White Paper

Automating Hydrogen Blending to Improve Operations

EMERSON

In This White Paper

Blending of natural gas with hydrogen offers a potential for carbon dioxide emission reduction in fuel gas combustion applications. However, the process has limitations and poses control challenges.

Reducing the effects of climate change through greenhouse gas (GHG) reductions has become a global endeavor that is being pursued with increasing diligence. Initial efforts to lower GHG emissions focused on methane, NO_x, and fluorinated gases due to their high global warming potential. As those sources were mitigated, attention turned toward carbon dioxide (CO_2) reduction due to the sheer volume of this gas emitted into the atmosphere. In the United States, CO_2 accounts for nearly 80% of GHG emissions.

One readily implemented option that can have immediate benefits for CO_2 reduction is hydrogen blending with natural gas. Every molecule of hydrogen burned instead of methane, the main component of natural gas (other components are only present in minute amounts), eliminates a molecule of CO_2 emissions, potentially creating a significant GHG gas reduction for every natural gas-burning application in industry, homes, and the transportation sector.

While simple in concept, hydrogen blending poses several chemical, logistic, and control challenges. This white paper discusses the benefits and difficulties associated with hydrogen blending, and it offers suggestions for how to measure and control the blending process.

A Burgeoning Environmental Problem

Globally, CO_2 emissions have been exponentially growing for decades, leading to increases in the average global temperatures and impacting weather patterns across the world (Figure 1). At the current rate of GHG emission acceleration, the long-term prognosis has many climate experts and government entities issuing warnings of significant and lasting impacts.

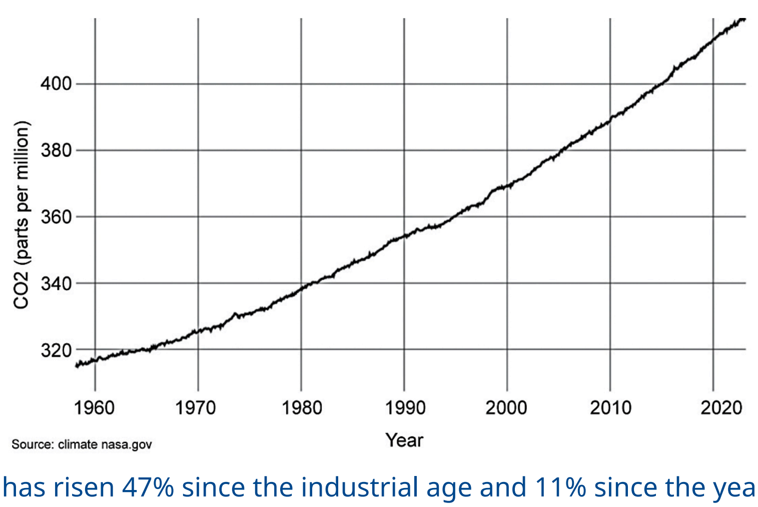

Figure 1. Atmospheric CO_2 has risen 47% since the industrial age and 11% since the year 2000. The average winter temperature in the United States has risen 3 °F since 1896. *(Figure courtesy of Climate.nasa.gov)*

A significant source of CO_2 emissions comes from burning coal and hydrocarbon fuels. The amount of CO_2 is directly proportional to the amount of carbon in the fuel. Consider the effects when the following fuels are burned for energys:

$$\text{Coal } (C_{137}H_{97}O_9NS) + \text{Oxygen } (O_2) \rightarrow 137\ CO_2 + 48\ H_2O + NO_2 + SO_2$$
$$\text{Gasoline } (C_8H_{18}) + \text{Oxygen } (O_2) \rightarrow 8\ CO_2 + 9\ H_2O$$
$$\text{Methane } (CH_4) + \text{Oxygen } (O_2) \rightarrow CO_2 + 2\ H_2O$$
$$\text{Hydrogen } (H_2) + \text{Oxygen } (O_2) \rightarrow 2\ H_20$$

Clearly the more carbon, the bigger the greenhouse gas effect. Coal contains as much as 75% carbon, so coal combustion creates significant CO_2 emissions. Gasoline is a hydrocarbon with more than twice as much hydrogen as carbon, so it creates less CO_2 when burned. Natural gas (methane) burns much cleaner, only creating a single CO_2 molecule for every molecule of methane burned, which explains why natural gas combustion is preferred over coal from a GHG emission perspective. Hydrogen offers the best fuel burning alternative, creating no CO_2 emissions at all.

