OFFICIAL REPORT
AITHISG OIFIGEIL

Net Zero, Energy and Transport Committee

Tuesday 13 May 2025

Session 6

The Scottish Parliament
Pàrlamaid na h-Alba

Tuesday 13 May 2025

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NET ZERO, ENERGY AND TRANSPORT COMMITTEE

17th Meeting 2025, Session 6

CONVENER

*Edward Mountain (Highlands and Islands) (Con)

DEPUTY CONVENER

*Michael Matheson (Falkirk West) (SNP)

COMMITTEE MEMBERS

*Bob Doris (Glasgow Maryhill and Springburn) (SNP)
Monica Lennon (Central Scotland) (Lab)
*Douglas Lumsden (North East Scotland) (Con)
*Mark Ruskell (Mid Scotland and Fife) (Green)
*Kevin Stewart (Aberdeen Central) (SNP)

*attended

THE FOLLOWING ALSO PARTICIPATED:

Professor John Andresen (Heriot-Watt University)
Sarah Boyack (Lothian) (Lab) (Committee Substitute)
Dr Simon Gill
Dr Graeme Hawker (University of Strathclyde)
Dr Nigel Holmes (Hydrogen Scotland)
Dr Jan Rosenow (University of Oxford)
Professor Mark Symes (University of Glasgow)

CLERK TO THE COMMITTEE

Peter McGrath

LOCATION

The Mary Fairfax Somerville Room (CR2)

Scottish Parliament

Net Zero, Energy and Transport Committee

Tuesday 13 May 2025

[The Convener opened the meeting at 09:18]

Decision on Taking Business in Private

The Convener (Edward Mountain): Good morning, and welcome to the 17th meeting in 2025 of the Net Zero, Energy and Transport Committee. Apologies have been received from Monica Lennon. I welcome Sarah Boyack, who is attending as her substitute.

Our first item of business is a decision on taking business in private. Agenda item 6 is consideration of the evidence that we will hear on the hydrogen aspects of the project willow study. Do we agree to take that item in private?

Members *indicated agreement.*

Grangemouth (Project Willow)

09:18

The Convener: Our second item is the first of two evidence-taking sessions this month on plans for the future of Grangemouth refinery. Refining there has ceased, and the United Kingdom and Scottish Governments are looking for new uses for the site as a green energy hub.

The project willow study, which is supported by both the UK and Scottish Governments, was published in March. It proposed nine possible projects, four of which relate in some way to the production of hydrogen, and we will discuss those today.

This is an opportunity to touch more widely on the prospects for a thriving and competitive hydrogen sector in Scotland, which to some extent lie behind any aspirations for Grangemouth to be a green hub in the future.

We will hear from two panels of witnesses. On the first panel are Professor John Andresen, professor of engineering and physical science at Heriot-Watt University; Dr Graeme Hawker, chancellor's fellow in future energy systems, University of Strathclyde; and Dr Nigel Holmes, chief executive officer for Hydrogen Scotland. Good morning, and thank you for attending.

We will move straight to questions. As usual, I have the easy question to ask at the beginning. The project willow study does not advocate the use of either green or blue hydrogen; it says only that a reliable source of low-carbon hydrogen will be required. Which of those production methods will offer the more reliable and affordable supply of hydrogen in Scotland? Nigel Holmes, do you want to kick off by answering that? I will then ask the same question across the panel.

Dr Nigel Holmes (Hydrogen Scotland): Thank you very much for the opportunity to give evidence today. I head up Hydrogen Scotland, which is the trade association for hydrogen activities in Scotland. We have members from industry, academia, local authorities and city authorities, and we work very closely with Scottish Enterprise.

I am often accused of sitting on the fence on whether green or blue hydrogen is better. We have members who work on projects of both types. One of the best examples is Storegga, which has been developing the Acorn project in St Fergus and has also been closely involved with the Speyside hydrogen project.

To answer your question on security and affordability of supply, when producing blue hydrogen from natural gas with carbon capture, as long as you have a supply of natural gas you can pretty much guarantee the supply of blue hydrogen. Green hydrogen is produced by using renewables, usually via the grid, and the supply of energy for the production of green hydrogen is dependent on the availability of that electricity. If you are on the grid and electricity is always available, you can pretty much guarantee that there will be green hydrogen all the time. However, if hydrogen production is being used to overcome intermittency in renewables, or constraints on the power transmission system, the availability of hydrogen might vary along with that of the wind or, in some cases, solar energy involved.

The affordability of green hydrogen, which is one of the big questions about it, is very much related to the cost of electricity. The cost of green hydrogen is impacted by that cost—75 or 80 per cent of its cost is connected to that, I have heard. Therefore, if you can keep the price of electricity down, you can keep the price of green hydrogen down. One of the big discussions at the moment is on how local pricing of electricity might affect hydrogen production. Various studies out there are trying to predict how the costs of green and blue hydrogen will change, and nearly all of them predict that the cost of green hydrogen will go below that of blue hydrogen. The question is when that will happen. Will it be in 2030, 2035, 2040 or whenever? Again, that will depend on the location and the price of electricity.

The Convener: You mentioned Storegga and the fact that it has a planning application in Speyside. I have an interest in a fishery on the River Spey. In case there is any doubt, I have no interest in Storegga, but I mention that so that people know that there is a tenuous connection between Storegga, the Spey and me.

Dr Graeme Hawker (University of Strathclyde): Good morning, and thank you for the opportunity to speak to the committee today.

I am perhaps a little bit less on the fence than Nigel Holmes is. I will say that there is a very particular opportunity around green hydrogen in Scotland. That is predominantly because it aligns so well with our targets on wind energy. There is a substantial ambition to use offshore wind in Scotland, but that is combined with the issue that there is not a huge demand for electricity here. I will put that into context by saying that we aim to have 11GW of offshore wind capacity, which is more than double the peak electricity demand in Scotland.

At the same time, significant network constraints mean that much of that energy is currently underutilised and cannot be translated to other parts of Britain where it can be used. Even if we were to catch up with the growth in renewable energy through more build-out of the electricity network, in the 2030s we would still reach a point where, even if we had infinite network capacity, there would be excess renewable energy on the system. It seems to me that, in the Scottish context, there is huge potential for alignment between offshore wind targets, in particular, and the potential for growth in the green hydrogen sector.

That is not to say that blue hydrogen does not have its part to play. When projects such as Acorn were first discussed, the original concept was that blue hydrogen would be a bridging technology. At that time, green hydrogen was seen as substantially more expensive than blue hydrogen; it was thought that it would not be economically viable for some years, or even decades. Hence, blue hydrogen was seen as the bridge across that gap, which would still, at some point, give way to green hydrogen as the predominant form of hydrogen production.

It has been some 10 or 15 years since that view was in place, and there has been no great growth in the blue hydrogen sector. However, there has been a huge reduction in the cost of electrolysers, and modular systems have been scaled up, which means that the gap in costs has started to come down significantly. As Nigel Holmes has pointed out, though, green hydrogen production is still exposed to very high electricity costs, so it does not fully represent the opportunity that exists for renewable energy.

I sit firmly on the side of using blue hydrogen where necessary to get the hydrogen economy moving, but the long-term view should still be that green hydrogen is the backbone. I would say, too, that setting a target of achieving 5GW of low-carbon hydrogen production capacity by 2030 greatly implies that we should make use of both forms. We will not get to that point unless we use pretty much everything that is on the table at the moment.

Professor John Andresen (Heriot-Watt University): I am a chemical engineer from Heriot-Watt University. I am colour agnostic about hydrogen. However, if the purpose is to produce heat and electricity, it is most likely that combined heat and power will be much more efficient than using blue hydrogen. Looking at the prospects for hydrogen growth, as I see it, green hydrogen offers the better one. Scotland's potential for wind energy production is probably one of the greatest in Europe—ScotWind aims to deliver 28GW, most of which will be produced all year round. In winter, that electricity will most likely be used for heat pumps, for example. However, in late spring, summer and autumn, it will need to be stored, because such electricity will be produced but not consumed. To achieve that storage, hydrogen is probably the only answer that Scotland has.

Let us look at other countries around Europe that have high renewable content. Denmark has a much higher population density than Scotland and has a surplus of biomass, so it uses biomass for its CHP and much of its district heating. Norway is virtually 100 per cent electrified—its electricity network is five times larger than that of Scotland—but, during summer and early autumn, it stores its water energy. As Graeme Hawker and Nigel Holmes have said, Scotland needs to find a way to store its excess wind capacity. Green hydrogen would be my choice for how to do that.

The Convener: Thank you. Nigel Holmes, I want to understand your comment about the cost. I seem to remember reading that, to create hydrogen from electricity, you lose about 40 per cent of the power when transferring it to hydrogen and then a further 10 per cent when transferring it back to electricity. Are those figures correct? That is the first question. The second question is, if you are using hydrogen to get the same effect as electricity, how much more are you paying for hydrogen than you would be for electricity?

Dr Holmes: There are various stages in producing hydrogen and then turning it back into useful energy at the point at which you use it. The general performance of the electrolysis stage—that is where you are converting the electricity into the hydrogen—is reckoned to be about 65 to 70 per cent efficient, so you have 25 to 30 per cent losses, which typically come off as heat. That then can be transmitted via the power networks with the same efficiency that you would have when transmitting electricity.

09:30

I am sorry—let me go back. When it comes to hydrogen, there is a simple but useful phrase to remember: make it, move it, store it, use it. Why is that important? It is important because, often, the place where you make the hydrogen is not the place where you might use it. Let us take the example of the Acorn project. The hydrogen that is made in St Fergus could be moved down to the central belt. We are talking about project willow, which is one of the users of hydrogen.

Graeme Hawker has already mentioned the need to move electricity around the UK. The challenge with the power networks is the availability of capacity. There is also the potential to use pipelines to move hydrogen. A typical big power transmission connection could carry 1GW or 2GW, whereas a nice big pipe could carry 10GW or 20GW. When hydrogen is moved down a pipe, the energy losses are probably comparable with, or slightly less than, the energy losses from the power networks. That means that hydrogen can be moved quite long distances without a lot of efficiency being lost.

Why does that matter? That comes back to the point, which has already been made, that it is the electricity price that determines the cost of the hydrogen. Hydrogen production could be low cost if it were located close to the point of renewables. In Scotland, that could be in the north of the country, where offshore and onshore wind power can be accessed. That power might not even have to go through grid connections and using an off-grid system would further reduce the cost. In such circumstances, the cost of the hydrogen would be lower than it would be if you moved the electricity.

For the sake of argument, let us say that, for project willow, all the hydrogen production was located adjacent to the Ineos Grangemouth site. The cost of electricity in Grangemouth would probably be significantly higher than the cost of electricity in the north of Scotland.

I do not know whether I am answering your question. There are two parts to the issue: one is about the efficiency, and the other is about the cost. The efficiency might be the same with power network transmission as it is with pipeline transmission, but the cost of the end product could be significantly less if the hydrogen is delivered via pipeline. Does that help to answer the question?

The Convener: It kind of answers the question, but once the electricity is put into the national grid, there will be a national pricing structure for it, even if it goes to an electrolyser. There is something that I am trying to work out. If it will cost, say, £1 to achieve X with electricity, how much will it cost to achieve X with hydrogen? What is the difference? How much more will have to be paid for hydrogen? I am told that more will have to be paid for hydrogen than for electricity.

Dr Holmes: That is true if the hydrogen and the electricity are made and used in the same place. I will give another example of hydrogen production in the north of Scotland—Statera Energy's proposed 0.5GW Kintore project. The plan was to move the hydrogen from Kintore, by pipeline, down to Grangemouth, where it would be used. The cost of producing the hydrogen in Kintore would probably be half of what it would cost to produce it in Grangemouth, because the price of electricity would be lower. With that combination of Kintore production and pipeline, the delivered cost of the hydrogen in Grangemouth could be half the cost of making it in Grangemouth.

Those are just examples. When you come to write up the evidence, please do not take this as an absolute statement, but where you have access to low-cost electricity, you can make low-cost hydrogen. You can then move that low-cost hydrogen by pipeline without much additional cost. For the sake of argument, that means that, in Grangemouth, the delivered cost of energy in the form of hydrogen that is moved from Kintore by pipeline could be half that of making the hydrogen in Grangemouth. That means that, on an energy basis, the cost of hydrogen in Grangemouth could be less than the cost of electricity in Grangemouth. That would be possible.

The Convener: But if the hydrogen was made in Grangemouth, it would be more expensive.

Dr Holmes: Absolutely. You might be able to play tricks with the power cost at different times through what is, essentially, grid balancing through the electrolysers. With hydrogen, we have the ability to timeshift the supply of and demand for electricity, as well as the opportunity to shift energy from one place to another at a large scale. That is the key attribute of hydrogen as a low-energy vector that has storability and transportability.

The Convener: I think that that is why it seems attractive to me, especially if it gets rid of constraint payments and suchlike, which I think are complete anathema to people who use electricity.

I will move on to my next question. I think that you have all said that blue and green hydrogen will be available. If we are going to make these changes at Grangemouth, which one will we have to rely on most to start with, and do you see it changing over a short or long period of time?

Professor Andresen: In Grangemouth, there is already a steam methane reformer, which, I believe, is the largest in Scotland. That would be an easy swap if the hydrogen is not needed for the refining that takes place in Grangemouth. You mentioned the conversion efficiency of hydrogen. You have to remember that, in a refinery, around 20 to 25 per cent of the energy in petrol or diesel is used to make electricity, so the conversion efficiency of hydrogen is very similar to what you have in a refinery anyhow and you will need something to convert it.

