Enabling an Accelerated and Affordable Clean Hydrogen Future—Fossil Energy Sector's Role

WORKSHOP FINAL REPORT

SEPTEMBER 27–28, 2021

U.S. DEPARTMENT OF ENERGY

NATIONAL ENERGY TECHNOLOGY LABORATORY

TABLE OF CONTENTS

LIST OF EXHIBITS

FORWARD

Through Executive Order 14008, *Tackling the Climate Crisis at Home and Abroad*, President Biden set a goal to "lead a clean energy revolution that achieves a carbon pollution-free power sector by 2035 and puts the United States on an irreversible path to a net-zero economy by 2050" (Federal Register, 2021). Specifically, President Biden empowers the United States (U.S.) to cut carbon emissions in half by 2030[1] while addressing the concerns of communities historically negatively impacted by fossil fuel dependence.[2]

At the U.S. Department of Energy (DOE), the Office of Fossil Energy and Carbon Management (FECM) has been at the forefront of carbon capture and storage (CCS) research, development, and demonstration (RD&D) for decades. The overall vision of FECM is to enable the deployment of technologies in a just and sustainable way that aids in the achievement of the President's goal of net-zero carbon emissions by mid-century.

One of several strategic pathways to this objective is the development of technologies and policies that will enable broader use of hydrogen (with carbon management) across the U.S. economy. Hydrogen production coupled with CCS and sustainably sourced waste feedstocks, such as biomass and plastics, is currently the most economical method of producing clean hydrogen. FECM is committed to collaborating with other offices within DOE, including the Hydrogen and Fuel Cell Technologies Office (HFTO) within the Office of Energy Efficiency and Renewable Energy (EERE) and the Office of Nuclear Energy (NE) in the development and deployment of effective, reliable, affordable, and safe hydrogen technologies, which support DOE's *Hydrogen Shot* target of $1 per kilogram of hydrogen within one decade (i.e., 1-1-1).[3]

Further, the $1.2 trillion bipartisan *Infrastructure Investment and Jobs Act* signed into law by President Biden on November 15, 2021 includes a suite of hydrogen-specific provisions that will drive large-scale deployment and investment in the hydrogen industry. The bill includes a package of hydrogen-specific policies, including: the creation of large-scale Regional Clean Hydrogen Hubs across the country, funding for clean hydrogen electrolysis research and development, and efforts to promote clean hydrogen manufacturing and recycling. In addition, the bill directs the federal government to develop the country's first national hydrogen roadmap and strategy.

It is within this context that FECM seeks to gather input on how best to invest in research and development that supports a rapid and effective contribution from clean hydrogen in achieving a net-zero carbon economy by 2050.

1 This 2030 target is relative to the 2005 emission level, estimated by EPA to be 6.1 billion metric tons per year, making a 50% reduction target about 3 billion metric tons per year (Inventory of U.S. Greenhouse Gas Emissions and Sinks | US EPA)

2 *The White House, FACT SHEET: President Biden Sets 2030 Greenhouse Gas Pollution Reduction Target Aimed at Creating Good-Paying Union Jobs and Securing U.S. Leadership on Clean Energy Technologies | The White House.*

3 *Hydrogen Shot | Department of Energy.*

1.0 MEETING OBJECTIVE

The virtual workshop "Enabling an Accelerated and Affordable Clean Hydrogen Future—Fossil Energy Sector's Role" was held September 27–28, 2021. The objective of this joint U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL)/Gas Technology Institute (GTI) workshop was to gather and share ideas on how to validate and advance the role of the fossil energy sector as an economic means to rapidly deploy hydrogen as a pathway to rapid decarbonization of energy systems.

The first day of the workshop focused on the big picture of the hydrogen economy, including timelines, scale and deployment scenarios across the fossil energy sector. The second day of the workshop focused on collaborative solutions and partnerships needed to overcome challenges faced by stakeholders throughout the hydrogen value chain. This event focused on the fossil energy sector with carbon management and in its goal of fostering dialog to accelerate the deployment of hydrogen as a low carbon fuel.

To promote a more candid discussion, the Chatham House Rule was adhered to during this event: "participants are free to use the information received, but neither the identity nor the affiliation of the speaker(s), nor that of any other participant, may be revealed." Participation by DOE staff in the workshop was only for purposes of gathering information, as DOE is prohibited from reaching a consensus with attendees.

Each day of the meeting was structured with keynote presentations followed by moderated panel discussions with Q&A periods, followed by facilitated breakout sessions where participants focused on prepared questions organized into several topic categories.

2.0 EXECUTIVE SUMMARY

The meeting was attended by 94 participants, representing 45 different organizations spread across the research, power generation, public utility, natural gas production, natural gas pipeline and distribution, steel production, specialty gas supply, original equipment manufacturing, technology development, Federal and state government, and legal sectors. Not including GTI, DOE staff and contractors responsible for running the meeting, the distribution of participants was: industry 65%, research organizations 12%, universities 10%, state and Federal government agencies 8%, and legal firms 6%.

Themes that emerged from the panels and breakout sessions are listed below. Their order does not indicate relative importance and no effort was made (as noted earlier) to reach consensus on any prioritization of these themes. These themes can also be found under Section 5 of this report.

Themes

- The key issue facing a transition to hydrogen is that production and utilization of clean hydrogen must increase by 50-fold from 10 million tons per year (Mtpa) to greater than 500 Mtpa by 2050 if decarbonization goals are to be met. This is a very challenging objective that must be achieved in a very short time frame and will require contributions from all hydrogen production sources. On the other hand, from a business perspective, hydrogen provides some of the largest market growth opportunities available in the energy industry.
- Government leadership will be critical in achieving the stated decarbonization objective, not only in terms of significant tax credits and incentives but also in terms of research, development and demonstration (RD&D) funding and the facilitation and encouragement of communication and collaboration across government entities at all levels—Federal, state and local—to reduce permitting, regulatory, and economic barriers to implementation of hydrogen projects.
- There is a need to articulate a clear rationale for using hydrogen and a clear pathway to achieving specific environmental benefits to ensure that all hydrogen production methods are treated in an objective, unbiased fashion. The step change pathway must be better communicated.
- The carbon intensity (CI) of hydrogen produced using natural gas as feedstock with carbon capture and storage (CCS) is significantly impacted by the methane emissions leakage rates from natural gas infrastructure. High carbon capture blue hydrogen[4] could contribute to a net-zero world with very low upstream emissions, if methane leaks are minimized.
- The use of Federal government purchasing power to stimulate demand for hydrogen (e.g., "green" steel produced with hydrogen, clean ammonia [5] as fuel for Coast Guard vessels) can be a pathway to generate demand and stimulate production capacity.
- CCS will be critical for production of hydrogen from fossil fuels. While technologically there are few hurdles to CCS, the issues of long-term liability risks and extremely slow permitting of Class VI injection wells are two factors that could jeopardize investor interest. Proactive government action will be necessary to solve these problems.
- Efforts to expand hydrogen should leverage initial opportunities in areas that couple high feedstock capacity, large volume infrastructure, significant storage capacity, and a nearby industrial base. While each region is unique and presents both opportunities and challenges, an important regional variable is the availability of geologic storage options for both hydrogen and carbon dioxide (CO_2) in places where industrial demand is centered.
- With regard to Environmental Justice issues, participants noted that issues need to be raised and mitigated through collaborative effort and better outreach, education and information-sharing with Energy Justice organizations and local communities. In this regard, DOE's Regional Carbon Storage Partnership (RCSP) initiative was successful and is a good model. Further, consider prioritizing hydrogen hub location sites where opportunities to lift disadvantaged communities are present. For example, coal mining communities where there are opportunities to source feedstock (e.g., natural gas, plus coal waste, plus biomass) and store CO_2 (subsurface reservoirs) while lifting under-employed workforce (e.g., coal miners) through training. In addition to jobs impact, it was suggested that inclusion of disadvantaged community organizations and members into projects would be valuable for Energy Justice concerns.
- Industry is eager to move forward, at a variety of scales and using a variety of approaches, to take advantage of what is seen as a growing demand for hydrogen in the U.S. energy portfolio. There is also significant potential to retrofit existing fossil-based hydrogen production facilities with carbon capture for nearby storage. The greatest challenges to lining up investment are policy uncertainties rather than technological hurdles.
- Infrastructure, especially CO_2 and hydrogen (H_2) pipelines and storage were flagged as key underpinnings of any hubs and the overall transition. The various regulatory regimes all need to be harmonized and synchronized to enable coordination of interstate and intrastate transport pipelines and storage, both for H_2 and CO_2. There is significant value in existing pipeline rights-of-way (ROW) for future construction of dedicated hydrogen pipelines.
- Federally supported research could provide funding to help technologies across the "valley of death;" late stage developmental/early deployment. There is a gap in applied research and development (R&D), and budgets should be expanded for more demonstration projects to support early deployment of emerging technologies and technology validation at scale.
- Techno-economic and life cycle analyses for hydrogen and ammonia pathways need to be performed in a consistent, scientifically objective manner to guide policy choices and pathways forward, in order to reduce the chances of wasted time and money in pursuit of the objective.

4 "Blue" hydrogen is produced from fossil fuels with carbon capture and storage (CCS), while "gray" hydrogen does not include CCS. "Green" hydrogen is produced via water electrolysis using renewable or nuclear electricity. The DOE prefers to use the term "clean" hydrogen to describe hydrogen that is produced with a carbon intensity below a threshold value (currently 2 kg CO_2/kg H_2 at the plant, per the Infrastructure Investment and Jobs Act). The color designations of hydrogen are retained in this report where they were used by participants during the workshop.

5 Ammonia is recognized as an important, carbon-free hydrogen carrier liquid that can also be used directly as a fuel.

- Legislation pending in Congress for a hydrogen production tax credit requires use of the Clean Air Act Renewable Fuels Standard to determine the CI of the hydrogen, and ties the greenhouse gas (GHG) reduction to the value of the tax credit. The existing framework for Federal-level life cycle analysis (LCA) was designed for biofuels, however, not for fossil fuels.[6] Agreeing on a methodology for determining the CI of hydrogen production is critical, as the policy uncertainty regarding the production tax credit has significant impacts on the economic viability of hydrogen production projects.
- Availability of carbon storage is critical to broader production of blue hydrogen across regions. Pipeline construction projects face more regulatory obstacles than in the past, making them more risky and expensive. There is a need to find ways to do sequestration locally where the gas production is located. Also, alternatives to conventional gas reservoirs for carbon storage (e.g., subsurface mineralization of CO_2 in mafic rocks) need to be considered.
- Effort should be made to facilitate the formation of partnerships between electric and natural gas utilities and other industry stakeholders to support a hydrogen project or hub to leverage the combined synergies in hydrogen production, storage, delivery (e.g., pipeline transport) and end use. Further, bringing multiple hydrogen end use sectors together can rapidly advance scale, so policy and regulations should consider the value of hydrogen across industries.
- Major safety incidents and social acceptance issues have the potential to impact a hydrogen transition, so they should be proactively addressed (e.g., H_2 safety training, public awareness campaigns, community dialog, etc.). Reliability and safety of the hydrogen infrastructure will be paramount.
- While there are many misconceptions about the safety of hydrogen transport and storage, there are opportunities to broaden dialogue on these issues, understand the concerns of hydrogen opponents and work to address such concerns by educating communities on the potential benefits of hydrogen as well as the safety of transport and storage.
- The requirement of hydrogen sensors for monitoring was indicated, along with the need for codes and standards for ubiquitous deployment and safe operations.
- Successful buildout of hydrogen hubs will likely require an "all-hands-on-deck" approach, with partnerships between industry, academia, government, non-profits, and community groups needed to ensure acceptance, safety, economic viability, and a smooth transition.

Finally, note that a list of suggested Federal government actions arising from the presentations and discussions at this workshop has been compiled in Appendix A. These suggested actions have not been prioritized, and are limited to specific, rather than general, suggestions. It should also be noted that this list is from a cross section of the entire industry and limited to input from those who attended this workshop. DOE coordinates across offices to share similar information through other workshops and processes that gather feedback and recommendations from the stakeholder community before prioritizing decision making.

6 https://www.epa.gov/renewable-fuel-standard-program/lifecycle-analysis-greenhouse-gas-emissions-under-renewable-fuel

3.0 DAY 1 MEETING NOTES – MONDAY, SEPTEMBER 27, 2021

Day 1 Theme: Focus on the big picture of the hydrogen economy, including timelines, scale, and deployment scenarios.

Day 1 Objective: Delineate the potential roles of the fossil energy sector in the future hydrogen economy (present, transition, and end state). Brainstorm stakeholder action items to advance the hydrogen transition by leveraging the vast expertise and resources of the fossil energy sector.

Opening remarks were delivered by Jennifer Wilcox of DOE's Office of Fossil Energy and Carbon Management (FECM), Principal Deputy Assistant Secretary (PDAS), and Acting Assistant Secretary for FECM. Kicking off the meeting, Wilcox thanked all of the attendees for their participation and encouraged them to offer their candid perspectives on how best to leverage the fossil fuel industry's capabilities in the effort to accelerate the deployment of hydrogen as a low- carbon fuel source in the U.S. economy.

Summaries of each of the presentations and panel discussions are provided below. **Links to each speaker's slide decks posted on the workshop's DOE web page follow the speaker's name and affiliation.**

3.1 DAY 1 – KEYNOTE PRESENTATION SUMMARIES

3.1.1 Keynote 1: Hydrogen's Role in the Energy Transition to Achieve Net-Zero by 2050

Speaker: *Julio Friedmann, Center on Global Energy Policy at Columbia University SIPA, Senior Research Scholar (https://netl.doe.gov/sites/default/files/netl-file/21CHF_Friedmann.pdf)*

Julio Freidman explained that hydrogen is "the Swiss Army knife" of deep decarbonization as it can play a key role in multiple sectors (i.e., heavy industry, transportation, power). In the power sector, it could provide a carbon-free fuel source play and also play a role as a long-duration power storage alternative to batteries.

Next, he highlighted a recent International Energy Agency (IEA) report about achieving a net-zero carbon economy by 2050, showing the dramatic increase in hydrogen production that will be required and the distribution of hydrogen demand across various sectors (industry, shipping, aviation, trucks, and heat) that is expected under such a scenario.

He discussed the true carbon footprint of hydrogen production and use, illustrating with a chart from the Global CCS Institute (2021) that any option without carbon capture and storage (CCS) is carbon intense, while biomass gasification with CCS can be net-negative.

He also highlighted some of the key challenges facing a transition to hydrogen, namely, that production and utilization of clean hydrogen must jump 50-fold from ~10 million tons per year (Mtpa) to greater than 500 Mtpa by 2050 if decarbonization goals are to be met.

Unfortunately, cost is a big factor. Green hydrogen (produced via renewable electricity, without carbon dioxide being generated) is very expensive ($3-8/kg), while blue hydrogen is cheaper ($1.2-1.8/kg). Friedmann pointed out that there really is not a market for hydrogen outside of the existing market (refining), which is a challenge, as is the lack of infrastructure.

He showed a chart from a 2021 BloombergNEF report illustrating the cost of blue and green hydrogen around the world; currently blue hydrogen beats green hydrogen in most places on price.

However, in 2030, in many markets, green hydrogen is forecasted to be less expensive than blue or even cheaper than gray. By 2050 (maybe as early as 2040) green beats both gray and blue in all markets.

