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The EU "Target Model" for electricity markets: fit for purpose?

Malcolm Keay

The Commission's priorities for the May 22 European Council discussion of energy were clear – the completion of the single market for energy. In a letter to European leaders, Commission President Barroso argued that "the completion of a fully functioning, interconnected and integrated internal energy market …. is central to Europe's competitiveness and must not be fragmented".[1] In pursuit of this aim, the Commission has been promoting a Target Model for electricity markets to facilitate border-free trading across Europe. But is that model fit for purpose?

That depends, of course, on what the model's purpose is and what criteria should be used to judge it. In the view of this commentator, six criteria could be regarded as significant:

1. **Efficient operation** The market model should give price signals which encourage efficient day-to-day operation and maintain security and reliability at minimum cost.
2. **Facilitating cross-border trade across Europe** Individual power markets in Europe, whether on a national or regional basis, should be designed and linked together in such a way as to permit barrier-free trade across the whole EU.
3. **Promoting efficient investment** The market should give signals which encourage the development of the clean power sources Europe needs and ensure adequate investment to maintain security of supply, all at minimum cost.
4. **Level playing field for different sources** The market should enable different sources, with different cost and operating structures, such as fossil and renewable plants, to compete on a level playing field.
5. **Effective risk management** The market should provide a basis for the development of intraday, forward, futures and derivatives markets which enable investors and operators to manage risk via markets.
6. **Robustness** So far as possible the market should be able to cope with expected (and unexpected) changes in electricity systems.

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[1] http://europa.eu/rapid/press-release_MEMO-13-416_en.htm

It is the contention of this Comment that the Commission is focusing almost exclusively on the first two of these objectives (and achieving them only in part). This is odd, given that most commentators would agree that the main challenge facing EU electricity markets is the need to generate the huge amount of investment needed to move towards the EU's carbon targets; that renewables in particular should be a major part of this drive and should therefore be able to compete on a level playing field; and that, even though special support may be needed at present for low carbon sources, the ultimate aim should be for investment to take place on the basis of market signals. Since the Target Model, as discussed below, is not well adapted for these goals, this Comment argues that it is not fit for purpose.

The Target Model

The Target Model is based on two broad principles:

- **Energy only** regional markets, preferably organised on a zonal basis, in which generators' revenues depend primarily on the price for each marginal unit of energy supplied.[2]
- **Market coupling,** which is a way of linking zonal day-ahead spot markets into a virtual market, so that the lowest priced bids are accepted up to the point where congestion constraints limit further trade (using flow-based transmission allocation, based on optimisation models).[3]

There are many complications when it comes to working out these principles but this Comment is concerned in particular with the first issue – whether the day ahead, energy-only market is a good basis for European electricity trade[4]. An earlier Comment[5] pointed out that this was one of the areas where tensions were arising between national approaches to electricity markets and the EU's single market goals. The UK has proposed the introduction

[2] The Target Model is a complicated (and developing) set of proposals. An outline is given in the Commission consultation document on market coupling - http://ec.europa.eu/energy/gas_electricity/consultations/doc/20120229_market_coupling.pdf

[3] In fact, a very large part of the mechanics of market coupling relate to capacity allocation and congestion management. However, the focus of this Comment is on the approach to electricity pricing, via day ahead spot markets.

[4] A number of other important issues related to the Target Model are not discussed here; in particular, the choice of a zonal rather than nodal basis for the market. (In essence, zones are larger areas and normally comprise a group of nodes). Nodal pricing is normally regarded as preferable; it gives better locational signals for new investment and is usually more effective at reducing congestion costs. These factors are of increasing importance in a system with large amounts of new renewable capacity. For a discussion of these issues, see *The EU electricity target model: the devil is in the details?* Oxera January 2013

[5] *UK Electricity Market Reform and the EU* April 2013

of capacity markets to complement energy markets as part of its Electricity Market Reforms and a number of other European countries are considering similar measures. The Commission is resisting these moves, primarily because they do not fit well with its Target Model framework – in its paper for the 22 May European Council, the Commission picked up the words from President Barroso's letter to complain that capacity markets are "likely to perpetuate the fragmentation of the internal energy market".[6] However, this is only one of the many points of tension between the Commission's approach to the single market and the measures needed to make progress towards climate goals. The attachment of the Commission to its particular version of a single market is likely to be the source of serious future difficulties.

