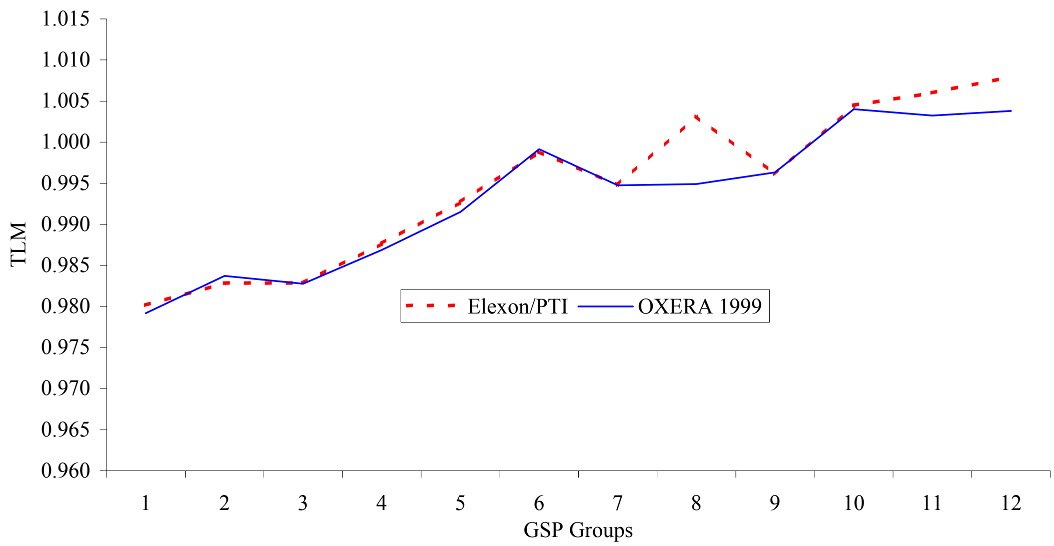
- The PTI/Elexon study used actual values of generators' outputs in 2001/02, while OXERA used the results of the wholesale model. Experience shows that TLFs are quite sensitive to despatch.

- The PTI/Elexon study included reactive power demands. They have calculated TLFs as $TLF_{ij} = (TLF_{Pij} \times P_{ij} + TLF_{Qij} \times Q_{ij}) / P_{ij}$, where TLF_{Pij} is due to real power injections, while TLF_{Qij} is due to reactive power injections. OXERA's modelling follows Modification P82, which stipulates that reactive power flows be ignored. Consequently, a unity power factor has been assumed for all demands and OXERA has calculated TLFs as those due to real power injections only (ie, in the OXERA model $TLF_{ij} = TLF_{Pij}$). Consequently, the second component of the equation used by PTI/Elexon vanished and the resulting TLFs in the OXERA model were smaller.

- Time averaging may also have contributed to the differences between the graphs. The PTI/Elexon study used a large number of annual operating conditions to calculate average annual TLFs, while OXERA used just three operating conditions, which were averaged across the year using weights derived from the load-duration curve.

- Probably the most important reason for the difference between the results was that the 2001/02 network modelled by Elexon/PTI was different to the 2004/05 network modelled by OXERA. In 2001/02 the Yorkshire line was still under construction, while in 2004/05 the line was assumed to be operational. The Yorkshire line reinforced the network, thereby reducing losses and TLFs. To test this last hypothesis, the Elexon/PTI results were compared with OXERA's earlier study, which used NGC's 1999 Statement data. The results are shown in Figure A2.2.

