HOUSE OF COMMONS

Science and Technology Committee

Oral evidence: The role of hydrogen in achieving net zero, HC 1066

Wednesday 12 May 2021

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Watch the meeting

Members present: Greg Clark (Chair); Aaron Bell; Dawn Butler; Mark Logan; Rebecca Long Bailey; Carol Monaghan; Graham Stringer.

Questions 332

Witnesses

I: Professor Jianzhong Wu, Head of Engineering, Cardiff University; and Carl Arntzen, Chief Executive Officer, Bosch Thermotechnology Ltd.

II: Antony Green, Hydrogen Project Director, National Grid; Angus McIntosh, Director of Energy Futures, SGN; and Dr Angela Needle, Director of Strategy, Cadent.

III: Professor Jon Gluyas, Executive Director, Durham Energy Institute; Dr Jonathan Radcliffe, Reader in Energy Systems and Policy, University of Birmingham; and Professor Clare Grey, Geoffrey Moorhouse Gibson Professor of Chemistry, University of Cambridge.

IV: Julian Leslie, Head of Networks, National Grid ESO.

Examination of witnesses

Witnesses: Professor Jianzhong Wu and Carl Arntzen.

Q237 **Chair:** Welcome to this evidence session on the role of hydrogen in achieving net zero. We are taking evidence this morning on the potential for hydrogen in domestic heating and within the gas grid, and also on the potential for hydrogen to provide energy storage and some alternatives to that.

I am very pleased to welcome our first panel of witnesses. They are Professor Jianzhong Wu, head of engineering at the University of Cardiff and co-director of the UK Energy Research Centre, where he leads work on energy for heat; and Carl Arntzen, the chief executive of Bosch Thermotechnology, which includes the Worcester Bosch domestic heating business, as well as Bosch-branded commercial and industrial heating operations.

Thank you both very much indeed for attending the Committee today. I will start off with a question to both of you. What role do you see for hydrogen in domestic heating as the UK works towards net zero?

Professor Wu: Thank you for the question. In my opinion, hydrogen will certainly play an important role in domestic heating in some geographical areas beyond 2035. I have considered three key factors.

First, heat is local. Heat cannot be transmitted over a long distance without significant energy losses, so its use needs to be addressed within one area. It is very different from electricity. I do not think there is a single solution that is one-size-fits-all for the country. Hydrogen will play a very important role, but to what extent is based on geographical location and other conditions as well. Whatever options we finally choose will have fundamentally different implications for the future of the gas and electricity networks. Each option will require infrastructure development and repurposing to some degree. These must be dealt with using a whole-system approach.

Secondly, the timeline of decarbonisation in the UK means that basically decarbonisation must rely on technologies and products that are currently mature, or almost mature, and available in the markets, or else we won't have time to deploy that.

Thirdly, the pace of innovation is much faster than we thought. We need to consider uncertainties, but in that case we should not wait. There are a lot of uncertainties in front of us, but we need to take a decision. Because the pace of innovation is so fast, it is highly possible that hydrogen could be a cost-effective solution beyond 2035 and play a very positive role in achieving net zero.

Q238 **Chair:** Thank you; that is very clear and concise. We are grateful for that. Perhaps I could push you a little, if I may. Given your research and expertise, in the central scenario, as we approach 2050, would you expect hydrogen to be contributing a majority of our domestic heating energy requirements?

Professor Wu: Currently, from our research, that probably will not be the scenario. It is a very complicated situation. Hydrogen is a very expensive resource. The largest question is where the hydrogen will come from. Currently, we go through the blue hydrogen route. We currently cannot take the green hydrogen route. For the current technology, the green and the blue ones are still very expensive and would not be competitive for domestic heating, compared with heat pumps or other technology, even resistive electric heaters.

Q239 **Chair:** We are going into more detail on that, but it is helpful to have your steer as to whether your current thought is that this is going to be a dominant technology or one of a stable.

I will put the same question to Mr Arntzen. As an industrialist and someone who makes very celebrated boilers and has a very distinguished heritage in both brands—Bosch and Worcester—what is your expectation for the future of boilers? Are they going to be hydrogen or natural gas, or are they going to be replaced with something else?

Carl Arntzen: Thank you for the question. I am probably a little bit more positive than Professor Wu. What we have seen historically is, obviously, a domestic heating landscape in the UK dominated by natural gas boilers. We have been iterating and developing those over the last 30 or 40 years.

What we see, moving forward, is a much more diversified technology landscape, where we see a role for electrification and using electric heat pumps. However, we still see quite a significant role for hydrogen in heating domestic properties, particularly the older Victorian and Georgian properties that are today connected to the gas network.

We see the best solution to decarbonising those very leaky and poorly insulated properties as decarbonising the gas supply. We see a much more diversified technology landscape moving forward. We see a role for hybrids as well—maybe a hybrid of an electric heat pump and a natural gas boiler and, in the future, a hybrid of an electric heat pump and a hydrogen boiler. We see a much more diversified technology landscape, but we see probably a greater proportion than Professor Wu was just alluding to in terms of hydrogen and the role it has to play in heating the very difficult to heat, difficult to insulate old properties connected to the existing gas system.

Q240 **Chair:** Is the corollary of what you have said about the importance of hydrogen in getting to the hard-to-service places that new builds will not have gas, whether natural gas or hydrogen? Will the place for hydrogen be in the older legacy properties, as one might describe them?

Carl Arntzen: I believe so, yes. Building regulations and the future homes standard, as we see it today, will almost certainly lead to all new houses being built from, let's say, 2025 onwards having electric heat pumps fitted in them. That is the most obvious technology to put into high thermally performing houses, where that technology perfectly fits into that application.

Chair: Thank you very much. That was very clear and very concise.

Q241 **Rebecca Long Bailey:** Thank you both for coming to the Committee today. You have already discussed in general terms the maximum feasible level of deployment of hydrogen, particularly for heating. Certainly, on this Committee, the maximum feasible level of deployment has been hotly contested. The variables include everything from issues around the suitability of the existing transmission grid all the way through to the technical changes that home boilers would need to process it.

Could I press you a little bit on this point? Very generally, in your view what is the maximum feasible level of hydrogen deployment for heating? What factors would determine a locality choosing to upgrade their grid network to facilitate hydrogen heating? You have both suggested that there will certainly be a geographical mix.

Professor Wu: Hydrogen is a core sector resource for decarbonisation. It could be used to decarbonise difficult sectors such as industry—it is heavily used in industry—and transport as well, which is another very difficult sector that we need to look at.

For heating, currently we have other alternative solutions such as heat pumps or district heating and other forms of renewable heat as well. Clearly, other technologies will not be used for older locations. I agree that for some locations hydrogen will play a very important role.

The key question is still where this hydrogen comes from. Based on the current technology for blue hydrogen, for example, they rely on CCS. The current cost is about 1.5 to two times more expensive than natural gas for the same amount of heat. For green hydrogen, it is up to three times higher in price. With the current technology, if you produce at scale, it will be very expensive. We must make sure that energy is affordable. In that case, it will be very tricky. As I said, there are other sectors still waiting for decarbonisation.

In my opinion, it will play a very important role, especially approaching 2050. For the shorter period, before 2035, we have a target, and if we want to achieve that target we probably need to look at the currently available mature and cheaper solutions. We need to bear in mind that we probably will not have a one-off solution. If we choose hydrogen and it is used up to 2050, we are still 30 years away. In the middle, it could shift. When the costs are analysed, it is a huge investment. We can look at the options maybe beyond 2035. At that point, it may have a large deployment. It is very difficult to predict because the technology is still not there.

Q242 **Rebecca Long Bailey:** Thank you; that is really helpful. The same question to Mr Arntzen.

Carl Arntzen: I take a different approach on this. In the end, we are developing and providing the product in the home to burn the fuel to generate the heat. From my point of view, I am not such an expert in how we supply the hydrogen or in what quantities and volumes we can supply it.

My answer to your question is from a slightly different context. Today, we have 85% of houses connected to the gas network. If we choose to do so in the future, we could repurpose all of those to fire 100% hydrogen. That is technologically feasible, from the technology in the home burning the gas supplied to the home. Whether it is a feasible proposition in terms of the supplies of hydrogen, particularly green hydrogen, and over what timeframe is a different question. I am not particularly expert on that. What I do know is that trying to apply electric heat pumps in all 28 million homes in the UK is, to a very large extent, very challenging when you are trying to retrofit.

There is a technology question and a supply of hydrogen question. Effectively, my answer is that we will supply whatever the technology to deliver the best outcome in the individual property. We have tried deploying heat pumps in old Victorian and Georgian houses in the past. The retrofitting of that technology has lots of hurdles to overcome, and it is not straightforward.

I have not answered your question directly, but I hope I have answered it from a slightly different angle.

Q243 **Rebecca Long Bailey:** That is really helpful. I was going to come on to the cost. There are two issues surrounding future Government decisions on where we go with hydrogen. The first is the upgrade of transmission networks.

In 2018, the Energy Systems Catapult warned that converting the existing gas grid to provide pure hydrogen would "involve the construction of a new gas transmission network." On the shift to electric heating, the National Engineering Laboratory said that to "provide all energy needed via direct electrification would require a five-fold reinforcement of the electricity grid, which would be both costly and disruptive."

In your view, which is the most cost-effective at the moment? Is it upgrading the gas network or upgrading the electricity network, or is it a mixture of both and, as you have both suggested, a locally based decision rather than an overall national infrastructure decision?

Carl Arntzen: My understanding of the challenge around hydrogen in the gas network is that 85% of that task has already been completed, with the repurposing of the gas network from iron pipework to the yellow polypropylene piping. As part of the Hy4Heat programme, there are investigations ongoing of the suitability of that plastic piping to carry hydrogen. My understanding is that it is proving to be successful in that regard. Very fortuitously, we have already pre-prepared the gas network to be suitable for hydrogen.

On the chances of us deploying, and the overall cost-effectiveness of what we need to do, I think there is a much greater likelihood of us being able to afford the repurposing of the gas network to hydrogen than the full reinforcement of the electricity distribution system.

Q244 **Rebecca Long Bailey:** Thank you. What are your thoughts on this, Professor Wu?

Professor Wu: In my opinion, both will play a very important role, but for the short and medium term the electricity grid will play a greater role because the technology is mature and it can be decarbonised very quickly. We know how to control renewable sources. It is how to connect that. Historically, the electricity grid was built based on a worst-case scenario. We predict the worst demand, plus headroom. Basically, a lot of places still have spare room to take more load, but we need to invite smart solutions, to make sure that we can control demand accurately to make the best use of the infrastructure.

I think we can do that upgrade. We know how to control the grid. On the other side, full electrification of heat and transport means that capacity must be increased by three times. Clearly, we cannot do that without using other technology to complement it. That is the key. The repurposing of the gas network, as far as I know, has been trialled in many countries. In the UK, we have a lot of trials as well.

From the technology point of view, I am very positive. Repurposing the gas grid is feasible, although it is still quite costly. From Government data, the domestic upgrade of pipework and boilers may cost £17 billion. If we look at the pipelines, investment of £4 billion is needed to do that. There are other associated costs, such as storage. However, this again is another thing linked to where the hydrogen comes from.

If we use blue hydrogen—currently 95% of hydrogen production is grey hydrogen—we must use CCS and CCU, carbon capture and storage. Currently, in the whole world, we have 18 to 25 active, commercial CCS projects. This means that the skills are not there. Even with CCS, we need huge investment. I do not think that current thinking about upgrading the gas network has considered the associated costs.

Q245 **Rebecca Long Bailey:** I have one final question. The main concern for people in their homes will be how expensive it will be either to upgrade their existing boiler or to install a new electric or hydrogen-powered boiler. In your view, which would be the most cost-efficient, both for installation and running costs?

A second question, on top of that, is this. There has been some discussion that we could transition to a hydrogen heat network by starting to blend hydrogen into the grid. Would that mean having to tweak boilers to take the blended hydrogen, but then have a completely new boiler after that for a 100% hydrogen network, or is it easy to shift between the two?