Dr Hawker: I do not think that there is a clear case either way. Each of the solutions has implications for the level of storage and transport networks that would be needed. As John Andresen pointed out, there is a case for blue hydrogen in that it would initially give a more direct, continuous supply of hydrogen, rather than being subject to the variability of renewable energy. However, a large number of developers are sitting on seabed rights for offshore wind and are very keen to find a route to accessing the hydrogen market in order to be able to start producing green hydrogen, and they would be able to invest in storage as a result of the low marginal cost of their production. So, either line could be taken as supporting the early growth of Grangemouth.

The Convener: Nigel Holmes, you said that you back both horses in this race. Are you sticking to that?

Dr Holmes: Yes, but maybe for slightly different reasons. I worked at Grangemouth for 15 years—it was for BP and in the chemicals area. A key thing that happened when I was there was that the refinery and the chemicals plant became much more integrated. There were a number of processes where by-products from the chemicals plant went over the fence and were used in the refinery—and vice versa. One of those by-products was hydrogen. The chemicals plant includes an ethylene cracker, which, I think, is one of two left in the UK; they are at Grangemouth and Mossmorran. It makes ethylene, a building block for the production of chemicals and plastics. In that process, it produces a by-product, hydrogen. The refinery was benefiting from a lot of the hydrogen that was coming from the ethylene cracker. If the refinery is closing down, that hydrogen will probably be used instead to help to fuel the cracker, as it is already at Mossmorran. The ambition is to further decarbonise the crackers with more hydrogen produced by green hydrogen from electricity.

At the same time, those processes create by-products that do not necessarily have markets—they are hydrocarbon products without markets. At the moment, the steam methane reformer that is used at Grangemouth has the capability to reprocess different by-products into things that are useful, including hydrogen. There is a function for a blue hydrogen-type process, which uses up products that otherwise would be wasted as part of those activities.

At the same time, and as I mentioned earlier, the Acorn project in St Fergus could also be part of the supply into Grangemouth. Access to secure supplies of natural gas from the North Sea means that liquefied natural gas does not have to be imported to produce blue hydrogen, and that gives us one of the lowest carbon footprints of blue hydrogen. We have to remember that the footprint of blue hydrogen is mostly about the CO_2 that is produced in the process, but there are also all the emissions that are associated with the production and transportation of LNG, which, if it is used as a feedstock, has a much higher footprint than locally produced gas that gets transported via pipelines.

Does that help?

The Convener: Ish. Mark Ruskell has a follow-up question, and then I will come to Kevin Stewart.

Mark Ruskell (Mid Scotland and Fife) (Green): I am interested in the definition of blue hydrogen as low carbon. That depends on carbon capture and storage being in place and working at a certain efficiency. I am interested in whether you see that as achievable, given that Acorn has not yet been constructed, and whether the capture rates that are predicted for Acorn have been replicable in other CCS commercial plants around the world. If the Acorn project happens, how much certainty is there that you will end up with blue hydrogen and that it will be a low-carbon product, or is there uncertainty about whether what eventually comes out of that process will be low-carbon enough?

Dr Holmes: I am not the expert on carbon capture and storage, so that evidence would be better coming from somebody else.

When we look at the carbon footprint, it is important to look at not just the CO_2 that is being produced—or, indeed, any CO_2 that is being released as part of the process—but at the supply chain for the feedstock, which is the natural gas.

LNG, in particular, has quite an energy-intensive production process. LNG from fracked gas has an energy-intensive process but it also has other challenges compared with natural gas from the North Sea, which comes straight out of the field into a pipe into St Fergus. My suggestion is that the biggest uncertainty is around the greenhouse gas emissions that are associated with the supply of the natural gas, rather than the difference between maybe a 90 per cent and a 99 per cent CO_2 capture on the process.

Kevin Stewart (Aberdeen Central) (SNP): Dr Hawker and others have mentioned storage and transportation. Is the current situation, in which the UK Government has failed thus far to update storage and transport regulations, creating uncertainties that might hold up our move towards hydrogen in Scotland and the rest of the UK?

Dr Hawker: The upstream producers are absolutely uncertain about exactly how they will get their product through a system of transportation and storage to end users. That could be done partly through incorporation into a national-scale system, which would involve the availability of a large-scale transmission network and cavern storage, for which there is not yet a clear route in place. However, when we are talking about an early, nascent hydrogen system, we are perhaps looking more at smaller-scale above-ground storage and smaller-scale local pipelines. The technology for that exists, and the route to market can be fairly clear if a match is made between upstream producers and end offtakers, such as Grangemouth.

09:45

Kevin Stewart: I will turn to Dr Holmes, although you may comment, too, Dr Hawker, if you wish.

You mentioned hydrogen being transported from Kintore to Grangemouth. Obviously, that would have to be piped. How do the regulations stand with regard to the transportation of hydrogen via a pipeline?

Dr Holmes: Pipelines are critical to the ability to supply hydrogen at scale. When we are talking about small-scale hydrogen production—1MW or 10MW, which is the scale that is being considered for Aberdeen, Orkney and the Whitelee project just south of Glasgow—tube trailers are perfectly fine for moving such quantities around.

However, once we are talking about more than 100MW of production, the number of tube trailer movements would be challenging. At that point, pipelines become important, but they can be expensive. It has been estimated that it would cost about £3.5 billion to lay a big new long-distance pipeline from Scotland to Germany. The good news is that, in the future, as we start to decommission gas networks and to develop projects such as project willow, various pipelines might become available. Between Kintore and Grangemouth, there is a gas feeder pipeline that is currently being used, but it could be repurposed. A big discussion is taking place about whether that could happen.

There are two approaches that are worth considering. The first involves a situation in which a pipeline is completely repurposed from 100 per cent natural gas to 100 per cent hydrogen. In many ways, that is the simplest approach. The other approach involves starting to blend a certain amount of hydrogen into the natural gas. That is a bit like having ethanol in petrol. You could blend in, say, 5 per cent.

Kevin Stewart: I understand the point about repurposing and using existing infrastructure where possible. However, I am asking whether, at this moment in time, the regulatory regime allows such transportation. As things stand, does that regime allow the mix that you have talked about to be transported, or do we need to get on with the job, as other countries have done, and change the regulations to allow such things to happen?

Dr Holmes: The regulation of what happens in gas pipelines is a reserved matter.

Kevin Stewart: Indeed.

Dr Holmes: I think that the UK Government has indicated—I would need to confirm this—that it will make a decision on pipelines carrying a blend of hydrogen either late this year or next year. That is the timescale for it to come to a “minded to” position, so we do not yet have clarity on the future use of blended hydrogen in the gas network.

With regard to the repurposing of pipelines, where pipelines are currently being used for natural gas duty—which makes them critical infrastructure—I believe that all those decisions are reserved, so that would have to go through due process.

Kevin Stewart: Does anyone else have anything else to add?

If not, I have one tiny final question. You have spoken about a move, but we have been waiting for a long while for the necessary changes in regulations. My understanding is that the Leeds 2020 project was supposed to help us to reach decisions on some of the regulatory changes that will need to be made to allow for the storage and transportation of hydrogen. Why has it taken the UK so long to do all that?

Dr Holmes: That is a very good question. The only project that I can think of that appears to be making some headway in that regard is the Aldbrough hydrogen pathfinder project, led by SSE, which is about the production of green hydrogen, its storage in salt caverns and its use in large-scale gas turbines. I think that, to start with, blended hydrogen will be used in gas turbines involving hundreds of megawatts of power, and the project is very much driven by the desire to develop responsive power at a large scale. That is clearly a step in the right direction.

Various other pieces of work have been started. Project union, which is being run by National Gas, is looking at the phased repurposing of some of the UK gas network for hydrogen. Likewise, SGN's H2 Caledonia project is looking at how we can repurpose existing infrastructure for hydrogen. SGN has gone one stage further and is about to start a trial between Grangemouth and Granton, through the Ofgem-supported local transmission system futures project, which involves recommissioning about 25 miles of existing gas pipeline to test whether, in practice, it can be repurposed for hydrogen.

There are some encouraging steps in that respect, but the regulation aspect is not so clear.

Kevin Stewart: It is taking too long, basically.

Sarah Boyack (Lothian) (Lab): I am keen to dig down into the opportunities for Grangemouth, particularly the green hydrogen options. As we know, the closer we get to new technology, the more the price can be brought down if the tech and the skills are available. What are the other opportunities for developing green hydrogen in Scotland? Would you put Grangemouth on the list? Where else would you identify?

Dr Hawker: There is a key opportunity for Grangemouth in relation to industrial decarbonisation as a particularly difficult sticking point in the net zero transition.

Another key enabler would be the transformation of the power system so that flexible new thermal power production was able to back up the amount of renewables in the system. In that regard, we would be looking in particular at the Peterhead power station, which is in proximity to the Acorn project. At the moment, that is on a fairly blue hydrogen-implied trajectory, but it could pave the way towards the use of green hydrogen in carbon capture and transmission technology.

There is potential for there to be more power stations in Scotland, as there used to be. We have a lot of power station sites with transmission capacity that are no longer being used, so, for example, we could look at reintroducing more thermal power production capacity in Scotland that makes use of green hydrogen that is produced next to offshore wind farms. That should be a key focus in enabling that market.

Professor Andresen: Grangemouth has very good infrastructure and a skills space. It is between Edinburgh and Glasgow, so, if there was any excess heat, it could be used for district heating, for example, as has been done in other countries. If hydrogen was used there, it could also be used to make more valuable chemicals, such as jet fuel, in the future. Grangemouth is very well placed to be a green hydrogen site.

Sarah Boyack: Do we need to do something to get more joined-up thinking between the National Energy System Operator and the grid for the next round of hydrogen allocations? Is there a way to make sense of this in those two sites?

Dr Hawker: The strategic spatial energy plan, the first iteration of which is due next year, will be a key enabler in that regard. That process is being undertaken to determine the optimal location for large-scale hydrogen infrastructure alongside electricity networks.

The first iteration of that is at a fairly low resolution—for example, the entirety of the south of Scotland and the central belt is one region in the model. Therefore, it is key that the Scottish bodies interact well with the NESO process to ensure that they properly represent the opportunities in that space and that, for example, specific social or natural factors are not seen as constraints on the development of hydrogen infrastructure in Scotland due to the fact that the area is being represented at a very low resolution. The strategic spatial energy plan is a key enabler in the process.

Sarah Boyack: Does that link to offshore wind production of electricity? A couple of you have mentioned constraint payments. Are those relative to the different sites that you are talking about?

Dr Hawker: Yes. The strategic spatial energy plan will include the network and the opportunities for production. You have the ability to produce much higher capacity wind energy in Scotland but, at the same time, you face more significant network constraints and the difficulty of moving that energy to centres of demand. Hopefully, the outcome of that measure will be to recognise that the benefits of having renewable energy located in Scottish waters outweigh the network constraint costs.

It is important to note that, on a national scale, transportation of gas can be a cheaper form of moving energy around than doing so with electricity. On a distance moved per unit of energy basis, historically, gas has been cheaper to move than electricity, and that remains the case for hydrogen. On that basis, if the strategic spatial plan recognises that having large amounts of renewable energy production in Scotland remote from British demand is a desirable outcome, hydrogen as a transportation method is a way of enabling that, alongside reinforcement of electricity networks.

Sarah Boyack: Dr Holmes, what are the key sites for green hydrogen in Scotland? Is Grangemouth one of them?

Dr Holmes: Project willow has identified a number of areas where Grangemouth can act as a conversion hub that takes clean energy and turns it into products. Again, that is where hydrogen, as a molecule, can offer all sorts of things that you cannot do with electricity. You can use hydrogen to treat biofuels to make them into a quality that is suitable for aviation fuel. You can use it to help make chemical feedstocks, such as methanol, and to make ammonia, which could be used as a fuel. In the world today, hydrogen has two main uses, which are split roughly 50:50. About half is used for refining and fuels production, and about half is used for fertiliser production. The fertiliser production is absolutely critical to food security globally. If you took fertiliser out of the market, food yields would probably drop by about a factor of two. Everywhere that has crops typically uses fertilisers.

There is an opportunity there, which has been recognised, and is starting to be taken up already. We have members here in Edinburgh who are working on a project to produce green fertiliser in Paraguay using 100MW of hydro power to produce pretty much enough fertiliser to make Paraguay self-sufficient in green fertiliser. Scotland has the same opportunity. The UK no longer has any fertiliser production, as the previous sites were both shut down about two or three years ago, when the price of natural gas went up. Locations such as Grangemouth are used to handling large quantities of industrial chemicals and, as I mentioned, have the skilled workforce.

That would appear to be a slam-dunk for Scotland. Scotland could access the low-cost energy from offshore wind, produce the hydrogen, move the hydrogen down to Grangemouth and then make the products that can, in turn, decarbonise not just Grangemouth but some of the strategic industries in Scotland, such as the whisky sector and other food sectors. If we do not get that, that is a massive opportunity missed. That is all that I would like to say on that.

Why Grangemouth? As mentioned in the project willow report, it has the location, the skills and the infrastructure, and it has rail, sea and road. All those things make it an ideal location. That is not to say that other locations could not make this work, but if you have everything at Grangemouth, why would you look beyond it?

