Cost of Non-Europe

in the Single Market for Energy

ANNEX II

Effectiveness of internal energy market policies

Research paper
by David Buchan

Abstract

Given the wide range of policies directed to creating the internal energy market (IEM), the approach of this paper is to focus, in some detail, on the five areas that, currently, are receiving most attention from EU legislators and policy-makers and where most challenges arise. The paper first tackles the issue of national renewable and capacity subsidies. From this supply-side problem, it turns to examining the likely impact of energy efficiency policies on demand reduction and how this will change market dynamics and the behaviour of market players. It then examines EU policies to accelerate infrastructure investment. The next section focuses on issues such as pricing arrangements, market coupling and network codes. The last section deals with the expanding external dimension to EU energy policy.

AUTHOR

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Executive Summary

The internal energy market (IEM) is designed to move the European Union towards a low-carbon economy as cost-effectively and securely as possible. These objectives have been partly met:

- Price convergence, a measure of competitive cross-border trade, has begun, although renewables cause some price volatility in some electricity markets, and progress is being made in unifying cross-border trading arrangements.
- Energy diplomacy and network improvements have increased EU resilience to external energy shocks. The main risk to continuity of energy supply probably now comes from the intermittency of wind and solar power, and the difficulty of providing back-up capacity in ways compatible with a single European market.
- The EU is on track to meet its 2020 targets for emission reduction and (probably) renewable energy. But the emission reduction owes less to any increase in renewable energy and energy efficiency (which lags behind) than to the economic downturn that has depressed investment.

The European Council of February 2011 set the goal of completing the IEM by 2014 and linking all member states to it by 2015. This goal will not be fully met; some markets will still be uncoupled, and some member states still isolated, by those dates. Europe's economic malaise has slowed progress and depressed investment in all parts of the energy industry except, to a large extent, the subsidised renewable sector.

Renewable deployment has run ahead of development of infrastructure to transport renewables, and conventional generation to back them up at times of intermittency. Near-collapse of the Emissions Trading System has left the renewable sector fully exposed to the distorting effect of national subsidies of varying value and scope. A further distortion is imminent as an increasing number of member states plan back-up capacity mechanisms that could segregate individual markets from each other.

To try to prevent this re-nationalisation of EU energy policy, the Commission is drawing up guidelines for member states to follow. [If you do not like the word recommendation, then use the word suggestion] Here are some suggestions for those guidelines and other aspects of EU energy policy could be:

Suggestions to europeanise national renewable subsidy schemes:

- Cost control should be carried out in ways that placate public concern without jeopardising investor confidence. Member states need to review their support tariffs transparently, regularly and quickly to keep pace with falling technology costs.
- Subsidies should take the form of market premiums that are an addition to, not a replacement for, market revenue. Renewable producers should be exposed progressively to market disciplines (like balancing) as well as market prices.

- Neighbouring countries should harmonise or merge their support schemes, on the basis of regions where regulators and TSOs are also coupling markets and harmonising trading arrangements.

Suggestions to avoid national capacity schemes if possible, but where necessary, to europeanise them:

- Calmly analyse generation adequacy across Europe. This will show that member states have different problems, and will therefore need different solutions. A very few like the UK have an impending shortage of overall generation capacity; many more like Germany lack flexible generation capacity to fill intermittent gaps caused by renewables.
- Improve short-term electricity balancing markets. This will help Germany and those similarly afflicted with lack of flexible generation, though not the UK which already has an effective balancing market that cannot make up for its shortage of megawattage in generation.
- Use state aid powers to force new building of cross-border grids. The Commission should use its state aid scrutiny powers to the full, and **only** approve capacity mechanisms where member states are ready to commit spending part of their capacity subsidy on building new cross-border infrastructure, thereby increasing their ability to draw on EU neighbours' supply in an emergency. It would be quite reasonable, and within state aid rules, for the Commission to insist that, in return for approval of capacity subsidies, member states show some action to increase cross-border interconnection so as to reduce, over time, the need for subsidising domestic generation capacity..

Suggestions on energy efficiency:

- Accept that it is too early to judge the energy efficiency element of the IEM - because the Energy Efficiency Directive is only due to be transposed into national legislation in mid-2014 – but continue to push for progress on this important front.
- Realise that the rate at which customers switch supplier may, and perhaps should, decline if efficiency programmes draw companies into satisfactory long-term relationships with their customers. High national rates of customer switching may come to be seen less as a good sign of competition, and more a bad sign of ineffective energy saving efforts.

Suggestions on infrastructure building:

- More top-down push from national governments and regulators. The European associations of TSOs are playing an active and vital part in designing blueprints for pan-European grids. But they cannot tell their members what to do. Individual TSOs often lack the financial incentive and means to initiate and carry through new projects, especially cross-border ones. Regulators need to spell out to TSOs what they need to do, but reward them better for doing it.

- The proposed cut in energy funding in the Connecting Europe Facility should be restored.

Suggestions on on pricing and on market and network unification.

- Press for de-regulation of retail end-user electricity and gas prices because regulated prices can stifle competition.
- Wait to see whether the new gas network codes can resolve inter-connector congestion before pressing on with market coupling, as in electricity.
- Examine the effect of gas entry-exit zones on the incentives for new investment.

Suggestions on external energy policy.

- Keep EU external policy focussed on practical infrastructure issues with Europe's neighbours. Many of these issues involve Russia, hence the importance of maintaining the often-difficult EU-Russia energy dialogue.
- Maintain support for Baltic member states, but ask them to do more to help themselves, in particular to resolve their indecision on siting a regional LNG terminal and regional nuclear power plant.
- Put more resources into the Energy Community in order to increase EU influence in Europe's south eastern near-abroad.

Introduction

Given the wide range of policies directed to creating the internal energy market (IEM), the approach of this paper is to focus, in some detail, on the five areas that, currently, are receiving most attention from EU legislators and policy-makers and where most challenges arise. The paper first tackles the issue of national renewable and capacity subsidies, which has now become the biggest challenge to the IEM's coherence. From this supply-side problem, it turns to examining the likely impact of energy efficiency policies on demand reduction and how this will change market dynamics and the behaviour of market players. It then examines EU policies to accelerate infrastructure investment. The difficulty of achieving this in the face of Europe's economic downturn makes it all the more important to maximise the use of Europe's existing stock of power lines and gas pipelines. This is the focus of the next section on issues such as pricing arrangements, market coupling and network codes, which provide essential plumbing to the system in order to ensure energy flows, and flow smoothly, across borders. Some of these borders are external, and the last section deals with the expanding external dimension to EU energy policy.

Emerging from all this is a mixed picture of the effectiveness of IEM policies. The internal energy market remains at the heart of the European Union's energy policy, which is to move towards a low-carbon economy as cost-effectively and securely as possible. These objectives have been partly met:

- Price convergence is an indicator of increasing cross-border trade and competition. Wholesale prices have begun to converge among member states, although renewables cause some electricity price volatility in certain member states, and lack of diversity in infrastructure and supply sources create a price disconnect in other member states. Considerable progress is being made in unifying cross-border trading arrangements (Section 4).
- In terms of security of supply, much has been done to improve EU resilience to external energy shocks (Sections 3 & 5). But the main risk to continuity of energy supplies probably now comes from the intermittency of wind and solar power, and the difficulty of providing back-up capacity for renewables in ways that are compatible with a single European market (Section 1).
- Emission reduction owes something to the growth in renewable energy and improvements in energy efficiency (Section 4), but even more to the economic downturn and the consequent decline or at least stagnation in energy demand.

In 2011 EU government leaders set the goal of completing the internal energy market by 2014 and of ending the physical isolation of certain national energy markets by 2015. Will the goal be met? Not in any full definition of the internal energy market. That definition, for instance, embraced adoption by 2014 of an "electricity target model" that included a coupling of power markets across the entire EU. As matters stand at present, next year will see only day-ahead electricity markets coupled and then only among countries of northwest Europe. This is still a significant achievement, but still short of the Europe-wide goal set by the politicians.

Outside factors have had an impact on the internal energy market's completion. One beneficial external impact has come from US development of shale gas. This has had the effect of diverting LNG gas supplies from elsewhere into the European gas market, and pushing the spot price of gas in Western Europe lower than the oil-indexed price of gas in Russia's long-term contracts. This has accelerated a shift away from buying gas on long term contracts and towards buying it more competitively on Europe's emergent gas trading hubs. Development in Europe of shale gas, under proper environmental control, would reinforce this shift.

However, Europe's economic malaise weighs far heavier on the negative side. The economic downturn and accompanying crisis in the eurozone has led to:

- Governments cutting their own spending on energy and other infrastructure.
- The EU cutting the share for energy infrastructure in the Connecting Europe Facility for 2014-2020 almost in half to EUR 5 billion.
- A decline in the credit rating of state-owned transmission system operators (TSOs) associated with the decline in the rating of their sovereign owners.
- Pressure on European utilities in general to reduce debt, sell assets and postpone any new investment unless, like renewables, supported by subsidy.
- Heightened sensitivity by the public, and therefore by politicians, to energy price rises. Although felt most acutely in poor countries like Bulgaria where electricity price rises recently brought down a government, this sensitivity to energy price increases exists everywhere across the EU.
- A decline in the price of carbon allowances on the Emission Trading System (ETS) to a point where the system seems to be having no influence on the behaviour of energy consumers or on the investment decisions of energy companies.

The ETS is the main Europe-wide instrument of EU energy policy. Therefore its weakening is serious for the coherence of the internal energy market. Instead of having a robust single carbon price to penalise carbon-intensive energy and thereby favour low-carbon energy sources, renewables are left being solely supported by a series of national subsidy schemes of varying value and scope. The renewables sector is therefore fully exposed to the distorting effect of national subsidies, which are themselves influenced by member states' varying macro-economic situations.

This is leading to a re-nationalisation of EU energy policy, in which national policies are beginning to diverge sharply, as can be seen in these three examples:

- Spain used to be the poster child for renewables. Exploiting its Atlantic-facing position for wind and southern latitude for sun, it leads the big member states in renewables, with wind and solar power accounting for 30 per cent of its generation compared to 20 per cent for Germany and 12 per cent for France. But, desperate to cut spending, Madrid has more or less suspended support for new renewable projects, and retroactively cut subsidies for existing projects. the Commission has warned Madrid that retroactive changes are especially damaging to investor confidence.

- Germany is now, belatedly, trying to restrain the growth in renewable subsidies. But its decision to phase out nuclear power over the next 10 years leaves it little alternative but to pursue renewables vigorously. Germany's renewables ambition is not out of line with EU policy, but the manner in which it is pursuing this ambition is disrupting links with neighbouring markets. German renewable power can produce negative prices on the German market, when there is insufficient cross-border transmission available to allow this power to be sold abroad – and when there is enough available cross-border transmission capacity, it can cause unwanted and disruptive loop flows in neighbouring markets.
- To compensate for years of delay in building new generation, the UK is planning an electricity sector reform composed of a series of state interventions in the market. These include a system of long-term guaranteed prices for renewable and for nuclear power, a capacity subsidy mechanism to remunerate back-up generators and an extra carbon tax on its electricity generators on top of the cost of ETS allowances. This UK goal to accelerate low-carbon energy does not, of course, clash with EU policy, but such extensive use of state aid may well conflict with EU rules.

Structural reform of the ETS (an issue beyond the scope of this paper) would not remove the need for all these unilateral measures, in particular Spain's attempts to save money wherever it can. But an effective ETS carbon price would remove the need for the UK's supplementary carbon tax. More generally, it would restore a uniform low-carbon investment incentive to the whole of the European market.

In its March 2013 green paper, the European Commission has admitted that, in designing the 2009 energy and climate package, it "underestimated" the impact of 27 different national renewable support schemes, and "did not address" the issue of the need for subsidised back-up for ever-larger renewable energy volumes[1]. [1]In an attempt to redress these omissions, and in the absence of reform to the ETS, the European Commission is aiming to produce guidelines in 2013 that would seek to "Europeanise" national renewable and capacity support schemes.

Nevertheless, the EU is beginning to arrive at a contradiction between its policy of liberalising and freeing Europe's energy market and its ambition to de-carbonise its energy system. It is becoming increasingly obvious that companies will not invest in low-carbon generation unless member states, or the EU itself, either force them to do so, or reward them to do so with subsidies, or do both. This is the inescapable conclusion that the UK has reached - this apostle of free energy markets is now proposing a series of state interventions to underpin low-carbon investment, both renewable and nuclear.

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[1] Green Paper: a 2030 framework for climate and energy policies, COM (2013) 169 Final, pages 6-7

In theory, liberalisation should not be sacrosanct. It was conceived as the best means to an end – the integration of the EU energy market. Integration provides scale, and scale is the EU's main gift to its member states, in every sector of the economy. Scale, a single market of 27 and soon 28 countries, can promote wider competition and through competition convergence on the most efficient price level; scale provides security through diversity of energy source and supply; and scale can provide a critical mass of low-carbon investment and the political influence in the world to make a different in international climate negotiations.

If state intervention policies can deliver integration as well as de-carbonisation, then fine. So far this does not look likely. The ETS is the one EU-wide instrument of public intervention in the market, and it is failing. It has been effectively replaced by national policies to promote renewables, which in turn are prompting national capacity mechanisms. If only EU member states would all intervene in the same way and to the same extent in their markets, integration might be perhaps compatible with de-carbonisation. Harmonised state intervention would certainly be a second best – and far harder to orchestrate – than liberalisation, but it may be the only viable course ahead. If so, member states, with the Commission's help, need to greatly improve coordination of their energy policies but this may require treaty change.