Currently, there are only 7 plants producing a total of ~4,140 tonnes per day of blue hydrogen (1 more planned to come online in China in 2021), and 2 plants producing a total of 2.7 tonnes per day of green hydrogen (1 more, NEOM, planned to produce 650 tonnes per day from wind and solar in 2025).

Infrastructure challenges are very real. They will limit deployment and add system costs. If the U.S. were to make all needed hydrogen green by 2050, we would need about $15 trillion in investments. If all is blue hydrogen, it would be about 75% less. Blending blue and green hydrogen would shave about $4 trillion off the total and could increase the volume available.

The IEA net-zero 2050 analysis (2021) illustrates the enormous lift that will be required. For example, electrolyzer capacity will need to jump from <1 gigawatts (GW) to 3,585 GW, electricity supply for hydrogen production from 1 terawatt hours (TWh) to 14,500 TWh, and the number of export terminals for hydrogen and ammonia from 0 to 150.

The emissions associated with blue hydrogen production has been receiving greater attention recently (i.e., Howarth & Jacobsen 2021 and NY Times). The point being made is that natural gas production may have more methane emissions associated with it than what is accounted for (upstream about 1.5% leakage rate according to the Environmental Protection Agency [EPA] but 2.2% according to Environmental Defense Fund and in flaring regions closer to 3% or higher). Blue hydrogen deployment using natural gas as feedstock with CCS could be impacted by the leakage rates from natural gas infrastructure. A Pembina Institute analysis, published in 2021, showed that if the methane leakage issue is fixed, blue hydrogen could reduce carbon intensity by 85%, about equivalent to green hydrogen produced with solar electricity. High carbon capture blue hydrogen could contribute to a net-zero world with very low upstream emissions, if methane leaks are minimized.

Friedmann remarked on the hydrogen policy landscape within the U.S., noting that the Hydrogen Production Tax Credit (PTC) of $3/kg for producers capturing 95% or more CO_2, $1/kg for 95-85%, and only $0.75 for 75-85%, drops off very quickly. In his opinion, it is not economically possible to achieve 95%, so the tax credit will not be that helpful in accelerating blue or green hydrogen production.

He also noted that 45Q credits could be as high as $85/ton CO_2 sequestered, but that these cannot be stacked with the hydrogen PTC.

He remarked that in the case of the Clean Electricity Payment Program legislation, which will provide payments to utilities that meet targets to sell increasing shares of clean power and require them to pay a fee for each megawatt-hour they've fallen short of that target, hydrogen footprint assumptions and baseline will affect payments. Currently, nine states have clean electricity standards but it is not clear how hydrogen might qualify for rate recovery.

He also provided a brief overview of hydrogen policy around the world, noting that blue and green hydrogen are a part of a national energy strategy in the United Kingdom (UK), Canada, European Union (EU), Saudi Arabia, United Arab Emirates, Chile, Australia and China. Japan and India also have policies that encourage hydrogen production.

If the U.S. wants to be globally competitive and lead the world in emissions reduction, we will have to provide clear policy direction… based on numbers to enable sound decision-making, and we need to continue research. U.S. policy is being shaped without these "numbers," which will impact this research/future use of hydrogen negatively. It could impact options for blue and green hydrogen, slow deployment, and impact trading value with other countries.

Questions:

"Which sector should we prioritize?"

The U.S. should prioritize chemical production. The next markets would be truck fuel, shipping fuel, and steel production. Currently, the U.S. is not supporting demand growth (e.g., purchasing green steel). We need to expand the production. One approach is to make the Coast Guard an ammonia-powered fleet. However, ammonia fuel bound nitrogen can lead to severe NOx emissions, possibly beyond the ability of selective catalytic reduction to clean up. Another option is to look at sustainable biomass gasification, particularly in regions such as California. This feedstock can be used with CCS and create a negative hydrogen factor, which is good for areas prone to fires.

"You mentioned that there were zero hydrogen/ammonia export terminals in 2020 ... but there are 196 ammonia export/import terminals operating worldwide today (see the data mapped at afi.dnvgl.com). We should incorporate more ammonia data in our analyses, as a hydrogen carrier (e.g., ammonia pipelines, etc.) not just as a fertilizer product, to make comparative analyses and the resulting hydrogen policy more robust."

Yes, fertilizer for farmers could play a role in lower emissions as well.

3.1.2 Keynote 2: Hydrogen Shot Summit Overview and Deployment Session Wrap-Up

Speaker: Sunita Satyapal, DOE Energy Efficiency and Renewable Energy, Director for Hydrogen and Fuel Cells Technology Office and Coordinator for DOE Hydrogen Program (https://netl.doe.gov/sites/default/files/netl-file/21CHF_Satyapal.pdf)

Sunita Satyapal opened her keynote by stating that the Hydrogen Program is DOE-wide. It is a very coordinated and comprehensive program.

The DOE *Hydrogen Shot* Summit was held virtually August 31 and September 1, 2021. The summit convened thousands of stakeholders online to introduce the *Hydrogen Shot*, solicit dialogue, and rally the global community on the urgency of tackling the climate crisis through concrete actions and innovation.

DOE shared results from the recent Request for Information (RFI) and solicited feedback on pathways to achieving the *Hydrogen Shot's* "1-1-1" goal of $1 for 1 kg of clean hydrogen in one decade. Breakout sessions on various clean hydrogen production pathways, as well as deployment and financing, helped identify key challenges and potential strategies to address them.

The main priorities discussed included low-cost clean hydrogen, safe delivery and storage (where she believes the U.S. needs more work),and enabling end use and applications at scale.

Satyapal then discussed the comprehensive portfolio across the entire value chain, which include near- and long-term goals. The participants at the summit included representatives from around 33 countries, which allowed for very specific feedback. Several challenges need to be addressed, but the *Hydrogen Shot* will be focusing on cost of production, in addition to the H_2@Scale initiative which focuses on the entire value chain from production through end use.

The summit looked strategically at renewables, natural gas, and CCS. DOE's RFI covered the following key themes: production, resources, and infrastructure; end users, cost, and value proposition; co-location potential; emissions reduction potential; diversity, equity, and inclusion (DEI), jobs, and Environmental Justice; and science and innovation needs and challenges.

The RFI findings were then presented according to regional cluster and geographic factors. When the participants were asked to select which region would be most ready for large-scale demonstration—not just production but also end use—many picked California, the Gulf Coast, and the Northeast. When asked what they believed to be the top three priorities for the *Hydrogen Shot* to be successful, the majority of responses were: increased R&D to reduce cost; getting to scale; and developing partnerships, policies, etc. A large focus was on the DEI aspect. Specific questions were asked in terms of end use. The responses were diverse.

A lot of interest was placed on the Appalachian region, as it presented very specific opportunities for blue hydrogen. Interest also included regional resources for production and infrastructure, primarily in fossil fuels and CCS and potential opportunities for large-scale storage. There was significant interest in and potential opportunities for, end uses, particularly in industrial communities and power generation. There was also specific feedback on emissions reduction potential and jobs, which is a very high priority for the stakeholders involved. The potential for hydrogen hubs in Appalachia, the Gulf Coast, and elsewhere were highlighted several times throughout the workshop as containing many characteristics of viable regional hubs.

Following the summit, the audience was asked, based on what they learned, how confident they were that the "1-1-1" goal of the *Hydrogen Shot* can be reached. The post-summit response was 6.7 out of 10.

Satyapal closed her keynote by saying that one new area getting a lot of visibility is natural gas leakage, so she will be interested in seeing the discussion during the breakout sessions.

Question:

"Which are the greatest barriers currently preventing public acceptance of wide-spread hydrogen in the United States?"

The majority of the participants replied with the cost to the end user (22%), the need for a sufficient infrastructure (19%), and an increase in public awareness/understanding (17%).

3.1.3 Keynote 3: Summary of Thermal Conversion with CCS – Hydrogen Shot Summit Breakout Session Wrap-Up

Speaker: *Sam Thomas, DOE Fossil Energy & Carbon Management, Director for Hydrogen with Carbon Management (https://netl.doe.gov/sites/default/files/netl-file/21CHF_Thomas.pdf)*

Sam Thomas provided a summary of the breakout sessions on thermal conversion with CCS at the Hydrogen Summit, which brought people together to discuss the Secretary's ambitious goal of reducing the production cost of clean hydrogen.

FECM has a specific role in DOE's hydrogen space. FECM funds R&D projects on carbon-neutral hydrogen pathways, including gasification, reforming, and solid oxide electrolysis cells (which is coordinated with HFTO which also funds electrolysis from renewables). A specific goal of FECM is to increase carbon capture rates while lowering the cost of clean hydrogen. They also invest in hydrogen transport infrastructure; hydrogen storage; and hydrogen use for electricity generation, fuels, and manufacturing.

The thermal conversion with CCS breakout was focused on the gasification of coal/biomass/plastic waste streams and natural gas to produce clean hydrogen with a carbon-abatement strategy. The panel took place over two days, with Day One focusing on natural gas feedstocks and Day Two focusing on the gasification mixture of waste coal plastics and biomass.

Presentations included an overview of traditional and new methods of producing hydrogen from fossil-based feedstocks, which included challenges associated with each pathway. The pathways presented included methane pyrolysis, plasma technologies, transformational natural gas conversion, gasification for clean hydrogen, and advanced gasification pathways to clean hydrogen.

The discussion also included a need for large-scale demonstration projects to drive momentum in the research community and to lower technology risk. Investment by the government was discussed as a risk mitigation element. Other key points of discussion included making prudent investments across the Technology Readiness Level (TRL) scale and incubating multiple production pathways. FECM will continue to host workshops on hydrogen similar to this one in order to continue the dialogue. LCAs are also very important across the entire hydrogen value chain and are critical to validate hydrogen's benefits and justify a hydrogen-enabled economy.

After panelists completed their presentations, key points of discussion included the fact that multiple demonstration projects are needed to drive innovation, and government policy incentives and investments were both discussed as critical to lower technology risk. Policy incentives will be critical to spur the clean hydrogen economy. A lot of discussion revolved around hydrogen consumers and the need to offset cost differences and to encourage early adoption of clean hydrogen. Biomass was also seen as key to achieve net-zero hydrogen from thermal conversion.

Question:

"Will FECM support R&D for blue hydrogen production from both natural gas and solid fuels equally."

The response was "yes and no." Thomas said that in general, yes, but the term "equal" needs to be better defined in order to properly answer the question.

3.1.4 Keynote 4: DOE Hydrogen RFI Wrap-Up

Speaker: *Tim Reinhardt, DOE Office of Fossil Energy and& Carbon Management, Director of Methane Emissions Mitigation Technologies (https://netl.doe.gov/sites/default/files/netl-file/21CHF_Reinhardt.pdf)*

Tim Reinhardt provided a brief summary of DOE's Hydrogen Program RFI responses. The RFI was issued between June 7 and July 7, 2021 and encompassed multiple offices within DOE (EERE, FECM, NE, OE, and SC). The primary goal was to obtain public input in support of DOE's *Hydrogen Shot* initiative to enable low cost, clean hydrogen at scale. Input was sought on hydrogen demonstration and deployment projects that enable clean hydrogen production, infrastructure and end uses to reduce emissions, create jobs, and enable a net-zero carbon emissions economy by 2050. Approximately 200 RFI responses were compiled. Responses by responder group (Private sector, Government and Academia) were about even across the five topic areas. Topics A (Regional Hydrogen Production, Resources, and Infrastructure) and B (End Users for Hydrogen in the Region and Value Proposition) together received the majority of responses across all sectors, accounting for about one third of responses each.

The ongoing need for R&D and government engagement was acknowledged, as was a general willingness to support demonstration projects. About 47% of responses were considered FECM related, with most of these related to the leveraging of existing programs/capabilities.

Each of nine regional focus areas (clusters) presents its own unique challenges and opportunities for hydrogen production and use. Snapshots were provided for Appalachia and the Gulf Coast.

Next steps include further evaluation of RFI responses (ongoing), presentation of detailed findings through webinars (future), organization of a series of workshops that will seek to include a broad stakeholder base within each region while fostering communication/collaboration among respondents with a common regional focus (future). DOE will also conduct analysis and pathway studies to characterize the relative importance of feedstock, end use, infrastructure, and regional diversity, the potential benefits with regard to emissions, employment, regional and community economic impacts, and environmental improvements. Assessments of scalability, replicability, and sustainability are also underway.

Questions:

None.

3.2 DAY 1 – PANEL SESSION SUMMARIES

3.2.1 Panel Session 1: State/Utility Perspective on Fossil Energy Hydrogen Challenges

Moderator: *Mark Berry, Southern Co., Vice President of R&D*

Speakers:

Anja Bendel, Wyoming Energy Authority, Program Director (no slides presented)

Peter Hoeflich, Duke Energy Corp., Director (https://netl.doe.gov/sites/default/files/netl-file/21CHF_Hoeflich.pdf)

Chris Kroeker, Northwest Natural, Emerging Technology Program Manager (no slides presented)

Joe Del Vecchio, National Fuel Gas Distribution Corp., VP and Chief Regulatory Counsel (https://netl.doe.gov/sites/default/files/netl-file/21CHF_DelVecchio.pdf)

Topic: *Plans, programs and drivers to enable hydrogen fossil hydrogen to achieve Net-Zero emissions.*

Anja Bendel discussed hydrogen from the perspective of a state energy authority. She made the case that Wyoming provides a unique configuration of abundant natural gas and coal feedstocks, existing infrastructure, and the capability to address CO_2 sequestration for blue hydrogen due to existing CO_2 transportation and sequestration resources.

The University of Wyoming has established a hydrogen center to address hydrogen and industry unknowns. There are ongoing pilot projects to examine hydrogen production challenges, transportation via existing natural gas pipelines and gas turbine issues related to hydrogen compression.

Question:

"How do you foresee exporting energy from Wyoming in a hydrogen economy?"

Wyoming admittedly is geographically disadvantaged as it is far from large markets. But the state has significant existing pipeline infrastructure and is looking to leverage existing pipelines and is also looking at electricity generation from renewables. Wyoming would like to be an enabler not prescriber of how energy gets to market, and support existing industries.

Peter Hoeflich discussed hydrogen from the perspective of an electric and natural gas utility (7.9 electricity customers and 1.6 million natural gas customers) with existing investments in renewables (approximately 4 gigawatts of wind and solar in operation).

Duke Energy Corp. recently announced a goal of achieving net-zero carbon emissions by 2050 and net-zero methane emissions by 2030. Their plan includes: continuing to retire coal power generation and replacing with natural gas generation, adding significant amounts of renewables and associated storage, maintaining existing nuclear fleet, and adopting advancements in demand-side management and energy efficiency. But they also need new zero-emitting, load-following resources (ZELFRs) like advanced nuclear, carbon capture/utilization/storage, zero-carbon fuels (hydrogen), and long duration energy storage starting as early as 2035. Hoeflich outlined the company's current activities, key requirements for commercial viability, and expected deployment dates for each of these initiatives.

With regard to hydrogen, Duke Energy Corp. is evaluating multiple use cases and production options, including electrolysis and carbon capture pathways. With few CCS options in their service territory, they may be an importer of hydrogen, but are also investigating methane pyrolysis with solid carbon co-production. They are collaborating as a sponsor of the Electric Power Research Institute and GTI's Low Carbon Resources Initiative and partnering with the Energy Futures Initiative to study a green hydrogen hub in the Carolinas. Clemson is partnering with Duke, Siemens and DOE to perform H_2Orange, a techno-commercial analysis of production, storage and co-firing of hydrogen at Duke Energy's combined heat and power (CHP) plant serving Clemson's campus.