10:00

Sarah Boyack: That is quite strong. You have just talked about the project willow report, which we have had a couple of briefings on, and some of the options for using hydrogen that are mentioned in that report. One option is to use it as a potential feedstock for low-carbon shipping and aviation fuels. Would you like to comment on that? There is an opportunity for airlines to undergo a huge transformation over the next few years. Is there an opportunity for Scotland in that area at Grangemouth?

Dr Holmes: Probably. I am not sure whether the project willow report mentioned fertilisers specifically.

Sarah Boyack: It did.

Dr Holmes: That is good. There is a difference between being able to do something and the market having a willingness to take it up. With hydrogen deployments, we have seen that some markets are much more willing to take that step forward. The food and drink sector has, typically, been looking closely at its overall carbon footprint. Thanks to public procurement support, the construction sector is also starting to look carefully at its overall carbon footprint. I mention those examples because they involve a willingness to change. The willingness to change of the aviation sector will be tempered by the cost of sustainable aviation fuels compared with the cost of standard jet fuel. Until Governments come forward with compelling reasons why aviation should use a much higher proportion of SAF, the market could be limited.

We are much closer to market with fertilisers and other approaches than we are with SAF. That is why I see those as the immediate opportunity.

Yes, there is an opportunity with SAF, but, again, for it to work properly, we would need to have access not just to hydrogen but to biogenic CO_2. The reason for that is that if markets, including Europe, are going to take the products—whether green methanol or SAF—they will expect them to be made with low-carbon hydrogen and biogenic carbon feedstocks.

The Convener: I think that John Andresen wanted to come in—I do not know if you saw that, Sarah Boyack, as Nigel Holmes was very quick off the mark.

Sarah Boyack: Yes, I was going to ask him next.

Professor Andresen: Whitehall is consulting on hydrogen blending in natural gas pipelines and sustainable aviation fuels. I believe that a decision will be taken in a year or two on the support for those fuels. For me, it would probably be best to wait until support materialises until you put finance behind that.

To reflect what Nigel Holmes was saying, for hydrogenated esters and fatty acids—HEFA—you will need oil. You are using waste cooking oil just now, but all of Europe is going to scavenge the market for waste cooking oil to do HEFA. For the alcohol-to-jet process, you need ethanol. I like whisky, but the price of whisky is probably going to go up with the use of alcohol to jet. So, there are some constraints, not only in the hydrogen field but in terms of where you get your carbon from. However, if you have hydrogen at Grangemouth and you build it up, as Nigel said, you can use it for the different chemicals later on.

Sarah Boyack: Okay. That is helpful.

I am going to go back and read the project willow report again, because it gets very techy about the alternatives. Sustainable aviation fuel stood out for me.

I am also thinking about rail and bus. I know that we are using hydrogen in Aberdeen. What are the opportunities in terms of joined-up thinking, electricity supply, the site and potential networks, given that we are talking about the central belt as well as the north-east? Dr Hawker, do you want to comment on the issue of green hydrogen, how you would use it and whether SAF is on the table?

Dr Hawker: It is a slightly separate point, but I want to make a distinction between hydrogen itself and hydrogen derivatives in Scotland's place in an international market. If you are producing and selling hydrogen to domestic users, you have an implicit advantage as a domestic producer over international imports, because you can supply hydrogen directly, whereas any imports would have to be converted to a transportation medium such as ammonia, which implies cost-efficiency losses. There is an implicit advantage to domestic hydrogen production over imports.

That is not the case for hydrogen derivatives such as aviation and marine fuels, because they are already in a form that is far more easily transportable. In that case, we need to consider carefully whether the products that are being produced at Grangemouth will be competitive with imports landing at a potentially competitive price, given that there are other countries where they could be produced more cheaply than they are produced in Scotland. Grangemouth would therefore face the same challenges as it has in the past over whether it is fully competitive in the context of the import market.

Sarah Boyack: Thank you. I will pause for reflection and let the next colleague come in.

The Convener: Douglas, you want to come in on that point.

Douglas Lumsden (North East Scotland) (Con): Why would Grangemouth not be price competitive? What are the reasons behind that?

Dr Hawker: I am not saying that it would not be price competitive. However, on the international production of hydrogen, there are other countries and means of producing green hydrogen, for example, which can come in at a much lower cost. For example, ammonia could be produced at a very low cost in the middle east by using solar power, which would still meet low-carbon standards.

Analysis has been done that shows that hydrogen as an end product would not be cost competitive, and if we are looking at ammonia as an end-use product, we could be undercut by those international markets.

There was also concern about the previous American Administration using, for example, the Inflation Reduction Act of 2022 to undercut prices in relation those same low-carbon products. We cannot therefore guarantee that Grangemouth would be the lowest cost.

Douglas Lumsden: I am looking at the project willow report, which has the capital expenditure cost of e-methanol and methanol to jet at £1.7 billion to £2.1 billion, and a capex cost of £2 billion to £2.5 billion for the e-ammonia plant. I guess that that would have to be factored into the price, because we do not want to be building something here that is not going to be price competitive going forward.

Dr Hawker: Yes. National-scale legislation that deals with that and with tariffs or whatever could help that situation. However, it should not be automatically assumed that the derivatives that are produced at Grangemouth would be cheaper than imports at the point of landfall.

Dr Holmes: I think that the committee has another session planned for next week at which you will take evidence from the industry. That would be a very good question to put to the industry representatives who will be attending.

I have heard from one of my members, who is developing projects in America at gigawatt scale, that Scotland closely matches the price of green hydrogen production in America. There might be places with lower-cost renewable electricity, but one of the challenges with solar is mapping its availability. It is regular, day by day, but if the electrolysers are running straight off the solar, you only run them half the time. Although that can be done, most of the evidence so far is that the steady-state production of hydrogen on electrolysers, which goes back 100 years, is by far the best approach to producing hydrogen at low cost.

Douglas Lumsden: How big a difference would zonal pricing make to the cost of hydrogen production in Scotland?

Dr Holmes: Again, 75 or 80 per cent of the cost of green hydrogen is probably associated with the electricity price being high. As the price comes down, the capex, operating expenditure and maintenance costs become more significant.

The challenge with zonal pricing is unintended consequences. If you reduce the price in a particular zone, you might get access to some of the electricity that is already there at a lower cost, but will that discourage further investment by the renewables developers in that particular location?

If we are looking to scale up, we need to find a way to make sure that what we do is sustainable in more ways than one and that we do not discourage the right level of investment in generation that we need in order to support growth.

I should have done the back-of-the-envelope sum for project willow. We are talking about a multigigawatt scale of hydrogen demand in order to deliver all of what is proposed for project willow. Multigigawatts of additional power generation will need to be in place, and we want to make sure that that power generation is encouraged to be located in Scotland.

Douglas Lumsden: We also want the price to come down.

Dr Holmes: Absolutely. We want to have that additional generation, but we also want to achieve the optimum price for production of the green hydrogen.

Douglas Lumsden: I want to go back to the issue of repurposing gas pipelines. How easy is it to repurpose gas pipelines? Do we have the capacity? Is there a spare connection between Kintore and Grangemouth, for example?

Dr Holmes: To a large extent, the question of how easy it might be to repurpose a pipeline is being looked at by the local transmission system futures project, which is recommissioning the pipeline between Grangemouth and Granton. In addition, a lot of work is being done in the UK with National Gas, which was previously National Grid, as part of what I think is called the high futures project. That involves taking components such as bits of pipe, valves and compressors that have been used in natural gas duty and running them in hydrogen duty under test conditions. So far, the results have all been good. The purpose is to show that most of the components in the existing pipeline networks can be reused with hydrogen.

There is also evidence from other countries. Germany, for example, is going through a similar process. Germany has a very clear strategy for developing a core network of just under 10,000km of hydrogen pipelines as an industrial supply network, which is to be in place, I think, by 2030. Germany is using a mixture of existing pipeline and new pipeline to achieve that.

The evidence from all the testing and from what is happening elsewhere is that existing pipelines can be converted from natural gas duty to hydrogen duty.

Douglas Lumsden: Can that be done with the pipelines as they stand, or does it involve a pipe-in-pipe system?

Dr Holmes: My understanding is that we are not talking about a pipe-in-pipe system. Clearly, it is necessary to be sure that the quality and the condition of the material that has been used are appropriate. Although slight changes to the operating conditions might be required, my understanding is that, substantially, the existing pipelines can be recommissioned for hydrogen duty.

It might well be the case that it is not just gas pipelines that can be recommissioned. Other pipelines could also be brought into hydrogen duty. That would be very relevant for Grangemouth.

The Convener: I have a question on that specific point. It is my understanding that, compared with natural gas, it is possible to move a lot more hydrogen in a smaller pipe. Is that right?

Dr Holmes: It is almost the same. Natural gas, by volume, has about three times the energy density of hydrogen gas, but hydrogen gas is very slippery, so it moves through the pipes more easily. The end effect, which is measured by something called the Wobbe index, is that there is not much difference between hydrogen and gas when it comes to energy deliverability down a pipe.

The work that was done back in 2016 as part of the Leeds city gate project looked at whether the pipework around Leeds could be converted from natural gas duty to hydrogen duty. I think that it was identified that all of it, with the exception of about 500m, could be used for hydrogen duty.

The Convener: I just want to get this clear in my brain. I cannot remember the size of the big pipeline that goes through my farm at home—it is something like 4 foot. It is a big pipeline that goes from Aberdeen to Inverness. If that was converted to pipe hydrogen, it would transmit the same amount of hydrogen as it does natural gas.

10:15

Dr Holmes: The same amount of energy could flow down that pipe as hydrogen or as natural gas. If it is a 48-inch pipeline, that is actually the size of the pipeline that—

The Convener: I understand that it will be the same amount of energy, but I am a simple soul and I am trying to understand. You said that hydrogen is more slippery. If it is more slippery, that suggests to me that it moves at a quicker pace.

Dr Holmes: Yes.

The Convener: So, over the period of an hour, you would probably be delivering more slippery gas than non-slippery gas, in layman's term.

Dr Holmes: By volume, yes. By volume, there would be three times more hydrogen going down the pipe than natural gas.

The Convener: Thank you for clarifying that.

Mark Ruskell has some questions.

Mark Ruskell: Coming back to the sectors that you think will be using hydrogen in the future, I note that the Climate Change Committee does not believe that hydrogen will have a significant role to play in relation to surface transport and is sceptical about its role in domestic heating. You talked earlier about thermal generation potentially using green hydrogen in the future, but as we understand it, SSE has no plans to take Peterhead to hydrogen and use it there.

I know that we are still in the early stages, but I am interested in hearing your thoughts on the sectors where you think that hydrogen has an application. Also, do you recognise the hydrogen hierarchy—that is, the hydrogen ladder of use? Is it accepted that that broadly reflects where the investment potential is and where we can get the greatest decarbonisation for the use of blue—or possibly green—hydrogen in the future? Graeme, do you want to start?

Dr Hawker: A lot of this brings us back to the efficiency question that was raised earlier. If we are talking about green hydrogen, the fundamental issue is that you lose a lot of the energy—electricity—that you put in to derive hydrogen, and you lose even more if you go full cycle and convert it back into electricity.

Efficiency is a very blunt metric, and it should not be used as a blanket reason not to do this, because it depends on the counterfactual. That is where, for example, assessments such as hydrogen hierarchies come in. What is the counterfactual? How efficient is the process that you might otherwise use? For example, with regard to the decarbonisation of heating, the CCC has come to its position of not recommending hydrogen for domestic heating broadly because the counterfactual is the direct use of electricity; that is seen as feasible, because we can install heat pumps and use electricity directly in that way. Wherever possible, we should use electricity directly to avoid efficiency losses.

There are, however, other components of the system where those losses are not so easily avoided, and that is where hydrogen becomes more competitive. There are also aspects such as industrial decarbonisation where, implicitly, you cannot always electrify, because there are processes that fundamentally require hydrogen. That is what provides the potential ordering, and I think that that is a useful way of viewing it. That said, there are many hydrogen hierarchies. The Scottish Government has produced its own, and many more are available; however, they do not all agree on the specific ordering of the competitiveness of hydrogen.

Moreover, a fair number of assumptions have been made of the counterfactual technologies that go into these things. For example, I agree with the CCC's position on residential heating that heat pumps should be the way forward, as long as we can deploy them effectively, because it avoids all those efficiency losses. However, if we are looking at other sectors where the translation to electrification is not so clear cut and not so easy to achieve, that is where hydrogen comes in.

Transport is a difficult issue, and it is where the edge case appears. However, there are other clear-cut cases. For example, hydrogen is really the only thing that we have available to address the seasonal storage problem, with cavern storage being used to replace the large-scale storage of natural gas that we currently rely on. There is really no other solution to that problem.

Mark Ruskell: Nigel Holmes, you mentioned the fertiliser sector; we do not have a fertiliser sector here, but it could be brought back effectively and decarbonised that way. What do you see as the areas that we need to focus most on in the hydrogen hierarchy?

Dr Holmes: The hierarchy is an attractive approach, as you end up with a ladder with the A stuff at the top and the Z stuff at the bottom. I recall that one of the use cases on Michael Liebreich's ladder involved using electricity to make green hydrogen and then turning that back into electricity. Why would you do that? It is completely bonkers: you lose 70 per cent of the energy when you produce the hydrogen and then another 50 per cent when you turn it back into electricity. As Graeme Hawker has said, we are now in a place where hydrogen storage is basically the only game in town for long-duration energy storage for clean power generation.