Section 1 - Nationalising EU energy policy: renewable and capacity subsidies

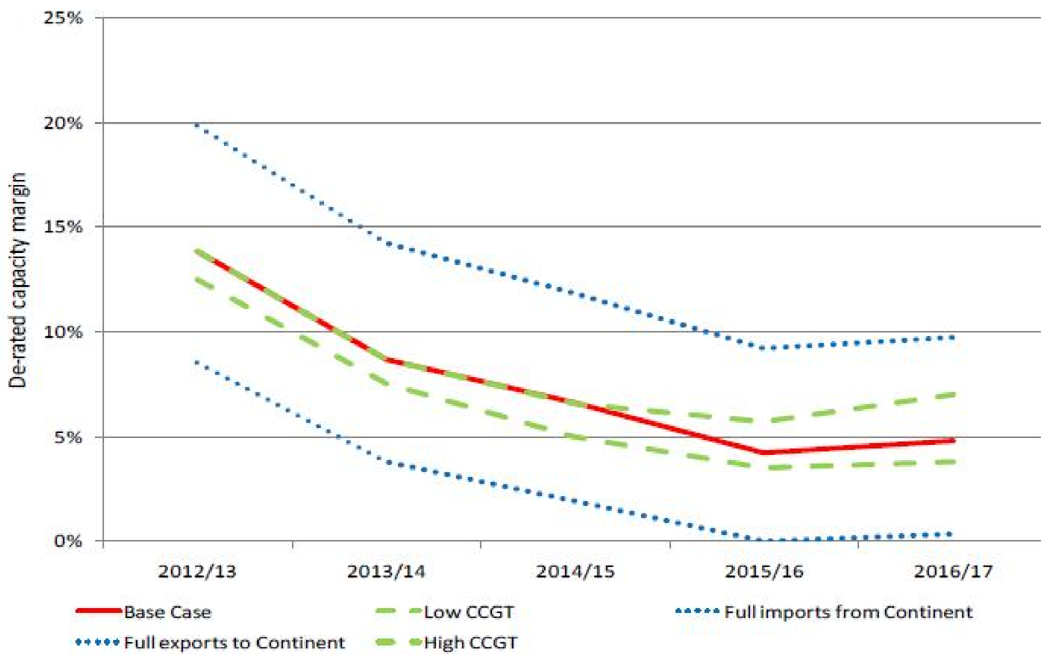
Introduction

Much has been done to create a unified energy market in Europe – Europe's legislators have passed packages of legislation to separate transmission systems from energy groups so as to turn them into common carriers of energy across frontiers. European organisations of national energy regulators, transmission system operators (TSOs) and power exchanges have been trying to couple markets together and to agree on network codes to harmonise trading arrangements across the EU. But all their work applies only to non-subsidised electricity, which is becoming a shrinking part of the total market because of the growing volume of renewables.

Now, there is the prospect that national subsidies will be applied to a further slice of the market in order to keep enough conventional, fossil-fuelled generators ready and willing to provide back-up for intermittent renewables, when the wind drops or the sky clouds over. In this way, subsidies could take over most of the electricity market, and if so, there could be little left of the "energy only" market where the forces of supply and demand are supposed to create competitive, cost-reflective and convergent prices. As the Eurelectric industry association of Europe's main generators says, "competitive markets cannot be a minor part of the market".

At present, there is not a general shortage of capacity across Europe. Nor is the capacity issue always related to the growth in renewables. It is important to realise that what is called the capacity issue can cover two somewhat different problems. The first is a lack of sufficient overall capacity, in which even if all of a country's power generators – renewable ones included – are generating full steam, there may still be a risk of the lights going out. The UK is a classic case where this risk of an overall capacity shortage is growing, due to the country's delay in replacing dirty coal plants and ageing nuclear reactors. The chart below shows the estimate from Ofgem, the UK regulator, of how the country's safety margin of reserve capacity (following the red line marking Ofgem's base case) will shrink from around 14 per cent of overall generation today to less than 5 per cent by 2015/16. This is a risk, even though the UK will still have relatively few renewables flowing onto and off its grid by 2015.

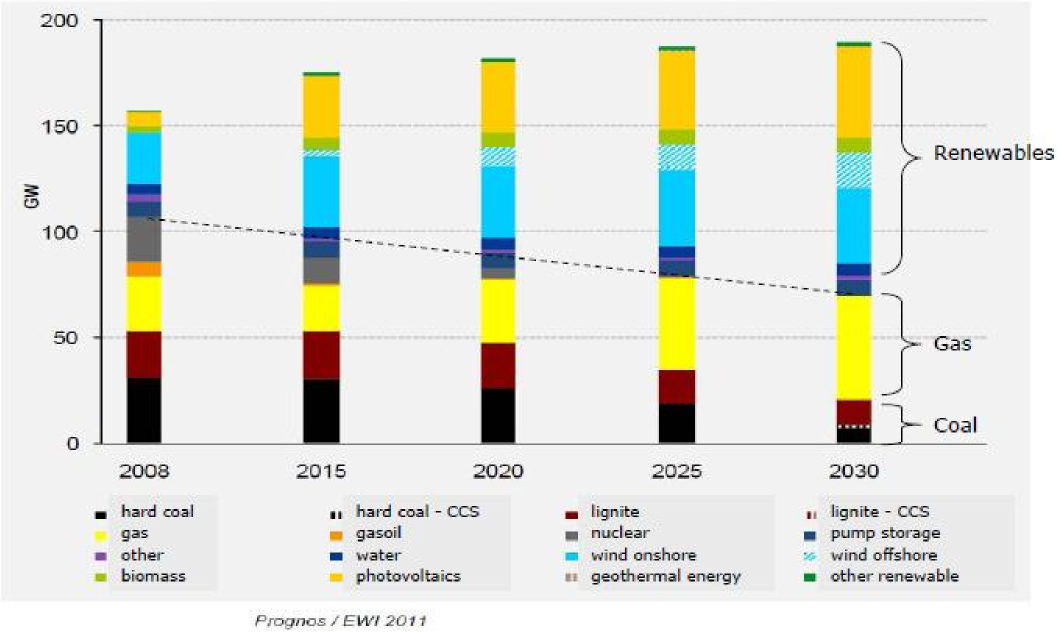
Figure 1 - Britain's declining safety margin of reserve capacity



Source: Ofgem

The second capacity problem is a lack of appropriate capacity that is fast and flexible enough to back-up intermittent renewables. This is Germany's problem. The country still has considerable overall spare capacity left over from the gold-plated pre-liberalisation era. The sudden shut down in 2011 of eight nuclear reactors with 8 gigawatts (GW) of capacity, at a stroke of Chancellor Merkel's pen, still left Germany with nearly 100 GW of generating capacity. This constitutes, for the moment, a comfortable reserve margin of at least 15 GW (or 15 per cent, roughly the current UK margin), because peak load or peak demand is around 82-83GW. But this demand is being met with an increasingly changeable supply mix. What Germany lacks is enough flexible conventional back-up to counterbalance the huge amount of wind and solar power coming on stream in Germany. The chart below is a projection of Germany's energy mix in the light of its nuclear phase-out decision and its *energiewende* programme to expand renewables. Above the dotted line, it shows the expansion of installed capacity for renewables, which is not at all the same as actual output because only a small percentage of total installed wind and solar capacity can be firmly relied on to produce. Below the dotted line, it shows what is available as installed capacity of conventional generating capacity – coal (hard coal and lignite), gas and (until around 2022) some nuclear power. This is all firm capacity in the sense that, unlike renewables, it can be switched on and off when needed – but only slowly in the case of nuclear, reasonably quickly in the case of coal and very quickly only in the case of gas and pumped water storage. And the chart shows that at least until 2020 Germany's conventional generating back-up available to offset variations in renewables will be mostly relatively inflexible coal and nuclear.

Figure 2 - Installed electricity generating capacity in Germany (GWs)



Source: Prognos; Energy Research Instititute; Ministry of Economics

The problem of sufficient capacity is one that particularly afflicts the UK. It is the reason why the UK government has launched its Electricity Market Reform. In addition to a system of guaranteed prices to entice investors into renewable and nuclear power, this reform proposes a capacity market to pay conventional generators to stay available to provide back-up power. However, far more EU states, and Britain too in the future, will face the issue of appropriate and flexible capacity, a need that will grow and grow as renewables grow and grow.

Renewables

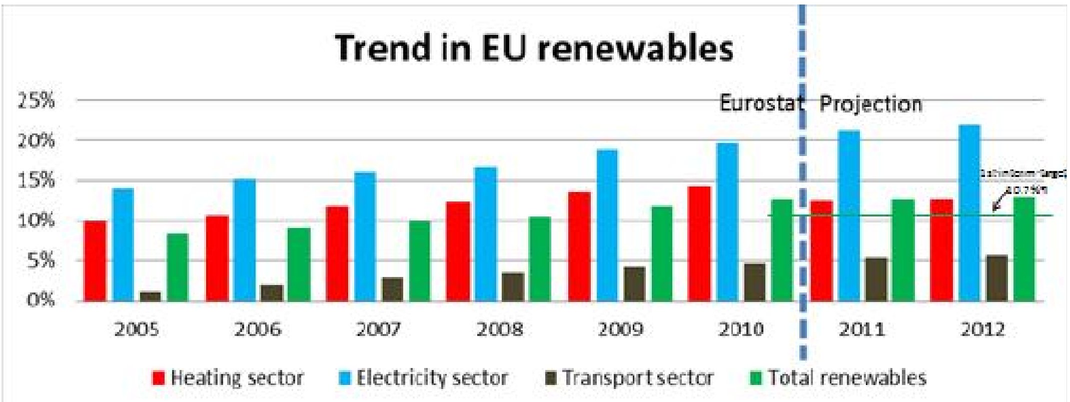
The focus in this section is on renewables as a problem for market integration rather than as a solution for climate change. In both cases, however, account needs to be taken of their progress.

Progress

Many of the achievements of the EU's energy and climate programme – notably progress in cutting carbon emissions and saving energy – are simply the silver lining of the dark cloud of economic recession that has reduced energy demand and use. However, the strong growth in renewable energy capacity has been achieved in the teeth of the economic downturn, though the Commission is warning that this may not be sustained.

In its March 2013 Renewable Energy Progress report, the Commission said the overall picture was of "a generally solid initial start at EU level, but with slower than expected removal of key barriers to renewable energy growth and with additional efforts by particular member states necessary"[2]. The table below from this report illustrates the solid start in the 2007-2010 period which according to this Eurostat projection has stalled in the last two years.

Figure 3 - Trade in EU renewables



2010 did not look too bad, even if, on the road to the binding targets of 2020 half the EU membership did not meet their indicative goals for 2010 in renewable electricity, and three quarters failed to meet indicative goals in renewable transport. By technology, the actual deployment of offshore wind is falling well behind the levels set out in the national renewable plans that member states file to Brussels. Onshore wind and biomass are also lagging. By contrast, the installation of solar PV capacity has outstripped expectations, though this has also led to disruptive cuts in subsidies. As a result, renewables are penetrating the electricity sector faster than other sectors (see table above). This is line with Europe's overall strategy of first de-carbonising its electricity supply and then further electrifying the wider economy.

Analysis done for the Commission[3] casts some doubt on the sustainability of renewable energy expansion, because of administrative and infrastructure obstacles and disruption to support schemes. Barriers to renewables are still widespread. Administrative procedures are still complex; only three countries - Denmark, Italy and the Netherlands - have a single permitting system for the building of renewable generation projects. Once built, renewable projects often have difficulty getting the necessary connection to the low-voltage grid. These problems of renewable grid connection usually occur inside a member state. Therefore the new EU regulation on infrastructure (see Section 3) is not much help here. This regulation streamlines planning procedures for a selected number of priority high-voltage and high-pressure power lines and gas pipelines across borders.

[2] Renewable Energy Progress Report, March 2013, Com (2013) 175 Final.
[3] Renewable energy and biofuel sustainability, Eocfys et al 2012.

