Transcript

**Hydrogen CPD-Module 3-Transport and Storage**

Slide 1:

Hello, my name is Julia Race.
I'm a professor of Subsea and Pipeline Engineering in the Department of Naval Architecture, Ocean and Marine Engineering at the University of Strathclyde, and I will take you through Module 3. This session will provide an overview of hydrogen transport and storage.

Slide 2:

There are currently 4 1/2 thousand kilometres of hydrogen pipelines in operation worldwide, so we are very familiar with material selection and safe pipeline operations.
Nearly half of these pipelines are in the USA along the Gulf Coast, where hydrogen is transported as a chemical feedstock from producers to industrial sites where it is used, for example, in the production of ammonia.
In Europe, the longest hydrogen pipeline is a 964 kilometre network operated by Air Liquid, which delivers hydrogen for chemical and petrochemical use in the Netherlands, Belgium and France.
An important consideration for transporting hydrogen is that while methane has three times the calorific heating value of hydrogen, hydrogen can be transported at much higher velocities than methane, meaning that the overall net energy transportation capacity of a pipeline converted to hydrogen from natural gas is only slightly smaller depending on compression and pumping costs.
There is a huge global investment in developing hydrogen pipelines, and the European hydrogen backbone is looking to establish hydrogen supply corridors by 20-30 and progressively connecting European and neighbouring regions.
This is to be realised by converting pipelines that fall redundant due to declining natural gas demand to minimise stranded assets and by developing new infrastructure where needed.
Retrofitting pipelines can save 65 to 90% of the cost of new pipeline development.

Slide 3:
It is anticipated that the development of a hydrogen pipeline network will be analogous to the development of a natural gas pipeline network.
It's, therefore, instructional to consider the component parts of a typical gas pipeline network.
In a gas system, gathering pipelines or flow lines collect the gas from the wellhead and transport it back to a rig or processing facility where it is partially processed, primarily to remove water.
Gas from a number of different wells could be collected at a single processing facility.
The gas is then transported via transmission pipelines which transfer the gas from an offshore to an onshore facility or for long distances between onshore facilities.
Transmission pipelines are generally between 6 inches to 56 inches in diameter and operate at high pressure.
In order to deliver the gas to industrial users and domestic customers, the gas undergoes pressure reduction before transfer to the distribution pipeline system.
The distribution pipelines are typically 2 to 10 inches in diameter and operate at pressures of less than 7 bar.
A hydrogen network would look very similar to this.

Gathering lines might collect hydrogen from a number of production sites, either onshore or offshore, to a gathering facility.
Transmission pipelines would transport the hydrogen from the facility, for example, offshore wind farms or between industrial clusters onshore, and distribution lines would transport the hydrogen to industrial and domestic end users.

So, the development of a hydrogen network would share many of the characteristics of the natural gas pipeline network.
However, there are a few additional considerations that have to be taken into account.
Gas moves through the transmission pipeline network as a result of pressure difference between the inlet and the outlet of the pipe.
This pressure difference is generated using compressors that raise the pressure at the inlet.
As the gas travels through the pipeline, it loses pressure due to frictional loss and therefore compressor stations are required at specified distances along the pipeline to raise the pressure again and maintain the differential.
Though the density of hydrogen is lower than that of methane, the energy density per unit volume is about 1/3 of that of natural gas.
Therefore, to attain an energy flow that is equivalent to natural gas at any given pressure, the volume speed of hydrogen in the pipeline needs to be increased threefold relative to natural gas.
This increases the velocity of the gas in the pipeline and also has an impact on the types of compressors used, potentially requiring an increase in compressor capacity in the network for the increased volumes of gas.
Gas transmission pipelines tend to be constructed from plain carbon steel, although stainless steel and corrosion-resistant alloys can also be used in highly corrosive environments.
High-strength polyethylene and low-strength steel are used in the distribution system, although older gas distribution pipelines can be made from cast iron.
It is likely that hydrogen pipelines will be constructed from steel and polyethylene for new pipelines.
More on this later although as there are still cast iron mains in the distribution system, the compatibility of cast iron for hydrogen service is being investigated.