Carl Arntzen: The research we have done so far—there are some trials ongoing, looking at the blending of hydrogen into the existing gas network, at Keele University—shows that up to a 20% blend into the existing natural gas network has no impact on existing appliances in the field today. Boilers, gas fires and gas cookers can accommodate up to a 20% blend. Once you start to go over that 20% blend, hydrogen starts to have a greater impact in the overall gas mix. Over 50%, it starts to dominate. At that point, we need to interfere and change some of the components on the appliance.

Our recommendation is clear: zero to 20% blending of hydrogen is fine, but the minute you go over 20%, you might as well go to 100% hydrogen to secure all the benefits that that investment gives you. What we have been advocating is that, from a certain date in the not-too-distant future, we should mandate for hydrogen-ready boilers to be installed, so you start pre-populating the park of boilers in the UK. Those hydrogen-ready boilers are designed to fire 100% hydrogen, but they are dispatched from the factory set up to burn natural gas. They can burn up to a 20% blend of natural gas. When hydrogen becomes available in a region or district, you need to make a few minor changes to the product to make it compatible with a 100% hydrogen network.

Q246 **Rebecca Long Bailey:** Thanks. That is really helpful. Professor Wu?

Professor Wu: I would like to answer the question from two aspects. First, we cannot only look at the cost. We need to look at the performance as well, and what objective we are trying to achieve. To pick an example, I have seen some studies where if we take one kilowatt hour of renewable electricity we can go through the green hydrogen route, we can go through the resistive heat route, or we can go through the heat pump route. Let's compare. Basically, even an electric space heater—the conventional technology—will deliver nearly 90% or more heat per kilowatt hour compared to the green hydrogen route. The heat pump will be six times more. That is the performance.

Regarding cost, I have not done the research, but this is recent research on the European mainland. They looked at a comparison for a single family household, including installation and maintenance costs. For hydrogen, it is around £1,000 every year, but for heat pumps the cost is around £500, half the price. I am sure that because the technology is developing very fast those costs will converge. One concern from the Government's point of view is that we need to make sure that everybody is fairly treated, rather than some people paying more than others for their heat bill.

Rebecca Long Bailey: Thank you both; that is really helpful.

Chair: For anyone watching the session, the discussion of blue hydrogen and green hydrogen that Professor Wu has been alluding to is clearly very important. We are not going into it in great detail in this hearing because we had a session devoted to that. It will be a substantial part of our inquiry, so we are very aware of the very important questions as to whether where the hydrogen is derived from is sustainable and green.

Q247 **Graham Stringer:** Could I ask Mr Arntzen a follow-up question from Becky's question? You said you were looking for mandation of hydrogen-ready boilers. Why is it necessary to mandate that boilers be hydrogen ready? Why won't the market just look after it?

Carl Arntzen: That is an interesting question. Certainly, we could take a leading position on that and start to populate the product with this type of technology. In trying to bring the costs down and getting the investment required to industrialise the technology, it would be much better if we had clarity as to what the market landscape and the market background we are performing in is based on.

In our opinion, if we mandate and get consistency across the whole supply chain, so that we are all developing and marketing hydrogen-ready boilers—we need to develop standards to which those are designed, built and tested—it enables the whole market to be consistent, and we will all be performing to the same standards as we do today with natural gas boilers.

In addition, there are 1.6 million domestic gas boilers sold in the UK each year. Pre-populating the park population of products in the marketplace so that it is hydrogen ready means that we can use the benefits gained from that technology in decarbonisation. The earlier we do that, and the earlier we make sure that the whole industry is doing that, the better it will be.

Q248 **Graham Stringer:** Would you care to hazard an estimate, if the Government legislated and made it mandatory, of the extra costs to the consumer?

Carl Arntzen: For the hydrogen-ready boilers, we believe that the cost of a hydrogen-ready boiler will be at the same level as a natural gas boiler very early in the cycle. The number of components that are different in the appliance is very small. It is purely around how we ignite the flame, how we sense the flame and then how we manage the combustion process.

We are confident that once we get to scale and volume, the price to the consumer will be the same as a natural gas boiler today within two to three years of that technology being mandated in the marketplace. That is the other reason why we think it is beneficial for the consumer if everyone is basing, developing and producing the same technology. We will get to that volume quicker, and therefore to cost neutrality much quicker, in the process.

Q249 **Graham Stringer:** The real cost to the consumer would not come from the cost of the boiler but from the increased cost of the fuel, if indeed that was the case, and if the Government said that you had to have those boilers, you would be installing them before the previous boiler had reached the end of its natural life. That would be where the extra costs came from.

Carl Arntzen: Yes, but what we are equally recommending is that if we can mandate—let's say, for argument's sake, from 2025—for the initial period you are installing the hydrogen-ready boiler on the natural lifecycle of the existing boiler. You replace them with a hydrogen-ready boiler as and when they come up for replacement. That still gives you lots of flexibility in the future deployment of hydrogen into the gas network.

Let's assume that we install a hydrogen-ready boiler in 2025 and it has an average life of 15 years. That boiler could spend its whole life operating on natural gas. That is a feasible proposition, but hopefully, in terms of the decarbonisation strategy, either we will get to blending hydrogen into the gas network up to 20% to give a lower carbon contribution, or the roll-out of hydrogen into the gas network will start to be deployed and we take the benefit of those appliances in the field. It could quite feasibly be that a hydrogen-ready boiler sold in 2025 never operates on hydrogen. That is a feasible proposition.

Q250 **Graham Stringer:** That is very interesting. Professor Wu, the UK Energy Research Centre has recommended that the Government should make progress on heat decarbonisation before uncertainties with hydrogen are resolved. What is the best way to do this? Is it sensible?

Professor Wu: This question is linked to the previous one. Decarbonised heat is a very difficult and challenging question. Currently, the UK has 29 million homes, and so far only 1 million are heated using low-carbon methods. We need to take radical solutions, rather than waiting for everything to be clearer.

At the same time, things will take time. Linked to the previous question, without Government intervention, it is very difficult to decarbonise heat. If we purely rely on the markets, time will not allow us to do so. We need strong intervention. From the market point of view, private investment will watch this space. They want stable policy so that they can put money in. Both sides need clear guidance on that.

Hydrogen will play a role, but currently, for example, we can look at district heating for dense urban areas. We can look at heat pumps. They can be very quickly deployed, but another very important thing associated with heat pumps is that we need to look at the improvement of building fabric. That is another very challenging thing. Heat pumps take time to collect the heat. It is not like a gas boiler, where you push a button and it heats very quickly. It will take time. Also, the temperature is lower than gas boilers. It may be below the comfortable level for a lot of people unless it is a very well-insulated building.

Currently, I think progress is very slow. If we look at heat pumps currently, for example, in 2017, 27,000 heat pumps were installed in the UK. In 2019, it is 1.6 million units for gas boilers installed. We need a clear policy to make sure that we go for low-carbon technologies. That is a need. If we do that, we need a clear policy to support it. If we say that we will wait for the costs of hydrogen in 2050 to be completely clear, and then make a decision, it will be too late.

Q251 **Graham Stringer:** From previous answers, there are quite clear difficulties in putting heat pumps into old terraced houses. It is expensive and not particularly effective. Does that mean that it would be very difficult to decide on particular regions to focus on heat pumps, because there are terraced houses virtually everywhere in this country?

Professor Wu: First, we need to look at new builds. The insulation level is very high. They need to be encouraged or pushed to use heat pumps and low-carbon technologies. As for the place, we have good spare capacity for the electricity network, and we can take more. We can look at that.

For the older houses that you mentioned in the UK, there is a very big challenge. Only 25% of the buildings were built in the past 40 years, so a lot of them have modest energy efficiency if you look at heat pumps. In my opinion, that is our priority. We need to get things going to improve the building fabric.

If we use heat pumps in a cluster, in an area that has a lot of new builds, we need to consider the impact on the electricity grid. If everybody turns on and turns off heat pumps, it will have a major impact on the electricity grid. We need some sort of co-ordination and investment to look at that as well.

Q252 **Graham Stringer:** That is really interesting. In making these decisions, are you reducing the consumer's ability to choose what sort of heating they want? This is my final question, and it is in two parts. Is there a possibility that people who install heat pumps now will be asked to change their form of heating in the future because that fits into the national plan better?

Professor Wu: From a system point of view, it would be more economical if a local area, a local energy system, deployed the same low-carbon heat option. Economy of scale can pull things down. For hydrogen, there is a similar option. If we have an industry cluster, and decarbonisation of transport, using hydrogen, has been determined, it is vital to associate that with a hydrogen route.

To come back to the question, if we look at heat pumps, the customer should have options, but they may have different cost implications. The customer can choose. They can go for hydrogen, but it may be much more expensive. It is up to them. From the Government point of view, for the local decision it would be better if the local authority could take more of a leading role, to make sure that they have a clear strategy. They could look at the resources available, the infrastructure available and the social culture and environment in that area, and then make a decision. I hope I have answered your question on that.

Graham Stringer: Thank you.

Q253 **Carol Monaghan:** Perhaps I could continue some of Graham's points. Both Professor Wu and Mr Arntzen have suggested this morning that older properties are more difficult in terms of heating and are probably less likely candidates for a heat pump system.

Is there a danger, if we move towards heat pumps in new builds, which are going to be more expensive to install but far cheaper to run, that the energy companies will still have to make their money somehow, and we will see a shift in cost of energy usage going to consumers in older properties and, potentially, properties that are not as well looked after?

Professor Wu: First, I do not think we should leave older buildings with low efficiency. We need to do something, or else a lot of energy will be wasted. Current technology allows us to do something to insulate buildings better. We need to take action to do that. That is the first requirement.

Secondly, we need to look at fairness among different groups, including the energy companies. They must make their investment back. It is how to balance that. We need to develop some mechanism. There is a lot of research and a lot of trials. It is a very complicated issue. We need to balance it.

For example, on the electricity grid we are building a new transmitter line. It will take 10 to 15 years. The investment is already there, and now they are in their return period, so how to make sure they get the money back is a really challenging thing. On the other side, we need to make sure that all customers are fairly treated. How do we do that? Probably we need to target different groups, to make sure that we give them sufficient support and help them.

Q254 **Carol Monaghan:** Thank you. Mr Arntzen, do you have any comments?

Carl Arntzen: I agree to a large extent with what Professor Wu has just said. It is really important to make sure that the costs are deployed appropriately. Fuel poverty is a big topic and we need to maintain a very close watch on that, and make sure that we do not exacerbate the problem by deploying any individual technology in certain areas.

I also agree with him that we should be improving the fabric performance of every building in the UK. That is money well spent. It is a good investment. Whether the technology stays with natural gas, with hydrogen or with a heat pump, you are still reducing thermal demand from that property, and that is a good, sensible investment to make. Which technology you deploy in individual properties is again, to a large extent, dictated by the energy supplied to the property. Overall, it is thermal performance. You have heard me say a couple of times that heat pumps are really low-temperature heating, designed perfectly to operate in thermally well-insulated homes. Deploying them in a property that is not so well insulated thermally, particularly a property that is used to operating a boiler and then switches over to a heat pump, is like changing from a petrol car to an electric car. You need to change your behaviour. Consumer behavioural change from one technology to another should not be underestimated.

Q255 **Carol Monaghan:** Professor Wu, we know that some countries have made great steps forward in the decarbonisation of heat. What can be learned from those countries? Can you give us an example of a country that has done it well?

Professor Wu: That is a really good question. It would be good to open our eyes to other places where they are doing well. One example is in northern Europe, in Sweden and Denmark. District heating is widely used. A lot of them are powered by vestigial heat. This is something we could learn from. On the other hand, vestigial heat is not available everywhere. They are looking at the fourth and fifth generation of district heating. This means that the temperature is very low.

