Northern Ireland Assembly

Committee for Enterprise, Trade and Investment

OFFICIAL REPORT (Hansard)

Energy Review: Single Electricity Market Operator

19 September 2013

NORTHERN IRELAND ASSEMBLY

Committee for Enterprise, Trade and Investment

Energy Review: Single Electricity Market Operator

19 September 2013

Members present for all or part of the proceedings:
Mr Patsy McGlone (Chairperson)
Mr Phil Flanagan (Deputy Chairperson)
Mr Steven Agnew
Mr Sydney Anderson
Mr Sammy Douglas
Mr Gordon Dunne
Mr Paul Frew
Mr Alban Maginness
Ms Maeve McLaughlin
Mrs Sandra Overend

Witnesses:

Mr Robin McCormick	Single Electricity Market Operator
Mr Brendan O'Sullivan	Single Electricity Market Operator

The Chairperson: The next item on the agenda is the electricity policy review briefing from the Single Electricity Market Operator (SEMO). Members have a briefing paper from the Assistant Assembly Clerk and a copy of the presentation from SEMO.

Briefing the Committee today are Robin McCormick, general manager, and Brendan O'Sullivan, the power market consultant. You are both welcome. Thank you for giving up your time to be with us here today. You have been here for most of the meeting and are seasoned practitioners in the game of talking to Committees. We are a wee bit pressed for time. That is not to say that we do not want to hear comprehensively from you, but please take us through the issues pretty succinctly.

Members, I remind you that another Committee is due to meet here shortly after lunchtime, so please make your comments and questions to the point.

Robin, I invite you to make your comments to the members.

Mr Robin McCormick (Single Electricity Market Operator): First, thank you for the opportunity to talk to the Committee about the single electricity market (SEM). It was a very interesting project when it was first considered back in the mid-2000s, and it was quickly grasped as an opportunity to deal with a number of issues that were arising in the South of Ireland and the North of Ireland. There was a security of supply issue arising, in that there was insufficient generation capacity on the island looking forward, so there was a need to develop a market solution to ensure that we had sufficient generation.

On 1 November 2007, the single electricity market came into operation. It was unique in that it operated with two different currencies, in two jurisdictions, with two regulators and was overseen by two Departments. Furthermore, it was in the general direction of travel that Europe wanted to see, which is to regionalise electricity markets. You have heard the term "regional markets" already this morning. The SEM is probably something that people look to now and ask, "How did you do that?" It is useful to step back and ask ourselves what the single electricity market is about and why it is deemed to be a successful market.

The single electricity market is a wholesale market. Any generator that has a capacity greater than 10 MW is required to be a participant in the market. The function of the electricity market operator is to operate the market to ensure that the generators abide by the trading and settlement code, bid into the market at the right time to allow us to calculate what the half-hour price is and make the payments that are required from the supply companies to the generating companies. We are the wholesale market, not the retail market. That is an important distinction.

The key to it is the calculation of the system marginal price (SMP). That is the price that generators are paid for the energy that they produce in each half-hour trading period. The strike price for the system marginal price is largely the bid price of the generator that meets the last megawatt that is required for that half hour. Therefore, if there is 100 MW of demand and you have two generators, one generator can generate 50 MW at x and another generator can generate the other 50 MW at y, and the system marginal price will be y. That is what we in the market call the shadow price.

Owing to the fact that the demand is changing, each half hour is a different total, because of our consumption pattern. We need to take into account the fact that you have to start and stop generators. To meet a peak, you have to run a generator up, and there are specific costs associated with running up a generator, as opposed to keeping it going. Those are incorporated into the calculation of the SMP. There is a diagram that shows how the market schedule and price are determined. We have talked about renewable generation. They are effectively must-run generators on the system. They have a zero bid price, so they are run first and then the next cheapest generator is run. We find that, in the main, it is the gas units that tend to set the system hours or prices. The price of around 55% of generation is set by a gas plant.

That is deemed to be a very effective way of running a market. That is not to say that there are not discussions around other market models, because those have their merits as well. The key issue for us is that the SEM is transparent, so everybody knows exactly how the system marginal price is constructed each half-hour period, and people can have confidence that it is the right price — the most efficient price — for that half-hour period.