Assessment

Taking each of the criteria suggested above in turn:

Efficient operation Energy only markets are the traditional basis for electricity trading. In systems dominated by fossil or traditional renewable plants like hydro they give effective short run marginal cost signals ensuring that the lowest cost plants are running at any particular time. Fossil plants have significant marginal fuel costs – at present, marginal generation costs constitute some 75% of the total costs of the UK system[7]. Hydro producers have low direct marginal costs but in most cases they face opportunity costs (ie before allowing water to pass through the turbine to generate electricity they need to consider whether it would be better to keep that water for generating power at some later time or date). So in both cases, short run operating decisions can usefully be based on an energy market and the prices it generates.

However with most "new" renewables (and to a large extent with nuclear) this ceases to be the case. There is no, or only a very low, marginal cost of generation and no opportunity cost decision – the wind cannot be stored for some future date and the fuel cost of nuclear generation is very low. So energy prices do not in general give very useful signals for short term operation. The Target Model does not really try to address the issue; in any event, renewables are not subject to the same dispatch criteria as other sources and are thus effectively outside the market. (Under Article 16(2) of the Renewables Directive of 2009, renewables are given priority in generation provided security is maintained – ie whether or not this is the most efficient outcome from a system viewpoint). Furthermore, the Target Model does not address the issue of curtailment, which is one area where price or market signals could be effective in relation to new renewables. With the growth of intermittent renewables, such as wind, it is increasingly the case that generation in a particular area is

[6] http://ec.europa.eu/europe2020/pdf/energy2_en.pdf p7

[7] See, for instance, the cost analysis in BERR publication URN 08/1021, June 2008.

greater than demand, or has to be limited because of transmission constraints. There are various ways in which a system operator can organise generation curtailment when it is needed. In Europe there is normally some sort of administered solution, though market approaches are possible (and have been implemented in the US, for instance in California). But the Target Model does not effectively deal with the issue – and the Renewables Directive simply says that renewables curtailment should be minimised via "appropriate grid and market-related operational measures."

In short, the day-ahead energy only market is well suited to creating operational efficiency in traditional markets, but is likely to be of less relevance as the proportion of renewables and other low carbon sources grows. New approaches to operational efficiency are likely to be needed in these markets with more emphasis, for instance, on short term adjustment to changing renewables output forecasts.

Cross border trade As indicated above, this seems clearly to be the Commission's main priority; energy only markets are probably the simplest route to enabling cross-border trade across Europe, which is no doubt why the Commission is promoting this model. But it should be stressed that such markets are not the only possible basis for trade. In the US, for instance, various more sophisticated models are used – PJM, for instance, has reliability pricing (a form of capacity market), well integrated demand response pricing across various timescales and a system of financial transmission rights to deal with congestion pricing issues. The Commission's argument that capacity markets lead to fragmentation is in all probability based on the belief that it would not be possible to get all Member States to agree to the same capacity market design, rather than any fundamental incompatibility between capacity markets and cross-border trade.