Slide 4:
Industrial clusters not only serve as hubs for the growth of local hydrogen economies but, in time, will connect to support the wider growth and connectivity of the hydrogen economy.
The High NTS Project is focused on developing a UK hydrogen pipeline backbone to provide the necessary high-pressure and volume hydrogen transmission network for delivering hydrogen to industrial and power users across the country in the same way as the National Transmission System, or NTS, does for natural gas today.
It is also designed to connect the European hydrogen backbone network to make the most of European hydrogen import and export opportunities.

Slide 5:
If the National Transmission System, or NTS, is the artery of the gas network, the Local Transmission System or LTS, are the veins of the gas energy network, delivering gas from the NTS to towns and cities across the country.
Launched in April 2022, SGN's £30 million LTS Futures project is a three-year project assessing the viability of repurposing Great Britain's 11,000 kilometer local transmission system from natural gas to 100% hydrogen.

The LTS Futures project involves repurposing a decommissioned pipeline to hydrogen through a live trial.
A statistically representative pipeline between Granton in Edinburgh and Grangemouth has been selected, and over the past year, a wide range of detailed survey and assessment evaluation tests have been undertaken to check for any issues ready for the live hydrogen trial.
In the last few weeks, Ofgem has given permission to continue to the second stage gate, which is to connect the pipeline to a hydrogen supply from project partners Ineos at Grangemouth in advance of the live hydrogen trials.

Slide 6:
Compared with natural gas, hydrogen has particular features that affect the design of the steel pipelines. Atomic hydrogen, dissociated from hydrogen gas on the steel surface, can diffuse into the steel structure and permeate through the steel from areas of high to low concentration.
This has an effect on the storage capacity of the pipeline, but more critically, the hydrogen can accumulate in the microstructure of the steel and degrade the ductility and toughness, termed hydrogen embrittlement, which can lead to cracking.

Slide 7:
The extent to which hydrogen affects the properties of pipeline steel is dependent on the microstructure of the steel, the loading conditions on the pipeline in terms of the applied stress, and the nature of the environment containing the hydrogen.

In general, the susceptibility of steel to hydrogen embrittlement increases with increasing strength.

Consequently, the standard for hydrogen pipelines in the USA, ASMI B 31.12, advises a limitation on the maximum strength of steel that can be considered for hydrogen pipelines.
Grade X52, which has a minimum yield stress of 358 megapascals and suggests a limitation on the maximum operating stress of the pipeline of between 30 to 50% of the minimum yield stress of the pipeline.
This limitation on material grade may affect the suitability of some pipelines in the network for repurposing from natural gas to hydrogen.
When developing a pipeline network, and in particular when deciding on the roof of a new pipeline, the risks associated with an escape of gas have to be considered to ensure that the risk of failure is as low as reasonably practicable to protect life, property and the environment.
Here, we make a distinction between a leak event and a rupture event.

In terms of leaks, as mentioned previously, hydrogen is able to permeate more readily through materials than methane, increasing the risk of leakage through joints and seals.
Hydrogen can also permeate through polymer materials, for example the material used for distribution pipelines, and does this at higher rates than methane.
Although the total loss of hydrogen by permeation is not considered economically significant due to the lower energy losses.
As methane is colourless and odourless, leaks are difficult to detect, so an odorant is added to the gas that alerts the public to a potential leak.
Odorants that are compatible with hydrogen gas are also being developed, although it has to be ensured that they are compatible with the intended end use, as some odorants can poison fuel cells and, therefore, have to be removed at the point of use.
For hydrogen pipelines, as is the case for natural gas pipelines, the consequence of a large-scale failure or rupture of the pipeline is a release of a cloud of gas into the atmosphere, which, if it were to find a source of ignition, would burn.
The procedures for conducting a dispersion and thermal analysis for release of natural gas from a pipeline, which subsequently ignites, are well understood and robust risk assessment methodologies are in place, regulated through pipeline standards.
However, when conducting consequence analysis for a hydrogen pipeline, there are some differences that need to be taken into account.
Firstly, as mentioned previously, hydrogen is lighter than methane, and therefore, it disperses more quickly away from the point of release.
However, the flammability range of hydrogen is much wider than that of methane, which means that it requires less air to burn.
In open areas, hydrogen will burn quickly.