Unfortunately, natural hydrogen is in very short supply, and the gas is mostly created through industrial processes that can create significant GHG gases as well. Hydrogen can be created through electrolysis powered by sustainable sources such as wind or solar. This hydrogen, called “green hydrogen”, has no GHG gases associated with it and is preferred, though green hydrogen sources are limited and currently in short supply.

An alternative option is to use existing industrial processes such as steam methane reforming (SMR) or auto thermal reforming (ATR) to make hydrogen, and to then capture and sequester the emitted CO_2. This hydrogen, called “blue hydrogen”, creates significantly reduced GHG emissions and is much more readily available since it utilizes existing industrial processes as a starting point.

As clean green or blue hydrogen becomes available, an obvious source of CO_2 gas reduction can be immediately achieved by blending hydrogen with natural gas for fuel combustion applications. As methane is gradually replaced with hydrogen in the fuel gas blend, the resulting CO_2 emissions are reduced (Figure 2). CO_2 emissions reach zero as the hydrogen concentration attains the 100% level.

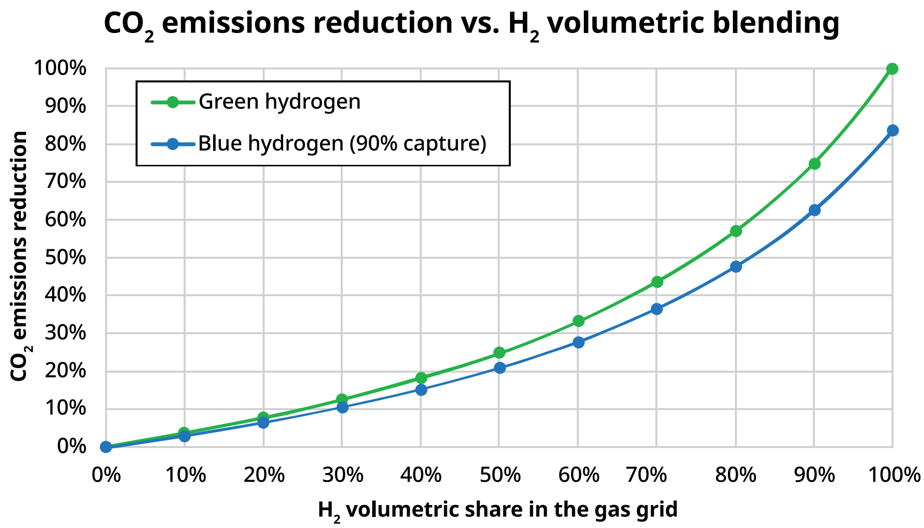

Figure 2. As methane is gradually replaced with hydrogen, the resulting fuel gas mixture will burn with reduced CO_2 emissions. Green hydrogen will have higher reductions since the hydrogen production process inherently generates no CO_2.

Hydrogen Blending Concept

Theoretically hydrogen blending offers an easily implemented strategy for reducing CO_2 emissions resulting from the burning of natural gas. The existing natural gas transportation network is enormous (Figure 3), offering a ready-made means of transporting the cleaner burning fuel gas blend to existing users.