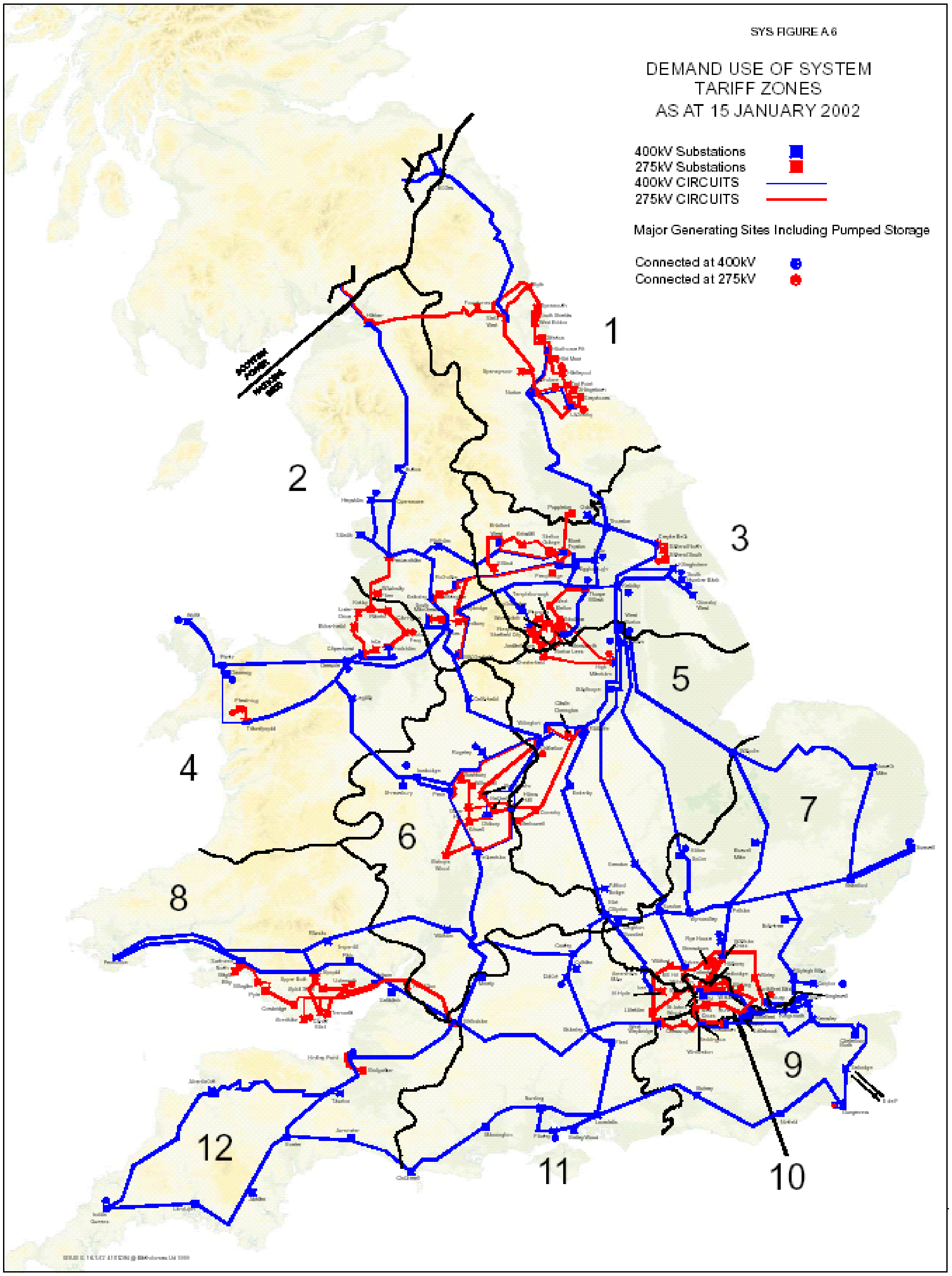
Figure A2.2: Comparison of earlier OXERA study on 1999 network data with Elexon/PTI report



Source: OXERA.

TLMs in Figure A2.2 are quite close, with the exception of zone 8. Again, this seems to be due to the differences in networks used. The 'bump' due to zone 8 does appear in the OXERA graph in Figure A2.1, indicating that the underlying network change appeared between 1999 and 2001/02.

Appendix 3: Map of GSP Groups



Source: NGC (2002), 'Seven Year Statement'.

Appendix 4: Renewables Profitability Model

This appendix provides detail about the cost and revenue assumptions used to assess the impact of zonal loss charging on the IRR of offshore and onshore wind generation projects. The methodology and results of the model are presented in section 5 above.

A4.1 Technology cost assumptions

This section examines an indicative range of entry costs of offshore and onshore technologies used in the modelling, taking into account expected cost reductions in the future.

A4.1.1 Cost estimates

Little actual information is available on the costs of large-scale onshore wind generation and those for offshore wind generation are uncertain due to the limited experience of such projects. As a result, the entry-cost assumptions for onshore and offshore wind generation are based on a number of sources, including turbine manufacturers, industry associations and research institutes. OXERA's choice of assumptions has also been informed by projects undertaken in Europe, notably the 40 MW Middelgrunden wind farm off the Danish coast, which is the largest offshore wind farm yet commissioned in Europe, and provides a unique insight into the cost of large-scale offshore wind farms. Since this wind farm has started operating in 2000, the development of a wind farm of 520 MW on Arklow Bank, off the Irish coast has been given approval. However, construction will not begin before summer 2003.