However, a hydrogen fire radiates less heat than a natural gas fire, so the risk of thermal damage is reduced compared with methane.

Understanding these differences and including them in the well-established risk assessment procedures for gas pipelines ensures that hydrogen transmission and distribution pipelines can be designed and constructed safely.

Slide 8:
Moving on now to consider hydrogen storage technologies.
Commercial hydrogen storage technologies used in automotive applications occupy the extremes of this phase diagram.
Hydrogen is often stored as a compressed gas, the red dot at ambient temperature shown on the horizontal axis, very high pressure indicated by the dotted lines, and relatively low density shown on the vertical axis.
On the left-hand side, hydrogen is much more compact as a cryogenic liquid, the blue dot, but with higher energetic cost.
The solid lines indicate the theoretical minimum work, also known as thermomechanical exergy to compress and or liquefy hydrogen.

Cryogenic capable pressure vessels have flexibility to operate across a broad region shaded in green of the phase diagram and therefore can be fuelled with gaseous hydrogen at low energetic cost.
When energy or fuel cost savings are important, or with liquid hydrogen when a long driving range or low-pressure operation is desired.

Slide 9:
Hydrogen can be compressed and stored in a gaseous form under high pressures.
This requires storage tanks to have pressures of 350 to 700 bar.
That's 5000 to 10,000 PSI.
The high-pressure gaseous hydrogen storage device has a fixed hydrogen storage tank, a long tube gas cylinder and a long tube bundle, a cylinder and a cylinder group, and the vehicle hydrogen storage bottle.
There are four types of high-pressure cylinders for tank storage.
Type I are pressure vessels of metal material.
Hydrogen for industrial gas is stored in type one tanks, which have pressures between 150 and 300 bar.
These are currently the most widely used and cheapest high-pressure tanks, but they are not suitable for use on vehicles due to their heavyweight Type II pressure vessels are made of a thick metal ring liner wrapped with a carbon fibre or glass fibre material.
They are used as high-pressure tanks in hydrogenators as they can withstand up to 1000 bar.
Type III tanks are pressure vessels consisting of an internal metal liner to prevent hydrogen leakage by diffusion, fully wrapped with composites which can withstand the mechanical stress by removing thick metal walls and increasing composites.
These vessels are less weighty than types I and II.
The type IV tanks are pressure vessels made of a high-density polymer liner which acts as a gas diffusion barrier fully enclosed with a carbon fibre compound.
These tanks are equipped with metal valves for hydrogen refuelling and supply.
They can withstand pressures up to 700 bar.
Type III and IV vessels are designed for portable applications for which weight savings are essential.
Where pressures between 350 and 700 bar are required, however, these vessels are much more expensive due to the use of carbon fibre.

Slide 10:
Cryo-compressed hydrogen provides a solution between the two extremes of compressed hydrogen at ambient temperature and high pressure 700 bar and liquid hydrogen below its boiling point of -253°C or 20 Kelvin at ambient pressure.
Cryo-compressed hydrogen not only offers the highest density for hydrogen in the vehicle storage tank, also requires less conditioning effort and corresponding equipment for refuelling.

Slide 11:
Regardless of whether the hydrogen refuelling solution is starting with compressed hydrogen or liquid hydrogen as a fuel, hydrogen can be stored cryogenically in a liquid form.
Low temperatures are required to stop the liquid hydrogen from boiling off back into a gas, which occurs at -252.8°C.
Liquid hydrogen has a higher energy density than gaseous hydrogen.
However, hydrogen liquefaction, getting it down to the required temperatures can be costly, consuming 4 to 10 kilowatt hours per kilogram, which is almost equivalent to the cost of 1/3 of liquid hydrogen.