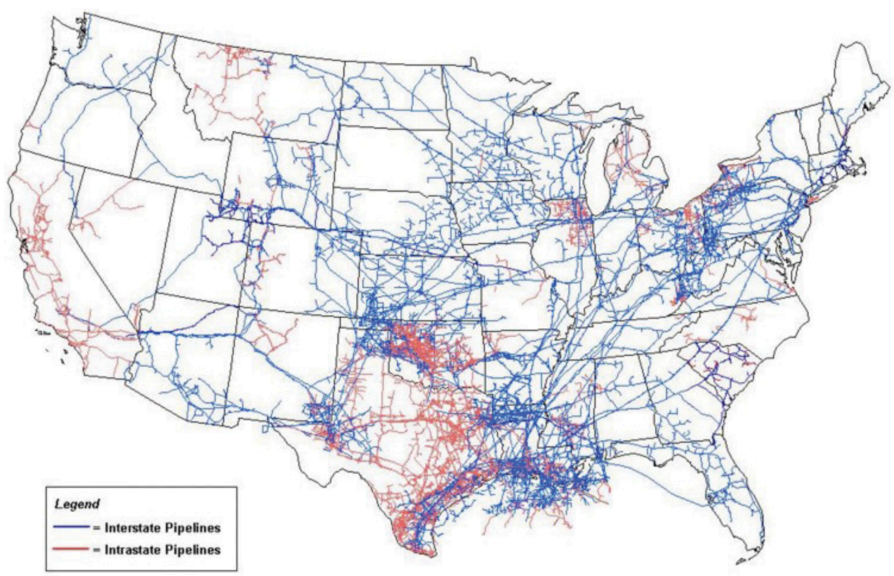

Figure 3. The existing natural gas transportation in the United States is enormous and well established. *(Courtesy of US Department of Energy)*

Ideally existing natural gas combustion equipment (industrial boilers, heaters, and gas-fired home appliances and furnaces) could burn the cleaner burning hydrogen mix, reducing CO_2 emissions at a global scale.

Carbon dioxide emission reductions are tied directly to the concentration of hydrogen in the mix, so as clean sources of hydrogen become available, they would ideally be used to increase the hydrogen blend as high as possible.

The concept sounds promising, but unfortunately there are stark realities associated with hydrogen blending that limit its implementation well below the theoretical maximums.

Hydrogen Blending Realities

The first challenge associated with hydrogen blending is caused by hydrogen itself. High concentrations of hydrogen can defuse into the walls of metal pipelines, making them prone to cracking and stress corrosion. The rate of hydrogen embrittlement depends on a number of factors, including the specific metals involved, the level of existing corrosion and stress in the pipe, the concentration of hydrogen, and the operating pipeline pressures.

The existing natural gas transportation network is vast and aging, so its ability to handle high concentrations of hydrogen is difficult to predict. The existing network also has specific pipe coatings and may have non-metal components near the point of use, which may not handle high hydrogen concentrations well. Overall, the long-term potential risk of pipeline failure appears to increase with increasing concentrations of hydrogen. Lower concentrations of hydrogen seem to have little effect on the pipeline infrastructure.