An onshore wind farm has three main components of cost: the turbine; balance of plant (BOP) costs (foundations, service roads, communications and network connection); and O&M costs. An offshore wind farm additionally bears the cost of electrical infrastructure—ie, cable from the wind farms to the shore. It is also expected to incur higher BOP and O&M costs as a result of the difficulty of working offshore.[67] Estimates for these costs are examined below, in turn.

Turbine costs—include delivery to the site and installation, but not the BOP costs. Estimates of turbine costs are provided in Table A4.1, and are sourced from three manufacturers and from the 2001 German wind energy yearbook. Costs vary from a low of £479,000/MW for the Nordex 2.5 MW wind farm, to £650,000–£700,000/MW for the Suedwind and Enron 1.5 MW turbines. However, the cost estimates obtained from UK manufacturers appear to be at the lower end of the range, between £490,000/MW and £550,000/MW. The latter estimate is for offshore turbines, which is in line with the assumptions used in DTI's Future Offshore consultation, where a central estimate of

[67] However, offshore wind farms are expected to have a higher load factor than onshore wind farms, which might partly or wholly offset the higher fixed cost.

£510,000/MW was chosen.[68] A study on the Middelgrunden site gives a lower cost estimate of £400,000/MW.[69]

Table A4.1: Turbine cost estimates

Manufacturer	Capacity (MW/turbine)	Cost (£/MW)
Nordex	2.5	479,000
Bonus UK	**1.3**	**490,000**
Nordex UK	**1.3**	**494,000**
Neg Micon	1.5	522,000
Enercon UK	**1.8**	**530,000**
Vestas UK (offshore)	**2.0**	**550,000**
Jacobs Energie	1.0	559,000
Enercon	1.8	594,000
Bwu	1.5	603,000
AN Windenergie	1.3	605,000
Jacobs Energie	1.5	607,000
Pfleiderer	1.5	616,000
Jacobs Energie	1.5	635,000
Fuehrlaender	1.5	639,000
Neg Micon	1.5	639,000
Suedwind	1.5	642,000
Suedwind	1.5	674,000
Enron	1.5	680,000
Enron	1.5	711,000

Note: Estimates in bold are specifically for the UK. These prices are for single turbines. When bought in bulk, the average turbine cost would probably be slightly lower; however, manufacturers are unwilling to disclose their bulk purchase discounts.
Sources: Bundesverband Windenergie (2001), 'Windenergie 2001'. Quoted prices were offered by manufacturers; personal communications with Vestas UK, Enercon, UK, Nordex UK, Bonus UK.

A series of National Renewable Energy Laboratory studies estimate costs for cutting-edge wind technologies.[70] Assuming cost reductions from learning by doing and five consecutive years of production, National Renewable Energy Laboratory analysis yields a cost estimate that is substantially lower than the current UK and European estimate—

[68] See DTI (2002), 'Future Offshore', November.
[69] Sørensen, H.C. and Hansen, J. (2001), 'Experience from the Establishment of Middelgrunden 40 MW Offshore Wind Farm', http://www.middelgrunden.dk/MG UK/article/hcsoc3 1pdf
[70] National Renewable Energy Laboratory (2001), 'WindPACT Turbine Design Scaling Studies Technical Area 1: Composite Blades for 80- to 120- Meter Rotor'; 'WindPACT Turbine Design Scaling Studies Technical Area 2: Turbine Rotor, and Blade Logistics'; and 'WindPACT Turbine Design Scaling Studies Technical Area 3: Self-Erecting Tower and Nacelle Feasibility'.

between £177,000/MW and £392,000/MW for turbines ranging from 0.8 MW to 5 MW. The potential for cost reductions is discussed further below.