Slide 12:
Liquid hydrogen storage vessels require excellent adiabatic devices to insulate them from boiling vaporization.
In addition, storage tanks and facilities for cryogenic liquid hydrogen storage must be insulated to prevent evaporation should any heat be carried into the liquid hydrogen due to conduction, confection, or radiation.
Cryogenic storage tanks are perhaps the part of the value chain with the highest technology readiness level, as several suppliers offer storage solutions for a range of volumes.
Liquefied hydrogen is transported in tank trucks and stored in cryogenic vessels, including specially designed ships moving up from the kilowatt to terawatt scales of hydrogen storage required for net zero takes us beyond the capacity of above ground storage tanks and into the realm of subsurface storage to deliver the required volumetric capacities.

Slide 13:
There is a wide range of underground geological hydrogen storage technologies available, which include kilowatt and MW scale storage in subsurface silos and tanks, GW scale storage in lined rock caverns, GW to Terawatt scale storage in solution mine salt cabins and ultimately on to terawatt scale storage in porous rocks such as depleted gas reservoirs and porous aquifers.

Slide 14:
The UK National Grid Future Energy Scenarios illustrates the scale of grid storage required.
The graph on the left shows the relatively small amount of consumer hydrogen needed by 2050, 10 Terawatt hours.
The yellow bars relative to the system transformation at over 50 Terawatt hours.
The blue bars relative to the system transformation at over 50 TWh.
The graph on the right illustrates that this transformation to grid-scale storage will require a change from engineered surface tanks to engineered subsurface geological storage.
Only geological storage provides the megawatts to gigawatts of capacity needed for months of discharge within the existing gas network.

Slide 15:
One of the most important short term storage technologies is line packing, i.e. increasing the amount of hydrogen in the existing high pressure national transmission pipelines.
This is where the gas in the pipeline is increased in pressure, enabling a higher energy density within the pipeline that is then ready for deployment when there is high demand.
So for example, this will occur overnight.
When demand is low, the NTS is pressurized with more gas, which is then ready to deploy in the morning when demand rises due to the low volumetric density of hydrogen.
This same network would be anticipated to store only 25% of this level of energy and work is underway to investigate the impact of this.

Slide 16:
We do have experience of storing hydrogen in geological formations to demonstrate the technical and commercial feasibility of underground hydrogen storage.
It began with the commercial storage of towns gas which was 50% hydrogen in porous aquifers over many decades.
Lobodice in Chechnya is now a natural gas storage site.
Kiel in Germany is now operating with natural gas and hybrid decarbonises steel production in Sweden.
We've also stored 100% hydrogen in three salt caverns in the UK for over 50 years for the chemical industry, and the new Swedish hybrid lined rock cavern, which is providing hydrogen storage for decarbonized steel manufacturing, has just begun gas tightness testing with hydrogen.
There is, however, limited experience with the required fast cycling needed during hydrogen storage, and there are several pilot hydrogen projects underway around the world, including two in the UK.
One in the Oldborough salt cabins and the second in the rough gas storage site.

Slide 17:
There is significant uncertainty surrounding hydrogen storage costs, and the figure on the screen shows our best guess at the moment for cost per stored kilogram of hydrogen, for the geological storage of hydrogen in depleted gas fields, salt cabins and rock cabins, and for the storage of liquid compressed or chemically bonded hydrogen in above-ground containers.
One thing is for certain is that for grid-scale storage, geological storage will be the most cost-effective option.
But until we have operational pilot sites, it will be impossible to die down the actual CAPEX, OPEX, cycling frequency, injection rates, production rates and round-trip efficiencies from underground hydrogen storage.

Slide 18:
This concludes the third module of the hydrogen course.
The next module, module 4, covers hydrogen HSE and regulations.
Thank you for your attention.
Please note down any questions or comments and bring them to the webinar that completes this course.