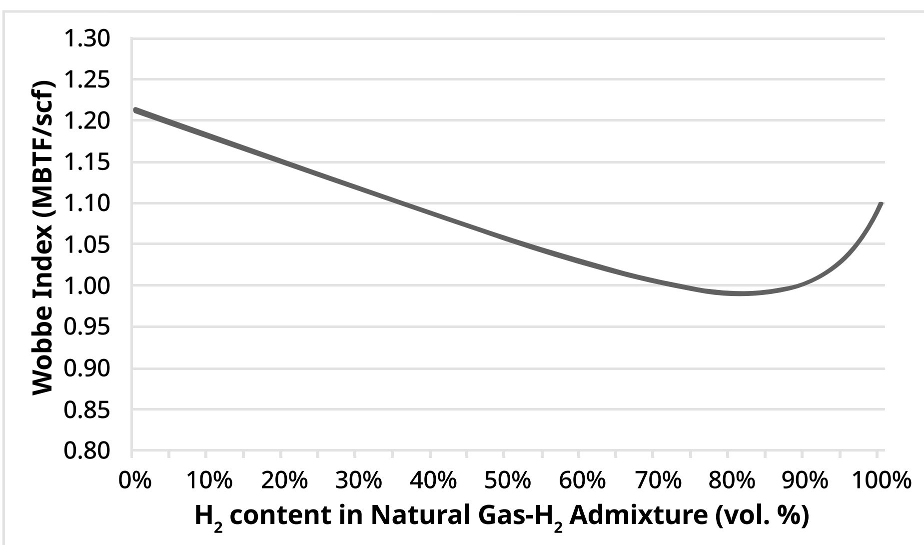

Figure 4. Hydrogen has a lower heating value than methane, so the resulting fuel mix heating value will fall as the hydrogen concentration is increased. *(Courtesy of National Renewable Energy Laboratory)*

If the pipeline infrastructure can handle higher pressures, it is possible to raise the operating pressure and deliver the same net energy to the field, but this increases compression costs.

One option to address these issues would be to inject hydrogen closer to the point of use, provided hydrogen is available in these areas. This limits pipeline exposure and compression issues, but each injection station will have capital and operating costs associated with it, increasing the blending project net cost considerably.

There are other challenges associated with hydrogen blending. As the percentage of hydrogen increases, the fuel mixture burns differently. Higher concentrations of hydrogen affect flame formation and stability, and they can create problems with fuel burning equipment. Most devices handle low concentration blends with minimal to no effect, but high hydrogen concentrations create operability problems.

Another less obvious challenge is that associated with electrical classification. Methane is classified as Class 1 Group D. Hydrogen concentrations of 30% or higher are classified as Class 1 Group B. Many devices that carry a Class 1 Group D rating are rated for Class C as well. However, far fewer devices are rated for Class B, so hydrogen blends above 30% may require replacement of electrical equipment throughout the transportation network.

For all these reasons, lower blended concentrations of hydrogen are a much more viable option. The potential CO_2 emission reduction of the resulting blend is less dramatic, but the numerous challenges associated with high hydrogen concentrations are largely eliminated. A number of pilot studies around the world suggest a hydrogen blend of 20–25% can be safely implemented within the existing natural gas distribution network, while performing well with existing combustion equipment.

Blended Hydrogen Metering

Extensive studies have been performed to investigate the flow measurement of hydrogen blends (Figure 5). One project, the JIP Renewable Gases DNV Groeningen Project in the Netherlands, created a circular flow loop, which was tested at variable hydrogen blend percentages and pressures to investigate how a host of metering technologies performed. The net results were illuminating.