Balance of plant costs—BOP costs generally include costs for foundations and crane pads; service roads; electrical infrastructure on site; grid connection (if paid for by the developer); other infrastructure (tower lighting, communications, meteorological); land purchase (if not rented); planning approval; management during construction; construction surveillance; and contingency (typically 1–3% of BOP costs). Costs estimates are summarised in Table A4.2. For onshore wind, a maximum quoted BOP cost figure of £261,000/MW was found and a minimum of £133,000/MW. For offshore wind, the Middelgrunden wind farm had a BOP cost of £357,000/MW, or 47% of the total investment cost. A study by the European research consortium, CAOWEE, reports a similar percentage (49%).[71]

Table A4.2: BOP cost estimates

Source	Total BOP costs (£/MW)
Risø Institute	133,000
Scottish Executive	136,000
European Commission[1]	161,000
Windenergie	195,000
British Wind Energy Association	231,000
Middelgrunden project	357,000
National Renewable Energy Laboratory	364,000

Note: [1] The European Commission figure is the average of the low and high estimates.
Sources: Data from Morthorst, P.E. (1998), 'Wind Power Development: Status and Perspectives', Risø National Laboratory, Roskilde; Scottish Executive (2001), 'Scotland's Renewable Resource 2001—Volume 2: The Context'; European Commission (2000), 'Wind Energy: The Facts, Volume 2: Costs, Prices and Values'; Bundesverband Windenergie (2001), 'Windenergie 2001'; www.bwea.com; Sørensen, H.C. and Hansen, J. (2001), 'Experience from the Establishment of Middelgrunden 40 MW Offshore Wind Farm'; National Renewable Energy Laboratory (2001), 'WindPACT Turbine Design Scaling Studies Technical Area 4: Balance-of-Station Cost'. OXERA calculations.

Electricity infrastructure—the costs of cabling vary from site to site, depending on the seabed geology, the depth of the water and the distance from shore—the latter cost factor being particularly influential for smaller and medium-scale installations. Substantial economies of scale are expected for large-scale installations. For example, DTI's 'Future Offshore' consultation mentioned cost savings of 10% if the electrical infrastructure carries 500 MW or more over distances of greater than 20km offshore, and more important economies of scale for even longer distances. It consultation assumed a cost of connection of £250,000/MW for cable and network connection. On the other hand, in

[71] Concerted Action on Offshore Wind Energy in Europe (CAOWEE), a consortium comprising developers, utilities, consultants, research institutes and universities, and funded by the European Commission—for information, see www.offshorewindenergy.co.uk.

work undertaken by NGC, estimates of wind generation costs assume a difference of £350,000/MW between onshore and offshore plant, which should mainly represent the cost of cable to the shore.[72] A study on the Middelgrunden project indicated offshore connection costs of about £60,000/MW, or about £130,000/MW with external grid connection.[73]

Operation and maintenance costs—O&M costs for transmission-connected wind generation are uncertain, as few large-scale wind farms have been commissioned yet. The estimates summarised in Table A4.3 range from as low as £2.5/MWh to a maximum of £21/MWh. The latter estimate appears very high, and does not seem to reflect cost assumptions in recent policy initiatives. The 'Future Offshore' consultation assumes a cost of £12/MWh, plus £0.88/MWh for Crown Estate rent.

Table A4.3: O&M cost estimates

	Total O&M costs (£/MWh)
Middelgrunden project	2.5
DTI 'Future Offshore'	12.9
European Commission	14
Windenergie	21

Sources: Data from Morthorst, P.E. (1998), 'Wind Power Development: Status and Perspectives', Risø National Laboratory, Roskilde; Scottish Executive (2001), 'Scotland's Renewable Resource 2001—Volume 2: The Context'; European Commission (2000), 'Wind Energy: The Facts, Volume 2: Costs, Prices and Values'; Bundesverband Windenergie (2001), 'Windenergie 2001'; www.bwea.com; National Renewable Energy Laboratory (2001), 'WindPACT Turbine Design Scaling Studies Technical Area 4: Balance-of-Station Cost'. OXERA calculations.

A4.1.2 Potential for cost reduction

In the future, offshore and onshore wind generation costs are expected to decline, as improved designs, techniques and materials reduce capital and operating costs. In addition, there may be national economies of scale in services that are likely to be supplied by domestic firms, reducing O&M costs. Historically, the learning rate for Danish wind turbines has been 4% for the period 1982–97.[74] Other countries have experienced higher learning rates (indices)—eg, 8% in Germany.[75]

Predictions can be made of the potential costs of wind generation one or two decades into the future. One method is to use typical patterns of changes in unit costs observed across a range of technologies—which is known as learning curves—and apply them to scenarios of offshore and onshore wind build across Europe. This analysis was

[72] See the presentation of Lewis Dale, NGC, at the Renewable Energy and Intermittency ECI Workshop, held on November 29th 2002 at the University of Oxford (www.eci.ox.ac.uk/lowercf/intermittency/intro.html).