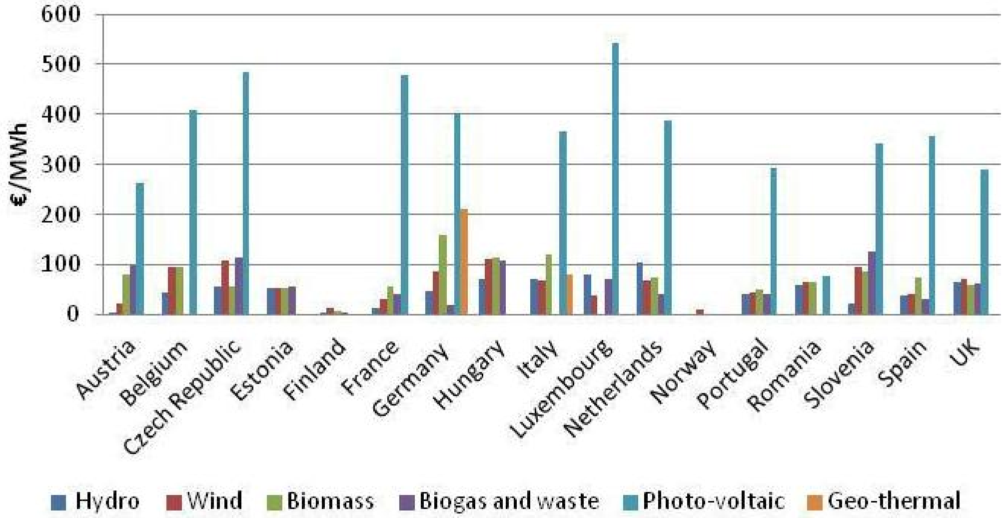
The other constraint on the growth of renewables is the growing criticism of the cost of subsidising them. The total cost is very high. The latest official figures, provided by the Council for European Energy Regulators (CEER) are for 2010, and only for 17 EU member states (but including all the larger ones)[4]. According to the CEER survey, the 17 countries spent a total of EUR 25.2 billion supporting renewable electricity. Nearly 40 per cent (EUR 9.5 billion) of this was in Germany, and the second largest subsidiser was Spain with EUR 5.3 billion spent in supporting green power. The reason why Spain was spending much more than the larger states of Italy, France and the UK is that the renewable share of electricity is much higher in Spain (200 per cent in 2011) than in Italy (10 per cent), France (3 per cent) and UK (5.7 per cent).

Today these subsidy figures will be different. Germany's renewable support spending is even higher. A 47 per cent increase in its 2013 consumer levy to pay for renewables could bring Germany's total spending on all renewables this year to around EUR 20 billion, though the Merkel government is trying to trim this. Meanwhile Spain might today be spending less on renewable support. Madrid is certainly trying to spend less. Last year it suspended negotiations on any new projects. In 2010 Spain placed an annual limit on the number of hours it was prepared to pay existing renewable electricity producers, who now have to operate from every August-September until the end of the year without support. This limit shook investor confidence because its imposition on existing producers appeared to be a breach of contract. Spain has not been alone in taking retroactive measures to cut subsidies. The Czech Republic and Bulgaria have also done so.

Much of the disruption has been in solar PV schemes. Solar PV deserves a fairly high level of support, because of its potential as a decentralised power source in cities and crowded spaces. The chart below shows how far solar PV subsidy levels have outpaced other renewable supports. In 2010, for instance, in the Czech republic it was being subsidised to the tune of EUR 496 per megawatt hour. Such a rate was far too high, given the sharp fall in the cost of buying Chinese PV panels and given that PV investment is particularly reactive to subsidy incentives. Where PV subsidies are generous, the relative ease of installing solar PV can cause a sudden surge in solar generation capacity, outstripping infrastructure and giving rise to real windfall profits to operators. So politicians and regulators have been scrambling to cut PV tariffs, leading to a boom and bust in several countries in a way that has disillusioned public opinion about renewables, dislocated supply chains and discouraged future investment.

[4] Status Review of Renewable and Energy Efficiency Schemes in Europe, CEER, 2013.

Figure 4 - Renewable support levels by country and technology (2011)



Source: CEER 2013

In the light of the unresolved barriers and uncertain subsidy regimes confronting renewable energy producers, there must be some scepticism as to how many member states will meet their national renewable targets for 2020. "I am not sure we are going to make our 2020 targets. We cannot afford to be complacent, because the trajectory [to meet the target] should go up sharply nearer 2020", Marie Donnelly, the European Commission Director in charge of renewables, research and innovation, Energy Efficiency told a conference in January 2013[5]. This trajectory allowed member states seven years, up to 2012, to achieve the first 20 per cent of the target. However, in every subsequent two-year period up to 2020 it steadily raises the bar, so that in 2019-2020 member states are supposed to achieve no less than 35 per cent of their total goal. Achieving this goal will not be impossible, given progressive expansion of the renewable base each year.

European guidelines for national renewable support schemes

The integration challenge posed by renewables is to reduce the differences between the 27 national schemes and so to reduce the trade and investment distortions they cause – and to do so, in a way that meshes renewables better into the energy market. So the challenge is one of both European market and energy market integration.

Renewable support schemes are national for a variety of reasons – because renewables are part of member states' energy mix which is formally still a national prerogative; because national renewable programmes long pre-date EU involvement in this area; and because member states have been given different renewable targets. Why different targets? Because they have different natural endowments (sources of hydro or exposure to sun and wind), different levels of wealth (which matters because renewable energy

[5] CEER annual conference 2013.

currently costs more than fossil fuels), and different levels of clean energy ambition (though this is not part of the official equation for calculating targets). And because governments have different targets, they insist they need to have control over the subsidy schemes to meet these targets.

In the face of the attachment to national subsidy schemes on the part of governments, their national renewable energy lobbies and their supporters in the European Parliament, the Commission confined itself, in the 2009 energy and climate package, to trying to reduce the differences in subsidy levels by encouraging cross-border trade in renewable energy or certificates of renewable energy. Twice (in 2001 and 2007) it proposed pan-EU trading of green energy certificates, and twice it was rebuffed by the Council of Ministers and the European Parliament, which have regarded cross-border trading as EU harmonisation-by-the-backdoor (which it could be). At present the only cross-border trading of renewables officially recognised and encouraged is between consenting governments in order to meet their targets. And even some of this cross-border trading would be virtual rather than actual, with one government selling a 'statistical transfer' of some of its renewable energy to another government that would be buying the right to count this foreign percentage of renewable energy towards its national target.

In 2013 the Commission is proposing to produce guidelines for national support schemes (alongside guidelines on capacity markets see below). These are expected, or ought, to address issues of:

- Cost control. The guidelines will stress the need for support tariffs to be adjusted transparently, regularly and quickly so as to keep pace with falling technology costs, as frequently did not happen with solar PV schemes. They will warn that retroactive subsidy-cutting damages investor confidence. The guidelines may seek to establish a benchmark of renewable technology costs that member states can use as a basis for setting subsidy levels.

- Energy market integration. The guidelines will suggest that renewable producers need to be more exposed to market prices and disciplines, as conventional power producers are. Feed-in tariffs, which provide renewable producers with a fixed subsidy covering all their costs and a mark-up, are considered less useful now than premiums that just top up whatever revenue a renewable producer can get from the regular energy market. As to market discipline, renewable producers should be made responsible for at least some of the imbalances their erratic solar or wind power deliveries can cause.

- European market integration. Member states will be urged to trade and cooperate more on joint renewable projects, as set out in the 2009 renewables directive. Neighbouring countries should also be encouraged to harmonise or merge their support schemes, on the basis of regions that might coincide with areas where regulators and TSOs are coupling markets and harmonising trading arrangements (See Section 4).

Figure 5 - Member states' progress – renewable shares in total energy consumption

Member State	2005 RES share	2010 RES share	1st interim target	2020 RES target
Austria	23.3%	30.1%	25.4%	34%
Belgium	2.2%	5.4%	4.4%	13%
Bulgaria	9.4%	13.8%	10.7%	16%
Cyprus	2.9%	5.7%	4.9%	13%
Czech Republic	6.1%	9.4%	7.5%	13%
Germany	5.8%	11.0%	8.2%	18%
Denmark	17%	22.2%	19.6%	30%
Estonia	18%	24.3%	19.4%	25%
Greece	6.9%	9.7%	9.1%	18%
Spain	8.7%	13.8%	10.9%	20%
Finland	28.5%	33%	30.4%	38%
France	10.3%	13.5%	12.8%	23%
Hungary	4.3%	8.8%	6.0%	13%
Ireland	3.1%	5.8%	5.7%	16%
Italy	5.2%	10.4%	7.6%	17%
Lithuania	15%	19.7%	16.6%	23%
Luxembourg	0.9%	3%	2.9%	11%
Latvia	32.6%	32.6%	34.0%	40%
Malta	0%	0.4%	2.0%	10%
Netherlands	2.4%	3.8%	4.7%	14%
Poland	7.2%	9.5%	8.8%	15%
Portugal	20.5%	24.6%	22.6%	31%
Romania	17.8%	23.6%	19.0%	24%
Sweden	39.8%	49.1%	41.6%	49%
Slovenia	16.0%	19.9%	17.8%	25%
Slovakia	6.7%	9.8%	8.2%	14%
UK	1.3%	3.3%	4.0%	15%
EU	8.5%	**12.7%**	**10.7%**	**20%**

The most objective measure is to judge Member States against their first interim target, calculated as the average of their 2011/2012 shares. Whilst on average such progress to 2010 is good, this does not reflect the policy and economic uncertainties that renewable energy producers appear to face currently.

Progress towards the first interim target:

>2% above interim target

<1% from or <2% above interim target

>1% below interim target

Source: Renewable Energy Progress Report, March 2013, COM (2013) 175 Final

Capacity mechanisms

Introduction

These are government-organised systems of separate payments to generators to be ready to provide power to the market when supply falls short of demand. So they are subsidies to maintain a ready reserve of generation 'capacity', generally gas or coal fired plants because they can be switched on and off dependably and fairly quickly. These capacity mechanisms should be distinguished from traditional short-term 'balancing' mechanisms or markets in which sudden variations in supply or demand need quick, or (in the case of electricity), instantaneous correction to restore balance; fast-reacting hydroelectricity is often used for this. However, expansion of balancing markets can play a role in easing the capacity problem.

Renewable energies, such as wind and solar power that have the greatest scope for expansion, complicate the economics of capacity back-up, because these energy sources are not only intermittent, but also free in the sense that they have virtually zero marginal or running costs. This feature puts them first in the 'merit order': the traditional line-up in which electricity grid operators call upon generators to supply demand. This dispatching system starts, logically, with the cheapest source of power, and moves to the most expensive source until all demand is satisfied. Financially, this means that the marginal cost of the last unit of power supplied sets the price for everyone. So, up to now, the most expensive source with the highest marginal cost (often likely to be gas or coal) has been able to cover its higher fuel cost, while the cheaper generation source with zero or low marginal cost (wind, solar, nuclear) can make enough money to cover its capital costs that are high relative to its fuel costs.

However, given the volume of subsidised renewable energy now coming on to the grid in some countries, the 'first' in the merit order can also be the 'last'. In other words, renewable energy can, at times of high wind and solar generation, supply the entire demand without gas or coal plants being called on and therefore able to earn any money. Moreover, when renewable energy supply not only fulfils demand, but exceeds it, the market price goes negative. This is now happening several times a year in Germany, where renewable producers, with near-zero operating costs, are ready to pay a power exchange to take their electricity, provided that penalty price is less than the subsidy they get for continuing to generate.

All this is bad business for the owners of gas and coal plants. If these plants can only operate a couple of hundred hours a year, it might not matter to their owners, provided they could capture the very high peak prices a free market would produce during those hours. But investors in conventional energy suspect that politicians would not dare risk such peak prices upsetting voters, and that they will therefore cap prices. The obvious back-up for renewable energy is fast and flexible gas plants. But no one in Europe is planning to build any more of these at the moment. "Paradoxically, well-wishers for the renewable revolution should want to see more capacity in – though not output from – fossil-fuelled generation, built alongside renewable sources as back-up. Triumphalist statements that renewables account for most new generation capacity built in Europe are not necessarily the good omen for the low economy they might seem"[6].

The remedy of capacity mechanisms is controversial. In planning capacity markets, the UK and other countries are making "a colossal error", according to Walter Boltz, Austria's outspoken national regulator. "We made the problem ourselves with the growth in renewables, so let us think of how we can fix it without killing the market"[7]. However, the Council of European Energy Regulators (CCER), of which Mr Boltz is a member, concedes that 'energy only' markets, meaning markets where a generator's only revenue comes from selling his energy, may have "some market flaws that lead to a sub-optimal level of generation adequacy"[8]. The regulators went on to say that "pure energy-only market designs have an inescapable tendency to produce scarcity from time to time", adding that it was difficult for regulators to distinguish between efficient (i.e. genuine) scarcity prices and prices that reflect market power (i.e. possible manipulation) during periods of scarcity. In any case, the regulators did not believe "policy-makers [i.e. politicians] are generally willing to accept potentially severe prices spikes and the demand rationing associated with energy-only markets".

For its part, the European Commission has now conceded that its 2009 energy and climate package "underestimated the impact on market integration of 27 different national support schemes for renewables", and "did not address the issue of whether the market offered the necessary incentives to invest in generation, distribution, transmission and storage capacity in a system with greater shares of renewables"[9]. What particularly haunts the Commission is the prospect that the combination of national renewable and capacity markets would effectively shut off countries' energy sectors from each other, and negate much of the pain-staking work, described in other sections of this paper, of building cross-border inter-connectors, agreeing pan-European network codes and coupling power markets. Many in the EU executive feel that they let "the genie out of the bottle" by conceding that member states could run their own renewable support programmes, and do not want to make the same mistake again with national capacity schemes. But the capacity genie is already uncorked. Several member states already have capacity mechanisms. Sweden and Finland pay certain generators to maintain a strategic reserve; Ireland, Spain and Portugal make more broadly based capacity payments; and the UK and France plan capacity auctions or markets.