He noted that utilities such as Duke Energy Corp. need ZELFRs to be developed, along with policy and stakeholder support for transition to a net-zero path. Fossil energy hydrogen production challenges include cost, supply, market value, conversion location, transportation, CO_2 storage and longevity issues surrounding public policy. CO_2 storage risks must consider the entirety of its future viability and liability. His presentation ended with a graphic illustration of the scale of the problem— … an aerial view of an 80 thousand standard cubic feet per day (Mscfd) steam methane reforming (SMR) plant— and he stated that it would take 8 such facilities operating together to supply a single 1,200-megawatt (MW) combined cycle power generation plant with hydrogen.

Chris Kroeker provided a second natural gas utility perspective on hydrogen. Northwest (NW) Natural is primarily a natural gas distributor, servicing residential, commercial, and industrial customers in Western Oregon and Southwest Washington in the Pacific Northwest. NW Natural's operating areas do not have a renewable portfolio standard yet, but they do have a cap-and-trade system for CO_2 emissions in development. Soon, utilities in these locations will be responsible for all carbon emissions by customers. This translates into a large and growing carbon responsibility in the upcoming future.

There is excellent sequestration geology in Oregon. A handful of large industrial customers use about 50% of natural gas demand. A straightforward option will be to focus on providing users with blue hydrogen. However, these customers are risk adverse and will be slow to respond to this pathway. Lower cost is not enough of a "carrot" and, without a "national" decarbonization plan, customers may simply leave the state, taking their emissions and jobs elsewhere.

A team of Pacific Northwest public and private organizations have signed a memorandum of understanding to explore the development of renewable hydrogen production facilities. The partners include the Eugene Water & Electric Board, NW Natural and the Bonneville Environmental Foundation. The facility would utilize renewable and low-carbon electricity to operate an electrolyzer to produce green hydrogen, which would be used to help decarbonize the region's space heating and transportation sectors. The facility in Eugene could range in size from 2 to 10 MW.

NW Natural sees no technical barriers to locally meet a 2050 goal to be a carbon neutral energy provider, and believes that renewable hydrogen will play an important role, along with energy efficiency, carbon offsets and renewable natural gas.

In 2019, NW Natural began testing a 5% hydrogen blend with natural gas to evaluate impacts on their system and end-use equipment performance at its Sherwood Operations and Training Center. They are expanding blend testing to include additional end use equipment performance on furnaces, fireplaces and water heaters. A 20% blend will be coming soon.

Kroeker said that NW Natural is looking for hydrogen to fill in the gaps, but they are interested in whatever is low-carbon and low-cost. Important needs are hydrogen storage, appliances that can safely use hydrogen mixtures, and a national hydrogen appliance test program.

Joe Del Vecchio described National Fuel Gas and its business segments. He explained the objectives of the New York Climate Leadership and Community Protection Act passed in 2019: 70% renewable energy by 2030, 100% zero-emission electricity by 2040, and 85% GHG Reduction by 2050. National Fuel Gas's goals include decarbonization through the use of hydrogen enriched gas, local industrial use of hydrogen, and CCS.

Del Vecchio also described the advantages of siting a potential hydrogen hub pilot in New York state. These included: multiple hydroelectric, solar and wind resources, proximity to Pennsylvania natural gas resources, potential for hydrogen storage in existing and abandoned salt mines, proximity to light and heavy-duty transportation demand via I-90, and proximity to Rochester and Buffalo industrial/commercial/residential markets.

Post Panel Q&A:

"How can power be at the table and provide the infrastructure for the different sectors (chemicals, transportation, manufacturing)?"

We need to recognize the value of long-term renewable energy storage, but who pays for that? How do we value that?

Because hydrogen is very broad, we need to pull in all stakeholders to find solutions and develop the best infrastructure for optimization so that we can reach multiple parts of the economy and many different markets.

Work is being done … the Low-Carbon Resources Initiative is looking at bringing technologies to scale. The Federal infrastructure bill is $9 billion dollars and it will jumpstart efforts.

Consideration needs to be given to the demand side to build up power generation along with chemicals and transportation.

"If you can make natural gas combined cycle with carbon capture and sequestration work (natural gas combined cycle [NGCC] with CCS) work, how will the use of low carbon hydrogen for energy be economically competitive?"

Two different technologies depending on where you are and cost associated with sequestration. We will be looking at the levelized cost of energy in the future (hydrogen vs. natural gas carbon capture, utilization, and storage [CCUS]), there are areas where the cost of hydrogen will be lower.

"I have heard comments from OEMs that current hydrogen economics work for (grid) energy storage, but not for outright power generation. Do the panelists agree or disagree?"

Storage use cases will more likely be economical sooner than fuel for power generation. The opportunity is to take excess low-cost renewables and produce green hydrogen, store it and then blend it into gas for power later. Also, it makes sense where the cost of CO_2 transport and storage is a factor. But we are years away from needing long-term renewable energy storage. We do not need it now at the current levels of wind and solar power.

"What is the role of commercially available carbon sequestration, carbon storage as a service? How far off are we and how important is sequestration moving forward?"

Technologically, it is not a problem. Policy and liability are the barriers – how can state and Federal policies align (particularly in the west) with Federal ownership of land? Currently, there is no definition of who owns the pore space on Federal land. We need to have policy that clearly defines pore space and long-term liability.

Geology is important, but we just do not know where sequestration will take place and we need to understand the risk profile. We need to keep an eye out for new technologies, bringing them into the regulation policymaking for carbon sequestration … making sure studies are conducted and followed up on those and tying the results into regulatory policies.

Need to consider alternatives to conventional gas reservoirs for carbon storage. In Iceland, they are doing carbon storage in volcanic rocks. Subsurface mineralization of CO_2 is a possibility that needs to be studied.

Some analyses show CCS being economical in the short term, but the long-term monitoring responsibility and liability is where the economics turn negative. Even when you follow all the science and regulations, you are still responsible for the sequestration integrity over very long time periods.

Pipelines are hard to build, and it is getting harder. We need to find ways to do sequestration locally where the natural gas production is located.

"Have we considered water usage with respect to hydrogen production? Will this be a concern in the increasingly dry West?

The west is an increasingly dry region and this is a concern. There is a current pilot project there ($250,000 in size) looking at using produced water and if it is of a quality that could be used for electrolysis. This would be a beneficial use for produced water (which is wastewater), instead of disposing it in deep wells.

From a hydrogen production perspective, we need better efficiencies. Could water be recovered through condensed flue gas? NOx suppression also needs water. There is a need to be working on new technologies. Original equipment manufacturers (OEMs) are working on low emission burners for hydrogen that give low NOx without water and look like a natural gas unit.

Water is needed for both blue and green hydrogen, there needs to be economic incentives to improve technologies. All of the zero-emissions technologies have challenges and need work to get to where they need to be. Ultimately, we need to get our customers comfortable with hydrogen or they will go elsewhere.

3.2.2 Panel Session 2: Industry Strategies on the Hydrogen Value Chain

Moderator: *Poh Boon Ung, BP, Manager - Hydrogen & CCUS Advisory Services*

Speakers:

David Edwards, Air Liquide, Director (https://netl.doe.gov/sites/default/files/netl-file/21CHF_Edwards.pdf)

Krish Krishnamurthy, Linde, Head of CE Technology NA and CCS (https://netl.doe.gov/sites/default/files/netl-file/21CHF_Krishnamurthy.pdf)

Michael Ducker, Mitsubishi Power, Vice President of Renewable Fuels (https://netl.doe.gov/sites/default/files/netl-file/21CHF_Ducker.pdf)

Topic: *What are the industry imperatives to approach Net-Zero across the value chain, including deployment, scale, and integration challenges?*

David Edwards of Air Liquide, a commercial gas supplier, noted that hydrogen provides some of the largest market growth opportunities Air Liquide's business. Air Liquide has been in the hydrogen business for over 50 years and has set a company goal of achieving carbon-neutrality by 2050.

He described two new investment projects, the first large scale (30 tons per day) renewable liquid hydrogen production plant in Nevada, and what will be the world's largest (20 MW) PEM electrolyzer designed to supply 8 tons per day of ~100% decarbonized hydrogen for Canada and East Coast markets in Becancour, Canada.

At the Nevada plant, hydrogen is produced from renewable natural gas supplied to an SMR, along with renewable electricity. There is no carbon capture or hydrogen storage at these facilities, although Air Liquide does that elsewhere.

But he noted that the challenge is scale; these are relatively small facilities. How do we do it 10x larger? Policy drivers need to be in place to make large scale hydrogen production possible.

Krish Krishnamurthy of Linde noted that they see clean hydrogen, blue and green, as a $100 billion market opportunity by 2030, which is about 1.5% of today's hydrocarbon market… a significant opportunity despite uncertain timing. He added that industry momentum is building and there is a strong push to limit carbon emissions, but that hydrogen technologies will need to deliver on expected cost reductions, end-user early adopters will be needed to build a hydrogen ecosystem, and perhaps most importantly, a regulatory framework that can ensure funding and access to renewable energy will be required. Linde's decarbonization approach is to reduce its own CO_2 footprint and to help customers reduce their footprints.

Michael Ducker of Mitsubishi Power noted that seasonal renewable energy surplus and deficits in California signal the growing need for long-duration energy storage "beyond the duck curve."[7] He explained how Battery Energy Storage Systems using lithium-ion batteries and Mitsubishi's Hydaptive™ green hydrogen energy storage systems (employing a variety of hydrogen storage options) can work in concert to support more reliable and cost-effective integration of renewables. Ducker also described two projects, the Intermountain Power Project (IPP) that boasts the world's first combined cycle designed for green hydrogen and is expected to begin operation in 2025 on 30% green hydrogen with 100% no later than 2045, and what will be the world's largest renewable green hydrogen storage project (150,000 megawatt-hours). This project will utilize salt cavern storage for hydrogen and will be 100x the entire U.S. installed battery capacity. Mitsubishi has successfully modified existing gas turbines to be able to run on hydrogen. Only the gas turbine combustor needs to be modified to run on hydrogen blends.

The moderator, **Poh Boon Ung**, spoke about BP's new strategy for switching from being an international oil company to an integrated energy company. Hydrogen is a new business line, expected to be a key part of a portfolio of business that will include CCUS, wind, solar and biofuels. BP aims to increase the proportion of its investment into these non-oil and gas businesses to around $5 billion by 2030. The goal is to achieve 10% share of clean hydrogen market by 2030. BP's focus is on two demand sectors where the switch to electricity will be difficult: the industrial sector and the transportation sector. BP's focus will be on deploying the best solution for each location, which can, over time, scale at the lowest possible cost. By 2050, BP sees equal amounts of blue and green hydrogen, with the color depending on location and with blue helping supply keep up with demand. BP currently has eight projects underway in Europe and Australia.

Post Panel Q&A:

"Where do you see the next phase of hydrogen projects occurring? How can we grow the market?"

We need to look at the application space – who is going to start demanding low-carbon hydrogen? Refineries asking for it now in existing markets. Transportation sector in California is a starting point. Production investments will be tied to where we think markets will grow but post-California markets are uncertain. Expect that it will be heavy duty transport driving broader national demand.

7 The graphic representation of the levels of wind and solar sourced power on the grid during the day and the resulting high peak load in mid to late evening, is shaped like a duck. Compared to a regular load chart the duck curve shows two high points of demand and one very low point of demand, with a sharp ramp up in between. As renewable energy has become more common over the years, the duck shape is appearing more often and is becoming more distinct (https://alcse.org/the-duck-curve-what-is-it-and-what-does-it-mean/).

"How do we close the cost gap?"

Scale: do what we're doing at scale and aim it at those new markets. But this will require favorable policies, incentives for new adapters. We cannot start at full scale. Cost will need to reach diesel parity for broad acceptance and when does that happen?

Looking at another industry, as an example, battery costs were driven down by demand for consumer electronics. The power industry is right to scale hydrogen quickly. Regulatory mandates are in place for large scale production and infrastructure. Consumer demand could drive cost reductions. With a push from the power industry, should be able to bring production to scale. It could also bring multiple industries together, further advancing scale. Policy and regulations should consider the value of hydrogen across industries. Initial deployments are also critical.

"How do we expand on scale and hydrogen infrastructure?"

One company's current infrastructure includes a number of large scale (>100 MMscfd of hydrogen) SMR systems in Texas serving refineries mostly, but CO_2 emissions are greater than 1 Mtpa. The company needs partners to apply carbon capture and storage to SMR plants for blue hydrogen.

If hydrogen is produced in one area but needs to be used in another, there will be a greater reliance on the hydrogen pipeline network. Expansion of pipelines with additional capacity and new storage capabilities are necessary.

"How many days of storage would a cavern hold? Can they hold weeks' worth of hydrogen for a power plant?"

Between caverns and pipelines, there is capacity to store 2.5 billion cubic feet of hydrogen.

As an example, one existing salt cavern can hold 1 months' worth of an SMR's production as backup, on the order of 100s of gigawatt-hours (GWh) of energy. It is used for backup.

"In salt caverns, at what temperature and pressure do you store the hydrogen?"

Caverns are about a mile underground, so they are at geologic temperature, from 120°F to 135°F. Pressure varies but is always above pipeline pressure, always held at a higher pressure than a gas turbine facility (~800 pounds per square inch [psi]). Working inventory is 1,000 psi to 3,000 psi.

"How long does a long-term storage cavern take to construct?"

That depends on existing geology/geography and the scale of the cavern. The two main variables are time and water. It takes about 2-2.5 years to produce a cavern that would hold 4.5-5 million barrels (~5,500 metric tonnes) of hydrogen.

"How much can we actually rely on existing natural gas pipelines for hydrogen transportation given the low volumetric energy density and high diffusion of hydrogen?"

Existing pipelines can provide some additional capacity. The idea is to get it started and build on it and that is easier with existing hydrogen pipelines. For large use, we most likely will need a significant number of new pipelines. Also, we will need to ask if the pipelines can be used for other gases; it will be harder to use pipelines that weren't created for hydrogen production and capacity. Complete conversion of existing pipelines to hydrogen would be challenging, mostly due to materials compatibility. The problem with interconnected natural gas pipelines is that one pipe can handle a 20% blend but it connects to a legacy line that cannot handle a 5% blend. In the case of some lines, the materials of construction are not even known. Ultimately, we will need new 100% hydrogen pipelines.

"Finally, what do you see as the biggest challenge to wider deployment, and the solution?"

The challenge is not technology, but rather how do we apply technologies at meaningful scale. To do that we need to find the right incentives, market pulls from customers, and regulatory framework. Solving the issue of an appropriate market structure is key.

The economics for blue hydrogen is attractive. To make it happen quicker we need to demonstrate CCS at scale.

Scale will require private investment, and investors need to be certain that there is a growing market that is stable and reliable for long term commitments.

In the end, hydrogen hubs will require four things: buyers, sellers, storage, and price transparency.

3.3 DAY 1 – BREAKOUT SESSION SUMMARIES

The overall objective of the breakout sessions held on Day 1 was to focus on the "big picture" of the hydrogen economy, including the topics of scale, integration with existing systems, cost, and deployment/timing. The participants were challenged to delineate the potential roles of the fossil energy sector in the future hydrogen economy and to brainstorm near-term stakeholder actions to advance a transition to hydrogen. Four facilitated groups addressed the same set of questions and framed their responses in terms of (a) opportunities/needs, (b) challenges, (c) solutions, and (d) next steps. The consolidated results are summarized below for each topic.