We could look at a local market. It could be something like a data centre. If they have some extra heat, they can pump it into the network. Like the electricity market, we could have a free local market to trade and share heat demand. If people have heat pumps, could they connect together using a low-temperature heating network? That would boost co-efficiency. There are a lot of good learnings on that side.

Another site is Japan, which has a very ambitious hydrogen strategy. We are discussing the hydrogen focus today. They have put huge investment into hydrogen technology. They look at fuel cells. Already there are a lot deployed. They are leading in the manufacture of fuel cells. We need to look at the whole supply chain, from technology innovation to the products. We need a supply chain to support that. I think that Japan is doing well on that.

In the UK, we probably need to consider the supply chain as well when we look at hydrogen, whether it is fuel cells or hydrogen boilers. I know that Carl's plant is producing these and that is really good. On heat pumps, we need to build manufacturing capability and skills. We do not have enough people to install and maintain these low-carbon technologies.

Q256 **Carol Monaghan:** Thank you very much. Mr Arntzen, I think you wanted to say something.

Carl Arntzen: Unfortunately, we come back to the thermal performance of houses each time. In Scandinavia and certain parts of Germany, the housing stock is very well insulated. Its thermal performance is way above what we experience in the UK, and that—

Q257 **Carol Monaghan:** I am sorry to interrupt, but does that include their older properties? One of the difficulties here is our older housing stock.

Carl Arntzen: Yes, although they have far less as a proportion of old housing stock, particularly Victorian and Georgian housing stock. They have a lower proportion of it and, to a large extent, they have replaced a lot of the housing stock, whereas we have retained quite a lot of it. It is good, robust housing stock, but you suffer from its poor thermal performance.

Carol Monaghan: Thank you very much. I live in a Victorian house, so I know exactly what you are talking about.

Q258 **Aaron Bell:** Thank you, Professor Wu, for setting out some of the international comparisons and some of the ways we can improve and decarbonise our energy systems. Do you have a take on what we can learn from geothermal energy in other countries? I represent Newcastle-under-Lyme in Staffordshire, which has Keele University, where we have the HyDeploy thing going on. We also have potential sources of mine energy in Staffordshire, next door in Cheshire and so on and so forth. What role does geothermal have in decarbonising our heating systems?

Professor Wu: That is a really good question. On a lot of occasions, geothermal is ignored, but it could play a very important role. In some countries, such as Iceland, they use it quite widely because of the available resources.

In the UK, I have heard of some studies looking at the availability of geothermal. Because of the limitation of the resources, and where we could use this technology in the UK, we need more study and research to really look at that. Geothermal is something underneath. Sometimes, if we estimate wrongly, we could put in big investment and the heat might disappear very quickly and we would lose the investment. We need more certainty. More research and study is needed to look at that. The geothermal side has potential from the research point of view. The technology could be looked at.

That is not to say that we must take very high temperature geothermal energy and that then we can power the district heating network. Even a low temperature could help the co-efficiency of heat pumps quite a lot. In some areas we have trials—in Wales as well—even using mine water. That is at a constant temperature, and can help efficiency, and in total, over the whole lifecycle, it could save a lot of energy.

Q259 **Chair:** There is a final question from me to Mr Arntzen. You talked about using heat pumps requiring different behaviour on the part of consumers from using the boilers that they have been used to. Other evidence that we have received talks about that. Could you illustrate it? How does a consumer at home change their behaviour if they have a heat pump compared with if they have a gas boiler?

Carl Arntzen: To a large extent, it comes down to some of the things that Professor Wu mentioned around how heat pumps operate. They operate at much lower temperatures to get the super-efficiency that we talk about. They are operating at radiator temperatures of below 50° C. They very much rely on a property that is well insulated, so they provide background trickle heat-type delivery. You are trying to maintain the ambient thermal performance of the building at a fairly consistent level.

Let me explain. When you operate a heat pump, in the most efficient mode of operation it can take three to four hours to come up to its operating temperature. It is a very slow and very shallow temperature gradient. Therefore, in other countries consumers look at the ambient temperature forecast two or three days in advance. They pre-empt what temperatures might occur in two or three days and adjust the controls accordingly.

In the United Kingdom, we operate on virtually 180 degrees full-scale deflection the other way. We have poorly insulated properties. The ambient temperatures fluctuate outside quite frequently. There are often 10 to 20-degree fluctuations in 24 to 36 hours. The internal temperature fluctuates quite dramatically, so the UK heating consumer is used to turning the thermostat fully up, getting the temperature of the radiators up very quickly, heating the house very quickly, and then cooling it back down. We are very much on/off, on/off. The ideal operation of a heat pump is to keep a very static, very low temperature gradient, and you operate it consistently over days rather than hours.

Q260 **Chair:** Thank you; that is very clear. During the recent cold snap, I think we were all whacking the heating up when we came in from work. We might have to look at the weather forecast better.

Finally, indulge me with one further question, Mr Arntzen. You said in response to the questions from Graham Stringer that, in effect, having a dual-function boiler that could work on hydrogen and natural gas is a no-regrets policy that would not cost any more than replacing an existing boiler. You gave the caveat that that is when production is at scale, which might be a couple of years. In getting to scale, the implication is that it is going to cost more. How much more would it be, because there is then obviously a question as to who might pay for that? Is it the consumer or the taxpayer?

Carl Arntzen: That is an interesting question, and one that we are asked all the time. As I said earlier, there are 1.6 million gas boilers sold in the UK each year. We have market share and are producing around 500,000 a year. That is fairly at scale. We have been honing the manufacturing processes of those appliances year after year. What we are saying is that, in the first two or three years when we switch over to hydrogen-ready, when the volumes are lower, some of the unit costs will be higher, to the order of £100 or £200 on a £700 appliance, but that will come down very quickly as we start to manufacture at scale. We expect to see our production costs hitting compatibility within a couple of years.

Chair: Very good. I am very grateful to you both, as is the Committee. You have both been very clear in your answers. Professor Wu and Mr Arntzen, thank you very much indeed for your evidence to the Committee.

Examination of witnesses

Witnesses: Antony Green, Angus McIntosh and Dr Angela Needle.

Q261 **Chair:** We will move on to our second panel of witnesses, whom I am delighted to introduce. We have three witnesses: Antony Green, hydrogen project director at the National Grid, which is the owner of electricity and gas transmission networks in Great Britain; Dr Angela Needle, director of strategy at Cadent, which owns four of Britain's eight regional gas distribution networks, supplying 11 million people; and Angus McIntosh, director of energy futures at SGN, a gas distribution company supplying natural gas to 6 million homes in Scotland and the south of England, principally. Thank you very much indeed for giving evidence today.

Perhaps I may start with a brief question and hopefully brief answers from you, given that we have three witnesses on the panel. Do you expect to see a big role for hydrogen in the gas grid, or a more modest supporting role as we move to net zero?

Antony Green: Good morning. Thank you very much for the opportunity to provide evidence. I am pleased to be here with my colleagues from two of the four distribution networks. We are very much working on developing these options. Probably the best way of describing it is that the role that hydrogen will play is emerging. We are seeing a range of options and predictions, ranging from around 200 TWh up to 600 TWh, depending on what scenarios we look at.

Hydrogen certainly has a role, and everybody agrees on that. The question is how much of a role. That is going to come down largely to some of the regional solutions that we have been talking about in the previous evidence that we provided.

Q262 **Chair:** So 200 TWh to 600 TWh. What is the current contribution of gas against those figures?

Antony Green: We would deliver between 800 TWh and 900 TWh a year.

Q263 **Chair:** The potential ranges from about a quarter to two thirds or three quarters. The same question to Dr Needle.

Dr Needle: Thank you for having us here today. I think that it is important that we think about what the gas infrastructure does. We have world-class gas infrastructure. I see Cadent as a net zero infrastructure provider, not necessarily a gas company. The question that we are answering from a gas network point of view is ensuring that the gas network is ready for the scale and size of solution that we might need regardless of how much that may be.

Q264 **Chair:** Dr Needle, on the specific point, I would like to get a feeling for what you think the potential is of hydrogen versus the current gas provision.

Dr Needle: As Tony said, today's natural gas is 900 TWh annual consumption across all the different uses. There is a range of different pathways that you will have seen from the National Grid scenarios, including CCC. The total amount of hydrogen needed is still uncertain and it goes between the ranges that Tony mentioned.

Q265 **Chair:** Do you have a view, personally or corporately, on your expectation of where it is likely to be? Is this going to be the dominant source or a supporting source?

Dr Needle: It is very much dependent on the choices that consumers and regions make about how they plan the energy transition. Our role in it as a gas distributor is to ensure that that is possible.

Angus McIntosh: I would build on what Angie just finished with there. What is going to be critical is: what does the customer want and what is the customer value proposition? That will dictate the extent of hydrogen.

Do we have enough hydrogen production capacity in the UK? Absolutely. Can we do it relatively quickly? Yes, through blue. Can we replace that over time with green? Yes, we can.

What is critical is the customer angle—is it what customers want? From a network perspective we need to ensure that we are ready. We are planning to be ready from 2025, wherever, whenever on the gas grid. We are carrying out all the evidentiary work in partnership and we are co-ordinating that across the UK. We will have the first hydrogen-supplied domestic boiler in Fife in 2022. We will have 300 homes by the middle of 2023. That is the critical or magic number that will give us all the information that we need on the relative supply and demand. The key thing that will dictate the scale of hydrogen in the UK is the customer proposition.

Q266 **Chair:** Mr McIntosh and Dr Needle, you are both saying that what will determine the role of hydrogen is principally the customer, and from the network operators' point of view there is no technical constraint on that—it is entirely down to customer choice. May I confirm that I have picked up the right interpretation, Mr McIntosh?

Angus McIntosh: Yes, we are working through the remaining technical aspects. We are already at the position where we are very confident that 85% of the pipes that were mentioned earlier are suitable for hydrogen. There are minor adjustments that we need to make, both within home and as part of the network, and we are working through what that level of intervention will be.

We have not identified any real technical issues that will be an absolute barrier at this time. All the research and development is under way, such that it will be completed by 2025. You have to remember that as gas network operators we are extraordinarily cautious around all aspects of safety. Safety is sacrosanct in everything we do. That is why we are taking our time to ensure that all R&D is complete at that point.

Q267 **Carol Monaghan:** Mr McIntosh, may I push you a little further on that? You said you are confident, but there are a couple of small things that have to be ironed out. What are these small things?

Angus McIntosh: We already, for example, have pipelines in every street in every city, and we know that if the pipelines are gas-tight, as you would say, or not leaking, they will be gas-tight on hydrogen as well.

We need to determine exactly what the intervention will be beyond the current repex programme, and the current mains replacement programmes that we are undertaking. We already have an absolute duty to replace all metallic cast-iron assets within 30 metres of property as part of our business. How much further we want to go will be determined by the "as low as reasonably practical" approach to risk. It is not a case of saying we need to replace everything; it is a case of determining what the appropriate intervention would be.

What I would add to that, though, is that that is not the dominant cost in the change to hydrogen. The network costs are actually relatively small. The largest costs are in production and in the home.

You have to look at this compared with the whole system costs of alternatives. For example, heat pumps are £10,000 to £20,000 depending on the level of insulation that you would seek to put in the property. If you take Scotland as an example, we supply 1.8 million homes, so that is about £18 billion to do just the heat pumps. That excludes the power, distribution and transmission system.

When you look at that from a gas network perspective and put hydrogen in, you could build all the reformers, you could build a brand new transmission system, or, indeed, as in the great work we are doing with Tony on transmission, you could repurpose that and reduce the cost, replacing all the customer appliances for significantly less than that, at around £11.5 billion.

Q268 **Carol Monaghan:** On customer appliances, we are talking specifically about boilers. Are we going to move to a situation—and we heard a bit about it in the previous panel—where boilers can be dual fuel? Are you doing any work on that, or are you specifically looking at replacing these boilers with gas boilers?

Angus McIntosh: We will design it for what the customer wants. It is not up to networks to decide the means of decarbonisation, but rather to provide options and deliver energy responsibly, and be responsive to all the new sources and technologies that customers want.