[73] Sørensen, H.C. and Hansen, J. (2001), 'Experience from the Establishment of Middelgrunden 40 MW Offshore Wind Farm'.

[74] IEA (2001), 'Experience Curves for Energy Technology Policy'.

[75] McDonald, A. and Schrattenholzer, L. (2001), 'Learning Rates for Energy Technologies', *Energy Policy*, **29**, 255–61.

undertaken by OXERA for the DTI's 'Future Offshore' consultation.[76] This methodology suggests that the cost of wind generation could fall by up to 50% over the next 20 years.[77]

A4.1.3 Model assumptions

Two cost scenarios have been chosen for the financial model, in order to reflect the wide range of current and future capital and operating costs of wind generation. The low-cost scenario assumes that up to 20% savings could be achieved in capital costs by 2005/06, which is the starting year of the projects assessed. The high-cost scenario assumes no learning curve or economies of scale beyond ongoing efficiency gains of 2% per annum. With respect to O&M costs, the low-cost scenario is based on the Middelgrunden project—ie, £2.5/MWh. Given the low level of this estimate, no further learning curve or economies of scale beyond ongoing efficiency gains of 2% per annum have been used. The high-cost scenario assumes no learning curve or economies of scale beyond ongoing efficiency gains of 2% per annum. Table A4.4 summarises the cost assumptions chosen for the financial model.

Table A4.4: Cost assumptions (2005/06 prices)

	Offshore wind		Onshore wind	
Cost scenario	**Low**	**High**	**Low**	**High**
Capital costs (£/MW), of which:	630,000	1,080,000	530,000	880,000
Turbine costs	420,000	620,000	420,000	620,000
BOP costs	110,000	260,000	110,000	260,000
Cable costs	100,000	200,000		
O&M (£/MWh)	2.5	14	2.5	12

Source: OXERA.

Load factors of 40% and 32% are assumed for offshore and onshore wind farms, respectively.

A4.2 Price assumptions

A4.2.1 ROC price scenarios

The RO places an obligation on electricity suppliers to purchase a proportion of their generation from renewable sources, with the obligation rising to 10.4% of electricity supplied by 2010/11. Suppliers must demonstrate their compliance by obtaining ROCs, either directly by buying electricity from accredited renewable generators, or by trading with other market participants. Alternatively, suppliers can buy out of the obligation by

[76] Similar work was undertaken by the Cabinet Office; see Energy Review Advisory Group (2001), 'Energy Systems in 2050', and 'Technical and Economic Potential of Renewable Energy Generating Technologies: Potentials and Cost Reductions to 2020'.

[77] For research on learning curves, see IEA (2000), 'Experience Curves for Energy Technology Policy', and Roberts, P. (1983), 'A Theory of the Learning Process', *Journal of the Operational Research Society*, **24**, 71–9.

paying £30/MWh (2001/02 prices; yearly adjustments are made by Ofgem to reflect changes in the retail price index),[78] with the buy-out revenues recycled to holders of ROCs. The revenue received by renewable generators comprises the wholesale electricity price plus a premium captured in the ROC price.

In the model, it is assumed that ROCs are given on the output generated without any adjustment for losses. This appears to be consistent with Article 9 of the Renewables Obligation Order 2002 and Renewables Obligation (Scotland) Order 2002, and Ofgem's interpretation of net input as being the gross output (which is the total amount generated) less any input electricity.[79]

The scenarios for future ROC prices considered in the financial model are summarised in Table A4.5. These are based on Platts' ROC forecasts until 2007/08 (released in January 2003), which have been projected until 2019/20. Platts' forecasts are based on Ofgem's RO database of existing accredited power stations and planning data, and take into account information on renewable projects and planning success rates.

Three scenarios are considered to allow for the build rate. This attempts to account, at a high level, for the feedback effects due to entry decisions (eg, if the financial modelling suggests that some renewables projects will no longer proceed, the expected ROC price is likely to increase, which may lessen the final impact of AZTL). Low build rates may be a result of factors such as difficulties with consent and planning permission, or low electricity prices. Since Platts published its forecast, a number of consents have been given to renewable projects—in particular, consent has been granted for three offshore wind farms with a combined capacity of 397 MW. Such a development would favour the choice of a high-build scenario if it is sustained and projects go ahead.