3.3.1 Breakout Session Topic: Cost

The breakout groups were tasked with focusing on three questions with regard to cost:

1. How can costs for hydrogen hubs and a more expansive clean hydrogen economy be reduced?
2. What are the issues regarding access to capital for hydrogen deployment?
3. What roles can policies play (e.g., incentives, credits) in establishing and implementing hubs?

The groups suggested (in no order of relative importance) that overall costs could potentially be reduced through:

- Employing methane pyrolysis rather than SMR. It does not require carbon sequestration and costs can be partially offset with sale of carbon product. Carbon could also be landfilled. Need incentives to encourage this approach by existing hydrogen producers.
- Large-scale deployment of major demonstration projects across the hydrogen hub value chain (i.e., production, transportation, hydrogen, and CO_2 storage) that include industry partners.
- Coordination of Federal attention towards regulatory, policy, financial and technical elements of initial hub deployments, with particular attention toward policy certainty; it is critical for establishing and predicting costs associated with hydrogen hub development.
- Suggested support for direct Federal incentives for hydrogen production, agnostic of feedstock.

Access to capital is an important issue and one option could be DOE loan program expansion to include hydrogen production and related carbon capture and sequestration. Quickly identifying end users and accelerating a market pull may help to make capital more available as revenue can be more accurately forecast. This could be facilitated through Federal policies. Competing technologies will act to limit capital availability until the market knows better what technologies will work best. DOE can help to facilitate that knowledge through internal and extramural research, development, and demonstration (RD&D).

Federal policies that clarify subsurface pore-space ownership on Federal lands and reduce long-term liability risk could help to advance long term CO_2 sequestration, which would enable blue hydrogen production. Production tax credits could also be used to make hydrogen more cost competitive, especially if production from a certain fuel/feedstock is specified, although production tax credits (PTCs) tied to carbon intensity are more impartial.

3.3.2 Breakout Session Topic: Deployment & Timing

The breakout groups were tasked with focusing on three questions with regard to deployment and timing:

1. How can existing fossil energy sector assets be leveraged?
2. How can initial and subsequent hydrogen markets be grown?
3. How can education and outreach efforts advance hydrogen deployment?

The groups suggested (in no order of relative importance) that the most likely opportunities for leveraging existing fossil energy sector assets would be:

- Existing facilities for fossil-based production of hydrogen. These are located along pipelines on the Gulf Coast or at customer sites (refineries) and have the potential for carbon capture and nearby carbon storage.
- Existing natural gas pipelines. They have an advantage as they are an interconnected system for flow and supply flexibility. The U.S. should recognize the value of existing pipeline rights-of-way (ROW) for future construction if dedicated hydrogen pipelines become feasible. Obtaining new ROW will be unlikely.

Challenges include:

- Not many of the existing hydrogen production facility assets are easily expandable. Some of these sites might not be around for long.
- End users for hydrogen/hythane blends are very specific and it is not always clear which customers can utilize blends of hydrogen and methane, at what ratios, and under what circumstances.
- In the case of natural gas pipelines, material compatibility is an issue. One pipeline that can take a 20% hydrogen blend might interconnect with a pipeline that cannot handle any hydrogen at all. This is an engineering challenge that needs to be worked out.
- Permitting and local regulations, the time required for site design plan approval, and supply chain issues are all significant challenges that cannot be solved by technical advances. Meeting things like local fire marshal requirements can be a stopping point. State and local support is needed.
- CO_2 sequestration required for blue hydrogen production is a significant challenge because the permitting process for Class 6VI wells is very time intensive. Federal government regulators are not ready to handle this on a large scale. Some states are requesting to be able to do their own.
- Long-term liability for the risks of CO_2 leakage from storage associated with blue hydrogen production needs to be addressed.
- We need more market pulls rather than market pushes for technologies.

Solutions include:

- Adding carbon capture and sequestration to existing hydrogen production facilities.
- Building a 100% hydrogen pipeline in an existing natural gas pipeline ROW.
- Building ammonia pipelines or converting product pipelines to move blue hydrogen-based ammonia to markets.

The overall challenge to deployment and timing is that cost and scale are huge impediments. If you cannot build up the scale and reduce costs, the end users have no incentive to buy because they are not rewarded for it in the market.

Initial markets can be jumped started by picking a couple of sectors where rapid shifts could be possible and applying government purchasing power to force a shift. Incentivizing end users to build up demand will stimulate supply. Markets will not change without an external stimulus.

Solutions for growing markets might include:

- The maritime sector could be used to stimulate demand on a large scale (i.e., mandating Coast Guard purchases of blue hydrogen-based ammonia as fuel).
- Federal government purchases of "green steel" (produced with green hydrogen).
- Federal regulation that requires a certain small percentage of hydrogen in all natural gas pipelines.
- Federal mandate that a small percent of ammonia production be renewable.
- Address the liability risk and monitoring cost issues facing CO_2 sequestration.

In terms of outreach, getting the message out on why hydrogen can be good for the consumer, rather than just a subterfuge for maintaining fossil fuel industry assets, will be important. The public perception of potential safety issues regarding underground storage of hydrogen will be a significant outreach challenge. We need to convince consumers that we're providing them a solution, not just finding a way for the energy industry to "get away with stuff."

Solutions might include:

- High impact Federal outreach effort that sets a decarbonization date.
- Characterizing and clarifying the energy economics of ammonia as an energy carrier.
- Take lessons learned from past DOE demonstration project successes (e.g., RCSPs, Field Laboratories) to communicate/educate public on framework for hydrogen deployment.

3.3.3 Breakout Session Topic: Scale

The breakout groups were tasked with focusing on three questions with regard to scale:

1. What are the smallest and largest starting scales for hydrogen hubs?
2. What infrastructure is required to establish those scales? How much exists?
3. How can these initial systems/hubs be reasonably expanded upon, and how far?

First, we should be thinking about "what is the outcome of a successful hub" rather than scale. Success is defined as something that allows the marketplace to take off so that the government can back off. We need to first set the conditions for long-term growth and success. The scale is not a static target – we need to recognize that the scale could grow, and allow for variability in that growth. Some may stay small until a national pipeline network is available. Starting at a smaller scale will allow for investor confidence, a critical factor for the success of any hydrogen hub of any size.

This is not a one-size fits all situation. To make blue hydrogen work, we will need multiple sizes of hubs. And they will depend on the region, industrial demand, and the infrastructure available and capability to build it out. The best thing to do would be to leverage existing industry and infrastructure to make that happen. You would have to start with the smaller hubs and build that out. We need to also consider the concept of a distributed hydrogen hub and the opportunities for modular production associated with local smaller-scale storage. Also, consider the possibility of hydrogen conversion to ammonia for both storage and end use as fuel, and how that option can enable smaller scale, near-term hydrogen initiatives.

Also, most importantly, for a successful hub you will not only need buyers and sellers (connected via dedicated pipeline capacity), storage (secure short-term and long-term hydrogen storage capability and CO_2 sequestration capability … large scale CO_2 storage is critical to enable the expansion of hydrogen production using existing technologies such as SMR, autothermal reforming [ATR] and partial oxidation), but also price transparency. The hydrogen market, as it currently exists with a relatively small number of producers and end users engaged in private transactions, lacks a mechanism for ensuring price transparency.

Challenges include:

- Lack of investor confidence, which needs boosting/incentivizing.
- Hub locations will be limited by the availability of appropriate storage options (for both H_2 and CO_2) and the proximity of end users (demand centers).
- Lack of any infrastructure for distributing hydrogen from hub to demand centers. Dedicated pipelines will likely be the final solution as blending into natural gas lines will be challenging due to leakage, legacy gas pipeline materials, and the need for separation at end use.
- Selection of appropriately sized compression equipment.
- Public perception of the safety of hydrogen production and storage.
- How to accommodate growth in hydrogen demand without overwhelming current limited production capacity.
- Fundamentally, what we need to do for environmental reasons doesn't align with how the market currently works.

Solutions could include:

- Utilizing existing underground natural gas storage infrastructure by converting to hydrogen, at least for near term to enable quicker hub start-up.
- Leverage initial opportunities in areas that couple high feedstock capacity, large volume infrastructure, significant storage capacity, and nearby industrial base. (e.g., places like the Gulf Coast or Appalachia).
- Utilizing mixtures of natural gas and hydrogen for power generation near hubs as a near-term solution to enable hub start-up. That way you do not have to separate natural gas and hydrogen. This can help strengthen the justification for dedicated pipeline to produce at scale. Also, it is possible to use current natural gas pipelines for blending up to 20% hydrogen, gas turbines can handle that.
- Launching a study of priority hub locations supported by geographic information system (GIS) work and coupled with techno-economic assessments.
- Government's potential to play a role in infrastructure expansion and improving pipeline capacity to support CO_2/H_2 transport.
- Government committing funds to solve the "chicken and egg" problem. For example, by utilizing the Federal government's purchasing power to buy hydrogen, creating significant demand, so the market will step up to supply it. The notion of the Navy buying ammonia as a fuel was suggested.

Next steps could include:

- Identify likely hub locations based on key factors: resources, storage options, pipeline infrastructure, demand proximity, etc.
- Assess natural gas pipelines on a regional basis for their suitability for hydrogen transport.
- Assess pipeline compressor stations and their buildout needs to accommodate different blends of hydrogen. Operability-type studies need to be carried out as well.
- Currently, the minimum hydrogen production volume for economically feasible production is about 1,000 tons per day. Carry out research that seeks to optimize process steps, improves carbon capture integration, and develops transformational processes that can significantly reduce this volume and also lessen the volume of CO_2 produced.
- Investigate options for Federal government policies that support hydrogen demand-building purchases.

3.3.4 Breakout Session Topic: Integration

The breakout groups were tasked with focusing on four questions with regard to integration:

1. Where are the best integration points with other infrastructure systems to keep costs and total GHG emissions low?
2. What are the regional and storage factors in integration?
3. How can issues of Energy and Environmental Justice be best addressed in developing hydrogen hubs?
4. How can we best leverage efforts happening in other countries?

The groups suggested (in no order of relative importance) that important opportunities for integration are at locations where:

- Hydrogen can be created and stored using non-dispatchable renewable wind/solar generated power; essentially using hydrogen as a battery (hydrogen can provide flexibility and resiliency in different ways in different regions).
- Next-generation, high-temperature nuclear power is available for high-temperature hydrolysis.
- There are opportunities to optimize economics and minimize emissions by using liquid hydrogen carriers (e.g., ammonia), particularly in grid-poor or off-grid locations. Liquid carriers could be a way to support underserved communities with low-carbon energy supplies.
- Storage opportunities for both hydrogen and CO_2 are co-located, including opportunities to utilize traditional subsurface gas storage reservoirs (not just salt caverns) or eventually unconventional reservoirs accessed via horizontal, fractured wellbores.
- Natural gas production (for SMR) and natural gas pipeline infrastructure (for blended transport) are available.

Each region is unique and presents both opportunities and challenges. An important regional variable is the availability of geologic storage options for both hydrogen and CO_2 in those places where industrial demand is centered. Beyond geologic limitations, local regulations and public perception are critical issues when seeking to build underground storage.

Challenges include:

- Lack of coordination between electric grid and natural gas systems.
- Lack of investor confidence and the need for demand incentives and long-term regulatory certainty.
- Potential pipeline infrastructure challenges in North America given age and variability of construction.

Solutions could include:

- Building investor confidence with long-term tax credits.
- Integrating hydrogen into the regulations that currently exist for energy markets.
- Investing in the creation of training capability to ensure a pipeline of skilled workers for building the necessary infrastructure needed to produce blue and green hydrogen.

Participant responses included the suggestion that communities that have not been fairly treated with respect to energy are also communities that, through proximity to industrial sites and inner-city congestion, bear the brunt of pollution impacts that could be lessened by the wider use of hydrogen as a fuel (e.g., less diesel exhaust from city buses running on hydrogen, accelerated transition away from bunker fuel, coal fired power, etc.). Also, there is a likelihood that initial investments in hydrogen infrastructure will be localized and could be designed to benefit local communities through employment in construction and distribution.

With regard to leveraging actions being taken in other countries and the opportunity to take advantage of lessons learned there, the point was made that we should be cautious that things do not always transfer from Europe to North America. However, we should be tracking what comes from the United Nations Energy Summit. It was noted that the UK is committed to a twin track approach, supporting both blue and green hydrogen, and that there should a publication out from the UK within the year (*https://www.gov.uk/government/publications/uk-hydrogen-strategy*). It was also noted that we need U.S. demonstrations with U.S. technology; if we rely too much on demonstrations and technologies in other countries, we will risk falling behind.

4.0 DAY 2 MEETING NOTES – TUESDAY, SEPTEMBER 28, 2021

Day 2 Theme: Focus on challenges of the various stakeholders throughout the hydrogen value chain, and brainstorm collaborative solutions to address them.

Day 2 Objective: Socialize challenges and opportunities of stakeholders throughout the hydrogen value chain, as well as stakeholder interactions to promote partnerships and overcome barriers. Identify next steps.

Opening remarks were delivered by Brian Anderson, NETL, Director, and Mike Rutkowski, GTI, SVP of Research & Technology Development, who provided a brief review of Day One. Day Two included two keynotes and three panel discussions, followed by breakout sessions as before.

Summaries of each of the presentations and panel discussions are provided below. **Links to each speaker's slide decks posted on the workshop's DOE web page follow the speaker's name and affiliation.**

4.1 DAY 2 – KEYNOTE PRESENTATION SUMMARIES

4.1.1 Keynote 1: Defining the Carbon Intensity of Hydrogen

Speaker: *Shannon Angielski, Van Ness Feldman, Principal (https://netl.doe.gov/sites/default/files/netl-file/21CHF_Angielski.pdf)*

Shannon Angielski, with Van Ness Feldman and representing the Carbon Utilization Research Council (CURC) and the Clean Hydrogen Future Coalition (CHFC), talked about the challenge of defining CI related to hydrogen.

CURC is an organization focused on technology solutions for the responsible use of fossil energy resources. It is engaged in bringing carbon capture technology and end users together, collaborating with research organizations and is interested in pursuing hydrogen pathways mainly in the electric power sector. CHFC was formed and launched earlier this year and is comprised of fossil energy producers, power generators, industry groups and unions. It sees decarbonization as a primary aspect of what they would like to see accomplished, with policies designed to stimulate clean hydrogen production and use throughout the U.S. economy that is fuel agnostic and technology neutral.

Determining the CI of hydrogen production requires that we begin with a baseline process against which we can compare. There is no framework for how to standardize the CI of hydrogen, but currently most LCA use SMR as a baseline. Is steam methane reforming the proper baseline?

What will be an acceptable low carbon intensity for hydrogen produced from fossil fuels? Tax incentive legislation is starting at a minimum 40%-50% GHG emission reduction below a SMR baseline. RD&D legislation (the Bipartisan Infrastructure Bill) is focused on a CI of 2 kg/CO_2 per kg/H_2.

The existing framework for Federal-level LCA was designed for biofuels, not for fossil fuels. Congress is considering the same framework for hydrogen, though this may not be the best approach.

Another key question is the location of LCA boundaries in determining hydrogen CI. Upstream including raw materials input to point of production, upstream to point of end use, upstream to use of product are all options.