The SMP is not the same every half hour. It is dictated by system demand, which can change dramatically from the early hours of the morning in the middle of summer to three or four days into a very cold spell in the winter, when everybody has put the heating on, and so on. The SMP is influenced by the actual fuel price, which is the bid price that each of the generators has to bid in. There is a code of practice as to how they set their bid price. It is largely the fuel price that dictates the bid price. If fuel prices go up, generators' bids go up to reflect that. I have said that, generally, the price of gas dictates that energy element of the fuel price.

Increasingly, the level of wind penetration will impact on the price. If we have a lot of wind, that will have a downward pressure on the system marginal price, because you have less demand to cover from conventional plant. We are in the process of increasing the amount of wind that we have in the system. As an island, we are probably well ahead of anywhere else in the world in managing high penetration of wind on to the system. We have a programme of work running at the moment to try to improve how we understand wind on the network and how much of it we can allow to run on the system at any given time.

The Moyle interconnector and the recently commissioned east-west interconnector provide opportunities for people to trade energy either importing on to the island or exporting to GB. The history of trading on the east-west interconnector and the Moyle interconnector is that it is predominantly an import. As such, it will reduce the system marginal price, because you are displacing generation that would otherwise have been run on the island. The other side of the use of interconnectors is that, after the market has done its job and set the flows on the interconnector, there is an opportunity in real time to manage the flows on the interconnector to minimise the constraint costs that result from having to hold back wind if there is more wind that we can accommodate at any point in time. We are looking at ways of doing that better.

The availability of plant is obviously important. If you have a large generator that is not available over a winter peak, there are more expensive units of plant that have to be run in order to cover that lack of capacity. That sets the system marginal price higher. If all the generators are available, you get the cheapest possible price. When generators are bidding on fuel prices, an element of that cost will be as a result of the carbon in the fuel.

The next graph is a simple indicator of how the system marginal price largely follows the demand curve. That is impacted on by only the start-up and shut-down costs that I talked about earlier being part of the system marginal price when it is calculated.

The next graph gives you a bit of an overview of how the single electricity market has operated since November 2007. You can see that the demand profile has reduced, largely because of the economic conditions that we have experienced since then. The blue area gives you an indication of the profile of the system marginal price. There are reasons for the system marginal price on occasions seeming to rise, such as gas prices and weather conditions. We have had a couple of particularly bad cold spells or snowstorms that have impacted on the system marginal price. That is an interesting little graphic to give you an indication of what we have to deal with.

The scale of the market —

The Chairperson: Excuse me, Robin, but I have a lack of awareness on this. What does the red area indicate? I know what the blue area represents, but the red area indicates MSQ. What does that stand for?

Mr McCormick: That is the system demand. The highest profile is the system demand.

The Chairperson: What is the distinction between the blue and the red?

Mr McCormick: The blue is the system marginal price. It is read from the right-hand scale, and the demand is read from the left-hand scale. I have probably piled a lot of things into the one graph.

The Chairperson: That is grand. Thank you.

Mr McCormick: I will now talk about the scale of the market. Some questions have been asked around the capacity mechanism, so there are a number of different elements to what people pay in their bills as a result of the market operating. The energy component is the system marginal price as is worked out through customers' bills. The capacity element is the payments that are made for generators that are available and open to operate on the system.

To clarify something that was said earlier, the capacity pot — the amount of money that is shared out across generators — is determined by the forecast generation adequacy needs. A number of megawatts are required. It is not determined by the number of generators around but by the number of megawatts that the system needs, and the pot is calculated from that number of megawatts times the amount of money to invest in a peaking-type plant — a piece of plant that may never be run on the system and would be paid only a capacity payment. Therefore, if there was exactly the right amount of generation to meet the adequacy, that particular generator could run a business just through the capacity payment that it receives. However, those are much less capital-intensive than the major generators. It is only a small amount of money for a large generator. The pot will not increase if some generators go off the system, and it does not increase if more generators come on to the system. It just means that if more generators are there, everybody gets paid a little less, and if there are fewer generators and you are under the line of adequacy, the generators get paid more, and there is an incentive for more generators to come on to the market.

The other element is constraint costs. The SMP is a calculated figure, but it does not take account of the reality of operating the system in real time. There are a number of things that you have to do and take account of in real time. First, you have to make sure that you have some reserves so that if one of the generators fails to operate or trips off the system, you have to run all the other generators with a little bit of slack so that they can take up the slack from the generator that tripped. If there are infrastructure deficits, such as with the North/South interconnector, and you have to run some generators more in Northern Ireland and some generators less in the South of Ireland because of the restriction of the interconnector, a constraint payment is involved. You give instructions to a generator to run at a particular number. It may not follow that exactly and instead generates a little bit more or a little bit less. Therefore, there are correcting payments around that. There are a number of different things that cause the constraints to be at that level. With wind generation, there is a difficulty with forecasting exactly how much generation there will be, and the profile of that can change during a day, so there are some costs associated with running a system with wind on it.