You need to understand how the different types of applications that you put on the network impact the supply and demand overall of your system. I would go back and make a wee point of correction or clarification on something that Professor Wu said about energy efficiency. What is really important to recognise is that it is a complex matching of supply and demand. In the energy system you do not have energy that goes in and is used exactly by that customer. You have significant variation in production from, for example, wind. You have profiles of demand from, say, solar, which is only when it is sunny, and the end-use aspects of it are very dominated, particularly for heat, by cold weather, and you cannot switch that. It is really important to understand the efficiency of the system, and you have to be careful when you are looking at calculations assuming 100% power coming into something, because, as you start to scale, all the low-hanging renewables fruit into the power grid has already largely been taken. What you have now is: what is the maximum economic recovery of energy? It is to produce a storable energy solution that can be generated all the time, so, for example, you would need fewer turbines to be producing hydrogen all the time than you would to electrify.

Dr Needle: Your question was about the extent to which we are looking at appliances in the home. We think that is the role of companies such as Worcester Bosch and Baxi, which are developing those appliances. We have been working very closely with them. When we are building our pilot schemes, we have blended hydrogen into the Keele University gas campus, for example, at 20% hydrogen—we have the manufacturers' appliances within that research programme. Similarly, the H100 Fife project and H21 project in Northern Gas's territory have those appliances. We are not duplicating effort. We are working very closely together.

That concept of hydrogen ready—a boiler that can burn methane today and hydrogen tomorrow at no extra cost to the customer—is really important because it means the consumer can make a green choice without it adding to their budget.

Q269 **Rebecca Long Bailey:** There was some discussion on our previous panel about whether changes to the grid infrastructure needed to be done on a localised or a national basis. Very generally, what are your thoughts about what changes are required to existing infrastructure to carry 100% hydrogen, and what might be the associated costs and disruption?

Antony Green: Thank you for that question. The evidence that was referred to earlier, about the need for a new transmission network, is an area we have been working on very hard. The evidence base has moved on a very long way in the last three years. We have been really focused on that topic, as have a lot of European TSOs, which are all studying the same work.

The European hydrogen backbone report put out just a couple of weeks ago suggested a 70% repurposing rate when you look at the 23 TSOs across Europe, but it is heavily biased, based on a lot of new build through Scandinavia. Our repurposing rates are potentially a lot higher in the UK. That is the work we are studying now through Project Union, which is looking at a hydrogen backbone for the UK.

More specifically, we have kicked off a project called Future Grid. We are taking some of our assets that we are currently decommissioning and are going to rebuild them as a test facility. That test facility is pretty large in scale. We are going to run from 2% up to 20% and all the way up to 100% hydrogen in that network. The idea behind that is to say that those assets have been running with natural gas for many years; let us see how they will perform in a hydrogen world and prove to ourselves this can be done. We would not be doing it if we did not think it could be done. Our colleagues in the Netherlands have already repurposed one of their main feeders. It has been running for two years on 70% hydrogen with absolutely no issues. Our colleagues in Italy and Snam have been running hydrogen blends through the transmission network over there.

The confidence is growing. We are not seeing any show-stoppers at all at this point, but, as Gus said earlier, this is all about proving safety. Safety is absolutely sacrosanct. We have to prove here on GB soil that this is absolutely doable with our assets.

Are we going to see anything different? We have to look at how we can operate these assets, how we can maintain them, so we are really going through that in a lot of detail at the Future Grid facility. It has just started construction. We are decommissioning some of the assets and now starting to pull those in. The evidence base is growing. It is going to carry on growing over the next couple of years. We have high degrees of confidence at the moment that high levels of repurposing are going to be possible.

Q270 **Chair:** Mr Green, you mentioned TSOs. For people watching who may not understand the acronym, will you explain what a TSO is?

Antony Green: The TSOs are the transmission companies across Europe. TSO stands for transmission system operator. It is companies like ourselves across Europe.

Chair: That is very clear.

Q271 **Rebecca Long Bailey:** The same question to Mr McIntosh: what changes to the existing infrastructure to carry 100% hydrogen would be required, and what would the associated costs and disruption be?

Angus McIntosh: I mentioned the Scottish example with some costs in answer to the last question, but from the existing gas grid perspective, in the existing mains replacement programme that is making our network hydrogen ready there is an additional level of intervention that we would need to do on that. New pipeline infrastructure will be required to start stimulating and supplying potentially other sectors.

One thing to note is that, if we provide all the evidence for the gas networks' conversion to hydrogen, it affords the opportunity for all the hard-to-abate sectors to access fuels that they have not before. We are talking about aviation, marine and heavy goods vehicles. The question is whether hydrogen becomes a ubiquitous fuel rather than a premium fuel, which was a bit of the debate this morning, where you had mention of a hierarchy of hydrogen use. Fundamentally, it is about creating the market and, if there is a market, the scale of that market will dictate how quickly it moves.

There are absolutely indigenous resources that can be scaled. In Scotland they are looking at a 20 GW production from offshore wind, but you should also recognise that hydrogen is potentially a global fuel and a global solution, not merely a local one like electrification, I suppose, where you are limited bar a couple of interconnectors. You can ship hydrogen and it could be replacing LNG.

Is it going to be local or national? Initially, I think it will be local areas, but to move to a national system there is the hockey stick analogy of how fast you want to go, and you can control that speed, if you want, towards 2050 once we have fully evidenced the programme.

Dr Needle: I will not repeat anything because I agree with that. I think it is important, though, that we look at things on a regional level. Properties are different. There are differences in where hydrogen will be sourced from and the electricity resources as well. It is not just one or the other.

We have been doing some great work with Greater Manchester Combined Authority, together with Electricity North West, to look at what that region will need from the electricity and the gas infrastructure working together to get to net zero. That is because not every home is the same. Not every customer is the same. Not every building can have the same solution. There is a range of different technologies—heat pumps, hybrids, hydrogen, district heating, etc. You have to look at it all.

When you have done that, you need to zoom out again and look at them all together and say, "How does that work on the coldest day when it is not windy?", to double-check we are keeping everybody warm, all the time. That kind of up and down through the levels of planning is going to be really important to ensure the system is resilient. While yes, there are costs to repurposing the gas network to hydrogen, which Gus has already talked about, and a potential opportunity to convert town by town, when you add that up with the costs of electrification and some of the other things, it makes sense to do it on a regional level and think about customer preferences. That is all I wanted to say on that point.

Q272 **Rebecca Long Bailey:** That is really helpful.

Finally, I have a more technical question. Dr Grant Wilson of the University of Birmingham told the Committee that a gas grid that transports 100% hydrogen would require detailed network analysis to understand how much linepack—that is the gas stored in the grid, for people watching at home—the new high-pressure pipelines could be designed to hold, and the within-day flexibility of hydrogen.

We heard from Gordon Taylor, an energy consultant, who said that linepack could be reduced by up to 84% in a hydrogen system, which could be "so low that even if the problems of safety, combustion, and leakage could be solved, it might well prevent the use of 100% hydrogen in the existing gas network."

A question to you all: will linepack in a hydrogen network be sufficient to provide peak power supply as natural gas currently can?

Antony Green: I am probably the best placed to start there because the transmission network ultimately holds the majority of that linepack. Linepack is within-day storage. It is like a water reservoir: you pack it at night and draft it during the day so it is available. We have done some of this modelling on the networks. We have taken methane models and converted them to hydrogen, and we have run some of this analysis.

Ultimately, there are two ways of looking at it. First, you have linepack by volume, and you get an answer of around 90% if you do the linepack by volume. Hydrogen has a third of the calorific value of methane. When you bring those differing properties into it, linepack by energy is approximately a third. The numbers that were referred to earlier were much lower, but our analysis was showing it is approximately a third. We typically hold two to three days of linepack within the current network. You can equate that to about a day in a hydrogen world if we play that forward.

All of our analysis has been done on the 2050 FESs for system transformation, which are the higher levels I referred to earlier—the 600 TWh. It is very much at the top end of the current scales. We can broadly move around that quantity of hydrogen within the transmission network.

I use the word "broadly" because it ultimately comes down to where hydrogen will be produced and where it is needed. We do not know all these criteria at this point. All the modelling we are doing is based on scenarios. Once we know where hydrogen will accurately be produced and where it is absolutely needed, we can start answering some of the more detailed questions. I anticipate that some reinforcement may be needed in some areas, particularly because hydrogen flows at a higher velocity. One test we are doing is whether the network can run with a higher level of velocity, or whether it is going to cause us any other issues. That is one of the questions for the Future Grid project that I mentioned earlier.

Q273 **Rebecca Long Bailey:** That is very helpful. Mr McIntosh, what are your thoughts on hydrogen and linepack?

Angus McIntosh: I absolutely agree with Tony's analysis. Those are the exact figures we have generated. When you are designing it from a regional perspective, you are going to have some new infrastructure and you build into that infrastructure the design to ensure that it is going to meet the needs of that local solution.

There are also really exciting developments in hydrogen storage more broadly, and linepack is just one component of the storage requirements. Regardless of whether it is an electrification or a hydrogen scenario, storage is going to be critical. You need hydrogen. You cannot escape it because it is the only net-zero molecular solution that can replace a fossil fuel. With regard to things like dibenzyltoluene, ammonia, some of the sodium borohydrides, there are lots of exciting developments in there that can form part of regional solutions. I do not see it as something we cannot overcome.

For me, the storage challenge is for the strategic storage where you are talking about the within-season and within-year resilience components. That has not yet had enough work put into it because it can take quite some time to get sub-surface storage offshore or onshore validated and ready for operation. While we can navigate that in the short term, with the regional solutions, certainly as we start to go really at scale, you are going to have to have that, again whether that is gas or electrification.

Rebecca Long Bailey: Dr Needle.

Dr Needle: I do not need to add any more to that point. It has all been made.

Q274 **Aaron Bell:** Professor Marcus Newborough told us that the UK should prioritise "energy efficiency…first, electrification second, and green hydrogen third." Would you agree with those as overall priorities?

Antony Green: Absolutely, I would agree with the energy efficiency. I do not think it is as clearcut when you come down to electrification or hydrogen. It comes down to the end uses and the most applicable uses. Aspects of industry are very hard to decarbonise with electricity. Aspects of heavy transport are very difficult. There are some very clear merit order aspects you can go down there.

Ultimately, you get into a much bigger area where you have choices. As we were referring to earlier, some of that starts to come down to choices from the consumer. There may be a cost differential, but there is also the impact of any change within a property, and so on. Taking a pure cost approach does not really get you to the end impacts overall. There are far more factors to bring into that equation.

Q275 **Aaron Bell:** To pick up on what you said about those areas where hydrogen might be the best solution, Michael Liebreich, founder of Bloomberg New Energy Finance, told us that hydrogen was a "Heineken solution" in that it reaches the bits that other parts cannot, but that we should prioritise electrification and batteries where possible. It seems to me from your answer that you broadly agree with that. Is that fair?

Antony Green: I think it is the case in early decarbonisation, particularly around the industrial clusters, and driving blue hydrogen production into our industrial clusters as soon as we can. That gives us the volume.

Similarly, it is early days for green hydrogen production. It is more expensive, but it is about where we could use that most efficiently, particularly in heavy goods transport, and perhaps fleet transport. It allows it to be deployed and really attack, as you said, where other energy sources cannot quite reach at this point.

Certainly in those early days—possibly, say, between now and 2030; I know the professor earlier was referring to up to 2035—the one thing that is very clear is that the date at which green hydrogen becomes more cost-effective is coming towards us, and it is coming towards us quite fast. I do not think any of us know when that will be, but Bloomberg has recently been suggesting it is before 2030 now, so that date is getting sooner.

Q276 **Aaron Bell:** Mr Green, National Grid announced in March its intention to sell its gas transmission business to focus on higher-growth areas. Does that mean that National Grid sees electrification potentially playing a more significant role in our path to net zero than hydrogen?

