**SUBMISSION FROM TUSNE (TRADE UNIONISTS FOR SAFE NUCLEAR ENERGY).**

TUSNE, formed in 1984, is an informal grouping of trade unionists who are supportive of the use of civil nuclear energy within a balanced energy policy and a safe and clean environment. The organisation's executive committee is made up of senior officials from the major trade unions within the electricity supply industry.

TUSNE's main mission is to provide a forum for debate about energy issues, and regularly attends trade union and political conferences in Scotland, including the STUC, the Labour Party, the SNP, the Liberal Democrats and the Conservative Party.

TUSNE submits this evidence to the Enterprise and Culture Committee in recognition of the proper contribution of all energy sources – fossil fuels, renewables and nuclear power – to Scotland's social and economic wellbeing.

**Introduction**

TUSNE welcomes the opportunity to comment on the Scottish Parliament Enterprise and Culture Committee's Inquiry into renewable energy.

This Inquiry is timely. A number of events in recent times have raised the profile of energy and electricity, of which the following are perhaps especially important:

- the impending depletion of the UK's North Sea oil and gas reserves, of particular importance to the Scottish economy;

- growing concern about climate change, against the background of the apparent failure of the international community to ratify the Kyoto Protocol;

- continuing liberalisation of electricity markets, notably the extension of the competitive market in England and Wales to Scotland under the BETTA proposals;

- the new European Large Plant Directive coming into force in 2008, which will require significant reductions in emissions of sulphur dioxide from coal-fired power stations;

- major power cuts in New York, Copenhagen, Italy and London.

TUSNE recognises that the Inquiry is being held at an early stage in the formulation of policy to support the strategic aspiration of 40% of electricity generated using renewables. As such TUSNE's main aim in making this submission is to suggest areas for further work and research as energy policy is being developed, rather than trying to offer a detailed quantitative roadmap towards the sustainable future we would all desire. There are many issues which are of importance to such an Inquiry. Some would take more space than is available here, but deserve a passing mention:

- How will the introduction of new trading arrangements (BETTA) to Scotland, replacing the previous structure of vertically-integrated utilities, affect investment in power projects, given global experience that competitive marketplaces tend to drive out investment in power plants and reduce capacity margins, thereby putting more emphasis on the reliability of the output of power stations?

- What level of subsidy will be necessary, and how should these subsidies be structured, in order to create a stable investment climate for renewables, given the relative failure of the 'green certificates' regime in England and Wales to attract sufficient investment in new plants? (Although renewable schemes totalling some 1,700 MW of capacity were described as 'planned' by Ofgem in November 2003, only 90 MW were actually under construction.)

- What are the key issues in the transition between the current system, which is characterised by a small number of very large plants (just five power stations account for three quarters of Scotland's 9,850 MW of installed capacity), to one characterised by a very large number of small, embedded generating units, e.g. the costs of rewiring to an entirely new grid philosophy, or the way that the day a large unit is switched off and replaced by a large number of small ones can be managed?

TUSNE would be happy to provide further submissions on these issues if requested. However, in this submission TUSNE will focus on two issues:

- What is the experience of countries with a considerable proportion of renewable capacity in their electricity mix?

- How will Scotland's economic and environmental objectives be met if the 2020 renewables aspiration is not met, and indeed if it is?

TUSNE believes that renewables will potentially play a valuable role in meeting future energy demands. However, we also believe that there are formidable obstacles to be overcome if renewables are to play as large a role as 40% of total generation and decision-makers must therefore make sure that a range of alternatives are pursued in case hoped-for outcomes prove difficult or impossible to achieve. It is vital, in our view, that the nuclear option also be kept open, both in case the potential for cost-effective renewable technology proves limited within the timescale involved, and in order to ensure that even if aspirations are achieved, the low-carbon benefits of renewable technologies are not used simply to compensate for the loss of another low-carbon technology.

*Power versus energy*

Electricity cannot be stored, yet demand varies enormously at different times of the day and year. It is therefore only part of the story to consider the proportion of Scotland's electricity *energy* which can be provided by renewables. It is also vital to consider the reliability of renewable *power* in covering peak demand. Unless Scotland has access to enough electricity at moments of peak demand then the lights will go out, and therefore the intermittency of many renewable sources – wind, tidal, solar – is of particular importance.