That gives you a sense of the scale of the payments. If we look forward, 2020 is in front of us, and we have the expectation that we will meet the target of 40% renewables by then. I have a graphic that indicates what the impact of that is likely to be on the market for capacity. It still represents a challenge to us, from both a generation perspective and a transmission perspective. As we move to 2020, other technologies will increase. We talked about demand-side management. There are smart meters, and there may be electric vehicles, and so on, which need to be taken into account. Key, I suppose, is the difficulty we have with delivering infrastructure to meet the needs of the target.

There was quite a discussion earlier about the GB market and some of its characteristics. The first thing to say is that it is of a completely different design. The GB market is based on bilateral contracts. Generators in GB contract with supply companies for the supply of whatever profile the supply company sets in front of them. That is really not transparent. You cannot see what those contracts are like, so you have to surmise a little as to what the costs underneath those contracts are. The market there is not as clear as ours, which is much smaller. We could probably represent ourselves as the market for greater Manchester, based on the scale of consumption on the island. That is reflected in the type of market that GB has compared with the type of market that we have, where we need to look at every single element of the operation of the system. There are some other statistics there that give you a sense of the difference.

I will move on to talk about some policy instruments and some of the things that we have had to encounter. The UK has moved into electricity market reform, and a number of issues have arisen from that almost immediately. One is the carbon price floor, which is an initiative that the UK Government wanted to impose across England, Scotland, Wales and Northern Ireland. As we looked at it, we realised that it had unintended consequences in our market environment. It was an extra charge on fossil fuels, and if that extra charge had been levied on Northern Ireland generators, they would not have been able to compete on a level footing in the single electricity market. Therefore, we assisted the Department of Enterprise, Trade and Investment (DETI) in a range of studies, backed by a lot of help from the Confederation of British Industry (CBI), and we were able to construct our argument, which the UK Government accepted, and carbon price flooring was not adopted in Northern Ireland. That was a plus from our perspective and from that of the market.

We have talked about the renewables obligation certificate (ROC) system and about how different technologies are incentivised by different levels of ROC support. That is due to be phased out through the electricity market reform proposals, and by 2016 anybody coming into the market will not receive a tradable ROC but will run on a feed-in tariff. It is a different mechanism, although it is actually the same as that used in the South of Ireland. The strike price for the contract for differences is something that we have assisted the Department with, to ensure that the strike price that is set in the UK is appropriate for Northern Ireland. That is an annual or biannual type of assessment and analysis that we will continue to be involved in.

We have the capacity mechanism, which was referred to earlier today as a difference between the two markets. There is quite a bit of discussion at the moment on whether a capacity mechanism would be appropriate in the GB market. That really all falls into the need to follow European legislation and establish a European model for electricity markets. That is due in the rest of Europe by 2014, but because of the work that we have done in establishing the SEM, and because the SEM is seen as a regional market, we have been given some extra time before we have to implement the capacity mechanism. Therefore, by 2016 we are expected to have a new market that complies with the European target model. Simply put, it is an attempt to ensure that the trading on interconnectors right across Europe is much more efficient. It is difficult to have all the information in front of you to make an economic trade on an interconnector at the moment. The proposal is to have a day-ahead price set to allow trades and for a helicopter view to be taken across Europe so that traders can see potential for trading across more than one interconnector and across a number of countries. That should lead to more efficient interconnector trading, which would benefit customers.

We are involved in the market integration project. Brendan was involved in the team that established the single electricity market. He then became part of the operations team and moved back into the market design side. He is aware of the work that the regulators are doing and the challenging timescales that we have to put the project in the open market.

The Chairperson: Thanks very much for that. We hear consumers, be they business or domestic, asking how we lower the cost of electricity. Do you have any ideas?

Mr McCormick: Ideas as to how to reduce it?

The Chairperson: Yes, to reduce the cost of electricity.

Mr McCormick: If the package of measures that is in place were working effectively, that would result in a reduction in prices or a downward pressure on electricity prices.

The Chairperson: What measures are you referring to?