Antony Green: No, I do not think so. I see this as being very clear and as part of what is called a strategic pivot towards the electric side. It largely comes down to the available growth it foresees side by side. John Pettigrew has been very clear that he sees gas as having a very firm future and a role as we head towards net zero in 2050.

Q277 **Aaron Bell:** I will turn to the other witnesses on the original question about the overall priority, particularly between electrification and green hydrogen. Dr Needle, Cadent is doing HyDeploy in my constituency, so it is probably right that I come to you first.

Dr Needle: Thank you for that. In terms of priorities, energy efficiency trumps everything. Using energy more efficiently, whatever kind of energy that is, is essential. To the points made on the panel earlier, we need to look at the fabric of buildings.

The word "prioritisation" is a little dangerous because it suggests you are not going to do anything with the things at No. 2. We really need a twin-track approach. This energy system is going to work together, so electrification, and lots of it, and hydrogen production, and lots of it, are both needed at scale in order to get to net zero. There are uncertainties across both those things, as we have heard already. I fear if we are going to have to pick one, we will not get to net zero. There needs to be a twin-track approach. I think we need to accept that and plan forward on that front.

Angus McIntosh: I reiterate that it is the customer and what the customer wants. I agree that you need to maintain real options throughout this. You do not want to make a decision on one or the other without fully understanding the implications.

Going back on the merit order and how that would dictate the roll-out, at the moment clearly you have different prices for different fuels. You have a higher price in the diesel market. The aviation market has no tax on it. You have all these different pricing regimes. What is going to happen as we move towards 2050 is that the carbon price is going to equalise a lot of these because it is going to be the dominant factor.

You need to move away slightly from this merit order in the longer term and recognise that it needs to be decarbonised. That is one of the reasons why I think hydrogen will move potentially more quickly, but only if you get that customer value proposition right.

Q278 **Aaron Bell:** Mr Green, the future of the UK's gas infrastructure is obviously going to be affected by what decisions we make about domestic heating technologies. Would the gas network be economically viable if in 20 or 30 years' time it is being used to supply hydrogen, say, at times of peak demand or has fewer homes connected to it? What are the long-term implications for the gas transmission network of the decisions we are making now?

Antony Green: The gas transmission network today is utilised approximately a third/third/third for industry, power and domestic heat. From our perspective, at that top level you have to consider that it is being utilised for other areas overall.

Rolling that forward, as you said, just using it, say, for domestic in peak, you still have to maintain that overall asset. That is one of the challenges people do not necessarily fully appreciate. It can sit there and be ready to respond when it is needed, but you still have to maintain that overall asset. It really comes back to this: how far do we need to maintain the assets? We already heard the question about linepack, and at the transmission level there are aspects of whether you want to retain more of it for that retention of linepack and make it available overall.

I guess the decision on the side of domestic heat is important, but as we pull that forward, it depends how much we are utilising in those other sectors overall.

Aaron Bell: National Grid has Project Union, which is exploring the potential for a hydrogen backbone. Could this supply key transport and energy storage sites as well as the industrial clusters it has referred to?

Antony Green: That is exactly the concept behind it, to be honest. We have designed it initially to join those industrial clusters, and to connect to some of the key sites in the UK, particularly out to Bacton to link with the interconnectors with Europe, working on the premise that Europe will have a hydrogen network as well, down to Project Cavendish at the Isle of Grain, which is another one or our projects.

It is about picking up those key storage sites and the key production sites. We do not have visibility about where all of those will be at the moment, but we are very much focusing on the industrial clusters being the start of all that.

As you will see in the report that the National Grid put out about the future of the North Sea, we foresee the North Sea with large quantities of renewable generation coming online being very suitable for green hydrogen production, but, equally, the industrial clusters—Teesside, Humberside and up at St Fergus—driving that blue hydrogen production as well. We see a role to anchor that via a backbone and we can build out from that backbone.

The most important thing, though, if that is there supporting industries, is that we can also start providing support for the future of heat and linking up the distribution networks as we go.

Q279 **Aaron Bell:** My final question to the panel is simply: which places or homes are most suitable for hydrogen heating? If I come to Dr Needle first, she can perhaps share some of the experience of HyDeploy and what you have learnt from your research at Keele.

Dr Needle: From a hydrogen heating point of view and from Cadent's perspective, all homes that are heated with natural gas today can be heated with 100% hydrogen in the future. Customers might choose different solutions, but the premise is there, because our role is to ensure that 100% hydrogen can be safely and successfully delivered 24/7 with a resilient supply, and, as you have heard from the likes of Worcester Bosch and others, the heating solution is a boiler similar to one of today.

The stepping stone to get there, though, is worthy of a quick conversation. Our work at HyDeploy, which is the project name for blending hydrogen, has been on the private network at Keele University. The reason blending hydrogen into the gas grid is quite important is that it creates that stepping-stone to 100% hydrogen. It gets consumers used to the concept of buying green gases and hydrogen as part of their energy bill. It can immediately decarbonise their energy use, but, more importantly, it creates anchor demand and a significant scale for hydrogen producers to want to invest in production. As we heard earlier, we need quite a lot of hydrogen to get to net zero.

Keele has 100 homes and about 30 campus buildings. We can provide more information if needed, but consumers have noticed no difference in 20% hydrogen being in their gas supply. All their appliances have worked as they normally would.

The next phase of that research is going to look at blending hydrogen in a public network so we can look at our different assets and a different range of consumers and appliances. There is going to be a third piece of work on commercial, because there is a bigger range of commercial applications of gas and blending today.

That stepping-stone is quite important. We think it is viable. At some point we want to collect all the 20% hydrogen off people and give 100% hydrogen to groups, and that is where you will start to plan out a town-by-town transition, most likely located from the industrial clusters outwards.

Q280 **Aaron Bell:** Mr McIntosh, the same question about your experience in Fife and what you think about which places are easiest to supply and which are the best targets for us.

Angus McIntosh: In Fife, we are testing this on what you would describe as typical hard-to-solve problems in a 19th century former mining area. We will get a very good gauge on what is perceived to be a difficult one for other solutions. We have not encountered any application, actually, that cannot be serviced by hydrogen. The only one is where natural gas is a feedstock. There is always a way of engineering hydrogen. It was described as potentially the Heineken of decarbonisation solutions because of its flexibility in being able to deliver and service all these sectors.

Q281 **Carol Monaghan:** We have heard quite a bit this morning about hydrogen blending and I am trying to get a better handle on this. At the moment the Gas Safety (Management) Regulations allow only a very small amount of hydrogen—I think it is 0.1%, or something of that nature. We have been hearing this morning that blends of up to 20% can be used without any real difference. Do we have a need to look at that quite urgently if we are talking about these test beds going on at the moment?

Dr Needle: The Gas Safety (Management) Regulations do not allow hydrogen in the gas network. We have had to get an exemption from the HSE to do those research projects. It is really urgent that we change and amend the regulation to enable different blends of gases and the introduction of hydrogen into the gas network. It is one of our asks of you.

Q282 **Carol Monaghan:** I think we have got that. If we are allowing hydrogen blending to go ahead, would there be a need for subsidies to encourage consumers to come on board? Mr McIntosh, you spoke extensively about it being about consumer choice, so how do we encourage consumers?

Angus McIntosh: For example, what we are doing in Fife is ensuring that no customer is disadvantaged through participation in a trial that is entirely an opt-in process. We are managing the commodity in the background. They do not even need to change supplier. They just need to consent to the new appliances going in.

That could form the basis for how you might deliver a system transformation going forward. You must of course balance how you protect fuel poverty and how you socialise costs, and actually, through regulated businesses like ourselves you have that opportunity to socialise costs against both current and future customers. There are models that could do that and you could dictate the speed at which we roll that out sector by sector within the overall UK solution.

Carol Monaghan: Does Mr Green wish to add anything to that?

Antony Green: No, I think Gus has covered it, thank you.

Q283 **Carol Monaghan:** We have also had evidence from the Energy Networks Association that mandating hydrogen blending would kickstart the growth of domestic hydrogen production. Should we be looking at this to take it a step further—not just enabling hydrogen blending but actually mandating it?

Chair: I think Dr Needle wanted to come in on the last question as well, so perhaps she can start.

Dr Needle: I will cover it off together. This is all related. How do you get consumers wanting to buy hydrogen at a cost that does not feel like it is prohibitive? How do you get this going?

I think about this from a green electricity point of view. How did we get that going? We invested in a contracts for difference mechanism that allowed scales, renewable power generation, and on the other side we enabled retailers to sell green electricity. Consumers paid a little more for it, but ultimately it was a choice that consumers could take.

We need to do something similar to put some effort into getting consumers on board. Again, if you think of the comparison with electric vehicles, we slowly made EVs a thing. We started off with hybrids, which would be the concept of blending. We are moving to a phase where we are phasing out fossil vehicles. We need to think of something like that for hydrogen in heating people's homes. We need producers to make it at scale and we need consumers not to pay much more than for natural gas in the first instance while the cost of production falls. Getting that hurdle rate and the learning of production going, which is exactly what we did with renewable electricity, is crucial.

On that front, we have a great opportunity to invest in all the industrial clusters that are currently planning large-scale blue and green hydrogen production. Enabling those to happen early brings that learning forward so that the price of hydrogen can come down.

Q284 **Carol Monaghan:** Dr Needle, you are talking a lot about the carrot rather than the stick. Is there a need for a stick as well, and is that where Government should step in and mandate a shift?

Dr Needle: It depends where the stick is applied. If the stick is applied to consumers, I do not think that is great. If you are mandating a hydrogen boiler the mandate is on the manufacturers of the boiler to make a hydrogen-ready boiler, not telling the consumer they must pick a hydrogen appliance, because they have a range of different technology solutions available to them. Enabling them to buy green gas and green electricity as they have done should be encouraged. We might have to think about mandates depending on the pace of change, but we have to think about that really carefully.

Q285 **Carol Monaghan:** Mr Green, do you agree that we should move toward mandating manufacturers to produce a dual-fuel or a hydrogen-ready boiler, or can we leave it to consumer choice alone?

Antony Green: I think the evidence is there. When we mandated condensing boilers back in 2007, we had that two-year period before it was mandated, and that was very successful. We created a huge shift in the market to condensing-only boilers being out there. At the moment we are proposing four years to get to a hydrogen-ready boiler. It seems almost more than fair to take that sort of approach.

It is almost a no-regrets scenario as well because, as Carl referenced earlier, if they can put hydrogen-ready boilers into the market, it is a bit like the digital TV switchover in the sense we could only buy digital-ready TVs for a long time before that signal got switched on. If we can start deploying hydrogen-ready boilers into the market it is a no-regrets option where, even if it does not ultimately get used, there is no additional cost to the consumer at that point.

Q286 **Carol Monaghan:** Obviously, we would be very supportive of that. You are saying four years from now, so you think 2025 would be the most appropriate date for a hydrogen-ready boiler mandate.

Antony Green: That certainly seems to be the date that is doing the rounds. We could bring that forward, as we did with condensing boilers, but 2025 seems to be the reasonable point of view. We have to ensure the infrastructure is ready and has gone through the proof phase of all the research projects that we are doing as well. That is where it takes a bit more time to get to that point.

Q287 **Carol Monaghan:** Would the other witnesses agree with that timescale?

Angus McIntosh: I would agree with what was said around it being hydrogen ready. All I would add is that meters should be included, because we have now developed as an industry the fully compliant, hydrogen-ready meter. Again, in terms of manufacturing it is a low-regret/no-regret option.

Q288 **Carol Monaghan:** Would that be distinct from your gas meter if it is blended hydrogen?

Angus McIntosh: It is hydrogen ready, in the same way as the boiler is, so it is ready to go and is easily converted.

Q289 **Carol Monaghan:** Dr Needle, are you happy with the timeframes being discussed?