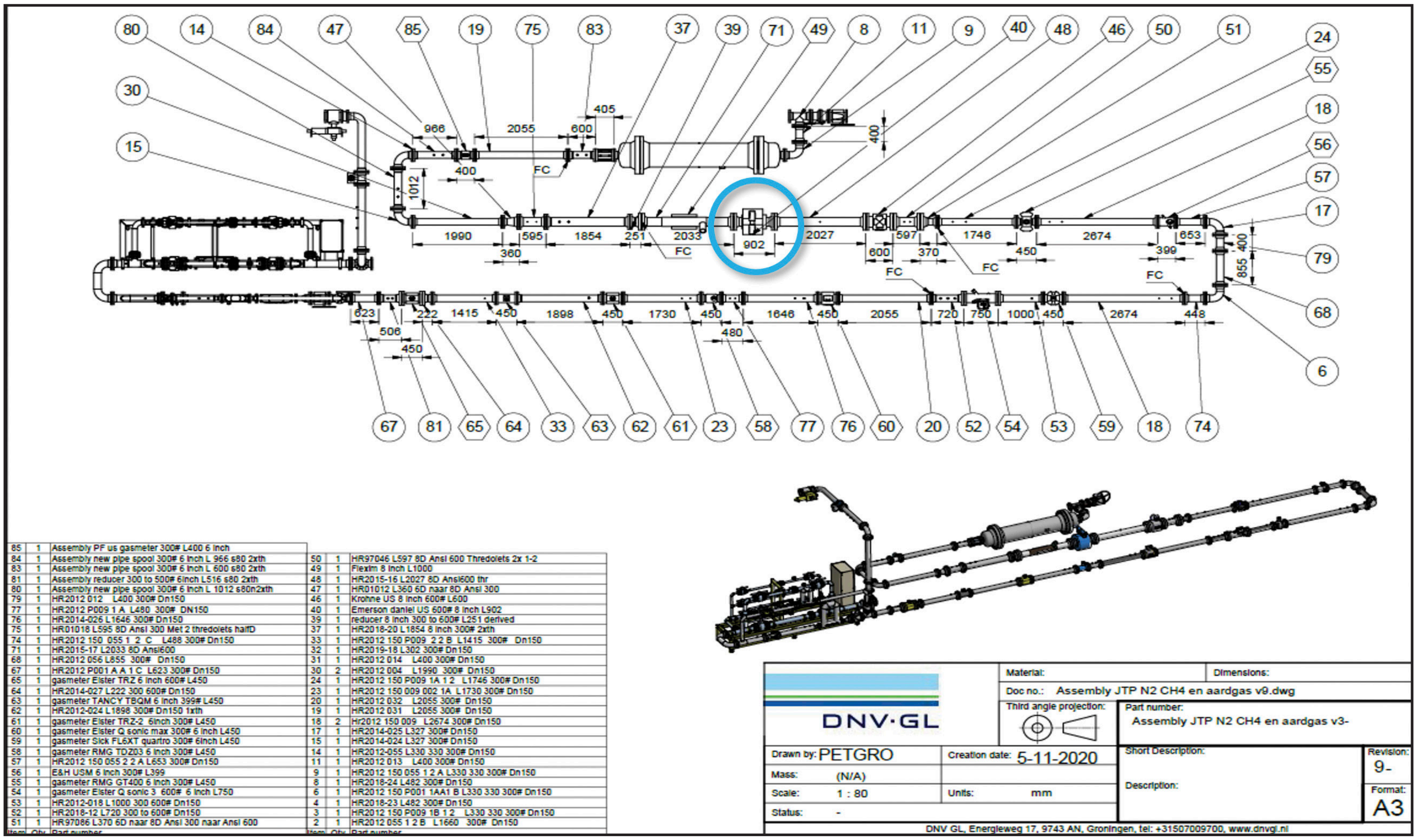

Figure 5. The Groeningen Project created a circulating loop of fuel gas to test variable hydrogen concentrations and pressures. The flow metering results of several metering technologies were compared against standardized flow meters.

Coriolis meters are generally considered the gold standard for flow metering, and they can handle the full range of hydrogen blends from 0 to 100% concentration (Figure 6). Unfortunately, Coriolis meters are generally limited in size to 16" or less, and the larger-sized meters (6" and greater) can be costly and bulky.

Figure 6. Coriolis meters are generally limited to 16" and tend to be costly at higher line sizes. However, they are very well suited and extremely accurate for metering hydrogen flow in blending applications.

As such, a Coriolis meter is not usually used for larger bore pipe natural gas metering, but it is an excellent choice for the smaller, pure hydrogen flow meter injection required in most hydrogen blending applications. The Micro Motion ELITE CMF Coriolis flow meter works well in this application, and it is certified for use in Group B, Class 1, Div 2 hazardous areas.

Differential pressure transmitters are another option for natural gas pipelines, but the reading must be compensated for component density, as well as temperature and pressure effects, and the pressure drop created by the orifice plate results in additional operating costs due to line loss.

Most natural gas metering utilizes multipath ultrasonic flow meters as their flow meter of choice (Figure 6). These meters cost far less than Coriolis meters in larger line sizes, have virtually no pressure drop, and are available in line sizes up to 42''.

Figure 7. Multipath and multi-sensor ultrasonic flow meters, like this Rosemount™ 3418 Eight-Path Gas Ultrasonic Flow Meter are an excellent choice for large natural gas pipelines.

Multipath technology improves flow measurement accuracy and reliability by making multiple measurements across many areas of the pipe to compensate for fluid dynamics and inconsistent flow profiles.