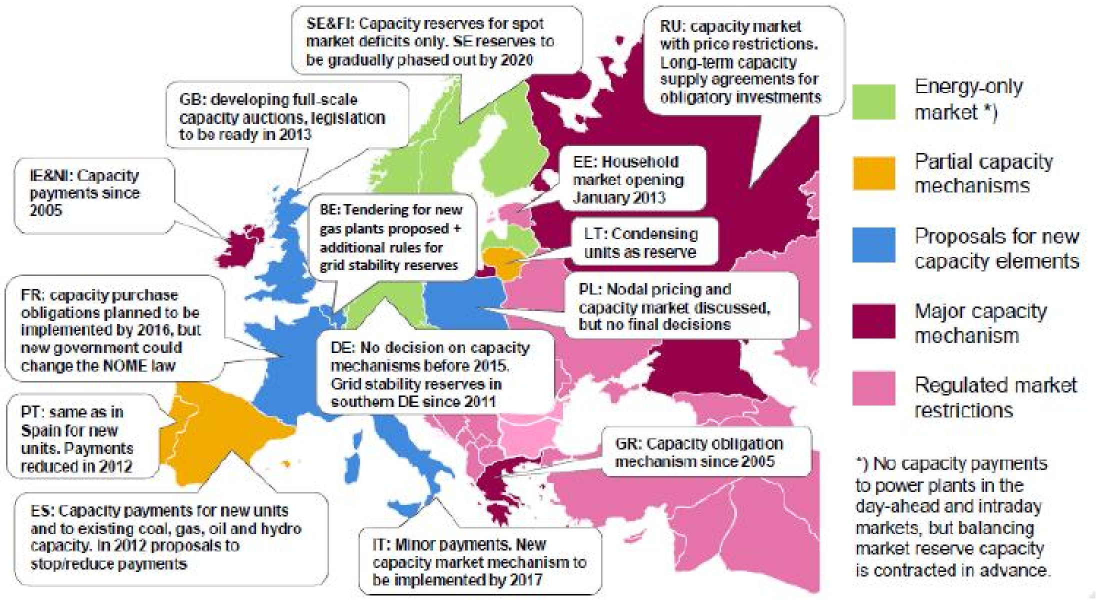
[6] "How to create a single European electricity market – and subsidise renewables", Centre for European Reform. D. Buchan, 2012.

[7] Quoted in Platts Power in Europe, 10/12/2012.

[8] CEER response to Commission consultation on generation adequacy, 2013.

[9] Green Paper on 2030 framework for climate and energy policies, COM(2013)169.

Figure 6 - National capacity mechanisms and plans



Source: Eurelectric presentation. 2013.

More specifically, the Commission fears that national capacity mechanisms, especially if badly-designed or introduced unevenly in some countries and not in others, could:

- Distort investment. Capital investment would be attracted to states paying the most for capacity, just as it follows the more generous of national renewable subsidies.
- Distort trade. Extra investment in a country with a capacity mechanism could create an artificial surplus of power there, encouraging more cross-border trade that would overload available inter-connectors.
- Negate efforts to couple markets. Market coupling aims to make efficient use of inter-connectors, but it only works to equalise prices if there is a reasonable amount of inter-connector capacity to make efficient use of. For example, German and Dutch prices initially converged after the two countries coupled their markets, but are now diverging again, because Germany is frequently producing such huge amounts of renewable power that it cannot all pass through the inter-connector to the Netherlands and thereby equalise prices between the two countries. A cross-border capacity mechanism might involve some cross-border transmission capacity to be permanently reserved for emergency back-up use, and thus taken out of the market.
- Create a re-distributional effect, with citizens of a country with a capacity system paying for security of supply for citizens in another member state.
- Cause problems with whatever capacity system is chosen. A strategic reserve of the Swedish or Finnish variety has only a limited impact on the wholesale energy market, because it is rarely called upon. However, it only works to improve the supply side by adding or maintaining generation capacity. In contrast, a capacity auction of the kind the UK is proposing would allow providers of demand

reduction, as well as suppliers, to bid for capacity payments – thereby impacting both sides of the energy equation. But capacity markets are more complex to design and administer.

Remedies

The Commission has the legal power, under its right to review state aids and public service obligations, to restrict and even block national renewable and capacity subsidy schemes. And it may have soon to use this power, in the case of the UK government's proposed Electricity Market Reform, which presents an unusually difficult challenge to the state aid regime. For this reform consists of a series of state-organised guaranteed prices for renewables and (for the first time) for nuclear power, without any provision for phasing out or reducing these price guarantees, as well as the introduction of a capacity market.

Normally, the EU executive has allowed states to pay declining amounts of aid to renewable projects because these are viewed as necessary, proportionate and in pursuit of an agreed EU policy goal: low carbon energy. As a matter of practical politics, the Commission may take the same broadly permissive attitude towards states organising capacity payments to keep the lights on – provided these are deemed necessary and proportionate – because security of energy supply is also an agreed EU policy goal. The Commission may feel it cannot afford, especially given the shaky overall state of integration in today's Europe, to be seen to thwart member states in the exercise of their legitimate right to try to assure their own energy security. Moreover, there is no easy European alternative to national capacity schemes. Those people, perhaps in the European Parliament, who might be tempted to urge the Commission to head off national capacity plans with a pan-European capacity scheme, should think how difficult such a scheme would be to design. And those, who successfully opposed earlier Commission plans to introduce a pan-European renewable support scheme (through tradeable green certificates, similar to ETS carbon allowances), might reflect that, technically, an EU-wide scheme would have been easier to introduce for renewables than for capacity. The aim with renewables is just to add supply, whereas capacity affects both sides of the equation - demand and supply – and the balance between them.

So, short of trying to design a pan-European capacity scheme, what should be done?

- Analyse the problem(s) to get the correct answers. It is important not to be seduced with the idea that Europe has a single problem. A few countries like the UK already have an impending capacity gap – a maximum level of generation that, even if all its producers generate exactly what they promise, will soon fall short of peak demand. Many member states, like Germany today but there will be more (including the UK as it expands renewables), face a diminishing share of flexible generation (basically, using biomass or fossil fuels) that can be started and stopped to match troughs and peaks in renewable power. Such countries have installed enough generation to cover all demand needs, but only if all renewable generation produces up to its maximum nameplate capacity – which it cannot. The European Network of Transmission System Operators for Electricity (ENTSOE), which has frontline responsibility for security of supply, makes this important distinction between 'sufficient' and 'flexible' generation. It regularly publishes reports on European generation adequacy, but feels it is not properly heeded by all member states. ENTSOE's secretary general, Konstantin Staschus, recently claimed "ENTSOE and its TSOs are best placed to provide the necessary expertise and coordinate the industry's input to determine the threats to general adequacy"[10].

- Improve short-term electricity balancing markets. This will at least help Germany and those similarly afflicted with lack of flexible generation. At present, only in 15 member states are renewable producers held responsible for the imbalances they create in the system, and elsewhere many renewable producers are 'free riders' on the balancing system. What is needed are balancing markets in which all are held financially responsible for correcting imbalances at marginal prices that reflect the extent of the imbalance. "People who cause the problem should pay and people who solve it should be rewarded", says an ENTSOE official[11]. The aim is to ensure that price signals reflect the correct value of electricity at each point of time during the day of delivery because the value can be very different from moment to moment – something that the traditional day-ahead trading market cannot provide. "Politicians are nervous about volatility in balancing markets, but they should not be", comments a Commission official. "This is an unnecessary concern. Consumers do not feel the costs in balancing, and balancing is not necessarily an extra cost – it can be a trading opportunity to reduce total costs, to dispose of excess electricity and to purchase power if you are short of it. Moreover, if you know the balancing market is liquid and therefore reliable, you can get away with less back-up generation in your system"[12]. At the moment, however, there is often an impasse in the development of balancing markets, with renewable producers claiming they cannot be held responsible for balancing until the development of liquid balancing markets, which may not emerge until it is clear that all producers will participate.
- Expand the grid. There is a limit to what the market can do. Market coupling and network codes can better use of the existing transmission capacity in cross-border inter-connectors. But there comes a point when more capacity must be built. That point might come quickly if member states are persuaded by the EU authorities to factor the European dimension into national capacity schemes and to rely more on their neighbours for back-up. Such reliance might require the permanent reservation of cross-border transmission if cross-border back-up arrangements are to be credible. Such permanent reservations would subtract from the capacity available for day-to-day trading – unless inter-connectors were expanded.

[10] Entsoe presentation to Commission conference on capacity issues, March 2013.
[11] Author interview March 2013.
[12] Author interview March 2013.

- A quid pro quo. One way to expand cross-border links would be for the Commission to require member states to put aside a certain proportion of their national capacity subsidies for building such links. The idea would be to invest some of the capacity subsidy in a partial solution to the capacity problem. It would not be unreasonable for the Commission to insist that, in return for state aid approval of national capacity schemes, member states show some action to reduce the level of subsidy over time.

Section 2 - Energy efficiency

Introduction

Energy efficiency is perhaps the hardest dimension of the internal energy market programme to comprehend and to tackle. Hard to comprehend because efficiency (using less energy input for a given output) is often, sometimes deliberately, confused with saving (cutting the absolute amount of energy used). Energy efficiency is only a stepping stone towards energy saving, a necessary but not sufficient condition for saving. In an economy with declining output, efficiency magnifies the fall in energy use; in an expanding one it limits the growth in energy consumption. Efficiency is not hard to measure retrospectively; past improvements in Europe's energy intensity, as in other industrial economies, can be clearly traced. And setting for future targets to accelerate efficiency is easy enough. But measuring whether such targets are met can involve an estimate of the counter-factual – gauging what would have been Europe's energy use in some future year without the efficiency improvements. The benchmark is not, therefore, known energy use in a past base year, but essentially unknowable energy use in a future year. Thus the EU target of a 20 per cent energy efficiency improvement by 2020 is to save 20 per cent of energy consumption relative to what EU energy use was projected to be by that date if Europe just continued its business-as-usual. It is hardly surprising that this target was not made a binding part of the 2009 energy and climate package, because there is nothing firm to bind it to.

However, progress in energy efficiency is vital. Reduction in energy consumption, albeit relative, should in the longer term exert downward pressure on electricity prices, as well as cut fossil fuel imports and emissions. The EU has taken a wide series of energy efficiency measures. It is beyond the scope of this paper to deal them all. For instance, the Eco-Design and Eco-Labelling directives are very important in the consumer sector, prohibiting energy-wasteful products and raising efficiency standards for all sorts of appliances. But these measures affect the whole market as much as the energy sector. This paper will focus on the 2012 Energy Efficiency Directive, because it has new provisions intended to change the dynamics of the demand side of the energy market and the behaviour of consumers and suppliers in that market.

The Energy Efficiency Directive (EED)[13]

The Commission concluded in 2011 that "the EU is on course to achieve only half of the 20 per cent objective"[14] It therefore came up with a plan to maintain the overall objective as a non-binding target, but to introduce some binding measures because, as it said in its impact assessment "individual measures are the ones to make a real difference". Adding to the 9 percentage point improvement in energy efficiency it expected from existing

[13] 2012?27/EU
[14] COM (2011)109/4

measures, it proposed to close the remaining gap with a 2 percentage point improvement from new car fuel efficiency standards, and a further 8.5 per cent efficiency gain from the new binding measures. At the same time, it proposed to give the 20 per cent goal more concrete form by expressing it in terms of a ceiling on EU energy use in 2020 of 1,474 million tonnes of oil equivalent (mtoe) in primary energy consumption or (subtracting for losses incurred in energy transformation) 1,078 mtoe in final energy consumption. This ceiling, written into the EED, is no more binding than the 20 per cent figure. But the Commission's purpose was to make clearer – rather like a mathematician showing his 'workings' – the total savings that its energy efficiency measures were aiming at.

The energy saving obligation

By far, the most significant new binding measure in the EED is for each member state to set up an "energy saving obligation" scheme for its energy suppliers. These schemes must produce "at the least the equivalent" of annual savings by energy suppliers of 1.5 per cent in their energy sales to final customers up to 2020. Unlike the old 20 per cent goal, this is a mandatory measure. However, like the 20 per cent goal, it does not necessarily mean an absolute 1.5 per cent reduction in the volume of energy sales. Rather, it requires companies to show they have taken energy-saving steps, such as installing insulation for householders, which result in their sales being 1.5 per cent less than they would otherwise have been. So, for instance, a company can increase its energy sales volume from a base of 100 to 103.5 in the following year, if it can show that but for its energy-saving measures its sales would have been 105. For the directive states that " the requirement to achieve savings of the annual energy sales to final customers relative to what energy sales would have been does not constitute a cap on sale or energy consumption". Setting the 1.5 per cent reduction in these relative terms may seem, and in a way is, feeble. But you only have to look at the Emissions Trading System (ETS), with its emission ceiling cast in absolute numbers, to see how an economic downturn can make nonsense of fixed numbers.

All this will be complicated. Compliance will have to be built up from the bottom. Companies will have to spell out their energy-saving actions, and show why x amount of double-glazing + y amount of insulation = z quantity of energy saving. Governments will then have to put all this together to convince the Commission they are complying with the directive. A further complication is that the directive allows member states to pursue different schemes "at least equivalent" to the energy saving obligation imposed on companies. This is in deference to countries like Germany, which claims that energy efficiency activities of its KfW public development bank produce as much voluntary energy saving in Germany as the compulsory corporate scheme will in other countries. Assessing this "equivalence" will be another headache for the Commission.