Dr Needle: If you started that now you would have some massive innovation. Knowing that the 2025 date was coming, the gas appliance sector would innovate. That is the signal that we need to enable things like its production lines to be developed and that innovation to happen. It feels like a sensible timeline.

Q290 **Chair:** To pick up on what Carol was saying about metering, will the current generation of smart meters that are being rolled out across the country work with hydrogen? I do not know who might be best placed to pick that up—perhaps Mr McIntosh.

Angus McIntosh: I am happy to pick that up. The answer is no. There are quite a number of lessons to learn from the smart metering roll-out, but current installations will not be hydrogen compatible in their current form. We would need to replace them with hydrogen-ready versions, which have exactly the same functionality but are just forward compatible.

Q291 **Chair:** It is a big additional cost. What is the typical cost of a smart meter at the moment?

Angus McIntosh: In terms of the overall equation, without having the cost figures to hand, which I can forward later, it is not the material cost across the whole system transformation. In fact, it is a relatively low-cost component of the overall system transformation that we would be talking about, which is dominated by the production and within-home works.

Q292 **Chair:** But in the current smart meter installation programme, the cost of the smart meter and its installation, which is obviously significant, has been justified on the basis it has a very long life, but from what you are saying, if we are to move to hydrogen, that is a miscalculation because it is going to have quite a short life.

Angus McIntosh: Potentially, yes. You are already seeing some of the issues with smart meters not being compatible when customers change supplier and they lose their smart meter functionality. Yes, there are some challenges there, and we want to ensure we can support the industry in facilitating what the future will look like and how best to design these going forward.

Q293 **Chair:** Mr Green, in a world in which, as we heard from the first panel, hydrogen may have a role for properties in which it is harder to deploy heat pumps, and new builds might have heat pumps and perhaps a district heat network, does that not lead to a significant problem for a company like yours? You have to maintain this vast network, but you have fewer and fewer customers for it. Those very people who are reliant because they have no alternative to hydrogen or gas are going to have to pay more and more to retain the legacy network, while people float free of it through heat pumps or direct heating through electricity.

Antony Green: Absolutely, it would be a concern, especially if, as we referenced earlier, people were left in fuel poverty, and the very people in the worst situation were left having to pay more. We have to work out how we do not leave anybody behind and the energy transition is very fair and equitable across the piece. That is going to need a whole-systems approach—most likely, as we said at the start, that balanced approach between electricity and gas to find that balance point in the middle where everything is at the optimum overall, where you get the benefits of resilience against the benefits of cost and, as I said, nobody is left behind.

Chair: Again, we are very grateful for very important and very enlightening evidence from all three of our witnesses this morning. Thank you for appearing before the Committee and helping us.

Examination of witnesses

Witnesses: Professor Jon Gluyas, Dr Jonathan Radcliffe and Professor Clare Grey.

Q294 **Chair:** We now turn to our third panel of witnesses. I am delighted to welcome and to introduce Professor Jon Gluyas, executive director of Durham Energy Institute, who has done particular research into carbon capture and storage, among other things; Professor Clare Grey, professor of chemistry at the University of Cambridge, who has researched, in particular, battery technology; and Dr Jonathan Radcliffe, reader in energy systems and policy at the University of Birmingham, whose work is also on energy storage. Thank you for helping us with our inquiry today.

Dr Radcliffe, is energy storage the key to unlocking a new energy system? Is that the critical point in this system?

Dr Radcliffe: It has been quite well established that we will need a much larger amount of energy storage as we transition through to low carbon, especially as we get towards net zero, and the opportunity for having more flexibility in the electricity system from fossil fuel power stations is reduced significantly. Energy storage will allow us to balance the supply and demand from variable renewables much more effectively and allow greater integration over time.

Q295 **Chair:** Professor Grey, how important do you think energy storage is in solving the various policy challenges?

Professor Grey: Since we are on the public record, may I start by declaring my conflicts of interest? I am co-founder of a battery company in fast charging and I am the special adviser for the House of Lords on the role of batteries and fuel cells in achieving net zero.

Having said that, to me, the scale of energy storage is so great that we need so many different solutions, and batteries are very integral to that. We can unpick exactly the roles they will play as we move forward, but batteries are already in many of the sectors. They have to be part of the solution and they already are.

Chair: If the other witnesses have similar conflicts, perhaps they will raise them before they answer any further questions.

Q296 **Professor Gluyas:** I do not have any conflicts of interest on this particular question.

I agree with the other two witnesses that energy storage in all its forms is critical. Clearly, battery is one, but physical storage of hydrogen is another critical element. Historically, we have not really had to think too much about storage in so far as, effectively, it came with the package of materials that we are dealing with, whether it was coal and the coal heaps or the very responsive gas fields, so our source became our storage. Now there is some separation and, as my two co-witnesses have said, it is critical to develop that.

Q297 **Graham Stringer:** To follow up on that, what are the main options for grid-scale energy storage, with the advantages and disadvantages of each option?

Dr Radcliffe: First, I will declare an interest. At the University of Birmingham we are working quite closely with Highview Power, which is developing liquid air energy storage technology, although I do not have any interest in the development of that technology.

It highlights the multitude of potential technologies that are available for providing storage over different timescales and for different roles. I think that is important to recognise. Up until now a lot of this storage has come from batteries. This has provided a quite quick response, which has been really important as wind and solar have been increasing their deployment.

As we move to larger deployment levels, especially of wind at large scale, we will need longer-scale energy storage, across days and potentially inter-day and intra-day storage at much larger scales. In that case, we could be looking at technologies such as liquid air and compressed air energy storage and flow batteries. There are a number just below commercialisation, and we need to provide some policy mechanisms to incentivise and conduct research and innovation to drive down the costs.

As well as electrical energy storage, we can see a need for thermal energy storage. If we are demanding heat for a lot of our energy services, we should be thinking about providing the storage that will hold heat just as much as electricity.

Professor Gluyas: If I may add to what Professor Radcliffe has said, there is a huge amount of research going on in the Energy Institute in Durham on a variety of storage vectors. I work on heat, but the opportunity for large-scale seasonal storage of heat, or indeed of things like hydrogen in the UK, either onshore or offshore, is substantial. That storage replay, if you like, needs to be accessible on a variety of timescales. Seasonal storage is the one that comes to mind to most people. It is colder in the winter obviously than the summer, but the same is true on a daily scale with peak use and so on, at 4 o'clock to 8 o'clock in the evening, so we need flexibility in some of these storage vectors to be able to cope with that.

Professor Grey: May I add one more point of emphasis? If we start from the shorter timescales of the frequency regulation through to days to months, we mentioned batteries, but there is not just one type of battery. At the moment, we have lead acid and lithium ion, and even within lithium ion we can divide it into higher energy density versus lower energy density. As we move up and think about increasing the amount of battery technology, we have to move towards more sustainable batteries and then we start to unpick different new systems at a lower TRL level, such as the sodium-ion battery, and on to the redox flow batteries that Jonathan mentioned. They are the ones that are infinitely scalable and have the potential to move from hours to days. I would be happy to talk more about it, but the message is that there is not just one type of battery, and different applications and different sizes will require different types of batteries.

The issue at the moment is that the lithium ion battery is still the cheapest because of mass production in the other sectors. That is very much influencing what sort of batteries are put in the grid at the moment, but they may not be the most suitable for all applications. That is an important point that we should talk a little more about.

Thinking about storage in general, recognising it is a massive problem, one also needs to tension it with overcapacity. If we are trying to balance seasonal demand in it, are we just going to build a lot more wind or solar, and that has to be put into the equation as well?

Professor Gluyas: There is one other point worth considering. Every energy transition involves either generation or, more rarely, the consumption of heat. If we just think back to your previous set of witnesses, the big item they were talking about was around the efficiency of energy use. Given that these energy transitions will produce heat that is not normally used, there are lots of opportunities for storing and reusing that heat and therefore improving the efficiency with which energy is used. The whole thing is integrated, basically.

Q298 **Graham Stringer:** There are obviously a number of options. Is there any particular technological area where most progress is likely to be made or where there are particular difficulties that need to be overcome?

Professor Grey: That is a difficult question because there are so many different technologies. There is lithium ion, of which you have two types at the moment: you have the ones that essentially look like an electric vehicle battery, and then you have the bringing in of the cheaper lithium ion phosphate ones. Those are almost fit for purpose. We can talk about improving their ability to last longer and the degradation. We can talk about the safety aspects. The lithium ion phosphate ones are safer. But then you look at sodium ion and already we are into them being more expensive than lithium ion, although in principle they should be cheaper.

We need to innovate and to increase manufacturing, and think about what is done in the UK versus what is not done in the UK. Then we go to redox flow, which in principle should be the cheapest and the largest, but where companies are still barely able to survive, and at the moment there is very little incentive to motivate that. I have not even mentioned lithium sulphur, which has the potential to sit somewhere in the middle with a little bit longer storage.

Each of these battery technologies has its own challenges. It is perhaps not a very helpful answer, but it demonstrates the complexity. Each of them also comes with its own individual resource requirements. Vanadium is a critical mineral, and there are also nickel and cobalt. The point about diversity is a resource one.

We have not touched on the other aspects that need to go around it in the recycling and the lifecycle analysis. There is a lot of work to be done. The focus at the moment has really been on lithium ion batteries, and optimising them for car, mobile phone and laptop applications. Inherently, we need to think big and manufacture for big, and think about how you do that in a smart way.

Q299 **Graham Stringer:** Obviously, from your background, Professor Grey, you are focusing on batteries and different chemical batteries. Is there a theoretical limit to the capacity you can get out of batteries?

Professor Grey: This is the challenge. Inherently, there is a physical limit because you have a box of stuff. That stuff has a certain weight that dictates how many electrons you can get out, and you are limited by the voltage. The thing about redox flow is that you can move from a fixed box to tanks of oxidised and reduced liquids that can flow in, and that makes them inherently scalable.

I still think, even having said that, that nothing beats the energy density in a carbon-carbon bond. Nothing beats a packet of butter, basically. Batteries will always be down by a factor of a third, except for lithium air. That is the one technology where you react lithium and oxygen, and you can do that with the same energy density as a packet of butter—I am using butter as a metaphor for fossil fuel. It has a lot of challenges and it is far from being technology ready.

Q300 **Graham Stringer:** That is where the cost of decarbonisation comes, does it not? Professor Gluyas?

Professor Gluyas: There are a number of things in addition that we can think about here. Not all of them are technological fixes as outlined by Professor Grey. One thing I have done a great deal of work on, and no doubt you have heard some of the discussions in Parliament, has been the storage of heat in things like former coalmines, and even the shallow sub-surface. Here, the opportunity is substantial and at scale. I think one of the calculations was in the order of 36 billion GWh of potential heat storage in the 23,000 now abandoned mines in the UK.

Some of the challenges are not ones of technology. We do not use exotic or difficult-to-obtain materials. Some of the challenges are perceptional. In the background to the work we have been doing, an oft-heard phrase is, "We have never done that before. Does it work?" It has been demonstrated to work at city scale in the Netherlands and elsewhere.

There are a number of challenges, and that was purely to illustrate that not all the challenges are technical hurdles. There are certainly many of those, but some of the others are the way society has developed within the UK over the past century or so.

Professor Grey: May I comment on that? It is important to recognise, even with the technologies you are talking about, that the scale is still so vast and, even if things are seen to be common materials, it is still large scale and a lot of chemicals. If you, for example, look at salts as a way of storing heat, they are commodity chemicals, and they still have a cost associated with them. We are talking about terawatt storage. Contrast that with the hydro systems that we have that are gigawatt. To get to that is a resource issue that we need to reflect on and be cognisant of, whatever technology we choose.

Dr Radcliffe: The success of lithium ion and the cost reductions that have been achieved give us some strong lessons because that has been achieved through this massive potential commercial opportunity that we have seen develop in the electric vehicle sector. That, alongside the investment in research and innovation, has been behind these big cost reductions and improvements in the technologies.