Peak demand 2000/01 was 6,050 MW. It is generally accepted that a margin of 20% should be maintained over projected peak demand, in order to cater for unexpected cold snaps or plants being unavailable because of maintenance or breakdown, implying required capacity of some 7,250 MW in 2000/01. At present this is comfortably covered by the five biggest power stations (combined capacity 7,400 MW), viz.:

- Hunterston B (1,190 MW, British Energy, nuclear, commissioned 1977),
- Torness (1,250 MW, British Energy, nuclear, 1989);
- Longannet (2,300 MW, Scottish Power, coal, 1970);
- Cockenzie (1,150 MW, Scottish Power, coal, 1968);
- Peterhead[1] (1,550 MW, Scottish & Southern Energy, oil/gas, 1980).

In other words, one or perhaps even two of these plants could break down or be withdrawn for maintenance without seriously threatening secure supplies of electricity, even at times of high demand. Scotland's hydropower capacity totalling some 1,350 MW, plus an extra 1,000 MW of smaller power plants, add an extra degree of comfort (see http://www.restats.org.uk/Regional_-_Chart_3.html).

However, by or around 2020 much of the above capacity will be unavailable. Current plans suggest that Hunterston B will be retired in 2011 and Torness in 2023. Cockenzie is one of the oldest of the remaining large coal-fired

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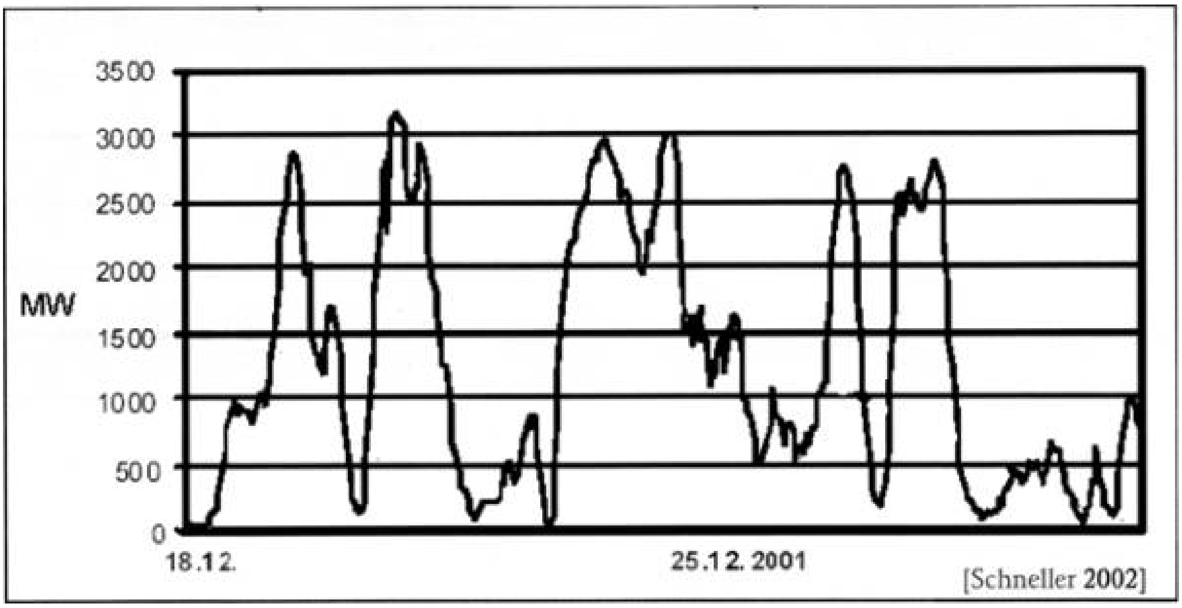
1 Peterhead has rated output 2,300 MW, but owing to grid constraints only 1,550 MW can be used at any one time.