Key upstream elements for hydrogen production include: water acquisition and transport, natural gas production and transport, biomass production and transport, production of raw materials for renewable energy equipment, manufacturing and transport of that equipment. Other questions include whether or not renewable energy credits will be considered an offset and also if carbon sequestered in accordance with 45Q can be subtracted from process emissions.

Key downstream issues for hydrogen production include: should liquefaction and compression be considered point of production or downstream, how will delivery methods to point of end use be handled (trucking, pipeline and rail options), and how will end use emissions be handled? GHG emissions of hydrogen are being evaluated by environmental non-governmental organizations and deemed to have some associated lifetime impacts.

Angielski noted that legislation pending in Congress for hydrogen production tax credit requires use of the Clean Air Act Renewal Fuels Standard to determine the CI of the hydrogen and ties the GHG reduction to the value of the tax credit. The tax credit is valued at a maximum of $3 per kg of clean hydrogen and pro-rated for percentage reduction of GHGs from steam methane reforming without capture. (Note: revised legislation, written after the workshop, uses kg CO_2/kg H_2 as the metric, rather than reduction from SMR).

The credit drops off abruptly, for example, a 94% reduction in GHG emissions wins $1.02 per kg tax credit and an 84% reduction wins $0.75 per kg tax credit. They are trying to incentivize the 95-100% lifecycle GHG emission reduction and disincentivize the other tiers by providing minimal credit. Because the PTC is still being formulated, there was discussion on how best to tailor the credits based on emissions levels. The Clean Hydrogen Future Coalition does not believe the clean air act framework renewable fuels standard is the right framework to be applied to hydrogen.

Questions:

"In terms of upstream and downstream issues, have you factored in the waste component and shelf life of materials?"

No, this is not in the analysis that was completed by CURC. The Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) model could be modified to address these questions. The LCA for the renewable fuels standard includes all of the upstream considerations from biomass and biofuels, however, it does not consider land use changes that would be undertaken for growing the bioenergy that is needed. The biggest emission reduction and best scenario has been a 60% GHG emission reduction. Again, it is the only existing Federal framework we have. Note that although most participants were not familiar with details of the PTC, the language in the draft bills defined LCA as "well to gate" because upstream emissions due to manufacturing of solar panels, electrolyzers, wind turbines, etc. are still not well known.

"What would you suggest as policy to incentivize hydrogen production and use?"

Look at a linear approach as opposed to the tiers that are in the framework. For every reduction based on CI, you would have an incremental incentive going up to $3 and into a net negative credit value on a linear basis.

4.1.2 Keynote 2: Role of Public-Private Partnerships

Speaker: *Bryan Morreale, NETL Research & Innovation Center, Executive Director (https://netl.doe.gov/sites/default/files/netl-file/21CHF_Morreale.pdf)*

Bryan Morreale of NETL spoke about NETL's partnerships. This keynote was given after the panel sessions and before the breakout sessions but is included here as the second of only two keynotes on the second day of the workshop.

Morreale described NETL's Center for Sustainable Fuels & Chemicals and, in particular, one of its four technical offerings, Developing Lower Carbon Footprint Feedstocks.

Morreale noted three examples of NETL's demonstration of hydrogen technologies: Natural Gas Pyrolysis – co-produces hydrogen, carbon fibers, and carbon nanotubes, yielding very low hydrogen production costs at a low carbon selling price of $2/kg; Modular, Flexible Ammonia Production – a process for producing a hydrogen carrier, done at atmospheric pressure, which is inherently modular and virtually instantaneous at start-up; and Rotating Detonation Combustors – that operate best on hydrogen and have the potential to provide a 4-7% improvement in gas turbine efficiency.

Further, Morreale described NETL's core competencies related to hydrogen R&D and its long history of building solutions. The value NETL offers to industry partners includes an ability to tap into a vast network of experts for accelerated technological advancement, risk mitigation through modeling and simulation, access to advanced equipment/facilities, and fully engaged expertise that is focused on partner needs.

Question:

"With regards to rotating detonation, have you addressed the impact to the rotating equipment in power turbines to both hardware durability and performance? These systems don't like non-steady flows."

We have an ongoing collaboration with Purdue University in developing diffusers. A lot of modeling has been done to minimize the effects of unsteady flow on the turbine. That modeling has led to a full-sized diffuser that we're installing. In the future, we have plans to test the combustor with the diffuser.

4.2 DAY 2 – PANEL SESSION SUMMARIES

4.2.1 Panel Session 1: Challenges for Fossil-Based Hydrogen Production

Moderator: *John Marion, GTI, Senior Program Director (https://netl.doe.gov/sites/default/files/netl-file/21CHF_Marion.pdf)*

Speakers:

Dan Williams, Wabash Valley Resources, Managing Director (https://netl.doe.gov/sites/default/files/netl-file/21CHF_Williams.pdf)

Rob Hanson, Monolith Materials, CEO (https://netl.doe.gov/sites/default/files/netl-file/21CHF_Hansen.pdf)

Perry Babb, 'KeyState To Zero', KeyState Natural Gas Synthesis & CCS, Chairman & CEO (https://netl.doe.gov/sites/default/files/netl-file/21CHF_Babb.pdf)

Topic: *What are the critical issues, research needs, and technology challenges for producing hydrogen from various feedstocks.*

The moderator, **John Marion** of GTI, provided a brief overview of blue hydrogen, fossil-based hydrogen production with CCS/CCUS. There are multiple ways to generate blue hydrogen, all on different maturity levels: SMR w/ CCS, ATR w/ CCS, gasification w/ CCS, pyrolysis w/ CCS, sorbent enhanced reforming

(SER), chemical looping w/ CCS, and others. GTI's Compact Hydrogen Generator is an SER process that is currently TRL 4-5, with estimated costs 20-30% less than conventional hydrogen production options, 15-25% cheaper electricity compared to the alternatives of SMR or ATR with CCS or NGCC with CCS.

Next, Marion provided an overview of CURC's work characterizing the current state of technology for blue hydrogen production processes. Blue hydrogen production and power generation RD&D "strawman" roadmaps are currently in development for 10 technical approaches: 6 for gas and 4 for solid feedstocks. All include 90% CO_2 capture and include potential for zero emissions.

Dan Williams provided an overview of the DOE funded Wabash Hydrogen Negative Emissions Technology Demonstration, a gasification focused front-end engineering and design (FEED) project. The project is to perform a FEED assessment for an existing gasification plant (constructed in 1994 and commercially operated until 2016) for production of syngas. The objective was to develop a net-zero or net-negative lifecycle with this facility.

The plan is to retrofit the facility to separate CO_2 for sequestration and maximize hydrogen production for power generation or other offtake opportunities. Initial capacity of 14,000 kg/hr hydrogen production (over 100k tons/year) with potential for ~290 gross megawatts (MW) clean electricity generation. Biomass will be introduced and blended with traditional feedstocks, targeting 10-15% biomass feed.

Retrofitting the facility will involve adding biomass feed handling equipment, water-gas shift reactors (already a well-developed technology), syngas dehydration and fractionation of CO_2, and CO_2 sequestration infrastructure. Illinois Basin geology can support industrial scale sequestration.

Williams reminded everyone that this is project is not a greenfield project but rather a large and commercially proven gasification plant, with reduced capital expenditures (CAPEX) due to the retrofitting of existing equipment.

However, there are challenges facing net-zero hydrogen production vs. the gasification to produce syngas. First, a lack of an available market for hydrogen, especially in the Midwest. Wabash is combusting the hydrogen on site using a full-size power block that may not be fully utilized in the future as long-term hydrogen offtakes materialize. Second, an uncertain supply market exists for low-cost corn stover or other "energy crop" biomass. Logistics of biomass supply with a potential 50-80-mile radius are expected to be challenging.

A third challenge is the CO_2 storage development time and expense. It is very time consuming and expensive to establish the data needed to support an EPA UIC Class VI permit application. (This was noted to be a learning experience vs a challenge given that this project is already three years old). Also noted was the importance of state and local support for sequestration development activities, that include economic development support and lawmaking. This will vary state to state, and there are a lack of guidelines and rules in certain states.

Williams noted several areas for research. First, biomass pretreatment and blending research to upgrade fuel value and eliminate variability in biomass feedstocks to achieve efficient and reliable gasification. Second, higher efficiency and higher availability of gasification technologies. Gasification is not as reliable as SMR; we need to continue to do research, expand the technology options and make those technologies more efficient. Finally, longer term incentives are needed. This project works from an investment case perspective only because it is a retrofit of an existing facility. A greenfield project will need a longer-term incentive to produce clean hydrogen.

Rob Hanson of Monolith Materials presented on the Monolith methane pyrolysis project in Nebraska, Olive Creek 1 (OC1). Monolith has been working for the past 10 years on the development of methane pyrolysis. They use renewable electricity and natural gas (renewable or pipeline gas) to produce clean hydrogen and high value solid carbon (three tons of carbon for each ton of hydrogen). This project is currently at TRL 8-9. Also, currently at 96% reduction in CI compared to SMR (11.30 to 0.45 CI) using fossil gas, but renewable natural gas is used, you can go carbon negative (-2.08 CI). Monolith has worked over four orders of magnitude in scale with this technology and a patent-protected commercial scale facility is operational (June 2020) and Monolith is adding on additional field (OC2) to the existing facility. OC1 hydrogen production capacity is about ~5 kilo-tonnes per annum (ktpa) and carbon sequestration capacity is about ~15 ktpa. The expanded OC2 facility will add 12 reactor units to provide additional hydrogen production and carbon sequestration, ~60 ktpa and ~180 ktpa, making it the largest blue hydrogen plant in the U.S.

Large volumes of hydrogen from pyrolysis will require markets for large volumes of solid carbon. Currently Monolith is focused on carbon black products, but research is underway on other things, such as road, cement, steel, plastics, etc. More research is needed on how to actually get hydrogen into the market; midstream and end-use research, as well as LCA, is still needed.

Perry Babb of KeyState to Zero next spoke about the plan for a natural gas synthesis plant with carbon capture and sequestration in north central Pennsylvania's Clinton County. The project, if implemented, will integrate onsite natural gas production from a stranded gas resource and onsite natural gas synthesis with onsite CCUS. It was estimated that 300,000 tons of CO_2 could be stored onsite, with ongoing work to expand to adjacent areas. The proposed products include blue hydrogen, blue ammonia and diesel exhaust and power plant exhaust treatment chemicals.

Babb noted that there needs to be more research to lower costs for hydrogen transportation, Federal policy to lower market risk, EPA policies to reduce the time it will take for Class VI permits, and both Federal and state policies to bring parity to hydrogen and renewable gas in pipeline blending.

Post Panel Q&A:

"What is the target for value and to make these clean hydrogen projects work?"

Economics will only win at scale.

"Can you comment on the levelized cost of hydrogen by pyrolysis at the OC1 plant?"

We must be cost competitive with other fuels. Looking at renewables like solar, CAPEX came down, but the investment tax credit persisted and the cost of capital also came down. Half of cost is from CAPEX side; other side is from operating expense side. If hydrogen can do what renewables did on the CAPEX side, it would be very beneficial.

As for gasification, it is the lowest cost producer for hydrogen. Biomass cost forces costs up. We need to find the cheapest sources of biomass and reduce the amount needed to achieve net-zero.

The Pennsylvania SMR synthesis plant can produce hydrogen that beats diesel on price at the plant gate but will consider ATR in the next phase of engineering. But the cost of transporting it is too high. We need a production tax credit or incentive to move it to market.

4.2.2 Panel Session 2: Challenges for Hydrogen and CO_2 Pipelines & Storage

Moderator: *Jared Ciferno, NETL, Technology Manager*

Speakers:

Michael Tritt, Lane Power & Energy Solutions, President (https://netl.doe.gov/sites/default/files/netl-file/21CHF_Tritt.pdf)

Seth Levey, Equinor, Director, Government Relations & Public Affairs (https://netl.doe.gov/sites/default/files/netl-file/21CHF_Levey.pdf)

Jason Ketchum, One Gas, VP. Commercial Operations (https://netl.doe.gov/sites/default/files/netl-file/21CHF_Kwtchum.pdf)

Angela Goodman, NETL, Senior Researcher (https://netl.doe.gov/sites/default/files/netl-file/21CHF_Goodman.pdf)

Topic: *To achieve net-zero, disposition of carbon dioxide must be integral to fossil hydrogen production. The panel examined challenges and solutions for moving and storing carbon dioxide and hydrogen.*

Jared Ciferno opened the discussion by saying that the focus of the panel will be the challenges of hydrogen and CO_2 transportation and storage. We can produce hydrogen today, and we know how to decarbonize it. The good news is that we can produce hydrogen from natural gas, adding carbon capture and utilization, or even capturing carbon through pyrolysis as a solid product. More good news is that on the conversion side, there are opportunities and advanced technologies to lower the cost and energy consumption.

The big question is that we have a complex transportation pipeline infrastructure. If you look at the infrastructure today, the natural gas system, the pipelines and unit operations are aged. It's not all new; it was intended and designed for natural gas transportation.

There are only three hydrogen subsurface storage applications in the U.S., so we have limited experience on the storage aspect. Big picture, we need to flesh out the challenges sooner rather than later in order to develop the technology solutions needed to close the gaps.

Michael Tritt opened the panel presentations by discussing how geologic storage will play a role in the development of hydrogen infrastructure. His presentation was on hydrogen storage in salt and hard rock caverns. His company, Lane Power & Energy Solutions, focuses on the core engineering, procurement, and construction business of caverns. They have team experience in hard rock caverns, salt caverns, and national energy security.

He then provided an overview of storage caverns. Salt caverns are about 300 feet in diameter and can be between 1,000–3,000 feet tall. Hard rock caverns use the same technology as hard rock mining, but the difference is they are creating a void space for storage. They use conventional mining technologies. Products stored include gas and liquid hydrocarbons, compressed air, hydrogen, ammonia, and helium. Solution-mined salt caverns have 60+ year operational history. There are 2,000 caverns worldwide, and several in hydrogen service (3 in the U.S. [Texas], 3 in the UK). He stressed that hydrogen has been safely stored in geologic formations for decades.

Hard rock caverns also have 60+ year operational history. There are 200+ worldwide, but none presently in hydrogen service.

There is a global interest in hydrogen storage caverns. Their design and operation are the same as gas storage caverns, the difference is the treatment of the well casings because of the size of the hydrogen molecule. Hydrogen storage caverns can store extremely large volumes.

The current U.S. interest is in Appalachia, along the Texas coast, and in Utah (compressed air energy storage [CAES] and hydrogen power plants). All initial conversations focused on salt, but secondary conversations are being held on hard rock.

Tritt posed the question: *Can we use existing natural gas storage caverns for storing hydrogen?* The answer is yes, but the materials limitations we have with pipeline infrastructure is the same, so it will be limited. What we can do is put a liner in the existing injection/production well casing that can be converted. However, that will constrict flow rates, so we likely need to drill a new re-entry well so that we do not have to decrease the flow rate.

Key takeaways from his presentation included: hydrogen is forecast to become a $130–170 billion U.S. industry by 2050; President Biden's Infrastructure plan allocates $73 billion for clean energy, transition, and hydrogen; DOE's *Hydrogen Shot* target is $1/kg H_2 by 2030; hydrogen can be stored in salt and hard rock caverns; caverns are far less costly than large-volume pressure vessels; green ammonia will be part of the energy mix, and has been stored in hard rock caverns for decades; and caverns take a long time to construct (three-four years for salt, four-five years for hard rock), so we should start early.