As Graeme has also said, efficiency is quite a blunt metric, and there are other things that we need to consider. I often go back to a simple model called the energy trilemma, which is a triangle with cost at one point, security of supply at another and environmental impact at the third. It is difficult to find approaches that meet the requirements of all three points—there is nearly always a compromise between them. I am sure that, in coming to its decisions, the CCC is thinking carefully about that energy trilemma.

However, when it comes to electrification for heat, if we are producing hydrogen, storing it and then converting it back into electricity to keep people warm on cold days, the overall efficiency chain looks pretty poor. All that I am saying is that, sometimes, a more direct approach might be quicker and simpler.

Mark Ruskell: You mentioned the storage scenario in summer, when there is lower demand for heat pumps and more capacity to store energy, but is the real issue not the fact that we need a basket of technologies with regard to electrification? The storage challenge becomes less of an issue if we are thinking about system-wide resilience across the entire year, with different balancing. However, I am also thinking of a situation in which someone with an air-source heat pump in their home is asking why they would also install a separate system that uses a different technology, such as hydrogen.

Dr Holmes: My job is to promote the hydrogen sector, but I fully recognise that it is just one part of the broader energy system and that, as I mentioned earlier, if we do things that discourage investment in renewables, we will compromise the delivery of hydrogen.

We also need to understand that the use of hydrogen will be shaped largely by industry and consumer uptake. Can we provide convenient fuel where and when people want it? That is the challenge across the energy system. If we want progress, we must always consider cost, security of supply and the environmental impacts.

Mark Ruskell: John Andresen, could you share your views on that issue, and also talk about the international comparisons? Are other countries taking different approaches to which sectors are being targeted for hydrogen investment? Are there stark differences in approach?

Professor Andresen: On the issue of efficiency in hydrogen production, when you turn electricity into hydrogen, energy is lost in the form of heat. At industrial clusters such as Grangemouth, about 70 per cent of CO_2 emissions come from heat and steam generation. There is a major opportunity to capture and use the heat generated during hydrogen production on the industrial site, which would increase conversion efficiency.

In Europe, combined heat and power is widely used; indeed, around 60 per cent of Denmark's energy is CHP-based. When they burn hydrogen in turbines, 30 per cent of the energy output is electricity and 60 per cent is captured as usable heat, with a conversion loss of only 10 per cent. If Grangemouth captured the heat that was generated, it could be used on site or diverted to provide heating in places such as Falkirk.

If you could showcase that that would work well at Grangemouth—that is, harvesting the efficiency losses arising from the production of hydrogen, storing the hydrogen into the winter, and using CHP to harvest efficiencies in terms of heat going out in the winter—you would probably have a very good business case. However, as Nigel Holmes has said, you will probably want to ask your panel of industry representatives about the economics of that.

Mark Ruskell: What you are suggesting would be very much a bespoke project—that is, the application of hydrogen heating in a particular geographic area, rather than more of a national approach to the adoption of heating in individual homes.

Professor Andresen: Indeed. At this point, I should also mention curtailed energy, or what you call constrained payments. In 2021, they amounted to about £230 million in Scotland, but last year, the figure was £390 million, or nearly a doubling within three years.

If you take in more and more wind, you will probably get a situation similar to what they have in the Netherlands, for example, where electricity has a negative cost during the day and then goes up to around €200 per megawatt hour during the night, because there is no sun. If you have Grangemouth harvesting that excess electricity, putting it into hydrogen and storing it, you should be able to balance the price and get the price of hydrogen down significantly, as well as not having to make so many constraint payments.

The Convener: Before we go to the deputy convener's questions, Douglas Lumsden has a specific question.

Douglas Lumsden: John Andresen mentioned hydrogen storage. How is it stored in practical terms? I guess that communities would not be too happy to have a huge storage facility next to their homes.

Professor Andresen: I was actually going to be in Austria—I go there a bit—and they have something there called Underground Sun Storage. They have this porous rock that is used in quite a well defined way—it is like a big tank. During the day, solar energy produces hydrogen, which is put underground; it is then taken out in the winter and run through a combined heat and power system. It just shows that you can have that kind of overall approach.

Scotland, unfortunately, does not have salt mines, which is the best way to store hydrogen—the rest of Britain has been storing in salt since 1972. However, if you have confined porous rock, with a cap rock on top and a cap rock on the bottom, you can still store hydrogen very safely and at low cost. We do a lot of research on that.

Douglas Lumsden: Do we know whether we have those facilities in Scotland, or is that something that we would still have to put in place?

Professor Andresen: You have a lot of storage opportunities in Scotland, even at Grangemouth. That is not a problem.

Douglas Lumsden: So, basically, it would be stored back in rocks.

Professor Andresen: Yes. You would have an initial loss, or what we call the cushion gas; you would then fill up with hydrogen to get a working volume, and then take the hydrogen in and out as you needed it. We are working on how to constrain that cushion gas, because that would fall within what you would call capital expenditure; the hydrogen will most likely stay there until the end of the project, when you can take it out. It is all about having a good working volume that you can take in and out quite quickly.

Dr Holmes: There are various ways of storing hydrogen, a lot of which involve putting the gas into steel tanks at pressures from 30 up to 100 atmospheres. The H100 project over in Fife uses above-ground steel tanks, but a company here in Edinburgh—Gravitricity—is developing steel tanks that can be buried in the ground and can give you 10 times more storage at higher pressure.

It is also worth reflecting on where we have come from—I am thinking of town gas and all the gas holders that used to be dotted around the country. You can actually store gas very simply and at almost no pressure at all; in fact, it is a tried and tested approach for local storage. There are other approaches such as biogas tanks and gas bags on farms that could be used for hydrogen. I am not aware of their having being tried in that way, but we are talking about a gas, after all. You need to be respectful, because it is quite slippery and flammable, but there are other tried and tested approaches.

Douglas Lumsden: Are the pressures the same, or is greater pressure needed for hydrogen?

Dr Holmes: Generally, if you were using gas networks, you would run your hydrogen storage at very similar pressures to those used today. As I mentioned earlier, because it is slippery, it moves through the pipes at pretty much the same pressure for both storage distribution and household applications. Old gas holders stored gas at very low pressures—only a few pounds.

10:30

Douglas Lumsden: And would hydrogen be the same?

Dr Holmes: Hydrogen would be the same. Town gas was 50 per cent hydrogen.

The Convener: I am sure that somebody will delve into that, but what might concern some people is whether the explosive content in those tanks would be the same as that of gas. If hydrogen goes wrong, does it go wrong big time, compared to gas?

Dr Holmes: A whole load of work, funded by the UK Government, has looked at hydrogen for heat and hydrogen use in domestic applications, and its key conclusion is that there is no additional risk from the use of hydrogen.

The Convener: Thank you for clarifying that. Michael Matheson has some questions.

Michael Matheson (Falkirk West) (SNP): Good morning. I want to turn to the export potential of green hydrogen from Scotland, which has obviously been an area of priority for the Scottish Government, some of the enterprise agencies and some of the commercially interested parties. What might be the export potential of green hydrogen, particularly from Scotland? Is the offtaker market in other European countries potentially developing at a faster rate than it is here?

Dr Holmes: I am happy to start. The Scottish Government put out its hydrogen policy statement in December 2020, and the opportunity for export of hydrogen from Scotland was one of its key features. The statement recognised that the amount of renewables could be built up in Scotland. I think that the 25GW target for low-carbon hydrogen production by 2045 was mentioned earlier. In numbers, that translates to 126 terawatt hours, which is pretty much what the total Scottish energy demand is expected to be by 2045. I cannot remember the exact number, but it was suggested that just under 100 terawatt hours could be exported from Scotland into adjacent markets, which could include the rest of the UK.

Germany, in particular, was identified as a potential market, given the scale of its industry and its desire to decarbonise. That has led to various studies, including the hydrogen backbone link project. That work, which the Scottish Government supports, is looking at a pipeline between Scotland and Germany and considering some of the ways in which different locations around Scotland—not only one point—could connect to that pipeline, which would centre on St Fergus and be due to land at Emden, on the north coast of Germany. The 10GW pipeline would be a £3.5 billion investment, and the estimated cost for delivering a kilo of hydrogen into Germany is something like 30p or 30 Euro cents.

If Scotland has a competitive price for producing gaseous hydrogen, it will have a competitive price for delivering it into Germany. It has already been mentioned that derivatives such as ammonia and methanol, if you start to make them, can be shipped around the world at low cost. However, although you could try to import ammonia and crack it back into hydrogen, that would probably be as expensive or more expensive than delivering hydrogen from Scotland, because the really interesting part, which has been picked up in Germany, is that Scotland could deliver that hydrogen gas into Germany at a competitive price. That has been identified as a key opportunity.

You asked whether the offtaker market is developing faster in Europe. In many cases, the answer is yes. I think that Germany is a very good case in point. I mentioned earlier the German work on a core hydrogen network, which is 9,600km of pipeline around Germany that will be dedicated to hydrogen and will connect all areas of production and import with offtakers.

Germany is not only looking to get the infrastructure in place, but looking at the commercial structures that would encourage that. Germany has an initiative called H2 Global, which is almost like contracts for difference. It involves looking at who wants to provide hydrogen, who wants to offtake hydrogen, the price of the providers and the price of the offtakers, and then matching the lowest price of supply with the people who are willing to offtake it. If there is a difference in the cost between the offtakers and the producer, it is covered through H2 Global. That is really helping to stimulate the market. As part of H2 Global, Germany has gone out to tender to suppliers outside Germany to bid into the German supply market.

It is about developing the infrastructure as well as the commercial and regulatory structures that help that to happen. It is worth looking at that model very closely, because it seems to be moving forward, driven to a large extent by Germany's focus on industrial strategy and decarbonising of industry, including steel, car manufacture, and all sorts of other heavy industry.

Professor Andresen: In Europe, there is close to 2,000km of dedicated hydrogen pipeline, so there is infrastructure to spread it throughout Europe. The European Union is putting billions of euros into hydrogen valleys, proving the concept of production, transport and end use. It is investing heavily in the hydrogen infrastructure chain, and there are also quite a significant number of hydrogen fuelling stations for cars and trucks. It is putting everything in place now.

What is needed is low-cost hydrogen that is produced at scale, which is where I believe Scotland can come in. You have water, because it rains quite a lot, and you have a lot of sea. You also have wind—probably the biggest wind potential in Europe. If you can merge those two and start with Grangemouth to show how it can be done, I think that you would have something with a bright future.

Dr Hawker: The competitive basis for Scotland to export green hydrogen in particular is the availability of low-cost renewable energy, as mentioned before, and the fact that our wind farms have higher capacity factors. Therefore, the low-carbon electricity can potentially be lower cost than it would be elsewhere, which implies a lower cost of green hydrogen production for us than for continental competition.

However, at the moment, hydrogen producers are not fully exposed to that low price. The market, as it currently exists, means that we would be paying grid average costs for the electrolysers that we would need to produce at scale to connect to the electricity grid. The low-carbon hydrogen standard only recognises a Great Britain-wide carbon intensity of electricity. That means that all the potential benefits that Scotland has to be competitive in green hydrogen production are not currently being realised, because the markets are not designed to enable that.

There was a question earlier about the potential for zonal pricing to improve that. That would be one solution. I would not say that it is the only solution, but it needs to be recognised that, at the moment, green hydrogen production would not be competitive, because it cannot directly access the low-cost renewable production opportunity that we have.

Michael Matheson: Thanks. I will move on to transportation. Pipeline would appear to be the optimal model for transportation if the hydrogen was produced for export purposes, but there would also be the potential to export it by ship. What is your view on the potential modes of transportation from Scotland to other parts of Europe or beyond? Is the cost of shipping just too prohibitive? Is the technology mature enough to give people the confidence to invest in the shipping of hydrogen?

Dr Holmes: I am happy to start on that. Your question is about shipping, but I will briefly come back to the pipeline point and the work on the hydrogen backbone link. The UK Government recently published a report on the opportunity for hydrogen exports between the UK and Europe, which picked up on some of the work that has been done recently on the pipelines that are being built out into the North Sea.

That work is worth reflecting on. The pipes are from the north German sector and the Dutch sector. A project called AquaDuctus is building that pipeline out to try to reduce the cost of bringing energy from offshore wind farms into north Germany. The pipeline does not quite go up to Teesside but it is not far off—it heads up towards Dogger Bank and it has 20GW of pipeline capacity.

The suggestion is that the UK and Scotland should consider joining up with the AquaDuctus pipeline. That would cut the cost of a pipeline connection between Scotland and Europe in half. Although the pipeline is expensive, it could be less expensive than we initially thought. Further work is being undertaken by the Net Zero Technology Centre on that.

To come back to your question about shipping, the challenge with hydrogen is that it is a very light gas. If it is transported as a gas, it takes up a lot of space. It must then be compressed, which means that high-pressure storage must be moved around. I am not saying that it cannot be done—some work has been done on doing it—but it is not the ideal. We would not be looking to move hydrogen over long distances with that approach, but it could work on a North Sea basis.

We have also considered moving liquid hydrogen, which is an established way of transporting it. The challenge with that is that it has to take place at a super-cold temperature—about 20° above absolute zero. Other carriers are being considered, such as absorbing the hydrogen into an organic molecule reversibly, so it is absorbed and desorbed. That method has its attractions, because handling the material would be a bit like handling petrol or diesel. All of those methods have complexities that have additional costs. The jury is still out on which one we might use.