On the face of it, one might wonder whether such complexity is worth it, especially as the actual saving will be less than 1.5 per cent because of some partial exemptions and credits insisted on by certain member states. The table (see below) shows how these concessions reduced the savings the Commission had hoped to get from the obligation.

Figure 7 - Projected savings (mtoe): Energy Efficiency Directive v. original Commission plan

Measure	Original savings	Final text savings
Energy saving obligation	75.0	52.0
Grids, demand response	7.5	17
Co-generation	25.0	11-12
Energy audits	8.5	8.5
Metering, billing	27.0	5.5
Public procurement	4.8	1.2
Building renovation	4.2	0.4
Total	152.0	c 97

Source: Platts, citing European Commission estimates.

However, the evidence from countries with energy saving obligation schemes already – notably Denmark, France, Italy and the UK – is that they work[15]. Moreover, the directive's complexity may be a price worth paying in order to convert the energy industry to the idea that it can make as much money out of supplying the services of heat, light and cooling, as just selling the commodities of electrons and molecules. Breaking the link between a utility company' profits and the volume of its energy commodity sales is vital to achieving any revolution in energy efficiency. It also presupposes a much closer relationship between utility and customer than often exists now. If a customer trusts a utility enough to come into his house and install double-glazing windows and insulate the roof, the same customer is unlikely to switch the following day to another energy supplier. Likewise a successful supplier of energy services is also likely to be a company that maintains steady custom for its sales of the actual energy commodity. There is evidence from California, which allows utilities monopoly control over their customers but regulates the utilities very heavily, that a permanent company/customer relationship, plus the right incentives, can produce exceptional gains in electricity efficiency[16].

Therefore there may be a case for changing the way customer switching is viewed in Europe. In the framework model that the EU has chosen of a liberalised energy market, the right for customers to switch from supplier to another is, correctly, considered vital. Indeed, high national rates of customer switching or "churn" are seen, very positively, as indicators of competitive markets. In the future, however, high churn rates may also be a sign of low energy efficiency gains.

[15] Energy Efficiency Obligations – the EU Experience, commissioned from Eoin Lees from the European Council for an Energy Efficient Economy, 2012

[16] California's Climate Policy – a Model? David Buchan, OIES, December 2010.

Other elements of the EED include mandatory energy audits for companies (to help close the information gas about energy waste that is a barrier to energy efficiency), and a planning requirement to use the waste heat, wherever possible, in new thermal electricity plants for co-generation or district heating. Two of the directive's other provisions caused more controversy. One was the requirement for member states to renovate each year at least 3 per cent of all their public buildings, measured by floor space. At the insistence of Germany, a federal state with many layers of government, this requirement was limited to the buildings of central government. The other serious dilution of the Commission's proposal related to smart metering. The Commission had hoped the directive would define the functioning of smart meters more clearly, so as to ensure the meters' installation would benefit the consumer as much as the energy company, for instance providing consumers with monthly bills based on monthly readings. In the end, the directive did little more than re-state the goal (already in previous legislation) of equipping 80 per cent of customers with smart meters by 2020.

Suggestions

1. **Do not judge the EED yet**. Its final version disappointed some, and it may leave the EU short of its 2020 goal by around 3 percentage points. However, energy efficiency has been the last piece of the energy and climate package to get a legislative 'make-over'. It is therefore too early to gauge the effectiveness of the EED. It is only due to be transposed into national legislation by mid-2014, by which time the Commission will report on National Energy Efficiency Actions Plans (NEEAPs) and judge whether these will meet national and EU efficiency targets.

2. **Do not pay too much attention to national rates of customer switching**. For reasons explained above, these rates may, and perhaps should, decline as efficiency programmes draw companies into a longer term relationship with their customers.

3. **Do not worry too much about the effect of energy efficiency on the ETS**. The problems of over-supply of allowances in the ETS emissions is far bigger than any likely reduction in demand caused by energy efficiency.

Section 3 - Infrastructure

Introduction

Improving and extending cross-border networks has always been at the heart of internal energy market policies. In the past the Commission pursued this goal through traditional market opening legislation and anti-trust measures to remove discrimination on the networks and to ensure that power lines and gas pipes become common carriers for all customers. Now, however, the EU is breaking new ground by involving itself in the planning and financing of energy infrastructure. Passed by Council and Parliament, a new energy infrastructure regulation is due to come into force in May 2013. It will identify priority 'projects of common interest', and make them the beneficiary of streamlined national planning procedures and some EU funding.

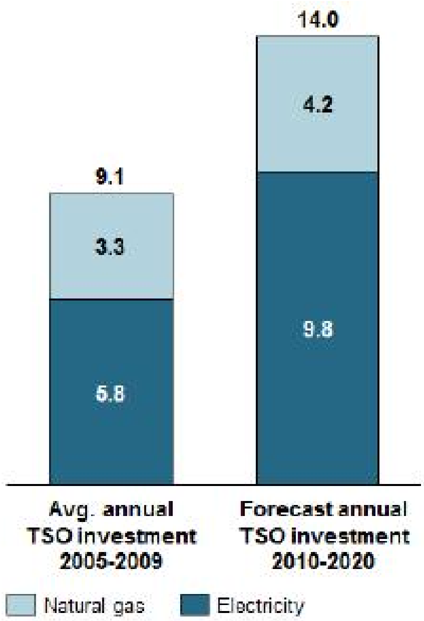
Before asking what this legislation will achieve, we first need to see what infrastructure needs to be built, and why it needs public support. When the Commission came up with its draft infrastructure regulation in 2011, it estimated that around EUR 210 billion needed to be spent extending electricity and gas grids and upgrading existing ones by 2020. This overall figure was made up of EUR 140 billion for high-voltage transmission (EUR 70 billion onshore, EUR 30 billion offshore), another EUR 40 billion for electricity storage and smart grid applications, and EUR 70 billion for high-pressure gas transmission gas pipelines, storage, LNG terminals, and reverse flow infrastructure[17]. (These are large sums, but smaller than the amount of money that needed to modernise the low-voltage electricity distribution network, to which most renewables are connected, and the low-pressure gas distribution network, as well as generation capacity of all kinds). The Commission is sticking to its 2010 estimate of EUR 210 billion for necessary transmission infrastructure, not least because since then deployment of renewables has continued apace. However, it now believes that, because the prolonged economic downturn has reduced energy demand, not all of this money may have to be spent before 2022 or 2025.

The chart below is a snapshot of how TSOs, in 2011, intended to increase spending on infrastructure in the decade to come. But it is far from the doubling of expenditure that is needed. Since then, the persistent economic downturn has made it harder to raise money for infrastructure investment. Even a couple of years ago the Commission concluded that of the EUR 210 billion, half "should be delivered by the market unaided, whereas the other EUR 100 billion will require public action to source and leverage the necessary private capital"[18]. A major reason why infrastructure investment fails to materialise are the delays in the planning and permitting process, which can take up to 8-10 years for new transmission lines. Permitting delays add to cost. They also add to uncertainty,

[17] Commission staff working paper, SEC(2010) 1395.
[18] Commission proposal for the 2014-2020 Multiannual Financial Framework, COM(2011) 500/II, page 55.

which in turn increases risk and this may cause financiers to increase their required rate of return beyond what a project can produce. Public acceptance is harder to win for electricity cables, which are 3-10 times more expensive to bury than for gas pipelines that are routinely buried.

Figure 8 - Planned increase in TSO investment (billion euros)



Source: Roland Berger report on financing energy infrastructure, 2011.

In recent years, the EU tried other means to create some of the missing links in Europe's energy networks. They included the appointment of special negotiators – for example, Mario Monti who brought to a successful end a Franco-Spanish negotiation on a trans-Pyrenean power line; this project was rejected in 1996, re-started in 2001 and finally concluded in 2011. There was also the Trans-European Networks programme, or TEN, set up in 1996, with a tiny budget (EUR 20 million a year) for the energy part of it, TEN-E, essentially to finance feasibility studies. "At the time it was assumed that only a relatively small initial impulse from Brussels would be needed to set in motion the market forces that would drive construction of all necessary cross-border links"[19]. Moreover, the TEN-E list of projects was the sum of every state's wish list, amounting in 2011 to a *short* list of 568 priority projects of European and national interest.

The Infrastructure Regulation of 2013

Under the new regime, the *long* list for 'projects of common interest' (PCI) starts with 420 projects, and this number will be winnowed down by autumn 2013 to 150 (100 for electricity and 50 for gas). Once a project gets PCI status, it can benefit from a national permitting process that, under the new EU regulation, should not last longer than three and a half years. This is composed of two years for the project promoter(s) to make all the necessary applications and carry out environmental impact assessments, and 18 months for decision by national planning authorities. The only significant modification by EU legislators to the Commission's draft regulation was to extend the permitting process from three to three and a half years. It had been thought that the regulation's requirement that each member state set up a one-stop shop, a body with the power to decide or at least co-ordinate, permitting for PCI projects would pose difficulties to countries with a federal system. But acceptance was made easier by the fact that federal Germany had already decided to pass decision-making power on major energy infrastructure to its network regulator.

The new legislation specifically directs national regulators to take a wider cross-border view of the costs and benefits of trans-frontier infrastructure, and to allocate the costs appropriately to match the benefits. Take the example of a planned new Hungarian-Slovak gas interconnector, most of which has to be constructed in Slovakia but most of the benefit of improved security of supply will go to Hungary; therefore it will be up to the Hungarian regulator to ensure that most of the cost will be borne by Hungarians. PCI projects will have to show that proper cost allocation has been carried out, before seeking any EU funding.

EU funding for energy infrastructure so far amounts to:

- Of the EUR 4 billion devoted to energy in the 2009 European Economic Recover Programme, EUR 1.36 billion went to gas infrastructure, and EUR 904 million to electricity infrastructure. (Some of this has been spent on the Baltic Energy Market Infrastructure Plan – see Section 5).
- As part of the Multiannual Financial Framework (MFF) for 2014-2020, the Connecting Europe Facility originally slated EUR 9 billion for energy infrastructure, but in the ongoing MFF negotiations this has been cut to EUR 5 billion.
- Most of the large amount of lending that the European Investment Bank makes to the energy sector - totalling EUR 11.5 billion in 2011 - goes to renewable energy generation and energy efficiency projects, rather than infrastructure. But the EIB is this year piloting a project bond scheme that could eventually leverage fairly big amounts of private sector lending. The EIB will not issue the project bonds itself. Instead, as part of project bond operations led by the private sector, the EIB will make loans or issue loan guarantees which would be subordinated to those of senior creditors such as private investors. The idea is to raise the credit rating of these project bonds, and so entice investors back into infrastructure finance that has more or less deserted by European banks preoccupied with their solvency and liquidity problems.

[19] Expanding the European dimension in energy policy, David Buchan, OIES October 2011.

Outlook

The infrastructure regulation should reduce permitting delays, especially important for electricity infrastructure projects, while its cross-border cost allocation requirements should benefit gas pipeline projects which tend to cross several borders. Moreover, it should not be beyond the wit of regulators to conjure new infrastructure into existence. The high-voltage power and high-pressure gas transmission systems are natural monopolies. Their rate of return is set by national regulators, who can make transmission system operators (TSOs) profitable if they choose.

However, regulators are usually under pressure from their governments to keep transmission tariffs low, and TSOs often find it hard to raise new money for investment on the capital markets. In electricity, all east and central European TSOs are majority state-owned, as well as some in west European countries like France and the Netherlands. In gas, most large east and central European TSOs are majority state-owned. State-owned or state-controlled TSOs used to have a credit advantage in being owned by governments because this elevated them to sovereign risk status. These days such status can lead to a credit demotion. Even when that is not the case, as in the case of the two Dutch state-owned TSOs, Gasunie and TenneT, governments are reluctant to inject more capital into their TSOs, especially if this is designed to help them abroad. TenneT has expanded into north western Germany, but has found itself without the resources to connect up German wind power operators to its electricity grid as fast as they would wish. For their part, Dutch politicians and taxpayers see no reason to pay to help Germany meet its renewable energy targets.

Generally, there seem to be enough investors to participate in existing infrastructure projects, and to buy the assets that some energy groups are selling as a result of EU pressure to unbundled their transmission systems. For instance, Germany’s Eon and RWE have found buyers for the power and grids they wanted to sell. But there is not sufficient investor appetite in new infrastructure.

Suggestions

1. **More top-down push** from national governments and national regulators. The European TSO bodies of ENTSOE and ENTSOG have developed Ten Year Network Development Plans (TYNDPs) as a guide to infrastructure strategy, and as the basis from which to select the priority Projects of Common Interest (PCIs) eligible for fast-track permitting and EU funding under the new EU infrastructure regulation. But these PCIs are only a small part of what needs to be added to Europe’s networks. Individual TSOs often lack the financial incentive and means to initiate and carry through new infrastructure projects, especially cross-border projects related to a public good like security of supply. The TSOs need to be told more what to do, but also to be better rewarded by regulators for doing it.

2. **Compulsory cross-border investment** in certain cases. The Commission should, using its state aid scrutiny powers, give approval only to those capacity schemes where governments are at the same time prepared to invest in more cross-border transmission. The logic of this quid-pro-quo is cross-border inter-connection is usually part of the solution to the back-up problem (see also Section 1).