One of the key goals of the DNV Groeningen Project was to quantify the ability of ultrasonic flowmeters to accurately measure various blends of hydrogen and natural gas under a variety of conditions. The findings suggest that higher tier, multipath ultrasonic meters can measure blends of hydrogen up to 20% with very minimal loss in accuracy. However, as the concentration of hydrogen was raised above that value, increasing flow errors occurred. The testing did suggest that it might be possible to compensate for these errors using Reynold's numbers and other parameters, but research in that area is ongoing.

In the immediate term, the lab results confirmed that multipath flow meters, like the Rosemount 3417 and 3418, can be used on 20–25% hydrogen blends with minimal impact on flow accuracy.

Blended Hydrogen Controls

A typical hydrogen blending station is shown in Figure 8. It includes a full-bore ultrasonic flow meter to measure the incoming gas flow, a Coriolis meter and control valve to measure and control the hydrogen addition, and a downstream gas chromatograph to confirm the resulting blend.

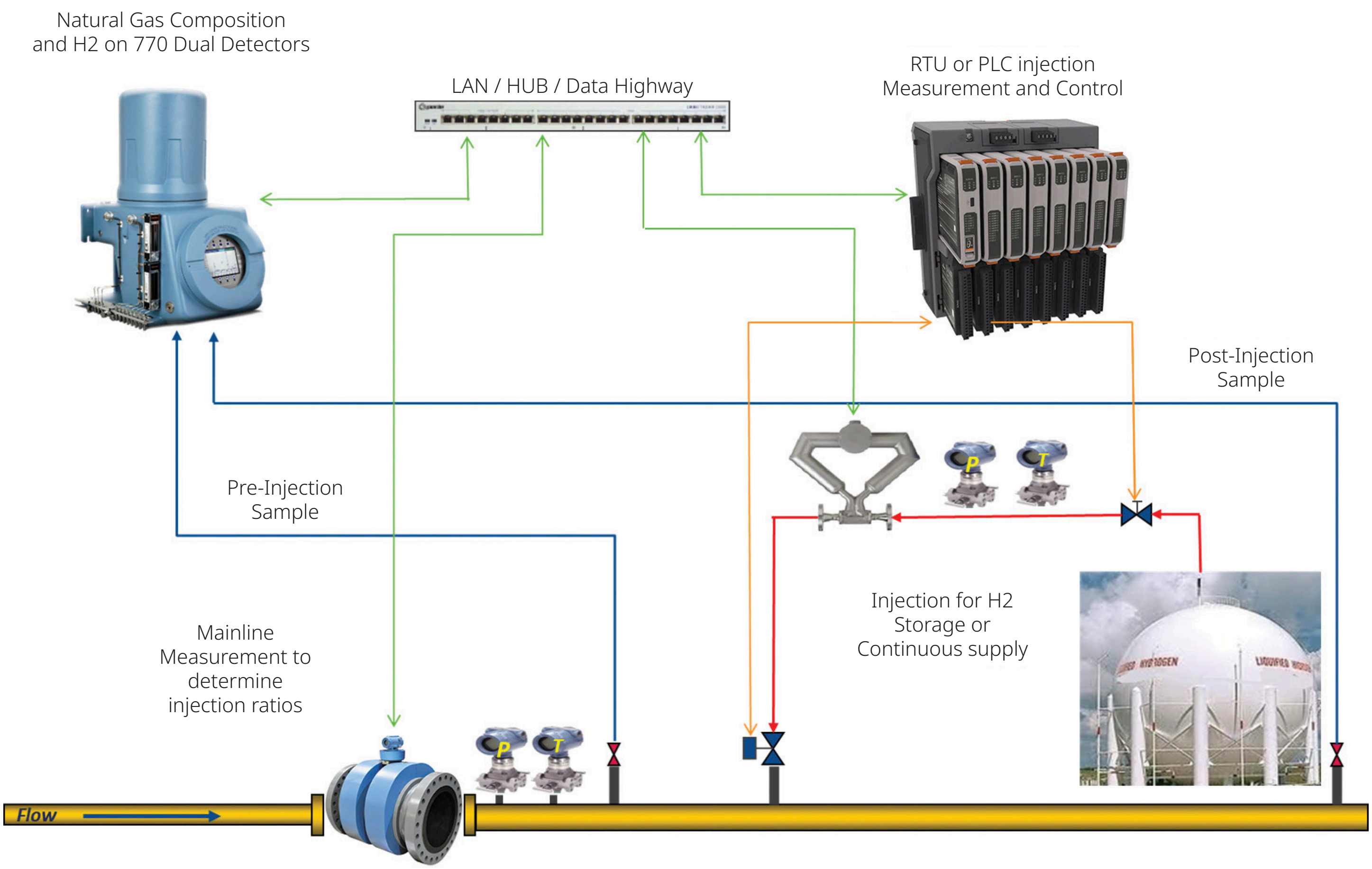

Figure 8. A hydrogen blending station will consist of a pressure/temperature compensated multipath ultrasonic flow meter on the incoming gas line, a pressure/temperature compensated Coriolis meter on the hydrogen line, and a gas chromatograph to confirm blend quality.

Both flow meters should be pressure and temperature compensated for maximum accuracy, and a chromatograph should be used to measure incoming and exit gas quality to confirm the resulting blended gas meets specification. The flow meters have been previously discussed. The gas chromatograph should be capable of handling multiple streams and measuring hydrogen as a component. The Rosemount 770XA is an excellent choice for this particular application, and it has been used in several successful hydrogen blending studies around the world.

Blended Hydrogen Case Studies

Several countries and organizations have implemented pilot studies to better understand the pros, cons, limitations, and benefits of hydrogen blending in real life applications. The United Kingdom implemented a HyDeploy trial at Keele University to blend hydrogen gas into the local natural gas grid to supply a number of residential halls, student facilities, and offices. Using a Rosemount 700XA gas chromatograph to monitor performance and troubleshoot issues, the project successfully proved that 20% hydrogen could be blended with natural gas in the existing natural gas infrastructure, with virtually no modification to the transportation infrastructure or the fuel-burning equipment.