Seth Levey spoke to the policy and regulatory landscape for CO_2 and hydrogen transport and storage. He said what we are seeing now is a new confluence of different regulatory regimes that all need to be harmonized and synchronized. We have to simultaneously coordinate on interstate and intrastate transport pipelines and storage, both for hydrogen and CO_2. While CO_2 is more mature in some areas, hydrogen is more mature in other ways. At Equinor, they have been working on such projects in Europe. At this scale, public policy is essential.

The regulatory framework for oil, gas, and CO_2 pipelines is relatively established. The need for CO_2 transport and storage to enable rapid decarbonization and to support net-negative CO_2 emissions (e.g., direct air capture [DAC], bio-energy with carbon capture and storage [BECCS]) is key. Proper communication around new pipeline infrastructure is essential.

In terms of CO_2 storage, the EPA provides a regulatory framework for storing large volumes of CO_2. So far, eight states have committed to the establishment of a regional transport plan. The issue with Class VI wells for storage, as opposed to transport, is at the state level. Transport is relatively established; storage has further to go to set a precedent and establish norms.

One area we need to work on is the transport of hydrogen and determine who has regulatory primacy, operators, policymakers, etc. must initiate dialogue on addressing regulatory barriers facing first-of-a-kind hydrogen projects in the U.S. There is a question of whether interstate pipelines carrying hydrogen are common carriers subject to regulation by the Surface Transportation Board under authority closely related to the Federal Energy Regulatory Commission's parallel authority over other pipeline types. There are also questions as to the roles of the states and localities.

There is still work to do on the policy side. Without a synchronized approach, it will be difficult to move forward.

Jason Ketchum followed with a presentation on the integration of hydrogen into a natural gas system. His company, One Gas, has a presence in three different states (Oklahoma, Kansas, and Texas). It is a 100% regulated natural gas distribution utility. Their primary focus is figuring out the policy perspective. They are currently participating in two other projects: DOE's H2@Scale Initiative, which brings together stakeholders to advance affordable hydrogen production, transport, storage, and utilization to enable decarbonization and revenue opportunities across multiple sectors, and the National Renewable Energy Laboratory (NREL) *HyBlend* Project, which is a collaborative R&D effort that addresses technical barriers to blending hydrogen in natural gas pipelines.

One Gas is focusing on increasing and advancing the adoption of hydrogen. There have been limited discussions about "all-energy" grid planning across the natural gas and power generation sectors. These types of discussions need to be held.

There is currently limited Federal and state policy guidance; some on a Federal basis, but at the state level, they aren't being mandated to integrate renewables or meet goals. With hydrogen, there is limited state guidance. (The closest example of state guidance is in Oklahoma).

He finished by stating that hydrogen integration has already been successful in one state. In the 1970s, Hawaii Gas began converting naphtha, a byproduct from local oil refineries, into synthetic natural gas and hydrogen in the Campbell Industrial Park, Kapolei, on the island Oahu. To this day, approximately 12% of the gas in Oahu's pipeline is hydrogen—this is the highest concentration of hydrogen reported by a gas utility in the U.S.

Angela Goodman closed out the presentations by providing an overview of DOE's Subsurface Hydrogen Assessment, Storage, and Technology Acceleration (SHASTA) project.

She discussed the importance of DOE's Hydrogen Program Plan and how SHASTA ties into it. Hydrogen has the potential to meet existing and emerging market demands across multiple sectors. The program envisions how innovations to produce, store, transport, and utilize hydrogen can help realize that potential and achieve scale to drive revenue opportunities and reduce costs.

The objective of the SHASTA project (three-year effort, began in April 2021) is to identify and address key technological hurdles and develop tools and technologies to enable broad public acceptance for subsurface storage of pure hydrogen and hydrogen/natural gas mixtures. The project also sets out to elucidate operational risks; quantify the potential for resource losses; develop enabling tools, technologies, and recommended practices; and ultimately develop a collaborative field-scale test plan in partnership with at least one natural gas storage industrial partner. The project focuses on reservoir performance and well component compatibility in the storage system (pipelines and surface components upstream from the wellhead are covered by separate DOE research activities). The SHASTA project is a multi-national lab effort (NETL, Pacific Northwest National Laboratory, and Lawrence Livermore National Laboratory). It leverages unique capabilities and a demonstrated expertise on subsurface energy systems. The SHASTA team is currently working on putting together a stakeholder group in order to make sure SHASTA aligns well with industry needs and also as a place to share knowledge.

Post Panel Q&A:

"There is a lot of opposition to pipeline buildout; how can we gather public support for new hydrogen/natural gas pipelines? What can be done technically and policy-wise? How can we ensure success of these hubs?"

This is a hard question to answer. These projects are essential for reaching net-zero. Pipeline opponents may be likely to also be concerned about climate change, so one approach is to engage in discussion with the stakeholders. There needs to be listening on both sides of the discussion. There are a lot of misconceptions about the safety of hydrogen transport and storage. There are places where we can broaden dialogue and understand goals of projects. U.S. hydrogen policymakers need to discover the precise concerns of the opposition and understand if we are not all striving for the same thing. The key is to educate people in communities on the value and safety of hydrogen.

"Can you comment more on the use of existing storage infrastructure for hydrogen (liners were mentioned during the presentations)."

The U.S. oil and natural gas industry uses the same techniques for handling casing leaks in existing wells. In the past, if there was leakage, liners were used to fix the problem. They run the smaller diameter pipe down into the well and the packing seals it in place. It is technically feasible, just never used for a hydrogen scenario. The liner would be made of special materials to handle it. Again, the issue is that the smaller diameter decreases the injection and withdrawal rates. Therefore, it may not make sense economically. It may be better economically to drill a new well and complete it with hydrogen-safe material and abandon the original well.

"Can you provide a sense of operation and maintenance costs with hydrogen storage as opposed to natural gas. Is it the same or is there a percentage increase?"

Not certain of the answer to this, only know what has been reported in the literature at the moment, which claims that storage costs $1/kg in different formations. It depends, salt dome storage for hydrogen will be slightly more expensive than conventional natural gas (maybe 5–10%), but only because of special requirements for well tubulars. The rest is very similar.

"Operationally, if you take an existing natural gas pipeline, what would you have to do differently to transport hydrogen/natural gas blends?"

In discussions with Hawaii Gas, they found out that when they originally started thinking of hydrogen in the system, engineers said they couldn't do it. From further discussions and research, they found out that it doesn't require the significant adjustments to the systems as they originally thought. The pipes have had cathodic protection. Engineers became a lot more comfortable blending up to 20%. They are looking at applications for a 100% hydrogen system.

"Will NETL publish a map of potential storage sites and is the key driver behind the SHASTA project to support large-scale validation pilots in a three-year timeframe?"

NETL is working on an online, interactive tool that will help the public see how much potential is available. The goal is to engage with industry partners to have a field-tested plan backed by science.

"Where do we stand with hydrogen in terms of storage and policy?"

The discussion is around classification of hydrogen and how regulators view it. In terms of how that discussion will play with an infrastructure buildout and getting a license to operate, getting regulators to provide clarity about how it must be done is important. There need to be discussions with other stakeholders as well. Broad goals are important, but the specifics are very complicated. The *Hydrogen Shot* is a very good goal, but what are the different policy elements that the Federal government needs to start now so that stakeholders get the signals needed to commence organizing? More discussions are needed between agencies, and with Congress.

Perhaps that's an opportunity where large demo plants, getting the hydrogen hubs sited and permitted, could actually reinforce policy and regulations in those areas.

"Is there any chance of stratification of hydrogen and natural gas mixtures stored in salt caverns?"

Panelists have only ever stored hydrogen as a pure gas project and not as a mixture. Hydrogen is lighter than a natural gas molecule. Stratification could be a possibility. This is one element NETL research will be trying to answer. We plan to answer that within the SHASTA project. There are a lot of theories, but nothing definite.

4.2.3 Panel Session 3: Challenges for Hydrogen Utilization

Moderator: *Brian Weeks, GTI, Senior Director, Business Development*

Speakers:

Brett Perlman, Center for Houston's Future, Inc., CEO (https://netl.doe.gov/sites/default/files/netl-file/21CHF_Perlman.pdf)

Josh Martincic, Long Ridge Energy Terminal, Chief Sustainability Officer (https://netl.doe.gov/sites/default/files/netl-file/21CHF_Martincic.pdf)

Trevor Brown, Ammonia Energy Association, Executive Director (https://netl.doe.gov/sites/default/files/netl-file/21CHF_Brown.pdf)

Bernhard Winkelmann, Nikola Motor, Global Head, Technology & New Product Development (https://netl.doe.gov/sites/default/files/netl-file/21CHF_Winkelmann.pdf)

Topic: *Technology challenges and other barriers to be overcome to expand use of clean hydrogen in existing (refining, ammonia) and new end-use sectors.*

Brett Perlman, of the Center for Houston's Future, Inc., presented on their role in bringing business, government, and community stakeholders together to engage in strategic planning and collaboration on issues of importance to the Houston region. They focus on leveraging Houston's energy leadership to accelerate a low-carbon future that combines economic growth and a positive impact on the environment

Houston's assets as a potential hydrogen hub include five core strengths: a large engineering workforce with energy experience, existing large-scale energy and industrial infrastructure, significant renewable generation capacity, a business-friendly ecosystem for startups, and the largest U.S. port with global shipping connections.

Houston's action plan involves three value chains: jumpstarting emerging sectors where Houston has a distinct advantage (CCUS, hydrogen, circular economy (plastics), battery manufacturing and energy storage), attracting companies in "new energy" industries (solar, wind, renewable natural gas, low-carbon liquified natural gas, biofuels), and deploying cross-cutting initiatives to attract companies across all energy value-chains (including things like energy efficiency, carbon trading, electric and fuel cell vehicles, geothermal).

Houston could gain 600,000 additional jobs – total gross domestic product gains could amount to \$70–\$160 billion by 2050, with a concerted effort to attract high-paying new energy jobs with wages that are, on average, 28% higher than Texas's median wage.

Houston has a large portion of Texas's GHG emissions (40%), and the Texas Gulf Coast has large portion of the U.S.'s refining and petrochemical capacity (28% and 42%, respectively). Reducing these is a vast undertaking.

Houston and the Texas Gulf Coast have several advantages in terms of H_2: over 900 miles of hydrogen pipelines (56% of U.S., 32% of global), ~3.4 million metric tons of hydrogen produced annually, largely through SMR (34% of U.S., 8.5x Rotterdam [Rotterdam is a leader in this area in Europe]), 48 hydrogen production plants, and the world's largest storage caverns for hydrogen (3 of 6 in the world are in the Houston region).

Green hydrogen will require greater technology and cost advances than blue. Requirements for advancing blue hydrogen are continued improvements in CCUS cost and technology, policies instituted to support CCUS adoption, and maintaining low-cost methane. Requirements for green hydrogen are reduced electrolyzer costs and significant improvement in that technology, substantial renewables penetration driving ubiquitous low-price power, and policies (and thus investor sentiment) favoring green hydrogen.

Decarbonization through hydrogen will be accelerated through a mix of localized and crosscutting drivers. Localized drivers include policy goals ("2050 net-zero" or similar), funding (carbon fees or other), and leverageable assets (for blue, hydrogen systems and at-scale CCUS hubs, for green, geologic storage and low power prices). Crosscutting drivers include cost and supply chain improvements (electrolyzers, renewables) and enhanced hydrogen and renewable synergies.

Perlman prioritized new hydrogen markets based on relative adoption barriers or advantages and emissions impacts, with heavy duty trucking topping the list, followed by energy storage, export markets and finally industrial processes.

Finally, Perlman described "H_2Houston – A Global Hydrogen Hub" as an anchor for local and national heavy transport markets, leveraging captured CO_2 for enhanced oil recovery and decarbonizing industrial process heat and power, with an ability to be a "market maker" exporter.

Josh Martincic of Long Ridge Energy Terminal in Hannibal, Ohio presented on his enterprise's hope to co-locate large industrial companies, knowing they need a "green" message to draw them in. They have been evaluating CCS and hydrogen production technologies and have chosen to focus on both hydrogen production and use. They have just recently completed installing a 485 MW combined cycle gas turbine power plant (GE 7HA.02 gas turbine, capable of blending 20% hydrogen) and are currently installing a hydrogen blending skid to blend first 5%. Blending should commence December 2021. Their initial hydrogen supply will come from a neighboring industrial facility, but they are exploring future hydrogen supply from onsite production. They have received a bid for creation of caverns in subsurface salt deposits allowing for long term underground storage of hydrogen.

Their vision for an Ohio Valley H_2 Hub (Hannibal, OH) includes flexibility to play in multiple attractive markets due to their location in the northeast, space to generate hydrogen on site, an onsite consumer (power plant) nearby natural gas pipelines, access to water (located on the Ohio River), subsurface storage potential, and access to rail and barge transport. Their location has a large brownfield area where they could set up incubation sites for companies to test systems.

Martincic sees a wide range of challenges to broader hydrogen value chain implementation ranging from production technology challenges, multiple location requirements, energy loss, how a CI score is determined, lower heat content (requires additional energy to convert to liquid and then back to gas), transportation challenges, storage location availability for scale needed, market understanding (how do we communicate different hydrogen colors, different CI scores) and acceptance (will consumers accept low a CI score as well as they accept renewables?), cost premium (even at $1/kg, hydrogen will be more expensive than natural gas - what markets will be willing to pay for that?).

Overcoming these challenges will require fostering collaboration (hydrogen producers, pipeline and storage operators, utilities, transport companies, electrolyzer/SMR manufacturers, industrial end users, developers, and municipalities/economic development agencies), facilitating on-going dialogue among industry participants, and bringing value-added capabilities to foster hydrogen development opportunities.

Trevor Brown of the Ammonia Energy Association (AEA) presented on ammonia's place in the global economy as a commodity chemical and a hydrogen carrier. Ammonia has a place on both sides of the hydrogen supply/demand equation: decarbonizing ammonia production (supply) and adopting ammonia in energy markets as a hydrogen carrier fuel (demand). If we can decarbonize ammonia production, those demand markets will open.

Brown noted that the U.S. produces ~10% of the world's ammonia production. According to the International Renewable Energy Agency, by 2050, in a 1.5°C scenario, ~70 million tonnes of existing ammonia capacity will be shut down or converted from fossil to renewable inputs and ~500 million tonnes of new ammonia capacity will be developed using renewable inputs (electricity, biomass). This new ammonia development will require carbon mitigation.

He noted ammonia's advantages as a hydrogen carrier: liquid at -33°C (vs. -253°C), 50% more hydrogen in liquid ammonia than in hydrogen gas (volumetrically), construction of ammonia pipelines costs 1/2 that of natural gas, 1/4 that of hydrogen lines, a 60,000-tonne ammonia tank holds 90 GWh while largest battery holds 0.129 GWh, ammonia cracking to hydrogen involves an energy penalty (~25%), but it is competitive for long-duration/long-distance hydrogen transport.

He also highlighted the benefits of ammonia as a maritime fuel for reducing emissions and for electric power. He noted the importance of ammonia in Japan's road map for decarbonization, with ammonia-coal co-combustion use targeted at 3 million tonnes by 2030 and ammonia use in gas turbines at 30 million tonnes domestic (100 million tonnes regional) by 2050.

He also summarized their announced, fossil-based ammonia conversion projects (low-carbon capacity) and described AEA's facilitation of the development of a Low-Carbon Ammonia Certification Scheme (and is welcoming input at *ammoniaenergy.org/certification*).