The other way in which we might move hydrogen around is as ammonia. We have already spoken about ammonia production at Grangemouth. Ammonia is much more storable and transportable than hydrogen is. A lot depends on what the customer wants: if the customer wants hydrogen gas, a pipeline is the best option; if they want ammonia or methanol, that is the way to transport it.

Michael Matheson: What role could Grangemouth play in that?

Dr Holmes: The facilities at Grangemouth make it an obvious choice. It does not currently handle ammonia, but ethanol and petroleum products and liquefied petroleum gas are all handled at Grangemouth. The port has the facilities for loading ships and it has staff with the experience of handling such things at volume. Grangemouth would appear to be the obvious choice. It is one of the best locations, if not the best location, in Scotland for that type of activity.

The Convener: Mark Ruskell has a brief question.

Mark Ruskell: The focus is on project willow and Grangemouth, but I am also interested in Mossmorran. Nigel Holmes talked about the ethylene cracker at Mossmorran. Do you see hydrogen as part of that mix—whether it is blue or green hydrogen as fuel, or bioethanol as feedstock? Where does Mossmorran sit in that industrial complex?

Dr Holmes: Mossmorran is already connected to Grangemouth by pipeline. There is an ethylene product line that runs between the two places. However, they are feeding different markets. I believe that, at the moment, most of Mossmorran's ethylene product is exported by ship from Braefoot Bay. Its feedstock is imported: some of it comes down pipes and some of it comes by ship.

Both Grangemouth and Mossmorran import the ethane. Mossmorran had a disadvantage compared to Grangemouth in that it was just a cracker; there were no other plants around it. Essentially, all the product from Mossmorran was exported. At Grangemouth, there is still a significant amount of petrochemical plastics production on site.

10:45

With Mossmorran, the opportunity is to decarbonise it. The way to do that would be very much like what would happen at Grangemouth: hydrogen would be brought in pipeline. There are good grid connections next to Mossmorran—it is probably better off than Grangemouth in that respect—so there might be more opportunity to produce green hydrogen on site there than there is in Grangemouth.

My understanding is that the project that RWE is developing in Grangemouth—the Grangemouth green hydrogen project—was originally going to be on a 200MW scale, but it is now expected to be 100MW. That is partly due to capacity constraints on the grid.

What we have not mentioned is that just over the river from Grangemouth is Longannet. Graeme Hawker mentioned legacy power station sites. Longannet has a super grid connection, so, with the scaling up of Grangemouth and pipelines, the Longannet could be one of the hubs of green hydrogen production in Scotland at a very large scale.

Mark Ruskell: Thanks.

The Convener: Sarah Boyack has a final question is for one panel member. Nigel Holmes has had quite a run, so go for whoever you like.

Sarah Boyack: I will go back to joined-up thinking on the economic opportunities for investment at Grangemouth. You were just talking about transporting hydrogen on ships, and ships can also be powered with hydrogen. How do we use hydrogen in a way that will be cost-effective and benefit the Scottish economy? What are the opportunities to deliver that in a joined-up way at Grangemouth? Would you like to go first, Professor Andresen?

Professor Andresen: Grangemouth is quite well located between Edinburgh and Glasgow. There are a lot of transport links, so it is an ideal hub.

I was talking with the Edinburgh airport, which wants to decarbonise. It installed about 17,000 solar panels last year, I believe. The environmental manager there wants the energy from those to be transferred into hydrogen, partly to decarbonise the airport even more, but more so that trucks coming from Glasgow and Edinburgh can fuel up with hydrogen there. Edinburgh airport has a small capacity, but the capacity at Grangemouth would be tremendously big and there would be no capacity issues there. It would be a very good seed to grow the hydrogen economy.

The Convener: Graeme nodded, so I will give him the final word.

Dr Hawker: The key thing to unlocking any kind of hydrogen economy in Scotland is that we need offtakers. We need somebody to actually be buying and using the hydrogen to get any of this moving. That has been the main stumbling block for many companies that are ready to make investments in hydrogen production but, at the end of the day, do not have anybody to reliably sell to. Grangemouth unlocks a lot of that potential.

As I am representing a university here, I would add that there is also the big question of skills and the loss of skills that will come from the reduction of fossil fuel usage. There is a huge opportunity that is mentioned in project willow alongside the just transition element, which is that hydrogen could stimulate a large amount of new investment in education, training and employment in the central belt areas. A lot of further education and higher education institutions in that region are, shall we say, looking for new sources of income, given the trends in the sector. This could create a lot of new opportunities across higher and further education.

Sarah Boyack: Thanks. I suppose that we just need a plan to deliver it.

The Convener: I thank the witnesses for giving evidence. As you say, our questions will continue in another panel discussion and into next week. I will briefly suspend the meeting to allow a changeover of witnesses.

10:49

Meeting suspended.

10:55

On resuming—

The Convener: Welcome back. We will now hear from our second panel of witnesses on the hydrogen aspects of the project willow study. Joining us in the room is Dr Simon Gill, independent energy consultant and author of "Green hydrogen in Scotland: A report for Scottish Futures Trust". Appearing remotely are Dr Jan Rosenow, energy programme leader and Jackson senior research fellow at Oriel College, University of Oxford, and Professor Mark Symes, professor of electrochemistry and electrochemical technology at the school of chemistry, University of Glasgow. I welcome you all. Somewhat bizarrely, Simon, the fact that our online witness appear on a screen below you, which is facing me, makes it look as though you are flanked by them.

If you were listening to the first part of the meeting, you will have heard me say to the first panel of witnesses that my first question is the easy one. Project willow did not advocate for the use of either green or blue hydrogen but said only that a "reliable source" of low-carbon hydrogen will be required. Which source do you think is most likely to offer Scotland a reliable and affordable supply of hydrogen? I put that question to Mark first, before coming to Simon Gill and Jan Rosenow.

Professor Mark Symes (University of Glasgow): It is a pleasure to be before the committee today. My background is in chemistry, specifically electrochemistry. I have spent about 15 years trying to come up with new and more effective ways of making green hydrogen from water, so my response will always be that I think that green hydrogen is the scalable and truly net zero option, and that therefore, at least in the long term, we will rely on green hydrogen. There might well be a role for blue hydrogen as we transition to green, but, ultimately, we will want to focus on green hydrogen.

The Convener: Simon, blue or green?

Dr Simon Gill: Thank you for this opportunity. I am a whole-system energy expert. My training is on the electricity side of electrical engineering, but I have focused on every part of the energy system in the past few years.

We will need both types at different stages of the transition. What matters is the pathway that will take us from today to a net zero world in 2050, and each type of hydrogen will play a role at different stages.

Blue hydrogen provides a resilient, secure and reliable supply, using a controllable process that is sort of akin to that used in dispatchable power stations. We are already seeing it being developed as part of industrial clusters in England. As Mark Symes said, green hydrogen provides a truly zero-carbon solution, but that is dependent on variable renewable resources.

We need to design a broad hydrogen system to ensure that we can get the same characteristics out of that as we do from the electricity system. That design would include really growing the hydrogen network and having storage at scale. My sense is that we want to focus on having a primarily green hydrogen solution at the end of that process because it is lower carbon and does not rely on natural gas. If we were to continue using blue hydrogen in the long term, that would keep us locked into the international market for natural gas. However, I do not think that we should completely write off blue hydrogen and I think that we should build it into our strategy for the next 15 years or so.

11:00

Dr Jan Rosenow (University of Oxford): My background is in geosciences, energy efficiency and energy policy more broadly. I very much agree with Mark Symes's remarks—the use of green hydrogen is preferable to the use of blue hydrogen, for the reasons that he set out. The carbon emissions of green hydrogen, if it is produced with electricity that is truly zero carbon, are zero, whereas the carbon emissions from blue hydrogen, even if high capture rates are achieved, can never be truly zero, because there will always be some carbon that is not captured.

Another issue, which the previous witness brought up, is the import dependency that is associated with blue hydrogen. You need about 40 per cent additional natural gas to make the same amount of blue hydrogen in terms of the energy content. That means that we will be more reliant on imported natural gas if the UK moves from natural gas to blue hydrogen. That has significant implications, as we have seen during the energy crisis, when gas prices went through the roof, which affected end users quite dramatically. Therefore, I think that green hydrogen is the more reliable source of hydrogen, as the costs are more controllable.

The Convener: With the exception of Mark Symes, who wants to move to green hydrogen straight away because he thinks—I realise that I am putting words in his mouth—that that will be better, I think that you are all saying that, realistically, we will need to use a bit of blue hydrogen to start with, and that we will move towards green hydrogen by 2045, which I think is our target. For how long will we need to have a mix before we move over totally to green hydrogen? I am not clear about that. Are we talking about five years or 10 years? What timeframe are we looking at?

Professor Symes: I think that we are some way from having a system that operates entirely on green hydrogen. There are significant issues not only with scaling up the devices that we would require to have for the hydrogen production but with getting the number of devices that we would need to generate the amount of green hydrogen that we are talking about that would be needed to power something the size of Grangemouth or to be able to power the industrial processes that would come out of that. Therefore, I would say that between 10 and 20 years would be a conservative ballpark figure.

Dr Gill: I have a similar view. I think that we are looking at being able to operate on green hydrogen towards the 2050 net zero UK deadline or the 2045 Scottish deadline.

In addition to the points that Mark Symes has made, we need to think about the investability and value for money of the infrastructure for blue hydrogen. If we are building that infrastructure now, we do not want to spend a great deal of money for something that will last us a couple of years. If we are going to use blue hydrogen, we need to think about that as part of a long-term strategy.

I should also say that I do not think that we will end up with a final energy system that is entirely reliant on green hydrogen. I think that there will be a mix of green hydrogen and blue hydrogen, and that that should be the case. That will provide diversity of technologies and different characteristics, and it will allow us to deal with the fact that we do not know what the future will look like.

In 2050, I expect us to have a system that will largely but not entirely use green hydrogen.

Dr Rosenow: I agree with most of those comments. We should not forget that, at the moment, the UK uses about 700,000 tonnes of grey hydrogen from natural gas, which is highly carbon intensive. The quicker we can replace that with blue or green hydrogen, the better. There might well be a transition period, because of the difficulties of scaling up green hydrogen production and how long that process will take.

It is clear from what has happened all over Europe and beyond that such projects do not come along as quickly as people had hoped. We will certainly require to use other sources of hydrogen for some time. Ideally, that would not be grey hydrogen.

The Convener: Will price—the price of hydrogen compared with the price of electricity—limit development?

Dr Gill: So—

The Convener: You were very quick, Simon.

Dr Gill: I am sorry.

The Convener: No—I am impressed. You were quicker to respond than our witnesses who are online.

Dr Gill: We definitely need to have a focus on driving down the cost of hydrogen. Hydrogen allocation round 1—HAR1—for green hydrogen cleared at £241 per megawatt hour, which is a much higher price than our electricity price, but that reflects the fact that it is an immature technology. We are dealing with small projects and quite a lot of risk for the developer who is signing up to a CFD that will effectively last for 15 years and needing to fix their costs and protect themselves for that period. Over the next few allocation rounds, there are real opportunities to drive down the cost of green hydrogen.

Ultimately, we will end up in a situation in which hydrogen has a particular set of uses within the energy system. My view is that it will not be used much for heat or transport but in more specific applications where there are fewer affordable alternatives. In that case, we will be looking at the cheapest and most technically feasible option. That might be for very high-temperature industrial processes and for the production of derivatives for aviation or maritime fuels, for example. We might well find that that ends up being significantly more expensive than it is today for those sectors, and we would need our broader industrial and transport strategies to look at how we ensure that those sectors continue to do what we want for the economy and for society overall.

The Convener: I am looking at those online now. Does anyone want to come back on that before I move to Kevin Stewart?

Dr Rosenow: I could quickly comment on the price differential that you asked about. It has been generally assumed in the projections for some time that blue hydrogen will be cheaper than green hydrogen. Of course, there are huge uncertainties. We do not know what the price of gas will be in the future. It is much more reliable to forecast the cost of renewables because we have established learning rates.

It is more difficult to determine the price of electricity in the wholesale market because that is still set by gas in the UK most of the year. It is, however, a fair assumption that blue hydrogen will remain cheaper for some time, although that will depend on how the gas price evolves internationally.

I also agree with Simon Gill's remarks on end users; I am sure that we will get into that later on. My work has shown that there is a limited role, if any, for hydrogen, certainly in heating buildings, and also in industry.

The Convener: Mark Symes wants to come in—briefly, please.

Professor Symes: Just to build on what Simon Gill and Jan Rosenow said, for green hydrogen there is an explicit dependence on the price of electricity, wherever it comes from, in order to generate it, assuming that it is being generated electrolytically, which is almost certainly the case.

On Simon's comments about capex, there is also an opportunity to make green hydrogen systems slightly more modular, which might therefore allow developers to spread their costs.

The Convener: Kevin Stewart is next.

Kevin Stewart: My first question is about the fact that you have all highlighted that blue hydrogen is a bridging technology, although Dr Gill seems to think that it will go on for longer than just being a bridging technology. In order for that to work for Scotland, how important is it that we have the Acorn carbon capture and storage project online to reduce the carbon emissions from that blue hydrogen? Maybe we should go to Mark Symes first.

Professor Symes: That is a bit outside my zone of expertise, but from what I know of blue hydrogen, we need somewhere to store the CO_2 that will be generated, so we should have an indigenous way of storing it rather than trying to export the problem at cost.