The United States Department of Energy started the HyBlend initiative to study the feasibility of hydrogen blending in the United States. This multi-faceted project is investigating the impact of hydrogen blending on existing pipeline materials of construction, as well as the optimization of hydrogen production and fuel cell facilities, along with creating life cycle emission models for a variety of alternate fuel pathways.

Southern California Gas worked with Emerson to create a functional demonstration microgrid home that utilizes hydrogen production from solar cells and hydrogen blending to prove the feasibility of a largely self-sufficient, very low-emission home. The home uses advanced controls, flow meters, and appropriate analyzers to harness and store energy during the day, and to utilize that energy to power the home at night with fuel cells. When outside energy is required, the incoming natural gas is blended with stored hydrogen from the solar electrolyzers to minimize greenhouse gas emissions.

Conclusion

Hydrogen blending with natural gas has the potential to yield significant and immediate greenhouse gas reductions by utilizing the existing natural gas transmission infrastructure. While higher hydrogen blend concentrations may be feasible for specific applications, 20–25% blends can be implemented with existing transportation pipelines and fuel-burning equipment, with little to no modification in either case.

Existing multipath ultrasonic meters can handle this level of blending with minimal impact on accuracy, and research is ongoing to create modified meters to handle a much broader range of blending. In the meantime, Coriolis flow meters can be used for pure hydrogen flow measurement in hydrogen blending applications. Industrialized gas chromatographs are well suited to measure incoming and outgoing gas streams to confirm product quality, and to adjust the ratio controls as necessary to keep the blend on specification.

Based on the available research, it is likely that hydrogen blending will be employed as clean hydrogen sources become available and price competitive. If specified correctly, existing instrumentation and controls are available for these applications, and ongoing research may yield even better options in the near future.

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