If we can translate that approach into these longer-duration storage technologies that we have been mentioning, which might be more appropriate to integrate large-scale renewables, we can also begin to see those cost reductions come through in other technologies. It is that twin approach of seeing where there is a market opportunity for private sector investment to come in that will really kickstart this revolution.

Q301 **Graham Stringer:** We have taken a long time, but there is one final question. I think you have partially answered the obverse of it. I was going to ask: is hydrogen the only realistic option for large-scale inter-seasonal energy storage? From what you have said about the storage of heat, the answer to that is no, but I would be grateful if you expanded on that, Professor Gluyas.

Professor Gluyas: I would confirm that the opportunity for storage heat on an inter-seasonal basis is substantial. There are heat materials, as mentioned by Professor Grey, that could work, but there are also large-scale opportunities in the sub-surface. Effectively, we can use the earth as a heat battery. We can, for example, capture solar thermal energy, as many people do on their roofs today, and that can be buried in the sub-surface.

There is a delightful but small-scale example of the way in which this is done—it is nothing to do with me—at the former fire station in Durham, where the car park roads have water pipes underneath them. These are heated in the summer—yes, even in Durham—and the tarmac becomes hot: that water is stored underground and replayed in the winter, and no salt is required to unfreeze the roads.

That long-term storage has been demonstrated in a number of instances. Returning to a phenomenal programme in the Netherlands, the whole city of Heerlen is being heated with a heat battery-type system using the old, flooded mines there. If we remember that something like 25% of all domestic properties overlie former coalmining districts, now naturally flooded with tepid water, the opportunity is phenomenal.

It extends beyond mines into the relatively shallow sub-surface where we can both store heat for heating and for cooling, so as the climate transitions and certainly the south of England becomes ever warmer, we can dump some of that heat long term beneath the ground as well.

That is an opportunity. It does not displace hydrogen, though. Hydrogen is a critical vector for the future energy security of the UK. They are complementary.

Q302 **Carol Monaghan:** Professor Gluyas, in Scotland we do not like dumping any heat. It is freezing here today.

You mentioned using coalmines to store hydrogen. We have had some evidence from the British Geological Survey that, if hydrogen storage in porous rocks is required, the performance of these reservoirs in terms of hydrogen containment and hydrogen bedrock geochemical reactions needs to be understood. Is there a danger that hydrogen could react with or escape from natural storage sites?

Professor Gluyas: We will not be storing hydrogen in former coalmines, because they are leaky. Heat is one thing, but we would not store hydrogen.

The opportunity for storing hydrogen is twofold: either, as you said, in porous rocks, rather like, if you walk on to the beach with your bucket of water and pour it into the sand, the fluid will flow through that; or in manufactured salt caverns. The easiest to use are manufactured salt caverns. Indeed, there is already a small storage site for hydrogen in Teesside, and it has been there safely for decades. Salt is impermeable; the hydrogen will not get out.

In terms of porous media there are natural accumulations. You have heard this morning of blue and green hydrogen. You will not have heard of gold hydrogen, or perhaps you have: it is a term I invented recently. It reflects naturally occurring hydrogen in the sub-surface. By accident, a discovery in Mali is producing 98% natural hydrogen from the deep sub-surface.

We know in broad terms that with the integrity of sites there are possibilities for the geological storage of hydrogen. That is not to say that the Geological Survey is wrong—I was chair at one time, so I am certainly not going to contradict it. There are a number of things that you would need to do to inform yourself about the integrity of the caprock. For sure, one of the concerns for hydrogen is that it is typically a very reactive species. You might not get a problem at the surface but, wrongly engineered, you might find that the hydrogen gets consumed particularly by bacteria and other microbes before you get to use it. There are certainly a number of things that need to be done, but we can demonstrate from natural systems that hydrogen storage in deep sub-surface porous rocks is completely viable.

Q303 **Carol Monaghan:** It is viable, but are we talking about the same quantities when we are talking about your gold hydrogen and the manufactured hydrogen that we are hoping to store in places?

Professor Gluyas: We do not know yet. No one has really tried to look for hydrogen. Here, I declare an interest. I have an active research programme on developing an exploration strategy for natural hydrogen. There may even be opportunities in the UK. They are in different areas from where you would typically search for oil and gas. I suspect the generation of hydrogen by nature equals that of petroleum. What we are uncertain about is the longevity of that hydrogen in those systems because of it being a reactive rather than a less reactive species, but it is large scale, without doubt.

Q304 **Carol Monaghan:** You have mentioned the possibility of hydrogen consumption by micro-organisms. Are there any other potential environmental consequences of large-scale hydrogen storage?

Professor Gluyas: Probably no more so—and this is half an answer—than large-scale methane storage, for example, which we know we can do safely over long periods. They are just slightly different because of the different chemistry of the hydrogen versus the hydrocarbons.

Q305 **Carol Monaghan:** Professor Grey, do you see any environmental consequences from this?

Professor Grey: I think that the discussion has already touched on them. I would like to ask Jon about movement of earthquakes and some of the issues we have with fracking. Is there no potential for leaks from those types of incidents?

Q306 **Chair:** You are questioning each other. This is very good. Professor Gluyas, you might respond to that very important question.

Professor Gluyas: I also work extensively on human-induced seismicity and on the impacts of things like fracking.

The integrity of storage sites is paramount. I am not aware of any large-scale incidents where natural earthquakes have resulted in the rupture of methane storage sites. Very little hydrogen is stored at the moment, but there is always a risk. What I have been working on in the commercial area is the integrity of would-be storage sites relative to the natural seismicity of an area. In other words, I advise the European Investment Bank on where not to store things like natural gases because the risk is high, or even moderate. You choose areas that have a very low incidence before you make a start on any storage.

Globally, there is a huge amount of natural gas storage, both in natural systems or manufactured salt cave systems, and the incidence of issues with that is extremely low but not zero, and it certainly requires constant monitoring.

Q307 **Carol Monaghan:** Could natural gas sites be used for offshore storage?

Professor Gluyas: Definitely, the opportunity there is substantial. We know the UK offshore—the individual pores, the holes between the grains—better than any other area is known globally. Between the UK, the Dutch and the Norwegian sectors we understand the North sea phenomenally well from 50 years or more of producing oil and gas. This is why it makes such a good storage site area for the disposal of CO_2. We have used several fields offshore already for natural gas storage and many of those could also be used for hydrogen storage.

Chair: We are overrunning a bit, so I will ask Aaron Bell and Graham Stringer to be quite brief, and the witnesses, too.

Q308 **Aaron Bell:** I want to go into the economics a little more. I note Professor Grey's earlier answers. Clearly, we need some more research and innovation in long-term energy storage. Does the panel think that market sources and Government funding are sufficiently focused on research and innovation? Are we looking at creating a strategic reserve that will have to be Government based, or can we do this through the market? I will start with Professor Grey because she has already commented a bit on this.

Chair: May I ask the witnesses for short answers?

Professor Grey: There are two issues. The first is that we need to think about regulation to ensure that some of the competitors to lithium ion have a role to play without smart grids and that aspect. We also need to think about how we are going to incentivise some of this. There is the whole issue of how batteries are used in the grid. I am biased, of course, but I think we need low TRL level all the way throughout, so low TRL to advance the next generation of technologies, medium TRL to think about the smart manufacturing, and then all the way through. I can flesh it out but that is the crux of it.

Q309 **Aaron Bell:** May I quickly follow that up? Are battery suppliers and storage providers remunerated on the number of times they charge and discharge the batteries? Is that a potential misaligned incentive?

Professor Grey: Be careful when you say battery suppliers. You have the people making the batteries. One of the challenges in the field is that because lithium ion batteries have got cheaper and cheaper there has been a race to the bottom, so the battery suppliers are losing out in all that. You have to think about how you make money. Professor Radcliffe is the expert in the financial models, but that is the challenge of how you incentivise this industry to ensure we get the industry we want in the UK and the advances, of course, in the context of this being a global activity. There is not going to be everything done in this country such that by 2050, or even before, we have some of these technologies coming online. We have to do this now.

Dr Radcliffe: I would say that there are not the incentives from the market to bring forward the longer-duration energy storage that we will need over the next decade. The market signals have been there for battery or short-term storage to meet the current needs for short timescale flexibility, but as we move to 10 GW of wind offshore we will need longer-duration energy storage. The forward price signals are not there at the moment in the market, and I think that is what we need to concentrate on.

The research and innovation funding has been increasing recently, and BEIS has a new competition for longer-duration energy storage, but it really needs to be coupled with those market mechanisms.

Q310 **Aaron Bell:** Professor Gluyas, do you want to add anything?

Professor Gluyas: You ask whether we need a strategic reserve. I would say yes. Since the beginning of the industrial revolution, the UK has been energy rich. It has not had to worry too much about storage. Since 2004, we have been a net importer of energy. Therefore, whichever way you look at it, we are at someone's else beck and call. I would say we need a UK strategic reserve of all sorts of energy storage.

Q311 **Graham Stringer:** Professor Grey, is it going to be possible to overcome the problem of providing batteries for long-distance heavy goods lorries?

Professor Grey: There will be batteries that can do this. Whether those batteries will power HGVs that are going to go 400 miles is another matter. The jury is still out on whether that will be done in a cost-effective way. There are already demonstration systems that can put batteries on a truck, but it may require a different mechanism for short duration and long duration, coupled with rail and freight. The batteries are poised to make a contribution, coupled with thinking about how freight is moved nationally.

Q312 **Graham Stringer:** Is the fundamental problem that batteries are heavy and, if you are going 400 miles, for the last part of the journey you are carrying very heavy batteries that are not helping the journey?

Professor Grey: Exactly. You are also paying that extra cost to have the big battery when sometimes a lot of your deliveries will be local. Why equip yourself with a battery that is perhaps half of your whole HGV so that you can go occasionally all the way from the south to the north of this country? It is thinking about how you do this flexibly so you do not have all the embedded costs of the expensive battery that you are towing around for short-duration journeys.

That is where the challenge comes in. That goes back to the idea of the challenges associated with the large numbers of batteries we will have to produce to make these HGVs. That is why it makes sense to be starting on the light trucks, and the HGVs end up being the last things to think about with the batteries.

Q313 **Graham Stringer:** Professor Gluyas, you are one of our few witnesses or Energy Ministers who have put energy security at the top of their hierarchy of energy policy. As you say, we are particularly vulnerable at the moment, as the Channel Islands dispute has shown, to losing our energy because it is supplied from other countries. What is the best way of storing energy at the moment to ensure that we are not vulnerable to that problem?

Professor Gluyas: At the moment I would say we need to reduce our dependency on gas, not only from an emissions perspective, but from the simple fact that if you look at the way in which gas is supplied to the UK at the moment, about 40% of natural gas comes from the UK, and about 40% comes through a single pipeline from Norway. We are not going to fall out with Norway, but there are some technical issues. The field it comes from, to go back to Clare's point, sits in a very vulnerable place for natural issues associated with mudslides.

Of the remaining 20%, about 15% comes from Qatar, which is obviously LNG and is transported by ship. As we have seen over the last few years, Qatar and Saudi Arabia have fallen out, with potential consequences. The last 5% or so comes through the interconnector to Europe. It is listed nominally on the BEIS website as coming from Belgium and the Netherlands, but effectively it is controlled from Moscow, although no single molecule comes through that. On a cold winter's day our supply is perhaps only 1% above our demand level. Therefore, if we could reduce our dependency on gas, using, as the other witnesses have said, other forms of energy, or indeed heat, we would improve our security.

Chair: Thank you very much indeed, Graham. Thank you to each of our three witnesses, Professor Gluyas, Professor Grey and Dr Radcliffe. As is evident, storage is a very key component of this energy system, and we are grateful to have benefited from your expertise this morning.

Examination of witness

Witness: Julian Leslie.

Q314 **Chair:** I am pleased to welcome to the Committee our final witness, Julian Leslie, who is the head of networks for the National Grid Electricity System Operator. The National Grid Electricity System Operator, in essence, moves high-voltage electricity from where it is generated, through the energy system to where it is consumed, balancing supply and demand all the way through—it has a crucial role to play in that.