Platts' forecasts have been projected up to 2019/20 so as to account for the speed with which renewables entry will occur. In the 2003 Energy White Paper, the government reiterated its firm commitment to the RO and stated that the current level of support will be maintained until 2027.[80] It also expressed its aspiration to double the share of electricity from renewables from the 2010 target by 2020, and said that it will pursue policies to that end. Progress will be reviewed in 2005/06 to inform the elaboration of a strategy for the decade to 2020.

[78] The first adjustment was made in March 2003, setting the RO buy-out price at £30.51/MWh for 2003/04.
[79] See Ofgem (2002), 'The Renewables Obligation—Ofgem's Procedures', February.
[80] DTI (2003), 'Energy White Paper; Our Energy Future—Creating a Low Carbon Economy', February, paras 4.12–4.13.

Given that the government has not yet taken a decision on which targets will be set beyond 2010, a target of 10.4% has been maintained until 2020. The buy-out price was kept at the current level of £31.74/MWh (2005/06 prices, assuming 2% inflation per annum). However, if the RO targets set after 2010 were higher than 10.4%, to reflect the government's aspiration to double the share of electricity generation from renewables sources by 2020, ROC prices would be expected to be higher than in the scenarios considered in the modelling. Having higher ROC prices would reduce the impact of zonal loss charging on a renewable project's IRR.

The level of compliance with the RO implied by the chosen ROC price scenarios is provided in Table A4.5. Assuming that ROC prices are equal to the buy-out price in 2010/11 (scenario 1) implies full compliance with the RO—ie, 10.4% of electricity supplied from renewables sources. When a medium-build rate is assumed, the implied RO compliance in 2010/11 is 7%, with full compliance being achieved in 2012/13, while under a low-build rate RO compliance in 2010/11 is only 5.4%, the total obligation being met in 2014/15.[81]

Table A4.5: ROC price scenarios

	ROC prices (£/MWh, 2005/06 prices)			Implied RO compliance (%)		
Build rate	**Low**	**Medium**	**High**	**Low**	**Medium**	**High**
2005/06	59.12	48.51	37.75	3.0	3.6	4.6
2006/07	70.86	59.74	49.70	3.0	3.6	4.3
2007/08	83.51	70.48	58.66	3.0	3.6	4.3
2008/09	76.12	62.73	45.20	3.8	4.6	6.4
2009/10	68.72	54.98	31.74	4.5	5.6	9.7
2010/11	61.33	47.24	31.74	5.4	7.0	10.4
2011/12	53.93	39.49	31.74	6.1	8.4	10.4
2012/13	46.53	31.74	31.74	7.1	10.4	10.4
2013/14	39.14	31.74	31.74	8.4	10.4	10.4
2014/15	31.74	31.74	31.74	10.4	10.4	10.4
2015/16	31.74	31.74	31.74	10.4	10.4	10.4
2016/17	31.74	31.74	31.74	10.4	10.4	10.4
2017/18	31.74	31.74	31.74	10.4	10.4	10.4
2018/19	31.74	31.74	31.74	10.4	10.4	10.4
2019/20	31.74	31.74	31.74	10.4	10.4	10.4

Source: Platts for data until 2007/08; OXERA calculations.

[81] The calculations are based on estimates of the total volume of electricity required by the RO in Great Britain provided in DTI (2001), 'New & Renewable Energy—Prospects for the 21st Century: Renewables Obligation Statutory Consultation', August.

A4.2.2 Wholesale electricity price assumptions

The financial model is based on the annual baseload electricity wholesale price obtained from OXERA electricity wholesale model—as discussed in section 3. The last year of actual data (2009/10) has been kept constant until 2019/20. Table A4.6 sets the wholesale electricity price assumptions used to calculate renewables plant revenue.

Table A4.6: Wholesale electricity price scenarios (£/MWh, 2005/06 prices)

	Uniform loss charging	Zonal loss charging
2005/06	19.79	19.81
2006/07	22.65	22.73
2007/08	21.45	21.42
2008/09	21.39	21.41
2009/10	21.29	21.29
2010/11	21.29	21.29
2011/12	21.29	21.29
2012/13	21.29	21.29
2013/14	21.29	21.29
2014/15	21.29	21.29
2015/16	21.29	21.29
2016/17	21.29	21.29
2017/18	21.29	21.29
2018/19	21.29	21.29
2019/20	21.29	21.29

Source: OXERA.

The model assumes that wind farms receive a discounted wholesale electricity price due to the imbalance charges attracted by intermittent generation. The discount factor assumed in the calculations is 10%.