power stations in the UK, while Longannet power station near Kincardine was built to take coal from the nearby coalmine. A flooding accident in March 2002 led to the premature closure of the mine, although Longannet (on the Forth) has good import facilities for foreign-mined coal. In addition, the environmental pressures on these two stations are significant. The Large Plant Directive of 2008 will have severe implications for coal stations without Flue Gas Desulphurisation. Friends of the Earth, in its report *Carbon Dinosaurs* (2003), named Cockenzie and Longannet as the first and third most polluting coal stations in the UK in terms of the amount of carbon dioxide (the main greenhouse gas) emitted per unit of electricity produced (http://www.foe.co.uk/resource/reports/carbon_dinosaurs.pdf). It is therefore unlikely that either of these stations will still be operating in 2020.

By 2020 or soon afterward, then, perhaps only Peterhead – then forty years old – of the major power stations now operating will still be on-line. The scope for expansion of hydropower is limited, notwithstanding Scottish & Southern's recently announced plans for a station of 50-100 MW near Loch Ness. In total, then, even if grid connections to Peterhead are improved only some 3,750 MW of today's installed 'firm' capacity (including some new hydro) will still be in service in or around 2020.

Assuming that peak demand grows at the same rate as general electricity demand, necessary 'reliable' capacity in 2020 (including the capacity margin) might be expected to be 8,400 MW. Over the next twenty years or so, then, a shortfall of nearly 5,000 MW will need to be filled.

Many of the renewables cannot be used for this purpose, as their output is unavoidably constrained by conditions such as the weather, time of day etc. In the case of wind, output is not only intermittent but also unpredictable beyond a few days' notice. As the below graph shows, even a windfarm of capacity 3,500 MW – nominally more than half of Scotland's peak capacity requirements – generates practically no electricity at all for short but significant periods of time in a typical winter. During those periods – which often occur at times of peak demand (since anticyclones which bring cold cloudless nights also tend to bring very low windspeeds, and also reduced levels of waves) – firm capacity must be available to maintain security of supply. Since most of the renewables face the same problem of intermittency, albeit in different ways, the back-up will probably need to be either fossil or nuclear.




*Windpower feed-in to grid of E.On Netz, Germany, winter 2001 (3500 MW installed capacity at that time)*
http://www.tu-berlin.de/~energiesysteme/downloads/publications/sacharowitz_2003_challanges_integrating_wind_power_iaee_mexico_speech.pdf

In other words, installed wind capacity of about 2,800 MW would be sufficient to produce 20% of Scotland electricity *energy* requirements in 2020 (assuming an availability factor of about 30%). This would require the installation of one 600 kW turbine of the kind used as the Danish 'reference' – see http://www.windpower.org/en/tour/wres/annu.htm **-** every weekday from now until 2020. However, it could not be relied upon to contribute more than a few tens of MW, if any, to *capacity* margins. Other forms of output would need to be retained, and their maintenance costs (including a proportion of their capital costs) for the periods during which they could not command an output because renewables were available would have to be met by consumers or taxpayers. Ironically, German windpower operators have found that high wind speeds are more difficult to manage than low speeds, as they can require large amounts of wind capacity to be shut down very rapidly to prevent damage, leading to significant difficulties in bringing replacement capacity on line quickly enough.

The potential problems associated with overdependence on unreliable electricity sources were illustrated in the summer of 2003 in Europe during the hot spell in June. Increased demand for air conditioning etc. was coupled with drought and a significant reduction in availability of power from other sources, notably large windfarms (and also from inland conventional power stations, including the French and German nuclear park – however, coastal nuclear stations such as those in the UK were unaffected). This led not only to very high prices, but also a major reduction in exports from France and Germany which led to blackouts in Italy, highly dependent on such imports.

Considerations of this nature were behind the decision, for example, taken in December 2003 by the Irish energy regulator to halt connections of windpower to the Irish grid. The Managing Director of ESB National Grid, said that wind connections 'pose an increased risk to the security and stability of the power system which exceed the level normally likely to be acceptable by a prudent system operator.'

A large-scale method for storing electricity would go some way towards ameliorating these problems, but no such method seems likely to be available for some time. Indeed, in December 2003 British utility Innogy abandoned its Regenesys electricity storage project after its German parent company RWE decided there was no commercial case for bringing it to market.