Bernhard Winkelmann presented on Nikola Motor's perspective of the market for hydrogen in heavy duty transport. Founded in 2015 in Phoenix, AZ, with a manufacturing facility in Coolidge, AZ, Nikola aims to decarbonize heavy-duty transport, supported by a strong ecosystem of partners. They design and manufacture battery-electric and fuel cell hydrogen-electric vehicles, as well as design hydrogen production and filling stations and battery charging solutions.

They are planning to operate on a Hub-and-Spoke Model, with hydrogen produced or purchased from third parties at a centralized hub and distributed to dispensing stations. They estimate a need for 25 million tons of hydrogen within their dispensing station system by 2028.

Alternatives for hydrogen distribution include over road (currently U.S. preferred, including liquid and compressed gas), over rail (was used in 70s and 80s and has come to a stop … whether rail can come back is a political question), and pipelines (will become more attractive as transport distances get larger). Nikola plans to evaluate the most cost-efficient model of hydrogen distribution for each use case.

In the case of hydrogen storage and dispensing, Nikola will leverage partnerships with existing truck station operators (e.g., Travel Centers of America) to optimize the speed to market and significantly reduce CAPEX. Depending on location, Nikola's infrastructure network will be tailored to incorporate: 1) Onsite, 2) Hub-and-Spoke, or 3) Other models of hydrogen production and distribution (i.e., the purchase of 3rd party hydrogen). The first two stations will be constructed at existing TA-Petro locations in California and are targeted to be commercially operational by Q1 2023. Nikola may also develop greenfield hydrogen dispensing stations.

In terms of challenges, Winkelmann noted scale up of production and distribution (will change as production increases), difference between the U.S. and EU in terms of the pipeline and highway network, capital needs to build infrastructure (government incentives are needed to kickstart transition), and the need to expand and streamline permitting. Further, safety is paramount – the industry as a whole cannot afford a hydrogen safety incident.

Post Panel Q&A:

"Since Nikola is building battery electric vehicles for short-medium haul, did the company consider battery swapping for long haul, is that feasible or how do the economics compare?"

If short distance, batteries are better than fuel cells. The longer the distance, the heavier the payload, the more beneficial it is to move to hydrogen fuel cells. The exception would be cities with large taxi fleets or public transit buses.

"If you could pick out one or two key milestones or drivers that are needed to spur the demand for clean hydrogen, what are they in your sector/geographic area?"

They do come down to policy. We'll see if a Federal infrastructure bill comes out to put some real muscle behind hydrogen policy. I think the other one is that you need customers. A corporate goal of carbon emissions is likely not sufficient. You need a supply-side driver and a demand side driver (like a carbon tax).

You need policy, especially when you're competing against low-cost power sources like natural gas.

None of the options we're looking at are prohibitively expensive, but we have to figure out how to share the risk. Perhaps a longer-term mandate. Something that isn't asking people to make price decisions. Allowing the market to do it, but defining what sort of percentage of low-carbon products (such as fertilizer) we need going into the market. That kind of mandating is a very powerful thing. That's why the maritime sector will decarbonize quickly—they have a clear signal, so the market has to step up and meet it.

It's true that we need policy and incentives, but we also need access to capital. To transfer into a hydrogen economy will be costly, and we do not have an unlimited timeframe to do it. The largest value will be in the transport sector, since hydrogen's closer cost parity with diesel makes it a sustainable prospect, hydrogen has farther to go to create cost parity (and hence sustainability) for power applications.

4.3 DAY 2 – BREAKOUT SESSION SUMMARIES

The overall objective of the breakout sessions held on Day 2 was to focus on challenges for the various stakeholders throughout the hydrogen value chain. The participants were instructed to identify the challenges and opportunities of stakeholders and explore ways to promote partnerships and overcome barriers. Four facilitated groups addressed the same set of questions and framed their responses in terms of: (a) opportunities/needs, (b) challenges, (c) solutions, and (d) next steps.

On the second day, the four questions addressed by the breakout groups were identical for all four topics identified under sections 4.3.1- 4.3.4:

5. How can costs and GHG emissions intensity of this segment be reduced in the initial and scale-up stages of deployment?
6. What are the technical gaps, and how can they be addressed by R&D, digital tools, energy systems modeling, or other means?
7. What types of partnerships (e.g., public/private, transportation + power sectors) and new business models are needed to accelerate hydrogen deployment?
8. How can Environmental and Energy Justice issues be addressed in this segment of the hydrogen value chain?

The consolidated results are summarized below for each topic.

4.3.1 Breakout Session Topic: Hydrogen Production

On the topic of hydrogen production, participants identified several opportunities/needs:

- Costs can go down by scaling up, but also being required to decrease emissions through carbon capture and sequestration in the case of SMR, or carbon use/storage in the case methane pyrolysis, will require that we "leapfrog" some traditional steps in the technology/technology readiness curve.
- Need new sources of capital and support from new investors willing to take on early-stage risk in order to compress the technology development timeframe, which will be critical in decreasing both costs and GHG emissions simultaneously.
- Opportunity to use biomass gasification as a source of power and hydrogen, as a way to reduce GHG emissions.
- There is an opportunity and need to establish a common understanding for evaluating CI with respect to hydrogen production, based upon LCA.
- Decarbonization of legacy facilities is an Environmental Justice opportunity.
- There is a need to quickly identify government policy drivers that will enable rapid hydrogen production.

Challenges include:

- Deep decarbonization, greater than 95%, will be difficult to achieve with conventional technologies.
- Making the correct decision to not scale up or deploy technologies that do not make sense. We need consistent techno-economic assessments and LCAs to inform these decisions.
- Hydrogen production from fossil fuels ultimately depends on economic carbon capture and secure sequestration or use; much more work to be done to show that these can be achieved at the locations where it makes sense to produce hydrogen.
- In terms of biomass feedstock, the technology is not there yet.

- Need more research on CO_2 utilization (e.g., for chemical manufacture) to enable blue hydrogen production. Defining new roles for and expansive uses of carbon will be important.
- Continued workforce development; transitioning chemical engineers from refining and gas processing to hydrogen production will be important to avoid loss of experience.

Potential solutions include:

- Industry-wide partnership focused on carbon dioxide sequestration, funded by Federal government (e.g., the *Regional Carbon Sequestration Partnership* program).
- Reduce transportation costs/issues by utilizing hydrogen near feedstock production.
- Expansive LCA to enable broad deployment and ensure cost elements are clarified.
- Right-sized solutions for carbon capture and hydrogen production in the short term (such as the LaPorte hydrogen production facility) is a clear way to enable market expansion.
- Known technical solutions can make ATR with CCS viable.
- Pathway analysis for RD&D opportunities based on cost, maturity, and emissions intensity.
- Adaptation of educational opportunities for workforce expansion.

In terms of Energy Justice, prioritize consideration of sites where opportunities to lift disadvantaged communities are present. For example, coal mining communities where there are opportunities to source feedstock (e.g., natural gas plus coal waste plus biomass) and store CO_2 (subsurface reservoirs) while lifting under-employed workforce (coal miners) through training.

4.3.2 Breakout Session Topic: Hydrogen Pipelines & Storage

On the topic of pipelines and storage cost reduction, participants' ideas on opportunities/needs included: good planning, incorporation of the use of digital tools and analytics, improved leak detection for pure hydrogen systems, and improved collaboration across Federal and local regulatory agencies. The notion of leveraging existing natural gas pipeline right-of-way (ROW) to build hydrogen pipelines was suggested again as a way to reduce costs. The use of hydrogen carriers like ammonia and rail transport of liquid hydrogen were also suggested as ideas worthy of consideration.

Identified challenges to managing costs and GHG emissions include:

- Difficult and expensive to build a hydrogen pipeline and trucking options are also expensive, particularly for bulk liquid hydrogen.
- Operational challenges that will vary depending on how and when hydrogen is added into a pipeline.
- The fact that end users have different fuel specification needs.
- Difficulty in adapting pulsation control and induced vibration mitigation technologies to different hydrogen blends.
- Potential hydrogen leakage into enclosed spaces.
- Incompatibility with current infrastructure is a huge issue. There are sections of pipe where the metallurgy is unknown. In addition, every junction is an opportunity for leaks.
- Current compression systems burn natural gas as feedstock. If we add hydrogen to the natural gas in the pipeline, we will need more gas to run those compressors. Electrification will not always be an option to avoid this problem.
- Adding hydrogen also means lower head pressure. There may be a need to increase horsepower in compressors and also decrease distance between compressor stations to maintain pressure.

Potential solutions to managing costs and GHG emissions included:

- Consider ammonia as a hydrogen carrier. There is no comprehensive techno-economic analysis on ammonia as a hydrogen carrier, and one is needed. The economics change when you look long-term vs short-term.
- Having rail as a liquid hydrogen transport option could be a middle-of-the-road alternative between pipelines and trucks. This approach could quickly lower the cost of hydrogen transport. The technology is there, the only thing missing is regulatory approvals.
- Variable pulsation control.
- Upgrade in compressor technology. For example, integrated machines without seals or with improved seals.
- Odorization of hydrogen plus modification of existing technologies to detect hydrogen in low concentrations.
- More and earlier collaboration and identification of synergies at Federal and local level. Strong working relationship with regulators and researchers. Early collaboration within DOE (e.g., FECM, EERE, GeoHydrothermal) and among agencies (e.g., USGS, DOE, DOT, EPA, USDOT, etc.) and state agencies.

Identified technical gaps include:

- Better understanding of potential for hydrogen storage in new subsurface reservoirs of various types.
- Real-time sensing approaches for hydrogen concentration in blends with natural gas.
- Better understanding of the safety issues associated with use of blended hydrogen/natural gas mixtures, particularly in residences.
- Better understanding of any issues related to hydrogen transport by rail and appropriate DOT regulations to permit.

With regard to the question of partnerships and new business models needed to accelerate hydrogen deployment, a suggestion offered was for DOE to consider the possibility of a hydrogen strategic reserve along the lines of the strategic petroleum reserve. Also, there was a suggestion that the Federal government could assign hydrogen-using industries (e.g., refineries, ammonia producers) low-carbon or zero-carbon targets for their hydrogen. This could quickly have a huge impact.

With regard to Environmental Justice issues, participants noted that issues need to be raised and mitigated through collaborative effort and better outreach, education and information-sharing with Energy Justice organizations and local communities. In this regard, DOE's Regional Carbon Storage Program Partnership (RCSP) initiative was successful and is a good model.

There is a need to prioritize the safety of existing pipelines in low income, underserved communities as vintage natural gas pipelines are upgraded/replaced. A focus on those could help to ensure that communities do not feel like they're getting hit twice; existing unsafe conditions complicated by additional unsafe hydrogen pipelines. Further, the issue of equity, ownership, and community participation have to be addressed up front in areas where local landowners are involved.

Finally, the point was made that it might be worth looking at the potential risk of "show stopper" safety incidents related to a hydrogen economy transition, a la Three Mile Island, and preparing for ways to deal with the outcome. A big safety incident related to human error could derail the transition. An incident in Norway might be a good case study for best practices on handling such a situation. (Note: On June 11, 2019, a hydrogen station for fueling fuel cell vehicles near Bærum, Norway exploded. The company took responsibility for the incident, caused by an assembly error on a specific plug in a high-pressure hydrogen storage tank. A $2.97 million dollar fine resulted. The company has changed its equipment assembly procedures as well). There is a government role in helping the public understand the safety of underground storage and pipeline transport of hydrogen.

4.3.3 Breakout Session Topic: Utilization

On the topic of hydrogen utilization, participants identified several opportunities/needs:

- Mid- to long-haul distance heavy transport is an opportunity for expansive hydrogen utilization. Shorter haul applications will be ceded to battery/electric users with minor exceptions, unless the efficacy of those solutions in cold environments or with difficult use limits their utility.
- Hydrogen hubs could start with large offtake users (e.g., power) and then transition to smaller end users where higher levels of hydrogen purity are required.
- Expanded hydrogen liquefaction capability could play a role in enabling transportation as a pathway for greater utilization.
- In order for hydrogen to be utilized in power production, especially as blue hydrogen, there is a need to lower the cost considerably. Hydrogen is currently used as a chemical, not burned for power, therefore there is hesitancy and uncertainty.
- Need to better define what the cost of using hydrogen will be for various end uses. Research towards this end may need to be scaled up or accelerated.
- Use hydrogen for combined heat and power (CHP) as a starting point, which improves overall efficiency and reduces GHG emissions. Could be done at a hub where demonstration of cost-benefits through scale up could improve commercialization prospects. Value is already there.

Challenges include:

- We need the infrastructure in place to integrate hydrogen into the energy mix, but we cannot switch to a fuel that is not available or too costly to produce. Lower cost and availability are dependent on scaled up infrastructure, but that cannot be deployed if there is no demand. Thus, a "chicken and egg" problem.
- Customers do not want to give up efficiency in order to switch to lower carbon fuels.
- Technical gaps depend on the end use. For industrial heating or chemical reduction of iron ore, there are potentially technical or equipment gaps to be resolved. Europe is currently leading in this area but all the information is not in the public domain.
- Existing hydrogen production levels and production costs are not going to make decarbonized electricity competitive/affordable. Need to find technologies that can minimize cost of CO_2 capture and thus minimize cost of blue hydrogen.
- Sensing technologies for hydrogen that can work in high temperature/high pressure environments may be lacking.
- Adequate codes and standards for the use of hydrogen are lacking and building, heating and ventilation codes and standards must be modified or new ones created before hydrogen can be utilized in residential and business settings.
- Establishing efficient mechanisms for hydrogen purification based on end user needs and building a better understanding of the levels of hydrogen purity required. Will there be a single standard or multiple standards unique to end users?

- Sector coupling is difficult because sectors are driven by separate and unrelated market forces. When you have someone producing molecules that could be sold into multiple markets, but there is no coordination between how each of these segments are regulated (e.g., if one sector gets a tax credit, does the other sector gets it as well?). A National Hydrogen Economy will require a national strategy that looks at the whole picture.
- There is a need to clearly articulate the rationale and benefits (e.g., environmental, affordability, resilience, choice of applications) for using blue hydrogen, otherwise, people will suggest using intermittent and currently unaffordable zero- carbon renewables from the start. The step change pathway must be better communicated.

Potential solutions include:

- Large scale demonstration projects that show impact of hydrogen use in highest CO_2 emitting sectors (e.g., steel production, chemical production, cement, and other industrial uses).
- Public/private partnerships with potential industrial users of hydrogen and industry standards associations.
- The cost of validating at scale is prohibitive for industry, assuming you can even source the required amounts of hydrogen. Government subsidization of validation toward first commercialization is necessary (e.g., recent NETL FOA 2332—Energy Storage for Fossil Power Generation [6/12/2020], some projects will be moving out of the lab to a Phase 2).
- Consider combinations of sectors to advance hydrogen utilization. For example, public transportation and utilities across a regional setting.
- Accelerate work original equipment manufacturers (OEMs) are doing by working to streamline testing and emissions (e.g., EPA approvals), so that when they have a technology that is ready to be developed, the commercialization pathway isn't presented with a huge regulatory barrier, thus allowing them to get to market faster.
- Provide more funding to help technologies across the "valley of death;" late stage developmental/early deployment. There is a lot of government funding support for early-stage R&D (e.g., university research). There's also a lot of subsidies or incentives for emerging commercial products (e.g., ethanol, electric cars, etc.). There is a gap in applied R&D, and the budget should be expanded in this area for more demonstration projects to support early deployment of emerging technologies. For whatever reason, industry is on its own to overcome this "valley of death" stage.
- Identification of smaller utilization (lower cost) projects where production and end-use are co-located will improve visibility and enhance utility.
- Distributed solutions for vehicle fleets, where CO_2 or carbon black can be locally stored, will enhance utilization.
- Expanding tax credits to include retrofitting existing technologies.
- Consider beginning with fuel ammonia. In Japan, they're looking to implement this option. It doesn't need to be carbon-free, just implement something that will give a carbon reduction over time. Build the demand center so that the market can come to maturity with lower carbon intensity products in years to come.
- We have examples on how to transition in a non-disruptive manner. For example, independent power producers phasing out coal and moving toward natural gas has helped reduce NOx and GHG emissions substantially over the past 30 years without disrupting energy markets. But we cannot wait that long, we need to apply lessons learned quickly.
- We can learn from what Europe is doing at the commercial scale using hydrogen as primary fuel source, but may have to wait a few years for technology to be in public domain.