Mr McCormick: For example, the policy to reach the 40% renewables target. We identified that through increased penetrations of wind, better trading on the interconnectors, which brings downward pressure on prices, and by asking what things are preventing or making it more difficult for those wind numbers to increase or for us to reach the target. The answer would be the delivery of infrastructure.

The North/South interconnector is an easy one to quote, but every time that a wind generator needs to connect to the system and there is a delay in the connection — a delay in the delivery of the backbone on the network — the opportunity to put downward pressure on prices is avoided. To have done the infrastructure bit more quickly would already have brought further downward pressure on prices.

The CBI talked about aggregated generator units, where people with small generators get together and play into the market as if they were one generator. The opportunity for that exists in Northern Ireland. There are a number of examples of that being deployed. There is no reason why that could not be deployed more widely. Some of the questions could answer themselves.

There is certainly an issue with the demand-side unit. It is probably more difficult to organise from an industry perspective, but the facility is not there, because we have not got the legislation and mechanisms in Northern Ireland. That is with DETI and the regulator. If they were to move that more quickly, it would be interesting to see whether industry would follow and bring demand-side units into the market.

Those are a couple of ways in which industry can take advantage of the mechanisms that are already in place.

The Chairperson: OK, thanks for that.

Mr A Maginness: Thank you very much for a detailed presentation. We have the single electricity market in Ireland, and it is now proposed to move to a European market or, certainly, a regionalised European market, I presume. Given the pressures that there are on prices and so forth, what effect do you estimate that will have on supply and price?

Mr McCormick: I do not think that an exercise has been done to capture the effect, whether it is 5%, 10% or whatever, but the evidence we have from bringing Moyle and the east-west interconnector (EWIC) into commercial operation is that you have access to a larger market. If you make the trading arrangements efficient, you want to see traders use those opportunities, which would be to everybody's benefit.

Mr Brendan O'Sullivan (Single Electricity Market Operator): At the moment, the European work is going in the direction of trading across the interconnectors, either in the GB market or the SEN market. The whole coupling concept is a pan-European concept, which technically, on paper, means that you can actually start trading with traders in France and all over Europe with the existing infrastructure that is there. Obviously, the more interconnection that exists, the more flows can happen and the more efficient it becomes. At the moment, it would mean that the existing interconnectors could be used to import cheaper energy from mainland Europe and not just be limited to what is in the UK.

Mr A Maginness: The previous submission by the Confederation of British Industry (CBI) indicated that it felt that the cost of generation was being lowered as a result of the single market. Do you agree with that?

Mr McCormick: The system marginal price has been reducing because of the mix of generation that we have at the moment. I think the model means that more efficient generation will want to come into the market and less efficient generation will want to move out of the market. A number of generators are likely to move out of the market over the next few years, because of the age and efficiency of the plant and because of the additional costs that they need to pay out to allow them to continue to comply with emissions legislation, etc. I think that the market model allows for new entrants to come in and, from a customer perspective, improves prices. That will obviously have the effect of pushing out people who simply are not able to compete. So, the model works.

There is an incentive for small-scale generation to operate. However, I heard earlier that, although there is an incentive for them to operate, they have a high connection cost that is prohibiting them from getting into the market. Maybe that is the right answer, because we heard that it is better to have a larger wind farm with a single connection, as that is economically viable. That is the way the market works.

The difficulty we have is that generators coming into the market can pay for a shallow connection from their site to the nearest point on the grid but the grid is not appropriate. It is that sort of backbone infrastructure investment that is the real concern. It is strategic. You have to think ahead about how much infrastructure you need. You have to have a regulatory set-up that allows for decisions to be made and investment to be made in infrastructure. There have been delays in some of those regulatory processes, and that is causing difficulty.

The Chairperson: Mr O'Sullivan, I just want to pick up on your point about tapping into other EU markets. At a practical level, what can or is preventing that from happening?

Mr O'Sullivan: At the moment, we are not connected to any European markets. We literally have an isolated market. The cross-border flows between ourselves and adjacent markets are determined centrally by the SEN.

The Chairperson: Do you mean that — just to get this into my head, because I am not a technical person at all — there is no interconnector between the European mainland and Britain?