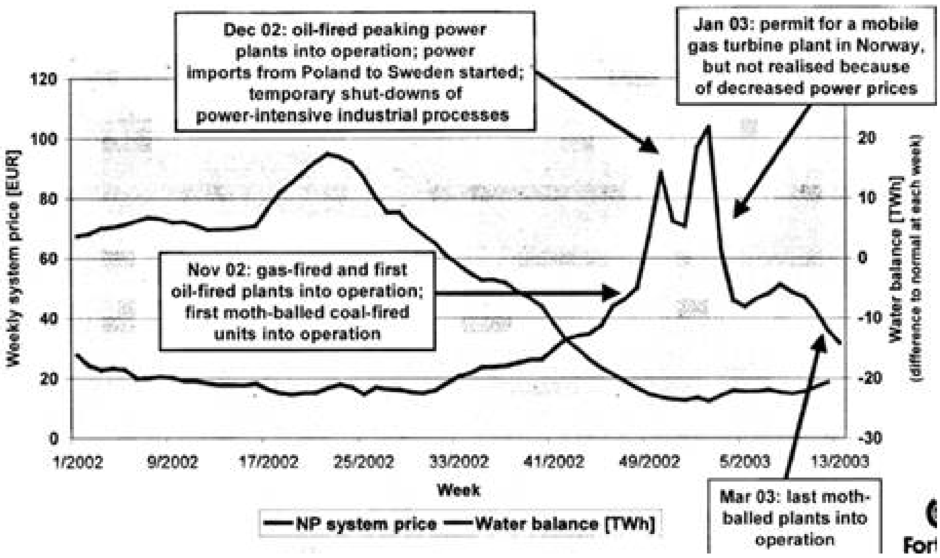
*Global experience of markets with high proportions of renewables*

There are very few countries in the world in which 'new renewables' make up a significant proportion of electricity production – Denmark (with 18% wind) is the most obvious example.

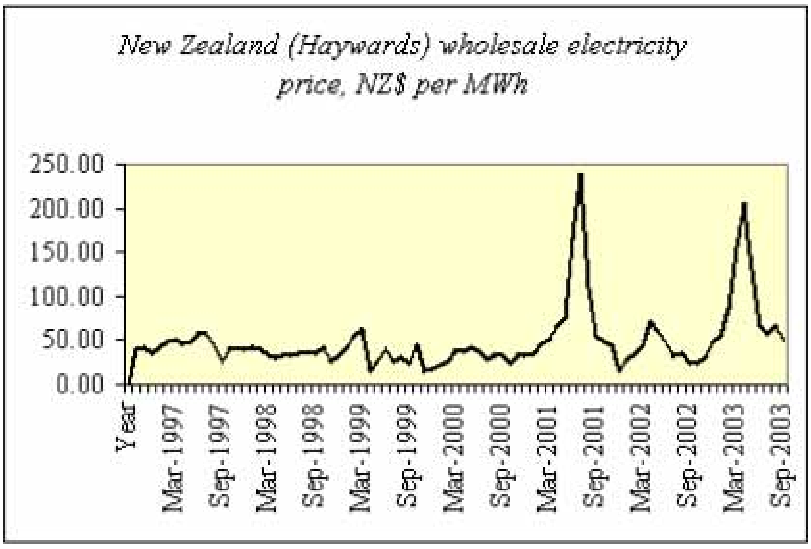
However, there are many countries in which hydropower plays a very major role – New Zealand (63% hydro), Norway (99%), Chile (56%), Brazil (81%) – and others in which hydropower plays an important regional role (e.g. California (18%) and the western USA).

Hydropower is not as intermittent in its output as renewable such as wind, solar or tidal power. Large dams act as storage systems for water, in a way that is not feasible for wind, sunshine or flowing water. Nonetheless, hydropower is susceptible to interruption caused by variations in weather conditions, in this case periods of low rainfall.