Dr Rosenow: I agree with that. It will also be important to make sure that the capture rates that are forecast are being achieved. I would want that to be very closely monitored. We have seen in previous carbon capture projects that those rates were not always achieved, and achieving those will be very important as we move towards net zero.

Dr Gill: That is an important element. One of the things to say about any hydrogen system is that it is complex, with multiple infrastructures, and we need to find a way to co-ordinate the investment and the development of those. For blue hydrogen, you need the production, the carbon capture, carbon transport and carbon storage; and then you need the hydrogen transport, hydrogen storage and hydrogen end use. That is a lot of stuff that you need to invest in.

You can start to see the benefit of the UK Government's cluster approach in England, where it is bringing together multiple support mechanisms for most of those technical elements. Particularly in the north-east—in Teesside and Humber—you can start to see how those come together in a whole-system way, which allows each element to prosper. We need that in Scotland, which means that there is a lot of pressure to get a track 2 cluster from the UK Government, to get support through the comprehensive spending review this year, and to ensure that Acorn carbon capture and storage happens and that that starts to do the same thing that we can see under way in the north-east and north-west clusters in England.

Kevin Stewart: We need the same investment here in Scotland in Acorn as they have had in the north-east of England and in Merseyside.

Dr Gill: Yes, I agree.

Kevin Stewart: You have kind of led me to my next set of questions, which you probably heard me ask in the earlier evidence session, about hydrogen storage and transportation regulations. We seem to be falling behind other countries here in the UK, so does the UK Government need to get on with modernising storage and transportation regulations in order for us to be competitive when it comes to hydrogen production and sale?

Dr Gill: Yes, and there are several elements to that. An element is blending hydrogen into the existing natural gas mains and another element relates to the development of a 100 per cent hydrogen system. The UK Government published the hydrogen road map in, I think, 2023, which set a lot of dates for last year for consultations and decisions on various elements of a hydrogen system, including the transport, storage and blending options. Due, at least in part, to the fact that there was a UK general election and, therefore, a bit of a hiatus, that process stalled last year. I get the sense that it is starting to pick up again this year. However, from a Scottish perspective, the issue really needs to be treated with a lot of urgency. That is because, as I am sure that we will come to in later questions, a GB national transportation system and access to GB hydrogen storage are essential to making the most of Scottish hydrogen potential.

Kevin Stewart: We need a GB system, but maybe we actually need a European system.

Dr Gill: There is no doubt that a GB system will link into that—yes, of course.

Dr Rosenow: I do not have anything to add. This is outside my area of expertise, so I would refer you to Simon Gill or Mark Symes on that.

Professor Symes: Thank you, Jan Rosenow, and thank you to Simon Gill, who phrased the problem very well. All that I will add is the importance of regulations and standards, not just in driving adoption but in driving public acceptance of hydrogen, so it is a really important question.

Kevin Stewart: That is a very good point.

The Convener: Thanks, Kevin. The next questions come from Douglas.

Douglas Lumsden: Actually, I think that they come from Sarah.

The Convener: I am sorry—you are right. I double jumped—that is a mistake. Sarah, you get the next questions. You look very offended, and rightly so. Off you go.

Sarah Boyack: No, not at all. I am delighted to ask this question. I asked the previous panel of witnesses about the extent to which Grangemouth could play a key role in green hydrogen production. The RWE project was mentioned in the earlier session. To what extent do the witnesses think that that is a realistic option at Grangemouth? I will kick off with you, Simon Gill.

Dr Gill: It would be great to see the RWE project happen. More generally, although Grangemouth might be an excellent site to be a user of green hydrogen—to use it as part of its processes or to turn it into some of the products that the project willow report talks about—what we really need, as I mentioned in response to the previous question, is large-scale hydrogen network transportation in Scotland and between Scotland and England and Wales. That would allow the location of green hydrogen production to be decoupled from where it is used.

11:15

The best thing would not be to put all the green hydrogen production at Grangemouth but to potentially put it further north in Scotland and connect it to a pipeline that goes via Grangemouth. That would allow for the development of a hydrogen market, which would mean that hydrogen producers could sell to Grangemouth or other users, and Grangemouth could access the lowest-cost hydrogen from multiple providers. Once that is in place, you would start to have a system that can help to drive down hydrogen costs nationally.

It is good that the project willow report covers green hydrogen production at Grangemouth, but the bigger picture is that we need to link it up with other infrastructure.

Sarah Boyack: Do the two online witnesses want to come in?

Professor Symes: Yes, I will. I definitely agree with Simon Gill that we should not just focus on Grangemouth being the point of production of green hydrogen. Of course, one of Grangemouth's benefits is that it can convert green hydrogen by using some of the existing workforce and adapting existing facilities for the handling of other chemicals that we are more familiar with, such as conventional fuels.

One excellent thing that Grangemouth can do, in part by acting as a hub for production and in part by handling the onward conversion of hydrogen, is really help to drive innovation across the rest of Scotland's hydrogen sector. Having that centralised hub will be really important.

Sarah Boyack: That is really useful.

Would you like to come in, Jan Rosenow?

Dr Rosenow: Just briefly. Given the availability of wind—particularly offshore but potentially also onshore—Scotland is in a unique position when it comes to green hydrogen production. Strategically, it makes a lot of sense to focus on green hydrogen production in Scotland. Grangemouth should certainly not be the only point of focus—the potential is much larger than that, and I underline that Scotland is strategically well positioned for green hydrogen production.

Sarah Boyack: That was all very positive. When it comes to jobs and skills, I particularly like the phrase "innovation hub", which was mentioned by our previous panel.

In relation to project willow, how would hydrogen be used on site at Grangemouth? The previous panel mentioned fertilisers and sustainable aviation fuels. Dr Gill, you mentioned maritime fuels, transport strategy and industry. What would your top priorities be for using hydrogen at Grangemouth?

Dr Gill: I would say that there are three priorities. The first one is to decarbonise the industrial processes at Grangemouth. Where grey hydrogen is used, green hydrogen should be used instead, and where natural gas is used to heat things—unless a very high-temperature heat is required—hydrogen should be used. The second priority is to use hydrogen for aviation, and the third is to use it in maritime fuel production.

Compared with the sixth carbon budget, it is interesting that the CCC's analysis in the seventh carbon budget was to suggest a significant reduction in hydrogen use in the GB economy, which would involve completely removing hydrogen from some sectors, such as heat and surface transport.

In relation to the suggested focus on sustainable aviation fuel for aviation, the CCC's advice was not particularly clear on the production methodology. There are two routes for that. The first is a biogenic route, which involves things such as used cooking oil, and the second is a synthetic route, whereby hydrogen and CO_2 are combined to synthesise the SAF. There is a limit to the extent to which the biogenic route can be used for that. If we want to keep flying but to do so in a low-carbon way, we need to find a way to mass produce synthetic SAF. That is a really important use of hydrogen.

On maritime fuels, a range of technologies could be used, including methanol, which can be created from hydrogen, and ammonia. The CCC's analysis suggests that, under its scenario—this is only one scenario—most of the ammonia that we will end up using for our maritime sector will be sourced from international markets. However, I think that there is an opportunity for somewhere such as Grangemouth to produce ammonia as a fuel, by making use of the otherwise-curtailed wind power in Scotland and the potentially low-cost hydrogen production. There was some discussion in the previous evidence session about the cost of doing that in Scotland relative to the cost of doing it elsewhere. I think that that is another opportunity.

Therefore, the three priorities for hydrogen use at Grangemouth are to decarbonise the industrial processes and to think about how it can be used for synthetic SAF and maritime fuels.

Sarah Boyack: In relation to SAF, both the EU and the UK are talking about the scaling up of its use in aviation, and there is also discussion about the use of hydrogen in maritime fuels. Does Grangemouth's location help in that regard, or does it not matter? Witnesses on the previous panel said that it does not matter, because hydrogen can be transported. Does Grangemouth's location matter, given that it is close to major airports in Scotland and is a shipping port? Will that be helpful? Is the big issue prioritising investment?

Dr Gill: It probably is valuable for Grangemouth to be in a strategic location. It is already a container port for shipping, it has access to shipping potential and, as you said, it is close to airports.

In addition, as one of the other witnesses said, it is a good thing to have the ability to use the workforce, from the point of view of the technical expertise that will be needed and of the social aspect of providing new jobs to replace the jobs in Grangemouth that are based on fossil fuels.

I get the point that was made by witnesses on the previous panel, but I think that there is value in Grangemouth's location.

Sarah Boyack: Thank you. Jan Rosenow or Mark Symes, would you like to come in on that point? Do you agree with the broad picture that, at Grangemouth, we have an economic opportunity in relation to jobs, skills and location?

Dr Rosenow: I want to add a point on the issue of the end use. You started by asking a question about the best end uses of hydrogen at Grangemouth. One of the end uses that we have not yet discussed is the use of hydrogen to back up the electricity system. We will have to replace a lot of gas plants in order to decarbonise. That is where most experts see there being a significant role for hydrogen, because it can store energy over very long periods of time—if the storage is done correctly—which batteries and many other technologies cannot do. That is a significant role for hydrogen, in addition to its role in fuel for aviation and shipping and its use as a feedstock for fertiliser production. I would add that to the list of high-priority end uses. It is potentially a significant end use; it will not produce the majority of electricity that is needed, but it will still be a significant end use in quantitative terms.

I fully agree with Simon Gill that hydrogen will have a very limited role to play in relation to buildings and road transport in the UK, and that is also the view of most other people who have looked at that.

Sarah Boyack: When it comes to storage, most of the focus is on pumped hydro storage. The other example that is often given is battery storage, although there have been some problems with that. However, hydrogen storage is not given the same profile. Why is that? Do you think that the use of hydrogen for storage needs to be given a higher profile?

Dr Rosenow: It is already pretty easy for batteries to be used to sell into the wholesale market and to make money by feeding electricity into the grid when prices are high. At the moment, there is not a good market mechanism that encourages the production of hydrogen for electricity generation, including the cost of storage. There is not currently a mechanism for long-term storage in the UK, and that is also the case in most other countries. That is a missing piece in the market landscape.

Sarah Boyack: That was a helpful comment. Mark Symes, do you have any suggestions on that issue?

Professor Symes: I would like to say something about synthetic aviation fuels. I want to put the scale of the opportunity into context, because that is an opportunity for Grangemouth and for Scotland in general.

It is useful to make a distinction between sustainable aviation fuels—SAFs—and entirely synthetic aviation fuels. SAFs can be made by hydrogenating biomass, which is one of the plans for Grangemouth. Another of the plans is to make synthetic aviation fuels, which involves combining CO_2 and hydrogen to make methanol, from which other jet fuels can be made.

I will give you an idea of where we are at the moment. Both the UK and the EU have sustainable aviation fuel mandates, under which any sustainable aviation fuel will be taken, whether it comes from biosources or is synthetic and comes directly from CO_2. The current targets are for about 2 per cent SAF, but those targets will ramp up pretty quickly.

The EU's numbers are especially interesting. The EU is aiming for 70 per cent of all the fuel that is consumed by jet aircraft being sustainable aviation fuel by 2070. There is probably not enough feedstock in the world to make all that from biologically available resources. Therefore, the EU has a secondary target, which is that 35 per cent of the SAF that it burns will be entirely synthetic by 2050, which is only 25 years away. That is SAF that is made from CO_2 and hydrogen using chemical processes. That amounts to about 15 million tonnes of SAF, just for the EU's sustainable aviation use. In that context, hydrogen—and what we have at Grangemouth, in particular—could be really vital in providing SAF for export, as well as for indigenous use.

You asked whether Grangemouth's location is an advantage. In this case, it definitely is, particularly when we think about the innovation cycle and where we would start. We would start, I presume, on quite a small scale, by supplying fuel to Edinburgh and Glasgow airports, which are close by. That would certainly be a way to get the operation off the ground and to rise through the technology readiness levels.

Sarah Boyack: That is helpful. Simon has an additional comment to make.

Dr Gill: I would like to add to the comments about storage. Is it okay to do that now?

Sarah Boyack: Yes, that would be helpful.

Dr Gill: It is important to set the context when we talk about energy storage in the energy system. Today, we have access to 35 terawatt hours of natural gas storage, and we have 59TWh of energy stored in crude oil stocks and petroleum products, so we are up in the high tens of terawatt hours for those.

The National Infrastructure Commission recommended that we should have 8TWh of hydrogen storage by 2035 and 25TWh of energy storage for electricity, to provide resilience and supply. Cruachan pumped storage, which is a brilliant and really important part of our electricity system, stores 0.007TWh. It is really important for our electricity system, as I said, and I am not making the point that we should not be thinking about pumped storage. However, the scale of energy storage that is currently in the form of fossil fuels, which we need to have in some form of low or zero-carbon options, is huge. Hydrogen and its derivatives are the main option for such storage, so it is really important.

Jan Rosenow mentioned the need for a mechanism to develop hydrogen storage. That is really important. The UK Government has the hydrogen storage business model, which is one of the things that was in the hydrogen road map 18 months ago. We are expecting a consultation on what that will look like fairly soon—possibly over the summer—alongside the parallel hydrogen transport business model. We expect that to start supporting hydrogen storage in the next wee while, probably in England and probably around the industrial clusters that are already there.

It is important to set the scene and to ensure that we are talking about the right scale. Those numbers are in the paper that I shared on Friday.