Investment signals But it is perhaps in relation to investment signals that energy only markets are most likely to be deficient as Europe decarbonises. There are two sets of problem:

- **High volatility and price risk for fossil generators** The main argument for capacity payments is the so-called "missing money" problem. In a system where there are only energy payments, a conventional plant's operating costs should be covered by the revenue per unit, but what about the capital costs? These will only be remunerated if, for reasonably significant periods, the power price rises above the short run operating costs of the plant concerned to a sufficient extent to make a contribution towards the capital cost. But there is a risk that there will not be enough of these periods; or the price will not be high enough; or the government will intervene to force down prices. If so, the money needed to reimburse capital costs will be missing. This could be happen in any system, but the risk is orders of magnitude greater in a system with significant low carbon generation, especially if that consists largely of intermittent, but coincident, plants like wind. In such a

system, because of the low marginal cost of the wind power, energy market prices will typically be low; but at certain times when the wind is not blowing, conventional plants will be needed to fill the gap and will need to receive a price much higher than marginal operating cost to cover their capital costs. One analysis[8] suggested that in the UK system in the late 2020s, if government wind targets are reached, market prices would have to range from -£50 or so to +£8,000 to provide a return for all investors (the negative prices are because wind generators receive an income from their Renewables Obligation Certificates, or other forms of support, so are not dependent on market income alone; in addition, there is a cost in stopping and starting plant, which is particularly high in the case of nuclear, so some plants will operate even if they are losing money in the short term). Clearly this is a theoretical modelling result – it would be an extremely risky proposition for a generator to have to rely on very short periods of very high prices (and discount the possibility that governments might intervene, as has often happened in the past, when prices soar above marginal costs) so in practice investment would probably not be forthcoming in such a market. A number of reports in 2009-2010, along with Ofgem's Project Discovery, all underlined how the growth of renewables would stretch current market design, probably to breaking point, and this is one main reason for the introduction of capacity markets in the UK (and elsewhere in the EU) – many governments have concluded that energy only markets do not provide a firm basis for building the capacity needed to guarantee security in a system with significant amounts of inflexible low carbon generation.

Not all commentators agree with this conclusion and the Commission is not yet convinced – in its consultation paper on capacity payments[9] it suggests a long check list of detailed criteria against which to assess them. However, a government like that of the UK, faced with significant analytical evidence of the need for capacity payments and the threat of an imminent security risk, cannot afford to take such a detached view. Waiting for the matter to be proved beyond doubt would effectively be waiting for the horse to bolt before locking the stable door. On such a politically sensitive matter as energy security it would be failing its electorate and jeopardising its chances of re-election (as experience in California in the early 2000s demonstrated).

[8] Poyry *Impact of Intermittency: How Wind Variability could change the shape of the British and Irish Electricity Markets* July 2009

[9] http://ec.europa.eu/energy/gas_electricity/consultations/doc/20130207_generation_adequacy_consultation_document.pdf p 12-14

Indeed in the UK, we may already be running a live experiment on the issue. Although the UK (like a number of other systems in Europe) does not currently have a formal capacity mechanism, it did until recently have what might be called a virtual capacity mechanism in the form of "grandfathered" emissions allowances under the ETS. These were granted to fossil power stations on the basis of historic emissions, provided they remained available on the system; they thus had the same effect in economic terms as a formal capacity mechanism. Since the beginning of 2013, the ETS has moved to full auctioning instead of grandfathering, so this incentive to maintain capacity on the system is no longer present. In addition, a number of other factors are encouraging plant closures – low "spark spreads", the impact of the Large Combustion Plants Directive, and so on. In the UK at least 7.5GW of capacity has been closed since the beginning of the year and much still also remains mothballed; although some new capacity is in the pipeline, security margins are tightening and the regulator, Ofgem, and industry commentators have been drawing attention to possible problems before the new capacity mechanism comes into operation.