Mr O'Sullivan: No; I mean from a market perspective. For instance, if I were a trader in France and wanted to send energy to Ireland, what I would have to do is set myself up in England and Ireland so that I could ship my energy, first of all, from France to England and then to Ireland. In the future mechanisms, what will happen is that all regions will go into a central market coupler, which, to all intents and purposes, is similar to what we do in the SEM at the moment except on a European level. So, all the cross-border nodes will be represented in that. Effectively, somebody bidding energy in Ireland could actually bid it into that central coupler. As long as the energy can flow across all the individual interconnectors, it will end up in a merit position. You could see a surplus on the island of Ireland serving a shortfall in Italy, for instance.

The Chairperson: Just to take that a stage further, where is that at the moment? Is the EU taking the initiative on that? How is that happening?

Mr O'Sullivan: A couple of initiatives are under way at European level. There is the development of what are called network codes, which will be binding legislation probably some time next year; the European Commission will pass those into law. From a technical perspective, the north-west Europe group, which is made up of system operators from Scandinavia, Germany, Denmark, France and the UK, is developing a pilot scheme. It is running a piece of software whereby those countries are pooling all their residual cross-border trades into one mechanism. It is determining all the individual flows of energy around those areas. That pilot scheme is expected to go live at the end of the year. As it goes live, an additional pilot scheme between France and Spain will join in, and others throughout Europe will join in at different stages. Our timeline in Ireland for joining in is 2016. That is on the basis that most of Europe operates decentralised bilateral-contract-type markets, so they are already working in the same area. We are in a centralised pool market, which is quite different. We have to take the time to reform the SEM arrangements to get to a point where we can more easily plug into this.

Mr Frew: My question is not so much on affordability but more on the security of supply. Everybody talks about 2020 targets and one thing and another to do with renewable energy. I am more focused on 2016, and the emissions regulations from Europe. Are we heading for an energy crisis? I will leave it at that.

Mr McCormick: No headlines, please.

One role that we have is to prepare what we describe as a generation adequacy statement. With EirGrid, the transmission system operator (TSO) based in Dublin, we have to do the same thing for the South of Ireland. We now produce an all-island document, which has a Northern supplement, because the North/South interconnector is not there, and that creates an inability to be able to look at it just on an all-island basis. That indicates that there is sufficient generation capacity on the island for the foreseeable future, but it identifies that, as we move towards 2016 and a potential retirement of units at one of the stations in Northern Ireland, we are coming very close to the adequacy standard. The adequacy standard is a statistical method of working out whether you have enough generation to serve the demand. The reality is that we have a small number of large generators in Northern Ireland. If you had a prolonged winter outage of one of the larger units and were to lose another generator for a time, you probably could not supply the full demand, all day every day, for that period.

So, there is a risk. It would be solved by an early commissioning of the North/South interconnector. That is looking increasingly difficult to achieve. The restoration of the Moyle interconnector would not be sufficient. A proliferation of very small aggregated generator units or demand-side units would not be sufficient to address it. The regulator and the Department are well aware of what the issue is. They have issued a paper setting out the issue and are more actively working on it at the moment to look at what possible interim solutions could be put in place to manage the time between when those units are to retire and the North/South interconnector is commissioned.

Mr Frew: With all of the weaknesses in our system at present, including the North/South interconnector not being there and the Moyle interconnector being at 50% capacity, and with all of the long-term plans for renewable energy, we do not even seem to be looking at additional or new large-scale generating plants. Should Northern Ireland be looking at that? We talk about connecting to Europe, but if we cannot even connect to Ireland, how will we ever be able to make it to Europe?

Mr McCormick: The market is there to incentivise generators to come, whether they are conventional or renewable generators. They have the opportunity of connecting anywhere on the island that works for them. There have been a number of new generators since the early 2000s. There are new units at Ballylumford, there is a new unit at Coolkeeragh and there are additional new units in different places in the South. That has led us to the place where there is a sufficient number. So, there is a sense that the incentive for the generators has delivered. The problem is that we have not followed that with the infrastructure investment. No one would want to build a generator in a place where they were constrained from operating fully in the market. We have to get the two in balance.

Mr Frew: I have a final question, Chair. Add into that mix the exploration for gas in Fermanagh and the exploration for oil in the Rathlin basin. How much impact could that make to our supply needs and demands, considering that we are talking about an increase in demand post-2016.

Mr McCormick: From an infrastructure perspective, we probably have been helped by the reduction in demand that we have seen over the past number of years. That reduction has come from the economic recession, so the need for that infrastructure at the pace that we had envisaged has helped us a little. We still need to pursue the infrastructure side. If gas extraction in Fermanagh were to come to fruition, we would have to look at the magnitude of that and at whether it is a domestic and commercial gas supply and whether there are generation opportunities. We would have to look at what size those would be. At this stage, we have not had any connection requests either from the gas folk or the oil folk.