In many of the above countries there have been periods of major increases in the market price of electricity during dry spells. Recent examples include Norway (winter of 2002/2003, when prices quintupled in a few months); New Zealand (winters of 2001 and 2003, again involving quintupling of prices); Argentina (1999 and 2002) and Chile (1997 to 1999). In some of these cases, notably in Latin America, the high prices were accompanied by power cuts.

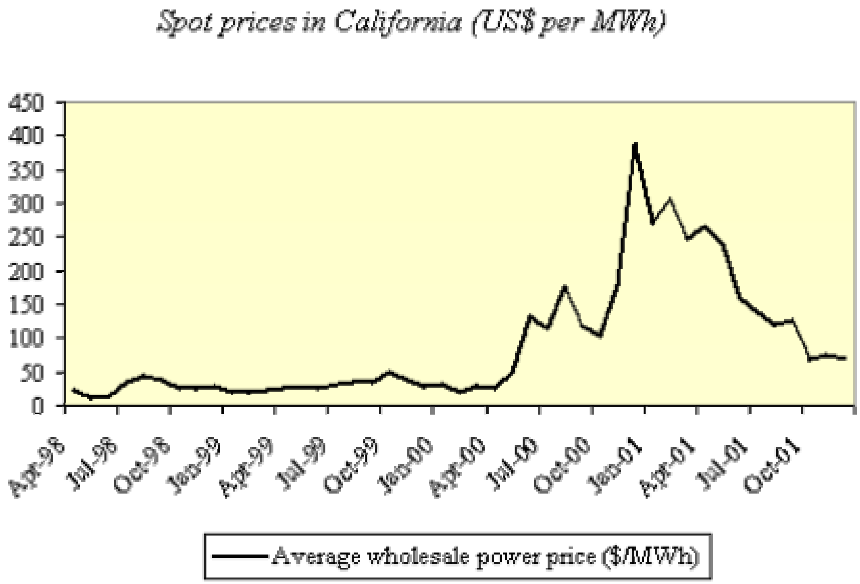



***Spot prices in NordPool during the hydro crisis of 2002/3***
(http://www.baltrel.com/Seminars/Moskova100403/PresentKuula0403.pdf**)**




It is noticeable that many of these countries are now following policies of reducing their dependence on renewable energy and increasing the amounts of electricity they generate from more traditional sources. To take one example, Chile, which suffered badly from failure of renewable energy in the late 1990s, first turned to natural gas imported from Argentina. Disruptions to gas supplies, owing to strike action and technical problems in early years of the 21st century, led to a further change in policy and more attention on use of oil for power production, with inevitable environmental consequences. (See http://www.eia.doe.gov/emeu/cabs/chile.html).

Most spectacularly, rainfall shortage in the western USA and very high gas prices were key factors in the California electricity crisis of 2000/2001. Reductions in the availability of hydropower, both within California and in neighbouring States on which California depended for imports, caused power shortages which (coupled with an inefficient system of price caps) eventually resulted in widespread blackouts. Quite apart from the direct costs of the power failures, the measures to remedy the position were extremely expensive, and many commentators believe them to have been a significant factor in the fall of Governor Gray Davis.




The Californian experience is of special potential relevance to Scotland, as California relies heavily on imported natural gas (36%) and renewables (32%) for its electricity (excluding electricity imports). The States of the eastern USA, more reliant on coal and nuclear power (for example, the States in the Pennsylvania-New Jersey-Maryland interconnection generate 85% of their electricity using these two sources), were easily able to ride the years of low rainfall and very high gas prices around the turn of the new century without interruptions to supplies or significant rises in price. These sources of electricity are much more resistant to short-term price shocks, being less susceptible on unpredictable changes in availability or price.

Windpower and other renewables such as solar or tidal power do not tend to suffer from very long periods of interrupted feed-in such as is represented by a long drought. However, in the short-term (including real-time) they can be much more intermittent.

Clearly price spikes of this nature, lasting from anything between a few weeks to well over a year in the Californian case, cause significant difficulties to consumers, both major industries (which will become less competitive in international markets if their input costs increase significantly) and residential consumers, especially those living in energy poverty who may not feel able to pay power bills which have doubled or trebled in a short period of time.