Could the electricity grid as it stands meet the peak power demands for the UK if we were fully to electrify heat and transport? I guess the subtext of that is this: if not, would it require something like hydrogen to supplement it?

Julian Leslie: Good morning, everybody. It is great to be here. That is a very good question. The forecast for electricity demand remains pretty flat over the next 10 to 15 years because, as we electrify transport and heat, those things become much more efficient themselves. We are talking about peak demand on the system. With the deployment of smart meters in people's homes, we are seeing already the advent of smart tariffs. With the Octopus Agile tariff, for example, people start to use and consume electricity at times away from the peak of the day. That is helping to drive and to smooth that peak demand as we go into the future.

Our network delivered a 60 GW peak electricity supply in 2007 and 2008. Since then, the peak has been in decline, and this winter just gone it was around 47 GW. There is a lot of latent capacity in supplying peak demand, first, with advances in efficiency in people's homes and how we consume energy and electricity, combined with the ability to shift when we consume it with the devices we will all have in our homes in the next five, 10, 15 years. There is enough capacity on the network today to meet that peak supply.

Q315 **Chair:** To be very clear, just as a hypothetical, if we fully electrified heat and transport in this country, say, by 2030, your view is that the electricity grid could meet that demand?

Julian Leslie: With the forecasts we have of the rate of electric vehicle pick-up, the amount of electric domestic heating and all the other forms of heating, our future energy scenarios show that in each of our four pathways to 2050, certainly in the next 10 years, there is no real growth in peak electricity demand. There is growth in overall consumption of electricity, but not in peak.

Q316 **Chair:** I think you may have misunderstood my question. I am talking about a different scenario, not the published ones. In a theoretical world in which we decided to go all electric, and we intended and we achieved the ability to have all heat provided through electricity and all transport, could the grid cope with that?

Julian Leslie: Not as it stands today. We would need to do the analysis, but that is a scenario that we have not forecast or predicted.

Q317 **Chair:** We could not have an all-electric future. We would need to have other sources of energy deployed in the system.

Julian Leslie: That would be my understanding today, certainly by 2030. We could build and plan for a system that was all electric by 2050. We have the time to do that, but if you are talking by 2030 to 2035, we need a range of solutions to decarbonise.

Q318 **Chair:** We could do it by 2050 but not by 2030. Do you have a feel for how much of a shortfall there would be by 2030 that would require a different trajectory and other forms to continue to be deployed?

Julian Leslie: I just do not know. As I say, we have not looked at a fully electric future because that is not the trajectory that we feel we are on. Talking to the 600 stakeholders who feed into our future energy scenarios, that is not a scenario that we have considered.

Q319 **Chair:** So a fully electric future is not a scenario that you think is worth thinking about.

Julian Leslie: In the challenge we have ahead of us to get to net zero, we believe we need to use all the technologies and all the energy sources we can lay our hands on to meet that future need and get to net zero. In bringing together that whole energy system of electricity, hydrogen and biomethane, those are the solutions we have been thinking of to get to the future.

There will be a lot more electrification and, as I say, the annual electricity consumption will be much greater than it is today. Your question is around peak electricity demand, which we believe is pretty flat for the next 15 years because of the reasons I have given.

Q320 **Aaron Bell:** Thank you, Mr Leslie, for your time. The key problem, as you are well aware, in balancing supply and demand is within the day but more importantly within the year—inter-seasonal energy storage. How significant a challenge is that going to be for a net-zero energy system?

Julian Leslie: Again, that is a challenge and, as the previous panellists were saying, we need the market signals in place to trigger that. We have storage for within day today. The storage of hydro that we have had for many years is a great example of that. But the three weeks of low wind we have just had on the system would call in the future for something that can store that energy and provide it over that three-week period when we go into the low-wind periods.

That is where hydrogen and other technologies can come in. There will be many times, as there are today, where we have a surplus of electricity. This could be utilised and diverted to create other storage sources of wind that we can then use over those three, four or five weeks when we have that low-wind/low-sun scenario.

Q321 **Aaron Bell:** You are obviously looking and researching and innovating in lots of different areas, but what has the National Grid ESO identified as the primary technology option for the net-zero future inter-seasonal energy storage? Is it hydrogen?

Julian Leslie: We are technology agnostic. At the end of the day we set out the capacity requirements. The policy and incentives that come from BEIS and others dictate the actual solution. Again, I think it will be a whole mix of different technologies, whether it is the storage of hydrogen, compressed air, cryogenic storage, gravity storage by holding weights up in deep mines, or things like that. All of those need exploring, but the market will determine the best value for the consumer.

Q322 **Aaron Bell:** We will go where the market takes us. Collectively, what are you currently doing to ensure that we will have that sufficient long-term energy storage, whichever technologies we use? What current projects is the National Grid ESO progressing on this front?

Julian Leslie: We are putting information into the market, so it can better understand the needs and the requirements. Ultimately, we are not responsible for the security of supply in the ESO. That is a BEIS responsibility. It runs the capacity mechanism and long-term market signals to get that investment. We are working very closely with Ofgem and BEIS, and very closely with industry, to look at all the technical requirements of the needs of storage, to get a mechanism in place so they can bring that to market.

Q323 **Aaron Bell:** We talked a little in the previous session about a strategic reserve. I appreciate you are saying these are properly and rightly decisions for Government, but could the National Grid support and welcome that?

Julian Leslie: What we need to do is understand the weather patterns in those periods of low wind and low sun—what is the duration, what is the terawatt hour capacity required. Once you have that in place and you can meet your year-round conditions, we will have a surplus of electricity for many periods of the day and week, and we just need to capture that surplus electricity and store it in some way. You have a natural strategic reserve as well as providing the response that we need for those long-duration periods when there is limited wind and sun.

Q324 **Aaron Bell:** Finally, what continuing role will there be for fossil fuels in a net-zero future? Obviously, it is net zero, not absolute zero. To deal with these particularly difficult scenarios you talked about—periods of low wind and low sun—what ongoing role is there going to be for fossil fuels in, say, 2040-50 in our energy needs?

Julian Leslie: It depends again on the technologies. If BECCS or CCUS really hit commercial scale and we can burn gas but capture all the emissions, or burn biomass, as they are at Drax, and capture the emissions to get a negative-emission station, that is absolutely part of the potential solution for the future. But there are other technologies that can meet the same requirements.

Q325 **Rebecca Long Bailey:** Thank you, Mr Leslie, for speaking to us today. As you know, curtailment—lack of energy storage capacity—means that, during periods of excess power generation, power generators could be asked, or even paid, not to generate power. How significant do you think the problem of curtailment could become as renewable energy sources are increasingly built, against the backdrop that our energy storage capability at the moment is not as advanced as we would like it to be?

Julian Leslie: That is a really good question. Wind curtailment is an active and proper part of managing an electricity system. If we never curtail any generation, we have over-invested in the transmission network. There will always be some level of curtailment of any generation, and there has been for many years. We used to curtail coal. We used to curtail gas in operating the system.

There is a real opportunity if storage is located in the right place. It is doing two things. First, it can capture curtailed wind and turn it into another form of energy that can be used in harder-to-reach and harder-to-decarbonise sectors, such as aviation or shipping. Equally, it could act as an alternative to network investment. If we could invest in huge amounts of electricity demand in, say, Scotland, on those windy days, we are not having to export all that power to the south and it can be used more locally to generate hydrogen, ammonia or any of the other energy sources.

Q326 **Rebecca Long Bailey:** That is really helpful. On the role of hydrogen in curtailment, the UK Hydrogen and Fuel Cell Association told the Committee that green hydrogen production would provide a substantial and firm market for low-cost renewable energy and in doing so offer flexibility to the system operator, allowing a future grid with lots of renewable energy sources to avoid incurring curtailment fees. On the other side of the argument, Michael Liebreich, the founder of Bloomberg New Energy Finance, has said it would be entirely uneconomic to run an electrolyser to produce green hydrogen on curtailed power alone. What is your view on what value green hydrogen production might provide in minimising curtailment? Will market forces reward this sufficiently?

Julian Leslie: I do not know the ins and outs of the economics of a green electrolyser. I know that in the next 10 to 12 years we are spending £13 billion on reinforcing the transmission network. A lot of that is going to be required to connect the large offshore wind and bring it onshore. In the 10-point plan, if much or some of the 5 GW of hydrogen was green hydrogen—again, located in the right places on the network—we could look to avoid some of that transmission investment and invest therefore in the green hydrogen.

It is really important that as we move forward there is this whole-energy system planning approach and understanding of the interactions between a hydrogen-based network and a methane gas-based network and electricity networks. Those trade-offs need to be made all the time to understand and ensure we invest and put the right incentives into each of these energy vectors to ensure that the right investments are made. It is about planning on that whole-system basis.

Q327 **Chair:** Looking to the future, you pointed out that the future energy scenarios help to inform some of the investment decisions you make. Will you summarise for us the leading scenarios that you think are most likely to characterise the development of our network between now and 2030 and beyond?

Julian Leslie: Between now and 2030 there is some divergence in the scenarios, but they are all predicated on the Government's 10-point plan—the 40 GW of offshore wind by 2030 and the 5 GW of hydrogen.

As we move beyond 2030, the scenarios are all achieving net zero but in slightly different ways. One is very much consumer led, where we invest in our homes and make them much more efficient—smart devices, solar panels on our roofs and batteries in our garages. The other extreme is very much centrally planned with very large storage, offshore wind and nuclear. It is more centralised planning and development of the system, where the consumers have less of an involvement in managing that future scenario.

All three of them are credible pathways to the future. No one of them is saying, "This is the way it is going to happen." They are exploring the challenges of this consumer-led scenario or whether it is a more centrally large-scale, generation-led scenario. The answer will be somewhere in the middle. It is describing the four corners of the envelope, and reality will be somewhere in the middle. Where we eventually end up will be determined by Government policy and the direction that plays in this.

Q328 **Chair:** The different organisations produce and publish different scenarios. You publish yours. The climate change committee publish theirs. The climate change committee's scenario on hydrogen includes a scenario in which the proportion of homes heated with hydrogen is low—in fact, zero. Do you consider that to be a potential scenario?

Julian Leslie: All these scenarios are potential scenarios. In our scenarios we believe hydrogen will play a part in decarbonising heat in homes because of the scale of what needs to be done. We think all technologies are going to have a role to play. Not all homes are on the gas grid today. As you know, many are heated by heating oil and are not on the gas grid.

It is understanding that full spectrum of houses. There will be different solutions deployed in different environments depending on where they are located, what technologies are in the home and how well insulated they are. All these factors will need to determine what is the best solution.

Q329 **Chair:** Let me put it the other way round: do you have any scenarios in which you do not expect to see hydrogen deployed?

Julian Leslie: No.

Q330 **Chair:** So you expect hydrogen to be part of our future energy mix.

Julian Leslie: We do.

Q331 **Chair:** I do not want to put words in your mouth, but it is helpful to summarise for the Committee when we make our report: the question is how much rather than if, as it were.

Julian Leslie: How much, exactly, whether it is converted into hydrogen that is then used to generate electricity, or converted into hydrogen that is then put into other energy vectors such as transport or heat. Hydrogen is an essential part of each of our scenarios.

Q332 **Chair:** To push it one step further, compared with where we are today, in your central view, how significant do you think hydrogen will be in meeting our energy needs?

Julian Leslie: That is a very good question. I think it will be significant. It is such a clean and flexible fuel and energy source that using it in the harder-to-reach vectors is going to be absolutely crucial. I have not seen anywhere where there are technologies that can provide an alternative that is transportable, storable and burns cleanly. I think it will be an absolutely essential part.

Chair: Thank you very much indeed. That concludes our evidence session this morning. We are very grateful for the expertise of the system operator. Obviously, it is crucial to the resolution of many of these questions of the future. We are grateful to all our witnesses this morning. Our inquiry continues.