Section 4 - Plumbing work to make energy flow: prices, networks and codes

Introduction

The EU authorities have used a lot of high-level policies, and written a lot of high-level rules, to try to unify the two energy markets – electricity and gas – that depend on fixed networks, with the goal of achieving a single energy market by 2014.

In particular, the Commission has made full use of its anti-trust powers to try to stop particular instances of discrimination on these networks. EU legislators have followed this up with across-the-board remedies, contained in the three packages of legislation (1996-8, 2003, 2009), chiefly designed to make transmission system operators (TSOs) independent of suppliers and customers, and to turn them into common carriers of energy for all. These structural remedies might have spurred TSOs into filling in the missing cross-border power and gas links in Europe's infrastructure, if the economic downturn had not removed most of the financial means and the demand incentives to do so.

So the Commission launched its own infrastructure initiative in 2011 with a draft regulation to streamline national planning procedures for certain priority power and gas inter-connectors and to target a small amount of EU funding to such projects. This will take time to show any results. However, the pace of subsidy-driven investment in renewables continues faster than the building of new electricity infrastructure to bring them to market, while this renewable investment helps depress demand for new gas-powered generation. (These issues are discussed in Section 1).

Nonetheless, at a lower level, the work of market unification goes on, chiefly carried out by the Agency for Cooperation of Energy Regulators (ACER) and CEER, the European groupings of national energy regulators, and by the European-level organisations of TSOs in electricity and gas- ENTSOE and the European Network of Transmission Systems Operators for Gas (ENTSOG). The vision of what completing the internal EU energy market by 2014 – as stated by EU leaders in 2011 - should look like has been set out in an Electricity Target Model and a Gas Target Model, and agreed among all stakeholders – Commission, regulators, TSOs, industry associations, energy exchanges, traders, and consumers. The aim is to harmonise cross-border trading arrangements and to integrate national markets through efficient use of infrastructure carrying electricity and gas to where they are valued most.

Crucial to this construction job are network codes that, in a sense, provide the plumbing to ensure that energy trade can flow, and flow smoothly. These EU network codes – which, when adopted by 2014, will supersede national network codes – are being drafted by ENTSOE and ENTSOG, working under the supervision of the Commission and

ACER. It is unusual to ask one part of an industry to draft rules for the rest of that industry. TSOs, though now unbundled, are still commercial organisations, and their quasi-legislative role has been queried by some other energy companies. However, they have been judged to be the only organisations with the expertise to carry out this technical task.

Before returning to network codes, this section will examine first the current state of market integration as measured by price convergence (or lack of it), and then the different building blocks being used in the market design to unify the electricity and gas sectors.

Electricity

Prices

Gradual integration of the EU energy market, leading to more competition and efficiency, has certainly not stopped energy prices rising. But they have probably risen less than they otherwise would have. In recent years, electricity price rises have lagged behind those in oil, gas and coal. Power prices at the retail level are heavily influenced by national governments, both by taxes and in many cases regulation. In 2011 end-user prices for households were regulated in 17 member states, and for non-households in 12 member states, a state of affairs that the Commission has sharply criticised. EU rules only permit regulated prices in strictly limited circumstances to protect poor and vulnerable customers. Moreover, if retail prices are set below the level of cost recovery, they may depress power generation and will certainly discourage new investment and new entrants into the market.

Retail end-user prices may be a measure of political integration, or lack of it in the sense of member states flouting EU rules. However, because they reflect more than just supply and demand, they are far less good, as a guide to market integration, than the level or rather convergence of wholesale prices.

Cross-border price convergence is the standard measure used across all sectors of the EU economy, to determine the degree and effectiveness of cross-border competition and trade flows. As ACER and CEER have shown (see table below), recent years have seen convergence in Dutch, Belgian, French and German wholesale spot power prices in the Central West Europe (CWE) region, even though within the past year surges of renewable power, especially those coming on to the German market, have often driven prices apart again. Prices in Spain and Portugal have tended to converge with each other, and the Iberian average with the CWE level. More erratic is the pattern in the Nord Pool countries, where reservoir levels affect the price of hydro-electricity. Increasingly important in this convergence is the mechanism of market coupling. This has led to an equalisation of cross-border prices for longer periods in the year.

Figure 9 - Annual average price at European spot exchanges – 2005 to 2011 (euro/MWh)

Area	2005	2006	2007	2008	2009	2010	2011
CWE							
Netherlands	52.4	58.1	41.9	70.1	39.2	45.4	52.0
Belgium	NA	NA	41.8	70.6	39.4	46.3	49.4
France	49.3	49.3	40.9	69.2	43.0	47.5	48.9
Austria	46.4	51.0	39.0	66.2	38.9	44.8	51.8
Germany	46.0	50.8	38.0	65.8	38.9	44.5	51.1
NORDIC							
Nord Pool	29.3	48.6	27.9	44.7	35.0	53.1	47.1
MIBEL							
Spain	53.6	50.5	39.4	64.4	37.0	37.0	49.9
Portugal	NA	NA	52.2	70	37.6	37.3	50.5

Source: ACER/CEER Annual report on Electricity and Gas Markets, 2012.

Market design

'Market coupling' deals with the problem of transmission capacity congestion that so often occurs at national borders in a system originally designed around nation states. Among other things, it is aimed at preventing situations in which a seller of power on one side of the border gets a deal to deliver the power to the other side of the border, but then finds he cannot get the capacity to transport the power. Market coupling allows buyers and sellers to trade electricity without explicitly having to buy the transmission capacity needed to make the trade. The way it works is a power exchange, or usually two (one on either side of the border) will take all the trans-border transmission capacity that the TSOs have declared to be available for any period of time, and will use a clever algorithm to automatically allocate this capacity, so that one country will continue to export to another for as long as the selling price in the first country is below the bid price in the second. This allocation of transport capacity (paired automatically with trades in the electricity itself) goes on until prices in the two markets converge or until all available cross-border capacity is used up. The system allows a) transmission capacity to be used efficiently, and b) prices to act as signal for the logical flow of power, from lower price to higher price areas. As a result of market coupling in the CWE region, what are called 'adverse flows', from high to lower price areas, have more or less disappeared. By contrast, these adverse flows of electricity, moving in "the wrong direction" in a commercial or economic sense, remain frequent in Central East Europe, where market coupling only exists between the Czech Republic and Slovakia – two countries that used to be one.

This coupling of electricity markets has been proceeding apace. It was pioneered by Nord Pool, then in 2006 France, Belgium and the Netherlands adopted a 'trilateral' coupling of markets, and in 2010 Germany and Luxembourg joined in to form a 'pentalateral' market coupling. There are now 17 member states that have markets that are coupled to neighbouring markets, although not all 17 to each other. The next significant milestone will come in November 2013, with the planned market coupling for day-ahead trading of North West Europe (composed of the Central West Europe region of Austria, Belgium, France, Germany, Luxembourg, Netherlands, plus the four Nordic countries and the UK). Estonia, now linked to Finland, will probably couple its market at the same time, and Spain and Portugal soon thereafter.

Realistically, this is likely to be the full extent of market coupling in 2014. This is despite the aims, set out in the Electricity Target Model, that by 2014 there should be:

- a single European price for day-ahead trading which would replace all remaining explicit capacity auctions on cross-border inter-connectors;

- a single continuous platform for intra-day trading. This is important for renewable energy suppliers who need to trade as near to 'gate closure' or the time of actual delivery as possible, in order to take account of the weather-related variations in their supply and therefore to minimise the imbalances they can cause;

- a single European platform for the allocation of long-term transmission rights, which market coupling is not designed to cope with;

- a flow-based allocation in highly meshed networks. Instead of just involving whatever spare capacity that TSOs care to specify as available on a particular border, this flow-based approach to capacity allocation would incorporate all available capacity in a price-coupled region, not just on its borders. The idea is to make even more efficient use of existing transmission capacity in a Europe where the building of new pylons and power lines is taking so long. The flow-based approach makes particular sense to maximise available capacity in and between member states with multiple borders and highly meshed grids, such as those in the centre of western Europe. For the moment, the idea is just at the stage of trial simulations in the CWE region.

If it is the result of market forces, price convergence across borders is a healthy sign of EU integration. However, if imposed artificially, a single price can lead to problems. This sometimes happens in national markets where a uniform bid price zone can aggravate congestion on the country's internal network, and where some price differentiation would ease this congestion. A proven case is Sweden. Northern Sweden has a surplus of electricity but cannot, because of transmission congestion, always get it to southern Sweden. At such times of congestion, the Swedish TSO used to curtail any southern Swedish power exports to Denmark, in order to prevent the price in southern Sweden rising above that in the north. Following concerns expressed by Brussels, the Swedish TSO decided to split the Swedish power market into several bidding zones, producing a lower price in the north than in the south. This has reduced congestion inside Sweden. It has also produced a different geographic pattern to price convergence, particularly between southern Sweden and Denmark, showing they share natural generating capacity characteristics.

The same recipe could be applied in Germany. A lower bidding price in northern Germany would reduce the incentive for wind-powered electricity that Germany's inadequate internal transmission system cannot fully transport to the centres of demand in southern Germany. The result of this German grid congestion is that unwanted 'loop flows' of north German wind power frequently surge into the neighbouring Polish, Czech and Dutch markets, causing disruption. Likewise in Britain, it would probably ease congestion of southward power flows from Scotland to England if the two countries had different bid price zones, instead of one as at present.

Network Codes

ENTSOE and ENTSOG were given a difficult task with a very tight timetable. Each network code (NC) is typically a three-year project between concept and delivery. This allows ACER six months to produce framework guidelines for the TSOs. The latter then have 12 months to draft the NC, which ACER then has three months to assess, recommend adoption or to ask for more work. If and when that process is over, the NC goes to comitology for the Commission and member states to write into EU law. Writing law to a deadline is challenging, the time for consultation has been short. Some companies, especially in electricity, have complained that the TSO organisations are imposing stringent NC requirements on them without sufficient cost/benefit analysis as justification. This is a criticism that the TSOs partly accept, but argue that it is inevitable given the time pressure.

Among the nine main NCs in electricity, the most important are:

- Requirements for generation. Before there were some regional codes in Nordic area, but most were national, and not aligned or harmonised with each other. The disadvantage for industry was that manufacturers of turbines had to produce different designs for different standards. For the TSOs, the importance of the new code, which categorises generators according to size and connection voltage, is that it gives them more technical certainty about how services such as for balancing for renewable energy will be carried out.

- Requirements on frequency. This sets common rules on voltage in synchronous areas (GB-Ireland, Nordic region, the Baltic states, continental Europe). Generators have complained about the cost of requirements which, not surprisingly, increase the bigger the size of generator. Some generators also moan about the lack of cost/benefit analysis, but ENTSOE points to the time pressure from ACER.

- Capacity Allocation and Congestion Management. This relates to markets, in line with the target model of progressive harmonisation of trading arrangements along the time line, starting with day ahead and moving to continuous trading. It sets a rule about the firmness of orders, and what happens to firm orders if transmission capacity is subsequently constrained. This code also defines bidding zones as areas within which energy flows without any congestion. The size of bidding zones helps determine the degree of competition and the number of buyers and sellers, helps determine prices according to the proximity of supply to consumption and, through prices, sends signals about possible new investment. More bidding zones can, as we have seen, be a solution to loop flows. This NC defines capacity allocation, which will become more complex with the move towards flow-based allocation that is important for the more meshed grids of continental Europe. Assessing capacity is vital for market coupling. This is done through the power exchanges, which take the available capacity and the bids and use their algorithms to set the price in a coupled market. This puts power exchanges, which are non-regulated commercial entities, in a potentially powerful position, and some have suggested that power exchanges should be regulated in some way. For their part, the power exchanges claim they can regulate each other, because several of them will be running the algorithms and thereby preventing monopoly power.

- Demand connection code. This covers all big electricity users such as factories. But it also contains a controversial provision that would require temperature-controlled devices, like refrigerators, to be able to react to frequency disturbances in order to keep the grid stable. This is a mandatory requirement for demand side reduction. But some electricity users argue they should be paid for providing this demand reduction service, and that if they are not to be paid, then this requirement should be legislated through standard EU law-making procedures and not rushed through in secondary legislation.

Gas

Prices

Gas prices have increased less than oil. This is because recession has reduced demand for gas, because imports of cheap US coal (displaced by the shale gas glut in the US) have displaced gas in power generation, and because more gas is being traded on a spot basis at European hubs and relatively less is being sold on oil-indexed contracts (chiefly from Russia). The volume of gas traded in continental Europe on a spot basis rose by 27 per cent between 2010 and 2011. In 2012 nearly half of all gas sold in Europe was at prices set at hubs, or trading points, inside the EU.

The reason for the shift in gas pricing from oil indexation to spot pricing at hubs is simple market economics. Gas indexed to the generally high world oil price is more expensive and is losing customers who are doing all they can to switch to cheaper gas sold at hubs, where the price is the result of competitive forces of gas supply and demand. The original rationale for linking the price of gas to that of oil was that gas and oil were substitutes for each other in power generation. This is no longer true in Europe, where almost no oil is used now to generate electricity. Most major gas sellers in the European marketplace, notably Norway and the Netherlands, acknowledge this reality and accept hub-based prices for most of their gas. Russia, however, does not. Gazprom is still hanging on to the oil-indexation price formula in its long-term contracts for as long as possible. Russia's monopoly gas exporter argues that only oil price-indexation guarantees producers a 'fair' price that covers the cost of expensive upstream gas fields. But Gazprom's protection of its upstream in Siberia is jeopardising its downstream market in Europe. In practice Gazprom is beginning to sell some of its gas at hub prices, though only to customers that have access to gas trading hubs (which does not yet include many central and east European customers). So, even in Gazprom's case, the move to hub-priced gas is slow but inexorable[20].