- **No market route for new renewable investment** But problems arise for renewables producers too, at least when there is not a fully diversified mix of such sources. Much of north west Europe, including the UK, is planning to build very significant amounts of wind power to meet carbon targets. The wind resource is very broadly homogeneous, that is, it tends to be strong or weak at much the same times across wide areas. When this happens, and large amounts of wind are feeding into energy-only markets, the price will tend to be low or zero. In Iberia, for instance, which forms a largely independent system and suffers from excess capacity, wind generators tend to bid into the market at zero (to ensure that they are dispatched). The higher the proportion of wind the lower the market price – it has indeed frequently reached zero (165 hours in March 2013). Many other markets, from Germany to Southern California have also seen significant periods of zero market prices. The trend is likely to intensify as the quantity of coincident intermittent generation increases, as a result of government policy. Prices will tend to be low or zero when the intermittent sources are operating at full capacity. It is only during periods when the intermittent sources are operating below capacity (or not at all) that prices will be set at a level which reflects the marginal costs of fossil generators; during the very high price periods referred to above, when generators are covering their capital costs, it is likely that no intermittent generators will be operating (since it is their absence that is the cause of the high prices). This means that in many markets wind generators will not be able to rely on energy markets to cover their capital costs.

It should be noted that this will be the case:

- **even if** the wind power is competitive in the sense of producing power at a levelised cost below that of conventional power (because the intermittent generator will receive a below average price, for the reasons explained above); and
- **even if** there is a high carbon price (since the effect of the carbon price is to push high carbon generators to peak price periods only; the price of energy will therefore be most affected in situations when there is least generation from wind and other intermittent renewables).

So even if the cost of wind or other renewable sources attains "grid parity" and even if there is a significant carbon price, the energy only market will not provide a secure basis for remunerating investment in intermittent renewables, if they are built in the quantities which governments want. They will continue, as at present, to need some other route to covering their capital costs, such as the FiTs the UK government is introducing. When power generated from these sources feeds into energy only markets it will produce the outcomes referred to – low or zero prices, bearing no clear relationship to costs and providing no useful signals for the wind generators themselves. There is no clear exit strategy from this problem and no roadmap to a self-sustaining low carbon market either in the Commission's Target Model or in the UK EMR. This is in some sense the equivalent or mirror image of the "missing money" problem for fossil generators.[10]

In short, neither for fossil plant, nor for intermittent renewables generators, do energy only markets provide effective signals for investment in a decarbonised system. (There are comparable problems in relation to nuclear and carbon capture and storage but for reasons of space, these are not analysed here. Hydro is probably the least affected source, but the scope for expansion in most of Europe is limited for environmental reasons).

Level playing field The Target Model also fails to create a level playing field for all electricity sources. Again, wind power is probably most affected because of its intermittency; as the European Wind Energy Association (EWEA) has pointed out "The EU Target Model does not effectively enable wind energy integration into the European power markets".[11] This is as much because of what it does not do as because of what it does do – it

[10] The underlying problem is one of so-called "pecuniary externalities" – that is, situations where the behaviour of one market participant affects the prices received by another. Normally this does not constitute a problem; it is just the normal operation of the market. Indeed, because of the pervasive system effects, pecuniary externalities are endemic in electricity markets. However, where one set of producers is subsidised, the pecuniary externalities can have the effect of distorting the overall market. There is a good discussion of these issues in the study *Nuclear Energy and Renewables* OECD/NEA 2012 p 34 – 37.

[11] http://www.ewea.org/uploads/tx_err/Internal_energy_market.pdf

does not at present harmonise the balancing arrangements, and various supporting markets, which are so important for intermittent sources. At present, the position varies considerably between different Member States. In some countries, like Spain, intraday and balancing markets are well developed but this is not true of all states and, without integration of these markets, coupling of day ahead markets may not be enough to permit unconstrained trade.

The underlying issue is that all electricity sources have different characteristics in terms of predictability, controllability, flexibility etc and these characteristics all have implications for market design. Markets are not technology-neutral; such apparently arbitrary factors such as the timescales chosen, the balancing requirements and so on can have a big effect on the potential for access by different technologies. This was underlined in the UK in the change from the Pool to the New Electricity Trading Arrangements (NETA). The Pool allowed all generators to sell into a single market and obtain the marginal price; there was no requirement for balancing, which was the responsibility of the operator. Intermittent and unpredictable generators found it easy to access this market and sell all their output at a market price. NETA and its successor BETTA are by contrast based on self-balancing, which is intrinsically more difficult for power sources like cogeneration and intermittent renewables; this has significantly slowed the growth of cogeneration in the UK, despite the fact that cogeneration is one of the UK government's favoured options. (It has probably also increased the need for support for intermittent renewables).