Mr Agnew: Thank you, gentlemen, for the information so far. Looking at the system marginal price, we talked about the fact that greater penetration of wind drives down the price but that gas tends to be the price setter. Is penetration across the island of coal or oil insignificant at this stage, or where do they come into the spectrum of price setting?

Mr O'Sullivan: On price setting of the wholesale price, they have pushed very far high up the merit order, so they are probably not setting the price in any shape or form. The curve that is in Robin's presentation shows that a huge amount of the volume is based on gas. The demand on the island has to go significantly high or be coupled with significantly dropped wind for the price to go into that space. Earlier this year, it probably did around the end of March. There were a couple of high price increases in the South, and those were driven by really compressed wind and a cold snap, which drove higher demand. It is an unlikely event at this stage. They are more driven on the constraint side, where some of these units still have to be run for local transmission constraints. So, they are contributing to that larger constraint number rather than the actual wholesale price that you are seeing.

Mr Agnew: In the SMP trends, we see demand going down but price increasing overall. It would be fair to say that that was down to gas prices. When we look at the factors, such as the big snow demand and the very cold spring, are those gas prices international prices or is that a local price?

Mr McCormick: It would be impacted by international prices.

Mr Agnew: So, the international price of gas is still rising as a trend, despite the exploitation through fracking and that type of thing, which, we were told, would bring prices down. Despite that, to date, the price has not come down.

Mr O'Sullivan: It has not come down at present. The prevailing trend that we see when we do analysis — we do a regular analysis of the shadow price against the prevailing gas price in the UK exchanges — shows that they are mirroring each other very closely.

Mr Agnew: I want to look at renewables. Going back to wind as being a downward pressure on price, has there been an assessment of how that interacts with the impact of infrastructure costs of renewables? I hear one presentation and I think that wind drives down price, which is great, and then I hear another presentation that says that the investment that we need in the grid infrastructure will drive prices up, that wind is the root of all evil and that we should not have anything to do with it. *[Laughter.]* I am paraphrasing. How do those two things interact? What kind of scales are we talking about when we consider the downward pressure on price from the unit cost and the increased pressure on price from the requirement for investment in the grid?

Mr McCormick: That is probably a difficult set of elements to try to pull together. The policy and the support mechanisms were set, the market was established and the belief was that the market would take all those factors into account and decide what it was going to run for. We had a discussion about tidal power versus wind or whatever, and the market has chosen wind because it is the most available technology at the moment. Some of the other technologies are, perhaps, a bit further away and the incentive of the support is there.

Customers have not paid anything out for tidal power as yet, but people believe that wind can deliver. They did that on the understanding in the same way that you, as a demand customer, go to the infrastructure provider and ask to be connected to its system. You would expect them to give you an offer and you would expect to be connected. If I am a wind generator, I expect to be given an offer, and if I accept the offer, I expect to be connected to a system that can allow me to operate in the market.

That piece of the jigsaw has not been working as efficiently as all the other elements, because the Regulator is trying to see the bigger picture and is asking whether that is good value for customers to spend that amount of money. He is acting in the middle of the market, and he can say that the market is great, but that decision needs to be taken on the basis of a strategic decision that says that we cannot get it right absolutely every time on every little decision. We have to take a strategic view that says that the policy is right. The direction of travel of world energy fuel prices gives us an indicator as to where it is going. There is an issue around security of supply; do we want to depend on international fuels being imported into the country? When you put all those together, there is a strategic decision to be made as well as trying to construct the detail of what this or that costs.

We have costs for the transmission infrastructure. The Grid 25 programme in the South sounds as though it will cost about €3·2 billion at the moment. That is reviewed periodically. The figures from NIE were somewhere just less than £1 billion. That is the sort of dimension of it. Those are investments for a 40-year life-of-transmission infrastructure.

Mr Agnew: When it comes to payback, though, looking strategically, we would need to factor in the downward pressure on the price, which is often left out of the discussions.

The Chairperson: Thank you very much, gentlemen, for your patience and your information, which was very helpful indeed. As you know, this is part of the review that the Committee is conducting. Hopefully, you will be involved when you see the report coming out with actions that will be taken up in the interests of all consumers. That is why we are here. Thank you for your time, and I will see Robin in the not-too-distant future.