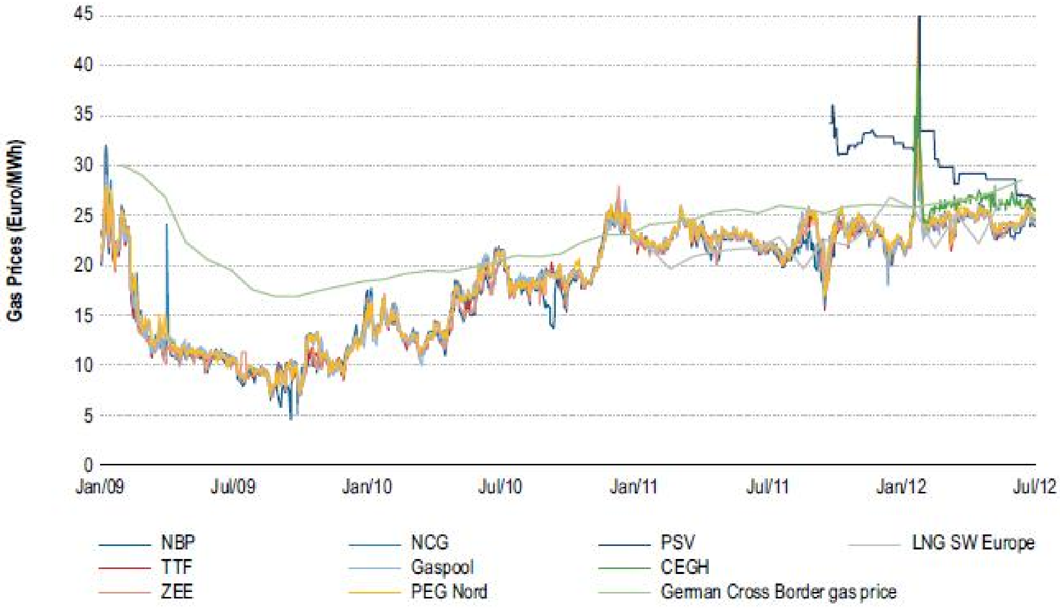
Again, retail end-user prices of gas, as of electricity, are not the result of pure supply and demand forces, but often the result of considerable state intervention in terms of taxes and regulation. End-user prices for households are regulated in 16 member states, though not for industry. Most new member states regulate retail gas prices. However, because the initial communist-era level in these countries was so low, the percentage increase in some of east and central Europe's regulated prices has been higher than in some west European countries with no regulated cap on their retail gas prices. Nonetheless, there was a wide dispersion in end-user prices in 2011, according to the ACER/CEER monitoring report, a spread of 1: 4 in household prices, between Romania (a gas producer itself) at the bottom and Sweden at the top, and of 1:3 in industrial prices between Romania at the bottom and Denmark at the top.

At the wholesale level, gas prices show some degree of convergence (see table below). The tightest correlation is between the three main gas hubs in North West Europe (NBP, TTF and Zeebrugge) which are highly liquid and have good physical interconnection. This region is beginning to influence the German gas market which is moving towards hub pricing and away from oil-indexed contracts. Fairly recently the Italian PSV hub price (in dark blue) and the Austrian-Slovak border's Central European Gas Hub price (in green) have also started to come in line. All hubs showed the sharp price spike due to the

[20] The Transition to Hub-Based Pricing in Continental Europe, Jonathan Stern and Howard Rogers, OIES, February 2013.

very cold weather of February 2012. There is still a pricing disconnect with parts of eastern and southern Europe that suffer from a lack of diversity of supply, a paucity of connecting pipelines, a scarcity of LNG and (because of all this) an absence of trading hubs.

Figure 10 - Wholesale day-ahead gas prices at selected EU hubs – 2009-2012 (euro/MWh)



Source: ACER/CEER annual report on electricity and gas markets, 2012.

Some of the price differences reflect transport costs, a relatively bigger item in gas bills than electricity reflecting the reality that electricity is usually generated close to demand whereas gas often travels thousands of kilometres. But much of the price differences is also alleged to be due to capacity congestion at cross-border interconnectors, and some of it purely 'contractual congestion' – in other words, where transport capacity is fully booked but not fully used. The European Commission's competition authorities have tried to crack down on such contractual congestion where this appears to be a deliberate strategy of hoarding. Nonetheless, ACER/CEER looked at seven interconnectors with 100 per cent fully booked capacity in 2011, and found that their actual utilisation ranged from 92 per cent down to 42 per cent with a central value of around 60 per cent.

Market design

Unlike electricity which is mostly generated and consumed within national borders, a large portion of Europe's gas comes from far away and is transported by pipeline across several EU states before reaching its destination. The transport regime for gas is therefore crucial. In terms of unifying and simplifying the transport of gas across, the EU has chosen as its basic building block so-called entry-exit zones (EEZs). These are required by the 3rd package of legislation, which stipulates that transport tariffs or costs should be independent of 'contract paths' or the actual distance between the source of gas and the point of consumption. In these EEZs gas can enter at any point or leave at any exit point, at prices which are not directly connected to the distance that gas may have travelled.

European countries used to have a system that more closely resembles that of the US, in which the inter-state transport and trading of gas is largely governed by long term contracts, in which transport tariffs are calculated on a point to point system and take account of the underlying infrastructure costs, and in which trading takes places at physical hubs, such as the famous Henry Hub, formed by pipelines coming together and also providing useful location for storage and balancing. Underpinning this so-called point to point system were well-defined property rights to, or long term contracts for, transmission capacity that had been crucial to funding the building of the long-distance pipelines within the US and also between Russia and western Europe. However, the European Commission concluded that many of these long-term gas transport contracts were effectively cosy arrangements between Europe's gas importers and outside suppliers that cartelised the market against new entrants and that helped sustain the increasingly artificial pricing of gas by indexing its price to oil product prices.

So the EU chose the very different model of EEZs in order to promote new entrants, competition and trading at virtual gas hubs that could be at any notional point within an EEZ. The EEZs, which coincide with the balancing zones, facilitate trading in several ways and use a simplified commercial model to promote more efficient market functioning. They expand the trading zones, with usually only one EEZ per country (as in the UK and Italy, though Germany has two EEZs and France three). They lower transaction costs because any gas is priced and traded regardless of its location within the EEZ. Balancing – to equalise injections and withdrawals of gas - becomes easier in a larger zone, and therefore the timeframe for balancing can be extended. The cost of transport and network services is separated from that of the commodity, and 'socialised' or spread across all users of the EEZ network.

Trading has become simpler (fewer transactions) and less risky (less worry about imbalances and mismatched trades). So trading activity has surged at Europe's hubs. Liquidity attracts liquidity, as buyers and sellers benefit from always being able to get a good price, and Europe's gas consumers and users can be more certain of purchasing gas that has been bought on a market where large volume makes price difficult to manipulate. Moreover, it is easy to see the ideological attraction to the Commission of EEZs, because they are mini-versions of Europe's single market.

However, there is a trade-off to the size of EEZs. They have to be large enough to attract buyers, sellers, traders, shippers, but small enough that any physical constraints resulting from different gas flows do not generate too high internal congestion charges and problems. Distance may have been 'abolished' commercially inside the EEZ for traders, but physical flow of gas still needs to take place as required by the network users. A TSO will always keep part of its infrastructure capacity out of the market in order to respond to requests for shipment in and out of any entry or exit point of the zone. "Therefore the larger the trading zone, the larger the amount of infrastructure that needs to be kept out of the market to guarantee the greater trade flexibility permitted within the larger trading zone”[21]. Moreover, the larger zone the greater the degree of cross-subsidisation of transport costs with shippers using a lot of transport effectively subsidising those who use little.

A further complication is that within the EEZs there are no locational price signals, or price spikes at particular bottlenecks, to pinpoint congestion and incentivise investment in new pipelines to resolve the bottlenecks. So, because transport price signals become blurred inside EEZs, in the opinion of some experts, regulators may have to take more of a lead in determining new transmission investments both inside EEZs and particularly between such zones[22]. This is the view of one regulator, Walter Boltz, head of Austria’s E-Control, who has said that “increasingly, regulators will decide what needs to be built because shippers will not commit themselves to long-term investments in cross-border pipelines”.

For some of these reasons, it is hard to see these EEZs being enlarged much further. Most will probably remain at the national level in size. Some may stay sub-national. The number of gas trading/balancing zones has been greatly reduced in Germany, with a further reduction in 2011 from six zones to two - run by the TSOs, NetConnect Gas and Gaspool. The German TSOs recently claimed that the cost of merging the two zones into one would be an extra EUR 395 million a year in the first year after the merger for a financial benefit to the market of less cost less than EUR 60 million a year, and that the extra investment to maintain current levels of service in the merged zones would be nearly EUR 3 billion[23].

In principle, according to the widely accepted Gas Target Model, any gas market that is smaller than 20 billion cubic metres in annual consumption and has less than three suppliers should merge with another. In practice, the only one likely to acquire a multinational, regional dimension is the Central European Gas Hub, which announced in January 2013 that it was switching from being a point-to-point trading hub to a virtual hub with an entry-exit system. It is already a key hub for Russia gas flowing into Austria, and thence on to Germany and Italy, and as an EEZ could eventually be extended to the Czech Republic, Slovakia and Hungary. In South-South East Europe few EEZs yet exist. The upshot is that no one is predicting the total number of EEZs across Europe will fall below seven.

An alternative suggestion is to improve the links between EEZs by making better use of cross-border inter-connector capacity through market coupling, as in electricity. But this is not going as fast as in electricity. There is a pilot project to couple gas zones in France.

[21] Designing the European Gas Market: More Liquid & Less Natural? Miguel Vazquez, Michelle Hallack and Jean-Michel Glachant, Economics of Energy & Environmental Policy, Vol 1 Issue 3, page 30.
[22] ibid. page 36.
[23] Poll by ICIS, quoted in European Spot Gas Markets 8/11/2012, also a PWC study I think.

The Dutch and German gas markets are coupled, through the common ownership by Gasunie of gas grids on both sides of the border. And this year, 2013, has seen the launch of a proto-European gas capacity booking platform by 19 TSOs from Austria, Belgium, Denmark, France, Germany, Italy and the Netherlands, though this will lack the automaticity of real market coupling[24].

The reason for the relative slowness of market coupling in gas is the strong aversion that many gas industry players have to the concept. They argue there are fundamental differences between gas and electricity. Electricity is generated and consumed locally, with a bit of spillage to export to, or shortage to import from, neighbouring countries with often very different prices. So why not develop an automated process for price comparison between adjacent markets for short-term trading of fairly small quantities of power in relation to total electricity consumed? But many in the gas industry dislike market coupling because the usual approach in electricity appears to put almost no value on transport which is a very important feature of the gas industry. Gas often comes from far away, and the gas industry, they say, has had to develop longer term arrangements to underwrite investment in extraction and transport. So gas has been traded on long term contracts that already incorporate value/cost of transport, with the end-consumer often paying for the gas network in several other countries as well as his own. The gas industry acknowledges that there can be congestion, particularly contractual congestion, on cross-border interconnectors between EEZs and national markets. However, the problem should be resolvable in the secondary capacity market. Concerns about hoarding and market manipulation have triggered reforms via the congestion management process, including the principle of use-it-or-lose-it-or sell-it to prevent hoarding. If capacity is congested, then the gas sector rules are designed to get capacity into the hands of those that want to use it, rather than using some clever algorithm that is only relevant very close to the time of the actual gas flow.

Network codes

The most important for gas are:

- Congestion Management Principles (CMP). This is the procedure for clawing back capacity that is not being used, and enabling its release to other market players that might want to flow gas.
- Capacity Allocation Methodology (CAM). This governs the way in which whenever free capacity is available to the TSO, the TSO has to release it to the market. So capacity is clawed back by CMP and then put out into the market by CAM.
- Balancing. This sets out how users should be responsible for balancing, and introduces market-based balancing for day ahead and intraday.

[24] http://www.open-grid-europe.com/cps/rde/xbcr/SID-49868E1A-4CB2CCE1/open-grid-europe-internet/2012-12-04_Press_Release_PRISMA.pdf

Suggestions

1. Continue to push measures that will lead to cross-border convergence of wholesale prices, but accept that, in electricity, uniform bidding prices may be counter-productive in some national markets.

2. Press for de-regulation of retail electricity and gas prices because regulated prices can stifle competition.

3. See whether the new gas network codes can resolve inter-connector congestion before pressing on with market coupling.

4. Examine whether, in view of future dependence on gas as back-up for renewable electricity, single trading zones for electricity and gas should be made to coincide geographically. If so, market coupling may have to continue in gas.

5. Examine the effect of gas entry-exit zones on the incentives for new investment.

Section 5 - External energy policy and action: the result of Lisbon and logic.