Conventional markets were largely designed around the characteristics of fossil fuels, so that balancing, for instance, is mainly about short term fine-tuning to deal with fluctuations in demand and unexpected supply outages. Day ahead markets are a suitable basis for trading for fossil generators, who can forecast with high confidence their availability over the next 24 hours. A high wind system would have very different characteristics and balancing needs; for instance, longish periods of low wind output are quite possible so it is not just a matter of fine-tuning. On the other hand, wind generators become increasingly able to forecast output with confidence as they approach real time, so short term (intraday) market responsiveness and short lead time balancing regimes are useful for them. These requirements do not fit very well with the traditional definitions of balancing and, for some European markets, would require different market structures. This is why the EWEA calls for the Target Model to "address fundamental features of intraday and balancing markets which should be cornerstones of a competitive market place and are essential for wind energy integration. These features include measures to improve their liquidity, harmonisation of rules across borders and the interactions between these markets".

But in future other sources with different characteristics may also be important and the market should be designed for them too. In Australia, for instance, a study of *Solar*

Intermittency by CSIRO[12] draws attention to the differences between solar and wind (and between solar PV and concentrating solar) – for instance, different ramp rates (ie how fast output can increase in the short term), different degrees of randomness, different timescales etc. – and to the challenges that integrating these renewable resources will pose for the Australian system. Markets suited to particular sources do not suit others – one size does not fit all and there is no perfect system. Nonetheless, given the EU's carbon, and in particular renewables targets, it would seem sensible that, as far as possible, markets should be designed with renewables in mind, rather than, as at present, around conventional generation.

The same applies to **demand response.** It is clear that the demand side may both need to play a larger part in future power markets (to balance intermittent renewable generation) and have a greater capacity to do so (because of developments in IT in general and smart grids and smart meters in particular). Where demand response plays a role in existing markets it is usually (as in PJM and many other US markets) via reliability or flexibility markets of one sort or another. Demand response is less developed in Europe because of the market structures and again the day ahead energy only market seems only to entrench the problems. It is ill-suited to attract demand response bids and it is not clear how, indeed if, a demand response market in Europe will develop against this background.

Risk management There have always been problems in creating market-based risk management tools for electricity and it is unclear how far such markets can be expected to develop given the special characteristics of electricity (non-storability, network effects and the like).[13] But the result tends to be that generators manage risk via vertical integration, long term contracts or some other such route, which in turn often creates a barrier to competition. In designing its target market model the EU should, so far as possible, be seeking to encourage market based options for risk management as an alternative to these less competitive routes. However, the energy-only market may not provide an optimum basis for risk management via forward, futures and other derivative markets.

Again, there are two aspects to this, relating to fossil and renewable generators:

- As noted above, most new **renewable** generation manages risk by seeking a FiT or some other administratively determined income stream. But even if this takes place, there may still, at least in principle, be a role for markets. For instance, the UK's approach of combining FiTs with Contracts for Difference leaves renewables generators to sell their output into the market. But given the various problems mentioned above (and in particular balancing issues and pecuniary externalities) many choose to sell via a Power Purchase Agreement to a large integrated producer or

[12] *Solar Intermittency: Australia's clean energy challenge* CSIRO Australia June 2012

[13] For a discussion see, for instance, *The Dynamics of Power,* Keay, OIES 2006 p 37-55

aggregator, which can effectively absorb the problems via their size and vertical integration. In the longer run, if renewables generators are ever to be able to invest, and manage risk, via markets they will need to have a suite of effective markets, from the very short term (intraday) to the medium or (ideally) long term into which they can sell or hedge their output. Otherwise, as suggested above, there will be no exit route from an increasingly managed market.