*The role of nuclear power*

Nuclear power presently plays a centrally important role in Scotland's electricity supply industry. Nuclear power shares many of the advantages of renewables – most importantly it does not contribute to climate change or acid rain and does not require inputs of fossil fuel (most of which will need to be imported before long) – but unlike many renewables it is not reliant on such factors as weather conditions, and can therefore be used for baseload power production, the irreducible minimum needed to keep society functioning.

Although its economic record in the UK has been somewhat disappointing (though much less so in Scotland than in England), new reactor designs based largely on successful construction projects in the Asia-Pacific region are becoming available. These designs are simpler in concept, depending more on passive safety features than on engineered components such as valves and pumps, and are therefore proving both cheaper to build and more reliable in operation, especially in their early years, than has sometimes been the case with 'traditional' nuclear technology. Progress on waste management is also vital, although experience from Finland and Sweden suggests that publicly acceptable ways forward can be found. Indeed Finland, a country with considerable similarities to Scotland in terms of population and fuel mix used for electricity generation, is in the process of building a new nuclear reactor to reduce future dependence on imported (Russian) gas.

However, renewables and nuclear power suffer from a shared difficulty with respect to investment in a competitive market, bearing in mind the forthcoming extension of the electricity market in England and Wales to Scotland (BETTA). In both cases initial investment (capital expenditure, or CAPEX) is heavy, although running costs (operational expenditure, or OPEX) tend to be relatively low. In a competitive marketplace investors tend to want a return on their capital in a short period of time, and so are strongly attracted to low-CAPEX high-OPEX sources such as Combined Cycle Gas Turbine (CCGT). The case of Denmark, where windpower accounts for 18% of the market and can therefore be regarded as a fully mature commercial technology, is interesting. Proposals in February 2002 by the Government to cut heavy subsidies were met with a barrage of protest from the industry and cancellation of three large offshore windfarms, and resulted in restoration of the subsidies in the form of a price guarantee well above market levels. It is likely that some ongoing involvement of Government in creating an environment attractive to investment would be required for both renewable and nuclear technologies, and it is important that the incentives that may be offered to the one are also available to the other if the most cost-effective solutions are to be found.

*Conclusions*

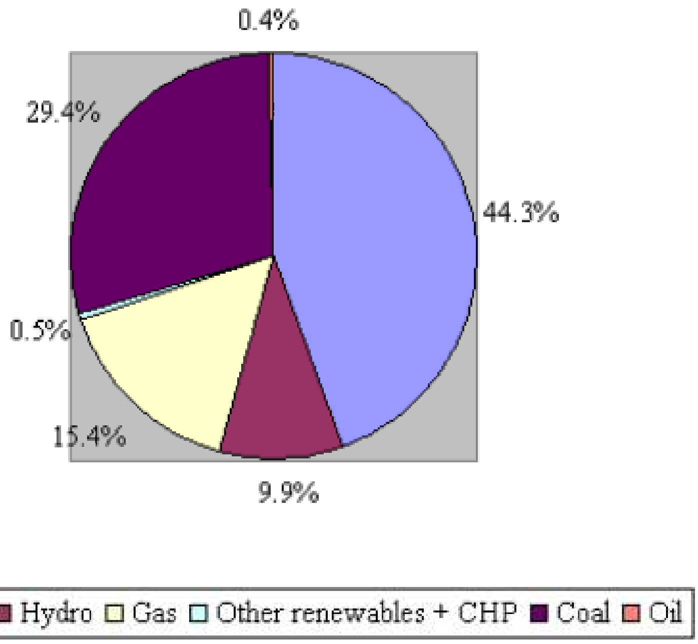
To reach the 40% renewables aspiration in 2020 will require overcoming a number of major obstacles and it cannot be taken for granted that this will be achieved. Even if it is achieved, significant issues will remain as to how Scotland can control its emissions and safeguard secure energy supplies. It would be ironic indeed if in 2020 or 2025 Scotland were to find that an enlightened policy of developing renewable energy had simply resulted in the replacement of one zero-carbon source with another, perhaps at significantly higher overall cost, without any benefit for the climate, security of supply or avoiding reliance on fossil fuel imports.