Introduction

Until recently, the role of the EU in energy policy was weakest in the external arena, because national governments jealously guarded energy foreign policy as their preserve. However, this has changed, as the result of Lisbon, and of logic. One of the competences conferred by the Lisbon treaty on the EU is to "ensure security of supply in the Union". This formal new responsibility responds to concerns about growing EU reliance on energy imports, and in particular Central and Eastern Europe's worries about dependence on Russian energy. Logic, too, is driving EU external energy policy along. As has happened in other areas of the single market – liberalisation of aviation, for example – the harmonisation of member states' internal market policies and practices has led to a more common approach in external policy. Indeed this logic is more compelling than in aviation, because the two major components of a European low-carbon energy system – electricity and gas – depend on fixed infrastructure that extends beyond the Union's frontiers. Infrastructure is still an abiding focus of EU internal energy market policies, and so it is proving with external policy.

In September 2011, Gunther Oettinger, the energy commissioner, presented his communication "EU Energy Policy: Engaging with Partners beyond Our Borders"[25]. He stressed the Commission was "not making a power grab", but was responding to the European Council of February 2011. This stated that "the Commission is invited to submit a communication on security of supply and international cooperation aimed at further improving the coherence and consistency of the EU's external action in the field of energy". The Council of EU government heads went on to state that "the member states are invited to inform from January 1 2012 the Commission on their new and existing bilateral energy agreements with third countries; the Commission will make this information available to all other member states in an appropriate form, having need for the protection of commercially sensitive information"[26]. Almost all of these agreements relate to gas and electricity imports through fixed pipelines and grids.

The same September 2011 communication on external energy policy also revealed that the Council of Ministers had given the Commission a mandate to negotiate some kind of trilateral legal framework with Azerbaijan and Turkmenistan for a trans-Caspian pipeline in order to increase the supply of non-Russian gas to Europe. These negotiations do not appear to be moving very fast. This is not surprising, in view of the way that Europe's economic downturn has depressed demand for gas. For the same reason, the Caspian Development Corporation, the corporate structure that the Commission has fostered to

[25] COM (2011) 539 Final.
[26] European Council 4 February 2011 Conclusions.

gather together companies interested in buying Caspian gas and building a pipeline to bring it to Europe, may remain a rather empty vessel until demand picks up.

Nonetheless, in terms of the politics of EU policy-making, the willingness of member states to let the Commission oversee their bilateral energy supply agreements, and, potentially, to negotiate a new agreement on behalf of the Union was a major development.

EU-Russia

The relationship with Russia continues to dominate the EU's energy horizon, for obvious reasons. Russia is a major supplier to the EU of oil, gas, coal, and, but for protectionism by the EU, of uranium fuel. Its energy exports reach every EU region, except for Iberia; even a country such as the UK that does not think of itself as dependent on Russia imports 40 per cent of its coal from Russia. Efforts to improve the relationship go back to the setting up in 2000 of the EU-Russian Energy Dialogue. Progress since has been difficult. When they joined the EU in 2004, central and east European states fed into the dialogue their concerns about Russian motives. Russian belligerent behaviour, particularly towards transit countries for their energy (Ukraine, Belarus, the Baltic states), justified these concerns. Repeated Russian-Ukrainian disputes led to gas supplies to the EU being cut in 2006 and, more seriously, in 2009. The Russian solution to tensions with fellow constituents of the former Soviet Union has been to sidestep them by building bypass routes – the Baltic Pipeline System as a purely Russian outlet for oil exports to the Baltic coast, the Nord Stream gas pipeline to bypass Belarus as well as Poland, and now, potentially, South Stream to bypass Ukraine. These diversionary routes produce a mixed reaction in the EU – welcome on the part of some west European states, worry on the part of some east European states at being among those bypassed. But the dialogue has produced some results – in the wake of the gas cut-offs Russia agreed on an early warning mechanism to give the EU advance notice of any impending transit dispute.

Gas pricing is replacing gas transit as the main irritant in the EU-Russian relationship. This is happening, because cheap imports of shipped gas, including LNG diverted from the shale-flooded US gas market, are driving down the spot price of gas at European trading hubs. As explained in Section 4, this in turn is making European gas users very reluctant to go on paying the higher price of piped gas from Russia that is indexed to oil product prices. Norway and the Netherlands have dropped oil indexing in their gas pricing, but Gazprom has only done so for big west European gas users that are ready take them to arbitration and that have alternative access to gas trading hubs. In a sense, this price divergence is a commercial rather than a public policy matter for EU authorities, though they appreciate the macro-economic effect, in at least Western Europe, of lower spot gas prices and the market development boost this is giving to trading hubs.

However, a serious market segmentation problem has arisen, because Gazprom continues to charge the higher oil-linked price to central and east European member states without access to trading hubs and alternative spot purchases. Suspicion that Gazprom is deliberately segmenting the supposedly single EU market is one of the allegations that the Commission is examining in its anti-trust inquiry into Gazprom launched in September 2012. Gazprom, and indeed President Putin, complain that the inquiry is political and that Gazprom has been singled out for such scrutiny. However, in 2007-2008 the Commission launched anti-trust investigations into German, French and Italian energy companies in cases where, though the specific facts obviously differ, the same overall allegations of discrimination and abuse of dominant position were made.

Nonetheless, the dialogue grinds on. In March 2013 the EU and Russia agreed on a road map of cooperation up to 2050[27]. The fact that this document is both general and about the future made it easier to agree on. Nonetheless, it is significant for the tone of realism that both sides appear to show. After several years of the EU saying it wanted security of supply from Russia and Russia saying it wanted security of demand from the EU, both sides accept absolute security is illusory, and state that "the objective [of the roadmap] is therefore to achieve a tolerable level of uncertainty". More remarkably, the document goes on to forecast decreasing dependence on each other in the future. It argues that "the EU will account for a shrinking share of global fossil fuel markets", if its low-carbon transition succeeds, and "emerging economies, particularly to the east, will become more prominent in Russian exports", as pipelines eventually link east Siberia to China. The result will be "a shift of EU-Russia energy relations from a pure consumer-supplier relationship towards a more technology-based cooperation". Over the long-term, a less entangled relationship could be smoother.

But in the immediate future, the EU and Russia find themselves entangled on several fronts:

- **The Baltics**. At present the three Baltic member states are still linked to the Russian electricity system, as they were in Soviet days, and the three of them plus Finland depend solely on Russia for gas. Part of the European Council's February 2011 pledge to complete the internal energy market was that "no EU member state should remain isolated from the European gas and electricity networks after 2015 or see its energy security jeopardised by the lack of appropriate connections". Fulfilling this pledge in electricity means effectively disconnecting the Baltic states from the Russian system, and linking them to the continental European system which happens to spin on a different cycle. Negotiating this with Russia, and also with neighbouring Belarus, is a complex business, not made easier by Baltic state suspicions that Russia is delaying in a bid to maintain

[27] Roadmap – EU-Russia Energy Cooperation until 2050, 2013.
http://ec.europa.eu/energy/international/russia/doc/2013_03_eu_russia_roadmap_2050_signed.pdf

a valuable export market, and by the slow business of constructing Baltic connections to the rest of the EU. Nonetheless, there is a plan called the Baltic Energy Market Interconnection Plan (BEMIP). EU funds are being used to build two power interconnectors – Estlink between Finland and Estonia, and NordBalt between Lithuania and Sweden – and there are plans for gas interconnectors between Poland and Lithuania, and between Finland and Estonia, as well as a regional LNG terminal to bring in shipped gas from elsewhere. However, the Baltic states have so far failed to agree where this regional LNG terminal should be, just as they have been able so far to agree on a common regional nuclear plant. There was initial agreement that the nuclear plant should be built in Lithuania to replace a Soviet-era reactor that the EU ordered shut down for safety reasons. This reactor replacement project was thrown into limbo after it was rejected in a local Lithuania referendum, though the vote was non-binding.

- **Unbundling of transmission assets by Gazprom** (and other energy groups), as required by the Third Package. This legislation allowed member states which are isolated and dependent wholly or very largely on one source of supply to delay forcing energy suppliers to sell transmission assets or make them operationally independent. This exemption was therefore open to the Baltic states and Finland, until such time as the BEMIP project is completed and they are connected with the wider European grids. Latvia, Estonia and Finland decided to take advantage of the exemption, and therefore Gazprom can continue to maintain its ownership shares of their gas pipeline systems. But Lithuania decided not to avail itself of this exemption. It has announced that it will spin off its gas pipeline system as a separate state-owned company, and that Gazprom must this summer sell its 37 per cent stake in it (and Eon of Germany must also sell its 39 per cent stake). Gazprom is contesting this, as it does the letter and logic of the Third Package. A particular Russian stake in this is that the Lithuanian gas pipeline system delivers gas to the Russian enclave of Kaliningrad.

- **Inter-governmental Agreements (IGAs).** In 2012 EU legislators agreed the information exchange on member states' bilateral energy agreements with third countries [28]. The Commission is now trawling through these agreements to see whether the agreements – said to be over 90 in number (60 for gas, 30 for oil and a few covering electricity – to see whether they conform to EU law. If they do not conform, renegotiation could be tricky. But for future negotiations, the requirement for conformity with EU rules could be a useful weapon for member states negotiators. Take the case of Poland's 2010 negotiations to renew its long term Yamal gas contract with Gazprom of Russia. The Commission first complained that Poland's draft agreement with Gazprom breached EU competition rules. The Poles then turned to the Commission for help in negotiating their overall deal with Gazprom. As a result Poland won a series of concessions from Gazprom – the right of third party access on the Yamal pipeline, the right to re-export Gazprom gas and to re-import back from Germany because reverse flow was to be introduced on the pipeline. The upshot is that Poland will no longer be a captive market for Gazprom, because the Yamal pipeline will give it access to gas from the west as well as from the east. It is this success, in making a bilateral agreement conform to EU law to the apparent benefit of EU consumers, that provided the impetus for the September 2011 proposal for an 'information exchange mechanism'. However, some new IGAs appear to pose a problem of conformity with EU law. These are the agreements that several EU governments – Austria, Bulgaria, Croatia, Greece, Hungary and Slovenia - have signed with Gazprom to allow South Stream to pass through their territory. These appear to infringe EU law on two grounds – they reserve all transport capacity for the operating companies, and these operating companies each take the form of 50/50 joint ventures between the local gas company and Gazprom.

Exporting EU energy policy

This has been done most effectively through the Energy Community (EC), a organisation of nine states, mainly in the west Balkans but also including Ukraine and Moldova and soon to include Georgia. Essentially, it is a transmission belt for the transfer of EU energy laws and rules to some of the EU's near-neighbours. The latter have been willing to adopt laws, rules and targets which they have had no part in making, in the hope of attracting investment to a region in need of post-Yugoslav war reconstruction and of gaining energy security by aligning themselves with the EU.

These hopes have not been fully realised, but for understandable reasons. Inward investment into EC countries has been low, but it has been low everywhere. The EU was of little help to the EC's Balkan members in 2009 when Russian gas cut off, because many EU countries were also cut off. However, the post-2009 gas security regulation which the EU put in place should also be of help to the EU's south east neighbours in any future gas crisis[28]. For, in addition to requiring individual EU members to do a better job of assuring their own gas security, this EU regulation measure has also led to more reverse flow capacity being installed on the main east-west gas transmission pipelines (Ukraine, for instance, can now import some gas from Germany, as well as Russia), and more north-south gas links are being built, creating a north-south corridor through central Europe from Poland to Croatia.

The EC offers a blueprint of sensible market-friendly rules, and also useful preparation for EU membership, for those few countries still likely to join the EU in the near future. Croatia is a case in point; its accession to the EU this summer was smoothed, in the energy field, by EC membership. Implementation of the EU *acquis communautaire* obviously is not easy in countries unlikely to join the EU in the foreseeable future and therefore on which no penalties for non-implementation can be imposed. In its 2011/2012

[28] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2012:299:0013:0017:EN:PDF
[29] Regulation 994/2010.

annual report, the EC's Vienna secretariat said it "increasingly becomes aware of the limits of market reform in real terms, and true implementation of the acquis beyond transposition". It went on to say that, despite such innovations as a coordinated auction office for electricity capacity, regional markets were not a reality. Moreover, there is something surreal about a country like Ukraine accepting a *mandatory* target to double its renewable share of energy by 2020, or Moldova to unbundle its gas transmission system, just as if they were in the EU. Nevertheless, that such countries are ready to make even nominal commitments of this kind shows that the EU can still project soft power, even if only in energy.

Suggestions

1. EU external energy policy will gain credibility if it stays focussed on the practical infrastructure issues that arise with Europe's neighbours. Many of these infrastructure issues, and the problems relating to the use and ownership of infrastructure, involve Russia. This highlights the importance of maintaining the EU-Russia dialogue policy in order to sort these problems out.

2. The EU must continue to build resilience against external energy shocks, like cut-offs in gas supply, through measures to expand internal networks and storage inside the EU. Such internal precautions are valuable when external energy diplomacy fails.

3. Baltic member states deserve EU help and support of diplomatic, technical and financial kinds. But they need to do more to help themselves, in particular resolving their indecision about where and how to site a regional LNG and a regional nuclear plant.

4. The Energy Community merits more than the small amount of resources that Brussels devotes to it. A modest increase in the investment of money and people would leverage a much larger return in terms of useful influence in the Europe's near-abroad.