- On the other hand, many **fossil generators** are effectively self-hedged, at least as long as marginal prices are set by fossil plants, so have limited need to access forward markets. Energy only markets based on short run marginal costs tend to be correlated with input fuel costs and, since the costs of the different fossil fuels are also partly (not, of course, completely) correlated, electricity prices tend to move up and down with fossil fuel prices, so price risk is substantially covered for a fossil fuel producer – or at least, this has been the case in the past. It is noticeable, for instance, that at a time of low fossil fuel prices in the early 2000s it was the nuclear producers (like British Energy) who faced the biggest problems, despite the fact that nuclear is generally regarded as having low marginal costs. With the growth of low carbon sources, this situation may change, but it is not clear how practical it will be to develop liquid long term forward markets, given the problems discussed above. It is likely that hedging will largely continue to be a matter of investing in physical assets rather than financial markets. For instance, the UK government is promising consumers that EMR will effectively give them a hedge against volatile fossil fuel prices. But it is doing so by ensuring that the physical assets are built. At least at present, neither consumers nor the government on their behalf, could buy a long term financial hedge against fossil fuel price volatility, assuming they wanted it, from markets, so there is no real way of knowing the value of the physical hedge – although, of course, this has not stopped the government and the Climate Change Committee from promising that in the long run consumers will save money.

The fundamental problem is that, compared with other commodities, there is relatively low liquidity in electricity forward markets. It is not clear whether this is likely to change in future but, at least as long as the balancing and other issues mentioned above remain, it seems likely that the energy only market structure plays a part in this, by lowering demand for hedging and increasing the cost.

Robustness In the view of this author, the discussion above leads to the conclusion that energy only markets are not robust against expected, much less unexpected, developments. The fundamental reason is that they were designed, as the discussion has pointed out, for systems based on conventional generation and are suited to its cost and operating characteristics. But the introduction of low carbon generation will change all this. As a

recent OECD analysis points out[14], the integration of variable renewables profoundly affects the structure, financing and operational mode of electricity systems. There will be huge new system costs, for balancing and back-up, grid reinforcement and extension. Energy (and short run marginal costs) will not be the main cost component in such a system; in the future system, costs will be mainly capital. Even for fossil generation, operating regimes will need to change, with more frequent starts and stops, and important consequences for costs and means of cost recovery. The Target Model does not really take account of these impending changes. Nor does it recognise the issues arising from the increasing proportion of FiT supported renewables. The position of such sources – within the market but financed outside the market – gives rise to a set of "pecuniary externalities" which will over time undermine spot energy markets.

As the OECD study points out, energy only markets are therefore creating "an increasing wedge between the costs of producing electricity and prices on electricity markets". They are increasingly failing to give effective signals for operation, investment or risk management; they are ill-adapted to the system changes needed in the move to a low carbon economy. In short, they are not sustainable.

Conclusion

The overall message is that the Commission has not integrated its approach to climate change with its promotion of a single market for electricity. Indeed, in its contributions to the latest European Council, it seems to have relegated climate change to the back burner, focusing instead on the completion of the single market. It is pursuing a Target Model for electricity which may be adequate for the single market objective but is likely to show itself increasingly unfit for purpose in other areas. In doing so, the Commission is liable to accentuate and increase the tensions between its own goals and member states' policy instruments for achieving their goals for the energy sector, in particular in relation to decarbonisation and energy security. One first manifestation of these tensions is the Commission's negative attitude towards the capacity mechanisms which many member states believe they need. Unless the Commission develops a more flexible attitude, or a more integrated approach, the possible conflicts are only likely to increase and intensify; they could create serious obstacles to the achievement of an 80% reduction in carbon emissions by 2050 (which is an EU as well as a UK objective). That reduction can only be achieved through changes in the energy sector; an integrated strategy towards energy, which does not just treat decarbonisation as an afterthought, is an essential first step. The EU does not yet have such a strategy.

[14] See footnote 10