Sarah Boyack: That is really useful, because the issue of storage at scale is not on our agenda. I have seen papers on the use of hydrogen for rail transport, as well as on its use for sustainable aviation fuel. The potential for hydrogen use has clearly been identified. The issue is about how we make the connection between its theoretical importance and delivery. The three of you have been very helpful in setting out the clear need for the issue to be on the agenda, so I appreciate that.

11:30

The Convener: Simon Gill, I should have thanked you at the outset for the paper that you provided on Friday. I had a note telling me to do so, and it was rude of me not to. I hope that you will accept my thanks now, in the good faith in which they would have been delivered at the beginning of the meeting, had I remembered.

We now come to Douglas Lumsden.

Douglas Lumsden: Everything that we have spoken about today seems achievable, but the problem is how we make the economics of some of these things stack up. For example, SAF has been mentioned. How will the cost of SAF compare with what we pay just now? I cannot remember whether it was Jan Rosenow or Mark Symes who spoke about SAF. Maybe we can go to Mark first.

Professor Symes: Yes, I said some things about SAF.

At the moment, SAF is certainly more expensive than conventional fuels. With its mandates, the EU is, in effect, creating a market for people to make synthetic fuels that are above the current fossil fuel price by saying that, by 2070, it will allow planes to fly only if 70 per cent of the fuel on board has come from sustainable sources. In a way, that move—that regulation and law change—takes economics out of it. The idea behind that is that, over the next few decades, synthetic fuel production will scale up to a level at which it will be competitive with fossil fuels. In other words, we will iron out the issues that we have with efficiency, for example, in how those fuels are made, so that we can make them at a price that is cost comparative with fossil fuels.

A lot of the technology that is used to make synthetic aviation fuels is quite old. It is simply not very efficient. There is an argument to be made for innovation through which we could increase the efficiency of the process and therefore decrease the cost of the fuel. At the moment, that is not taking place, because there is no market for that fuel but, anecdotally, I have heard that airlines, if they were forced to do so, might pay double what they currently pay for fossil fuel for SAFs, so there is some wiggle room.

Douglas Lumsden: We have also mentioned that the cost of hydrogen is still a lot higher than it is in other parts of the world. Seventy-five per cent of that is due to electricity costs. The CFDs for floating offshore wind, for example, involve a price of £155 per megawatt hour. How will that cost come down, given that the CFD has the price up so high?

Dr Gill: The price of electricity is really important. I heard Nigel Holmes, who was on the first panel, say that about 70 per cent of the cost of hydrogen is in electricity, which is more or less the same as what my analysis has suggested. You can break that into halves. About half is in the wholesale cost of electricity, and the other half is in the electricity system costs—the costs of the network, balancing the network and all the other elements that we have to pay for in our big electricity infrastructure national network.

There are some things that would drive down the cost of green hydrogen. One of those is to find appropriate ways of designing the system so that hydrogen production does not face some of those system costs—particularly if it supports a more efficient electricity system.

For example, at the moment, a demand transmission network use of system cost would have to be paid for hydrogen electrolysers. I am sure that members will be familiar with discussions on TNUOS charges from the perspective of renewable generators, but those charges are also paid by demand consumers, including industrial consumers. Over the past year, the UK Government has introduced a policy that has exempted those industrial consumers from 60 per cent of that TNUOS charge if their industry is counted as an energy-intensive industry. That has dropped some of the costs, but there are still significant costs.

However, electrolysers that are located in Scotland—particularly if they operate in a way that aligns with wind generation—reduce the pressure on the electricity transmission system. Therefore, there is an argument that they should receive a significant negative cost, or a payment, which would align with how we treat wind farms that are located in the south of England, which we pay through the TNUOS system. We have system effects that can help to do that.

The second element is in relation to the wholesale cost of energy. As I think that Jan Rosenow mentioned earlier, the price of gas sets the electricity system price during large parts of the year but, increasingly, renewables will set the price during large parts of the year, and that will force the wholesale price down to pretty close to zero during some hours. Last year, we had 155 hours of what was, in effect, zero or negative-priced electricity in the wholesale market. The number of hours when that is the case is likely to increase significantly as we continue to build out renewables. If you design your electrolyser to operate flexibly and to be capable of turning on when there are excess renewables, either across GB or behind the transmission constraint in Scotland, you will start to be able to access electricity at a very low wholesale cost.

There are those two components—you can reduce your wholesale cost by careful, targeted operation of your electrolyser and, through policy arrangements, you can maybe reduce the electricity system costs as well. If you combined that with scaling up electrolysers, you could make a significant impact on the cost.

Douglas Lumsden: This is where I get confused. If I was a wind farm operator, for example, I would get a CFD at £155 per megawatt hour, but the wholesale price is low, so—

Dr Gill: You want to know where that has come from.

Douglas Lumsden: Yes.

Dr Gill: If you have a CFD at £100 a megawatt hour and the price clears at £10 a megawatt hour, the market pays you £10 and then GB consumers collectively pay you the other £90 through an outside-the-market system. It is called the energy levy.

By contrast, if the price is £150 a megawatt hour, the wind farm operator pays £50 back to GB consumers collectively. We have this extra system that works around the outside of the wholesale market. However, if you are a wholesale market consumer, such as an electrolyser, you are focused on the actual price.

In the first example that I gave, you would be getting £10 a megawatt hour electricity, and the additional money to the wind farm would be coming from a flat levy on all GB consumers.

Douglas Lumsden: Which is basically a subsidy, really?

Dr Gill: In that hour, it would be a subsidy, yes.

We will see what happens with the next round of CFD prices, but with some of the lower CFD prices that we have had in recent auctions, a lot of the time, the electricity price is above the strike price, and we get much more of what I would describe as a hedge for both generators and consumers.

Douglas Lumsden: But the CFD prices for offshore wind—floating offshore wind in particular—do not seem to be coming down. In the last round, for example, the price went up significantly, because there were no takers the round before. I am still struggling to understand how we will get the price of electricity down when we are moving more to renewables, and how we will get the price of hydrogen down to be competitive with other countries.

Dr Gill: Ultimately, energy is not a cheap commodity. In effect, I am talking about trying to move the costs around between different actors within the system. Although renewables do not take anything to run once you have built them, they have huge capital investment costs, which have to be recouped over 15, 20, or 25 years, for example. It is not as though the quantity of energy is cheap—that is a fact that we cannot work around.

That will be equally true in other countries, and you need to think about elements such as the amount of tax-based subsidy and the amount of bills-based subsidy that you give the system, and which groups of consumers you target those subsidies on, as well as thinking about what actually makes up the underlying cost base.

Douglas Lumsden: Okay. Does anybody else want to come in on that?

Dr Rosenow: Just quickly—

The Convener: I think that I saw on the screen that Mark Symes put his hand up to come in, but it looks like Jan Rosenow is heading off.

Dr Rosenow: Apologies, Mark—I did not see your hand.

Professor Symes: No—it was not my hand, Jan. You had your hand up.

The Convener: You are both so polite.

Dr Rosenow: I will keep my response very short. The question is a good one. What I observe is that many countries offer subsidies to encourage the production of green hydrogen or blue hydrogen but that there is often a problem on the demand side because, even after the subsidies are taken into account, the fossil-fuel alternatives are still cheaper. Why, then, should end-use sectors adopt hydrogen? That issue remains to be tackled. It could be done through quotas and regulation—as was said, airlines could be forced to use an increasing share of SAF or other low-carbon or zero-carbon fuels. Alternatively, it could be done by paying end-use sectors to adopt hydrogen—that is, you could offer them incentives to do it. However, at the moment, that problem has not been solved, and projects around the world have struggled to find offtakers as a result.

That demand-side question is quite important. It is a question not only of bringing down the cost of hydrogen but of making sure that the demand side is either required or incentivised to use hydrogen or its derivatives.

The Convener: Mark Ruskell is next—I hope that I have got that right.

Mark Ruskell: The session has been really enlightening so far. We have already had some discussion about sustainable aviation fuel and thermal generation as back-up, as well as the role of hydrogen in relation to that, but I want to return to the questions that I asked the first panel of witnesses about the hydrogen ladder or hierarchy. Do you think that there are particular sectors within that hierarchy on which it makes sense to focus investment? Are there sectors that face challenges? In particular, we talked about where domestic heating sits. I am also interested in what the international picture is in relation to some of those sectors.

I invite Jan Rosenow to answer first.

Dr Rosenow: It is a great question, and a complicated one.

There is a great new paper that was published just two weeks ago. I encourage the committee to look at it, as it takes a pretty deep dive into that question, looking at the most appropriate end uses, the economics and the alternatives.

As we mentioned earlier, the high-priority end uses clearly involve replacing existing hydrogen use—especially in fertiliser production, but also in refining—and then using hydrogen or its derivatives in shipping and aviation, and for long-term storage for the electricity system.

The evidence is now pretty robust that the path toward the end uses that were promoted quite heavily in the past—hydrogen cars and heating homes with hydrogen—is now unlikely to be taken in the majority of countries. Of course, places with very specific conditions, such as an extremely cold climate, might heat homes with hydrogen. For example, Canada might think about having hybrid systems or district heating systems that are co-located with hydrogen production—or, indeed, peaker plants that operate on hydrogen—and using some of the hydrogen waste heat from the electrolysers to feed into those systems. However, the evidence is now pretty clear that we are probably not going to see a lot of hydrogen-powered cars. The latest sales figures show that we are approaching a world in which about 20 per cent of new car sales are electric, while fewer hydrogen vehicles were sold last year than Ferraris, which suggests that there are some big question marks around whether hydrogen can ever catch up with the electrification of road transport.

The situation with regard to home heating is similar. There are now more than 200 million heat pumps installed globally and the number of hydrogen boilers is minuscule. Many of the trials that have been proposed have been cancelled—not just in the UK, but elsewhere.

The consensus about what the highest and best use cases are is now relatively strong. However, as Simon Gill said, the CCC has said that, in personal road transport and home heating, where there is potential for a very large use of hydrogen, the use case has become increasingly weak. A similar view has been taken by the National Infrastructure Commission, the International Energy Agency, the Intergovernmental Panel on Climate Change, the European Commission and the UK Energy Research Centre—and I could list many more organisations that have come to that conclusion.

Mark Ruskell: Where is the incentive, then, to invest in more pilot projects? You will be aware of the H100 project in Leven, in my region of Fife, which is a proof-of-concept project. Are we at a point where we know a lot about hydrogen for home heating now? Is there a need to continue to look at those areas and do pilot projects, or have we now got quite firm conclusions internationally about the applicability of hydrogen for heating and where it does or does not make sense?

11:45

Dr Rosenow: The evidence is pretty clear, yes. More than 60 independent studies—so, not funded by industry—have been published over the past five years or so. None of them suggests that hydrogen will play a significant role in heating—unless the evidence dramatically changes, which is unlikely given the underlying physics and the efficiency of hydrogen production.

That evidence is pretty robust. We might need to reassess it if the cost of hydrogen declines very dramatically and unexpectedly, but that does not look particularly likely, given that hydrogen costs have not come down by as much as people hoped in the past few years. The international evidence is strong, and it is probably a better use of effort and resources to focus on those really high-use cases where there are fewer alternatives, because it is absolutely clear that we will need a lot of hydrogen for those cases.

Dr Gill: I agree with Jan's points around the areas of focus. Another potentially important area, which is maybe slightly niche as the demand is probably quite small, is off-road vehicles—things such as quarry trucks and large-scale vehicles that you might struggle to electrify. That is one of the only areas in which the CCC thinks that hydrogen might play a niche role. Beyond that, it is about the sectors that we have talked about.

We have mentioned storage, and energy resilience is very much related to that. Hydrogen plays a really important role in energy resilience—resilience that we currently get from fossil fuel sources. That is an area where energy system modellers on the whole are perhaps slightly weak. I put a lot of trust in the work that the CCC does—I do not necessarily think that everything that it says will happen, but if it says something such as, "There's not going to be any hydrogen in domestic heating", that is worth thinking about quite deeply, because it has thought quite deeply about it. However, a wee piece is perhaps missing in relation to resilience.

The NIC is the organisation in the UK that is—or was, until it was subsumed into a wider body in the past few months—very good on resilience. That is why its recommendations in the second national infrastructure assessment had a greater emphasis on things such as hydrogen storage at greater scale than the CCC's equivalent modelling. In short, beyond what we have said already, my additional point is that hydrogen can play a really important role in energy resilience.

Mark Ruskell: Okay. Is that in the context of society becoming increasingly electrified in terms of both transport and heating, and therefore needing a back-up system to release that energy during winter or at other times when demand is high?

Dr Gill: Yes. There is that national, societal aspect. I also feel that where industry absolutely requires baseload industrial processes, it is important to think about how specific sites would roll through an event similar to what happened in Spain, for example. If you have a national blackout, how do you deal with industrial processes that really need to carry on? I do not know the answer to that. If there is no electricity supply, one option is for all those sites to have electrical batteries on site, which could be quite expensive. Hydrogen storage might be an alternative way to provide that resilience on a site-by-site basis and on a national basis—you might think about the issue in those two contexts at least.

Mark Ruskell: Does Mark Symes want to chip in on this?

Professor Symes: Yes—thank you. In fact, where and how we use the hydrogen are really important questions. You referred to the hydrogen use ladder, covering fertilisers, aviation fuel and shipping fuel—all the things that we are talking about. Those are all things that would be made in centralised facilities, and that plays well into the idea that we would have an industrial hub at Grangemouth.

It also plays into two other things. I have already raised one and will raise the other now. The first is public acceptance of hydrogen. If hydrogen is being used in a centralised facility by experts, a lot of the concerns that the public might have around hydrogen use domestically go away.