In due course the Scottish Executive will need credible fallback positions should progress prove disappointing for any reason. In TUSNE's view nuclear power would make a valuable partner for renewables in a new low-carbon economy, offering baseload electricity which does not depend on weather conditions of the day as a balance to the inherent intermittency of the major renewables.

**APPENDIX – background information and assumptions**

In 1999/2000 Scotland generated 42.5 TWh (net) of electricity. Of this output, 32.0 TWh were consumed in Scotland and 10.5 TWh were exported to England and Wales. In 1990/1991 generation had been 32.4 TWh, consumption 29.9 TWh and exports 3.1 TWh. The total amount of electricity generated in Scotland therefore increased by 32% between 1990/1991 and 1999/2000, but consumption only increased by 8%. In 1999/2000 25% of the electricity generated in Scotland was exported to England and Wales, against 10% in 1990/1991.

*Electricity generated by fuel in Scotland, 1999/2000*




(http://www.scotland.gov.uk/library3/environment/sesg-03.asp#2)

Nuclear energy was most important source of electricity in Scotland in 1999/2000, its output of 18.7 TWh accounting for 44% of the total (up from

37% in 1990/1991). Natural gas increased its market share from 0% to 15% over the decade, while the market shares of coal and oil each fell by about 10 percentage points.

Despite the reduced use of high-carbon sources (coal and oil) and increased use of lower-carbon (gas) and zero-carbon (nuclear) sources, the emissions of carbon dioxide, the main greenhouse gas, from Scotland's energy industries (mainly electricity) increased from 19.2 million tonnes in 1990/1991 to 23.3 million tonnes in 1999/2000. This was principally as a result of increased exports to the UK. Scotland's emissions of carbon dioxide per head from all sources (14 tonnes per head) are rather higher than the UK average, despite relatively low emissions per TWh of electricity generated.

*The future*

It is notoriously difficult to make accurate predictions about future energy production and use. Nonetheless, scenarios can be built which illustrate how the future might look if current trends continue.

In TUSNE's response to the DTI Energy White Paper (available from TUSNE) we build a scenario for the future based on UK Government documents such as Energy Paper 68 and the White Paper itself. From these sources one possible future scenario, which we refer to as 'central', would see electricity demand in the growing by 15.5% between 2000 and 2020, implying consumption of some 37 TWh in Scotland in that year. Assuming no new build of nuclear power, output from the existing nuclear station, Torness, will be approximately 8.8 TWh (assuming an 80% availability factor).

Let us further assume that Scotland would aim to produce roughly the same quantity of electricity as it consumes.1[1] In this scenario, output from renewable sources would have to be about 14.8 TWh to meet the 40% aspiration. Zero carbon sources, then, would account for some 65% of Scotland's electricity (as opposed to 55% in 1999/2000).

Note however that if Torness were to come off line before 2020 (its current closure date is expected to be 2023), or if we look forward to 2025, fossil fuels will be accounting for 60% of the market in this scenario – a higher

1[1] This may prove problematic, as capacity margins in England and Wales have been falling. If Scotland were part of a wider GB or perhaps UK electricity market, shortage of capacity anywhere in the system would be equally likely to affect all parts of that system. Consumers in Scotland would in effect have to pay their share of the cost of new power stations and transmission wires, wherever they were located. Furthermore, the limits on interconnector capacity – at present 2,200 MW between Scotland and England and 500 MW between Scotland and Northern Ireland – would introduce the risk that at times of high power demand congestion on the interconnectors would limit the amount of power which could be imported. This might imply a need either to build more interconnector capacity or to build more back-up generating capacity, with obvious financial and environmental consequences in each case.

proportion than in 2000. The projected move from coal to gas would still result in a reduction in greenhouse emissions, but the ‘dash for gas’ is essentially a one-off bonus. Once all coal has been replaced by gas only a further increase in zero-carbon energy sources will contain further carbon dioxide emissions.

In effect, then, this policy would result in simply replacing one zero-carbon source of energy in Scotland with another, with no net benefit for greenhouse gas emissions or for reduced dependence on imported fossil fuels.