Secondly, there are what are called fugitive emissions. You heard from the first panel about hydrogen slipperiness. It is a very small molecule, and it tends to leak out of places. That is not necessarily an issue, but it effectively means that we end up with hydrogen pollution. Hydrogen is not a greenhouse gas itself, but it interferes with processes in the atmosphere that break down methane, which is a very powerful greenhouse gas. If we have lots of emissions of hydrogen from leaks, that could act as an agent of global warming by prolonging the lifetime of methane in the atmosphere. Having centralised facilities where we could better control and monitor those leaks could be an advantage. The role that hydrogen plays could therefore perhaps be in making things that we are already used to using, such as hydrocarbons and ammonia.

Mark Ruskell: Thank you very much—that is very useful.

The Convener: The next questions come from the deputy convener, Michael Matheson.

Michael Matheson: Good morning. I turn to the issue of the export potential of hydrogen from Scotland, particularly green hydrogen, which the Scottish Government emphasised in its previous hydrogen action plan. What do you think the potential is for the export market in green hydrogen, and what role do you think Scotland can play in that market, particularly at a European level?

Dr Gill: Some work has been done to scope out what might happen with a pipeline between Scotland and Europe and to consider the relative economics of hydrogen production in Scotland versus hydrogen production elsewhere. My understanding is that Scotland could be cost competitive if we were to make an early start on getting hydrogen produced in Scotland, getting a pipeline built across the North Sea and feeding into markets for the use of hydrogen, which appear to be developing in Europe a bit faster than they are in GB—that is particularly the case in Germany.

On a purely economic basis there seems to be a case for it, but it is something that we need to get on with. There is a risk that we will face stiff competition from places in the south of Europe and perhaps north Africa, where the production of green hydrogen from solar power could be significantly cheaper even than our cheap wind power—if it is cheap—in Scotland. That needs to be taken into account.

One of the big things to note is that that depends on a centralised, strongly Government-supported pipeline investment between Scotland and elsewhere. A lot needs to happen around that to realise it.

The other option is that, as we develop a GB-wide pipeline system for hydrogen—a transmission network—we could think about Scotland exporting to Europe via England and via interconnectors that connect further south, in much the same way that the natural gas system works today. Ultimately, that feels like a more likely scenario, but it is also a much longer-term scenario. I imagine that developing a national hydrogen core network within GB and then connecting through to Europe would mean looking to the early 2040s, rather than any earlier date.

Michael Matheson: Since Jan Rosenow or Mark Symes do not want to come in on that issue, I have another question. Given that it appears that some mainland European countries, particularly Germany, are further ahead of us in developing this technology, is export potential likely to be a key driver in the growth of the green hydrogen sector in Scotland? If so, will that be to a greater extent than demand on a domestic level?

Dr Gill: My view is that the best option for Scotland is the GB domestic market—not only the Scottish domestic market. However, that depends on the pipeline infrastructure in GB, which I have talked about.

There is a risk that that market will develop slowly or that it will not develop at all—it is in the hands of the UK Government and the National Energy System Operator. Ideally, it would develop during the early 2030s and be fully in commission in the late 2030s. That would provide confidence for green hydrogen providers to connect into the network and access the demand from GB and then, potentially, from Europe and further south. However, there is a risk. Scotland and the Scottish Government should think about what happens if that market does not come to pass, or it does not come to pass as quickly as we would like it to.

There are issues for the offshore wind sector in Scotland associated with the ability to get its energy out of Scotland. At the moment, it depends entirely on the electricity transmission network and the interconnectors—the only interconnector that Scotland has is to Northern Ireland. It is important to think about that issue.

As far as I can tell, the economics are in the balance. I am slightly sceptical about how easy it will be to realise that market but, in light of what else is happening and the direction of travel from the UK Government and NESO, we should be continuing to develop plans for it.

Michael Matheson: My final question is, where do you think that the hydrogen sector will be in the next 10 years?

Professor Symes: We are at a crossroads. We can decide, as a society, that we are going to invest in hydrogen, as China invested in batteries 15 or 20 years ago, and we can turn the UK—or, indeed, Scotland—into a powerhouse for hydrogen innovation for production, use, storage and conversion. On the other hand—I genuinely think that we might do this—we could sit back and say that we think that it is too expensive right now, and watch other people take up the mantle.

From a fundamental resource point of view, we have everything that we need in Scotland to generate large volumes of hydrogen, if we invest in the renewable energy sector and in ways of converting that hydrogen. Export of hydrogen is more likely to happen and to be more valuable in the form of things such as sustainable aviation fuels. I am going out there a bit now and stating my opinion but this is what you wanted to hear. The main profit will be in those liquid fuels. We have an opportunity, including through the decisions that this committee makes, to set the tone for how the hydrogen sector develops in Scotland over the next decade or so.

Dr Rosenow: A lot will depend on what we do on the demand side. I have said before that it will be important to think of the hydrogen economy that will be created, not just from a production perspective but from the perspective of stimulating uptake on the demand side. If we can get that right, there could be a buoyant market and a vibrant hydrogen industry. If we do not do that, I fear that we will not see the uptake that should be possible and is required to reach that place.

We need a much more granular debate about how we build markets for long-term storage, for example, and about how we get sustainable fuels derived from hydrogen into the market. That is an area in which I would love to see more action and more political engagement from Governments.

12:00

Dr Gill: I will answer the question in a slightly different way. We absolutely need a strong, evolving green hydrogen sector by the mid-2030s. I say that because we are putting a lot of focus on decarbonising electricity fully through the clean power 2030 action plan. That is a good, strong push to take the sector forward. However, it effectively draws forward the development of renewable electricity generation ahead of the creation of new electrified demand, so we will end up in a situation in the early 2030s in which we have even more of an excess of renewables than we may have been expecting without the clean power 2030 plan.

We need to focus on ways to use that electricity. Green hydrogen is one of the most important ways to take electrical energy, turn it into a different form and use it in some of the sectors that we have been talking about. Scotland needs to be at the forefront of that because we already experience most of the curtailment: last year, there were 4 terawatt hours of curtailment of Scottish wind power. The numbers in National Grid and NESO's scenarios show that they expect us to have about 60 terawatt hours of curtailment by 2035. If we do not get on and electrify things and develop a hydrogen economy and green hydrogen, there is a huge amount of energy that will not be used efficiently, so we must do that.

My concern is that, with the focus on the clean power 2030 plan, some of the longer-term issues will get put on the back burner. We do not have time to do that—it takes a decade or more to get the necessary infrastructure up and going.

The Convener: Mark Ruskell has a quick question about markets.

Mark Ruskell: I want to go back to the issue of the export market to EU countries and the status of blue hydrogen in that mix. If blue hydrogen is going for export, will there be countries that want to buy it? Does it have integrity as a low-carbon form of hydrogen or are the market rules already shifting towards green hydrogen? How long will that blue hydrogen export market exist, does it have integrity now and will it continue to have integrity in the future?

All the witnesses are nodding; I will go to Simon Gill first.

Dr Gill: I might pass the question to the others.

Mark Ruskell: I will go to Jan Rosenow.

The Convener: The trouble is that if you all look away or do not say anything, we have to nominate somebody to answer, and a pressed person is not as good as a volunteer. Who would like to volunteer?

Dr Rosenow: Sorry—my microphone was muted.

Green hydrogen can always be sold, regardless of what the rules are, because it is a zero-carbon energy source. More risks are associated with the rules changing in Europe and becoming more stringent if you go down the blue hydrogen route.

There has been a shift in Europe in terms of the language and what the potential standards could be, towards being more open to blue hydrogen rather than being solely focused on green hydrogen. It highly depends on how those standards change. Green hydrogen seems to be the less risky option.

Professor Symes: I agree with what Jan said. From a chemical point of view, blue and green hydrogen are the same. Provided that the CO_2 from the blue hydrogen is stored effectively, there should be no environmental issues with that. However, we do not know what regulations will be brought in or what the public will think about blue hydrogen—that is, whether green hydrogen will be preferred.

The Convener: I thank you all for giving evidence this morning, and thank you, Simon Gill, for your paper, which was interesting. We will discuss the matter more as a committee in the private part of our meeting. Next week, there will be two more panels—one on green hydrogen and one on blue hydrogen and carbon capture.

12:04

Meeting suspended.

12:10

On resuming—

United Kingdom Subordinate Legislation

Persistent Organic Pollutants (Amendment) (No 3) Regulations 2025

The Convener: Our next item of business is consideration of a type 1 consent notification relating to a proposed UK statutory instrument. The regulations in question would remove two persistent organic pollutants from the list of those to be eliminated, due to certain uses of those chemicals, relating to medical technology, having come to light.

On 22 April, the Acting Cabinet Secretary for Net Zero and Energy notified the committee of the proposed instrument, which involves the United Kingdom Government legislating within devolved competence. The UK Government is seeking the Scottish Government's consent in that respect, and the committee's role is to decide whether it agrees with the Scottish Government's proposal to consent to the UK Government making the regulations within devolved competence and in the manner that the UK Government has indicated to the Scottish Government.

If members are content for consent to be given, the committee will write to the Scottish Government accordingly. In writing to the Scottish Government, we have the option to draw various matters to the Government's attention, and to pose questions or ask to be kept up to date on relevant developments. If the committee is not content with the proposal, we might make one of the two recommendations outlined in the clerk's note.

Do members have any views on the regulations?

Mark Ruskell: I note that the two chemicals in question have an impact on human health. The notes say that UV-328 is

"toxic for mammals, endangering human health and the environment (causing damage to liver and kidney),"

while dechlorane affects the nervous system of aquatic animals. It is right, therefore, that those chemicals are being phased out.

Although I accept the Government's approach and the representations that have been made by the medical industry, I note that those two chemicals will be prohibited in the European Union in autumn 2025. I am content to accept the regulations, but I would like to know whether the chemicals will be phased out on a similar timescale to that of the EU's. Given that the chemicals have an impact on the environment and human health, phasing them out is the right thing to do.

The Convener: We could easily write to the Scottish Government and ask those questions. However, if we are writing to the Government, we also have to give it an answer to the substantive question, which is whether the committee is content with the proposal. Is the committee content?

Members *indicated agreement.*

The Convener: We will write to the Scottish Government on that basis. We will also ask the Government to tell us the timescale on which it proposes to ban the chemicals.

Waste Electrical and Electronic Equipment (Amendment) Regulations 2025

The Convener: Item 4 is consideration of another type 1 consent notification relating to a proposed UK statutory instrument. The regulations in question would make two key changes to existing provision on extended producer responsibility for waste electrical and electronic equipment. First, they would extend the term "producer" to include online marketplaces, and secondly, they would create a new category of equipment for vapes and electronic cigarettes to ensure that producers are responsible for the waste disposal costs.

On 22 April, the Acting Cabinet Secretary for Net Zero and Energy notified the committee of the proposed UK SI. As with the previous instrument, the key issue is whether we agree with the Scottish Government that the UK Government should legislate in this devolved area in this way. If we are content for consent to be given, the committee will write to the Scottish Government accordingly. We have the option to pose questions or to take up any issues with regard to the date and relevant developments.

If members do not have any views on the matter, we will move to the substantive question. Is the committee content that the provisions set out in the notification should be made in the proposed UK statutory instrument?

Members *indicated agreement.*

The Convener: Thank you. We will write to the Scottish Government to that effect.

Petition

Air Quality Standards (PE2123)

12:15

The Convener: The next item of business is consideration of petition PE2123. The petition, which has been lodged by Asthma and Lung UK Scotland, calls on the Scottish Parliament to urge the Scottish Government to amend the Air Quality Standards (Scotland) Regulations 2010 by setting new limit values for nitrogen dioxide and fine particulate matter in order to align with the World Health Organization's 2021 air quality guidelines.

The committee first considered the petition in April, when it agreed to write to the Scottish Government to get an update on its review of its strategy, "Cleaner Air for Scotland 2: Towards a Better Place for Everyone". The Scottish Government responded on 22 April, and its letter is provided in annex B of the relevant paper, which also sets out some options for going further.

Do members have any views?

Sarah Boyack: This is an important issue for people's quality of life and health. The committee has now had a response from the Scottish Government. Given the petition's importance, could we write to the stakeholders who were involved in the inquiry that the committee did on this matter a couple of years ago to get an update and see whether they have any more thoughts? That might allow us to think about how we take the matter forward and whether we have enough information.

Mark Ruskell: I would welcome that approach. Since the committee last took evidence on this issue, which was in May 2023, we have seen quite a few changes. Low-emission zones have been rolled out in Scotland; there is increasing evidence with regard to particulates from wood-burning stoves; and new scientific evidence is coming along about the impact of air pollution on child development. Therefore, I would say yes to the suggestion that has been made. Now would be a good time to reflect on the evidence, take stock and write to the stakeholders who were part of the initial inquiry.

The Convener: Thank you. I think that the committee agrees that we should write to those who were involved in the 2023 report on air quality. I would like to consider carefully the list of people to whom we should write, just to ensure that we include those stakeholders, and the clerks will circulate the list to committee members for their agreement after the meeting. Depending on what we get back, we can decide on the next action then—I think that that is the simple solution.

Thank you, Sarah, for making that suggestion, and thank you, Mark, for agreeing.

Does the committee agree to the suggested action?

Members *indicated agreement.*

The Convener: We will now move into private session.

12:18

Meeting continued in private until 12:33.

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