Next steps could include the following:

- Consistent techno-economic analysis (TEA) and LCA of hydrogen utilization options.
- Government-funded RD&D. OEMs cannot afford to do RD&D when there is not yet a market for hydrogen.
- Use Federal government purchasing power to stimulate demand for hydrogen (e.g., "green" steel produced with hydrogen). Military purchases can be pathway to generate demand.
- Accelerating approval for Class VI CO_2 injection wells in order to enable blue hydrogen production.
- To the extent possible, leverage existing infrastructure (e.g., hydrogen production and transport systems) to keep costs reasonable while you make the transition.

4.3.4 Breakout Session Topic: Dependent Systems/Sectors

On the topic of dependent systems and sectors (e.g., natural gas, electricity, carbon sequestration, water, transportation), participants identified several opportunities/needs:

- The potential for water demand to be an issue with hydrogen production.
- The need to determine where the power goes; towards making hydrogen or to the grid? If we are too aggressive with hydrogen, we could see "electron shortages" in other areas. Also, if renewable power is being used to make green hydrogen, how do you deal with constant demand versus variable power output?
- One opportunity to reduce costs is to produce hydrogen from natural gas where the gas is produced and used on site, with added carbon capture and sequestration, to eliminate the costs of transport.
- The need to identify technical gaps through comprehensive LCAs and TEAs.
- The need to identify policy mechanisms, other than tax credits, that can accelerate hydrogen deployment. Companies need incentives that will de-risk investment.

Challenges include:

- Site selection is a challenge. There are advantageous characteristics associated with specific sites that can lead to reduced costs, but may need further research to identify the best site characteristics.
- How do we define CI? Will it include the upstream, midstream and downstream? How can you perform a LCA for a specific site? This all needs to be better understood and communicated.
- Current lack of oversight/regulation/incentives to drive development and investment efforts.
- In many cases we may not know what the technical gaps are yet because we have not used technologies in working environments/production environment.

Potential solutions include:

- Potentially using oil and gas produced water for electrolysis for hydrogen production.
- Use of excess power to produce hydrogen as a backup to renewable energy to fill gaps.
- Tailoring energy production to local needs/priorities.
- Government policy that would help incentivize development and financial certainty to build access to tax credits. New business models will be built around changes in policies.
- Targeted government purchasing of hydrogen-related products (steel, ammonia, etc.).
- Conduct analyses around the whole value chain, including inputs and outputs.
- Demonstrations and modeling (digital twin) of scenarios would be beneficial to learn challenges before investing.
- Identifying opportunities for regional hubs through private partnerships in locations where the hydrogen production can be utilized, emissions can be sequestered, and existing capabilities exploited.
- Facilitating the formation of partnerships with electric and natural gas utilities. Combine utilities that need to support a hydrogen project or hub and identify how those utilities may need to change because of these new projects. Utilities can supply assets and other capabilities.
- Federal government help dealing with the funding/financing issues (e.g., The Infrastructure bill could help answer some questions and challenges).

Next steps could include the following:

- Funding studies to support dynamic modeling would help understand challenges. Economic models and reports (right now they are more international, broader-based). We need more U.S.-based models.
- Forming regional entities to review issues would help. Working with government at various levels, along with business, to discuss issues and conduct outreach.
- Establishing industry standards for CI.

Energy and Environmental Justice should be a criterion for site selection. Energy and Environmental Justice will be served by focusing on regions of the country that have been affected by pollution and communicating that hydrogen could be an important clean energy solution to those past problems (e.g., mitigation of NOx), but only if jobs and significant economic benefits accrue to the communities previously impacted.

5.0 KEY FINDINGS

Themes that emerged from the panels and breakout sessions are listed below. Their order does not indicate relative importance and no effort was made to reach consensus on any prioritization of these themes.

Themes

- The key issue facing a transition to hydrogen is that production and utilization of clean hydrogen must increase by 50-fold from 10 million tons per year (Mtpa) to greater than 500 Mtpa by 2050 if decarbonization goals are to be met. This is a very challenging objective that must be achieved in a very short time frame and will require contributions from all hydrogen production sources. From a business perspective, hydrogen provides some of the largest market growth opportunities available in the energy industry.
- Government leadership will be critical in achieving the stated decarbonization objective, not only in terms of significant tax credits and incentives but also in terms of research, development and demonstration (RD&D) funding and the facilitation and encouragement of communication and collaboration across government entities at all levels—Federal, state and local—to reduce permitting, regulatory, and economic barriers to implementation of hydrogen projects.
- There is a need to articulate a clear rationale for using hydrogen and a clear pathway to achieving specific environmental benefits to ensure that all hydrogen production methods are treated in an objective, unbiased fashion. The step change pathway must be better communicated.
- The carbon intensity (CI) of hydrogen produced using natural gas as feedstock with carbon capture and storage (CCS) is significantly impacted by the methane leakage rates from natural gas infrastructure. High carbon capture blue hydrogen could contribute to a net-zero world with very low upstream emissions, if methane leaks are minimized.
- The use of Federal government purchasing power to stimulate demand for hydrogen (e.g., "green" steel produced with hydrogen, clean ammonia as fuel for Coast Guard vessels) can be a pathway to generate demand and stimulate production capacity.
- CCS will be critical for production of hydrogen from fossil fuels. While technologically there are few hurdles to CCS, the issues of long-term liability risks and extremely slow permitting of Class VI injection wells are two factors that could jeopardize investor interest. Proactive government action will be necessary to solve these problems.
- Efforts to expand hydrogen should leverage initial opportunities in areas that couple high feedstock capacity, large volume infrastructure, significant storage capacity, and a nearby industrial base. While each region is unique and presents both opportunities and challenges, an important regional variable is the availability of geologic storage options for both hydrogen and carbon dioxide (CO_2) in places where industrial demand is centered.
- With regard to Environmental Justice issues, participants noted that issues need to be raised and mitigated through collaborative effort and better outreach, education and information-sharing with Energy Justice organizations and local communities. In this regard, DOE's Regional Carbon Storage Partnership (RCSP) initiative was successful and is a good model. Further, consider prioritizing hydrogen hub location sites where opportunities to lift disadvantaged communities are present. For example, coal mining communities where there are opportunities to source feedstock (e.g., natural gas, plus coal waste plus biomass) and store CO_2 (subsurface reservoirs) while lifting under-employed workforce (e.g., coal miners) through training. In addition to jobs impact, it was suggested that inclusion of disadvantaged community organizations and members into projects would be valuable for Energy Justice concerns.
- Industry is eager to move forward, at a variety of scales and using a variety of approaches, to take advantage of what is seen as a growing demand for hydrogen in the U.S. energy portfolio. There is also significant potential to retrofit existing fossil-based hydrogen production facilities with carbon capture for nearby storage. The greatest challenges to lining up investment are policy uncertainties rather than technological hurdles.
- Infrastructure, especially CO_2 and H_2 pipelines, and storage were flagged as key underpinnings of any hubs and the overall transition. The various regulatory regimes all need to be harmonized and synchronized to enable coordination of interstate and intrastate transport pipelines and storage, both for H_2 and CO_2. There is significant value in existing pipeline rights-of-way (ROW) for future construction of dedicated hydrogen pipelines.
- Federally supported research could provide funding to help technologies across the "valley of death;" late stage developmental/early deployment. There is a gap in applied research and development (R&D), and budgets should be expanded for more demonstration projects to support early deployment of emerging technologies and technology validation at scale.
- Techno-economic and life cycle analyses for hydrogen and ammonia pathways need to be performed in a consistent, scientifically objective manner to guide policy choices and pathways forward, in order to reduce the chances of wasted time and money in pursuit of the objective.
- Legislation pending in Congress for a hydrogen production tax credit requires use of the Clean Air Act Renewable Fuels Standard to determine the CI of the hydrogen, and ties the greenhouse gas (GHG) reduction to the value of the tax credit. The existing framework for Federal-level life cycle analysis (LCA) was designed for biofuels, however, not for fossil fuels.6 Agreeing on a methodology for determining the carbon intensity of hydrogen production is critical, as the policy uncertainty regarding the production tax credit has significant impacts on the economic viability of hydrogen production projects.
- Availability of carbon storage is critical to broader production of blue hydrogen across regions. Pipeline construction projects face more regulatory obstacles than in the past, making them more risky and expensive. There is a need to find ways to do sequestration locally where the gas production is located. Also, alternatives to conventional gas reservoirs for carbon storage (e.g., subsurface mineralization of CO_2 in mafic rocks) need to be considered.

- Effort should be made to facilitate the formation of partnerships between electric and natural gas utilities and other industry stakeholders to support a hydrogen project or hub to leverage the combined synergies in hydrogen production, storage, delivery (e.g., pipeline transport) and end use. Further, bringing multiple hydrogen end use sectors together can rapidly advance scale, so policy and regulations should consider the value of hydrogen across industries.
- Major safety incidents and social acceptance issues have the potential to impact a hydrogen transition so they should be proactively addressed (e.g., hydrogen safety training, public awareness campaigns, community dialog, etc.). Reliability and safety of the hydrogen infrastructure will be critical.
- While there are many misconceptions about the safety of hydrogen transport and storage, there are opportunities to broaden dialogue on these issues, understand the concerns of hydrogen opponents and work to address such concerns by educating communities on the potential benefits of hydrogen as well as the safety of transport and storage.
- The requirement of hydrogen sensors for monitoring was indicated, along with the need for codes and standards for ubiquitous deployment and safe operations.
- Successful buildout of hydrogen hubs will likely require an "all-hands-on-deck" approach, with partnerships between industry, academia, government, non-profits, and community groups needed to ensure acceptance, safety, economic viability, and a smooth transition.

6.0 APPENDICES

6.1 Appendix A – Suggested Government Actions

Following is a list of potential Federal government policy/regulatory actions or clarifications identified as needed based on the discussions at the workshop, as detailed in the report. These items are not prioritized and were not developed as part of any consensus. In addition, they will be considered as part of a broader DOE wide process across all offices to help on informing and prioritizing potential RDD&D activities.

- Government facilitation of an ongoing dialogue among industry participants (hydrogen producers, pipeline and storage operators, utilities, transport companies, electrolyzer/SMR manufacturers, industrial end users, developers, and municipalities/economic development agencies) to foster hydrogen development opportunities.
- Facilitate more and earlier collaboration and identification of synergies at both Federal and local levels. Build a strong working relationship among regulators and researchers through earlier collaboration within DOE (e.g., FECM, EERE) and among Federal agencies (e.g., USGS, DOE, DOT, EPA, USDOT, etc.) and state agencies.
- Elevate Environmental Justice issues through collaborative effort and better outreach, education and information-sharing with Energy Justice organizations and local communities. (e.g., DOE's Regional Carbon Sequestration Partnerships [RCSP] initiative was successful and is a good model).
- Evaluate and act on lessons learned from past DOE demonstration project successes (e.g., RCSPs, Field Laboratories) to develop a plan to communicate with and educate the public on a framework for hydrogen deployment.
- Implementation of a high impact Federal outreach effort that sets a clearly defined decarbonization date for the U.S.
- Government funding of studies supported by dynamic, U.S.-based economic modeling efforts to help understand the challenges for broader use of hydrogen. Pathway analysis for RD&D opportunities based on cost, maturity, and emissions intensity.
- Implement a study of priority hydrogen hub locations supported by GIS work and coupled with techno-economic assessments.
- DOE internal and extramural RD&D to determine which hydrogen production technologies work best and how to lower the cost of hydrogen transportation.
- Carry out a DOE study that characterizes and clarifies the energy economics of ammonia as an energy carrier.
- Direct Federal incentives for hydrogen production. For example, production tax credits (PTCs) could be used to make hydrogen more cost competitive, either from a specified fuel/feedstock, for feedstock agnostic production, or via PTCs tied to carbon intensity.
- DOE loan program expansion to include hydrogen production and related carbon capture and sequestration.
- Consider alternatives for Federal government assistance for hydrogen developers in dealing with the funding/financing issues.
- Investigate government incentives for the use of methane pyrolysis rather than SMR as a method for hydrogen production, as it does not require carbon sequestration and costs can be partially offset with sale of the carbon product.
- Clarification of which government agency has regulatory primacy with regard to hydrogen transportation.
- Develop a strategy for regulatory approval for rail transport of liquid hydrogen as a middle-of-the-road alternative between pipelines and trucks.
- Development of both Federal and state policies to bring parity to hydrogen and renewable gas in pipeline blending.
- Investigate Federal regulations that require a certain small percentage of hydrogen in all natural gas pipelines.
- Develop a national hydrogen appliance test program.
- Develop and implement a strategy for utilizing the Federal government's purchasing power to buy hydrogen, creating significant demand, so the market will step up to supply it. The maritime sector could be used to stimulate demand on a large scale (i.e., mandating Coast Guard purchases of blue hydrogen-based ammonia as fuel). As well, Federal government purchases of "green steel" produced with green hydrogen would stimulate hydrogen production.
- Development of a strategy for longer-term Federal mandates that define the percentage of low-carbon inputs or products required in specific markets (e.g., refineries, ammonia production), to provide a clear signal for the market to respond to.
- Investigate feasibility of a Federal regulation that requires a small percent of all U.S. ammonia production be renewable.
- Consider the possibility of a hydrogen strategic reserve along the lines of the strategic petroleum reserve.
- Development of EPA policies that reduce the time it takes for obtaining Class VI well permits.
- Develop policies that clearly define subsurface pore space ownership on Federal land and clarify long-term liability risks with regard to CO_2 storage.
- Federal regulations that address the liability risk and monitoring cost issues facing CO_2 sequestration.

6.2 Appendix B – Agenda

Exhibit 6-1. Day 1 Agenda

TIME (EST)	STRUCTURE	THEME	SPEAKER/MODERATOR/FACILITATOR
10:00	**Welcome**	Welcome & Workshop Objectives, Logistics	NETL/GTI
10:10	**Welcome**	Opening Remarks	**Jen Wilcox**, DOE, Office of Fossil Energy and Carbon Management, Principal Deputy Assistant Secretary
10:30	**Keynote**	Hydrogen's Role in the Energy Transition to Achieve Net-Zero by 2050.	**Julio Friedmann**, Center on Global Energy Policy at Columbia University SIPA, Senior Research Scholar
11:00	**Keynote**	Hydrogen Energy Earthshot Summit Overview and Deployment Session Wrap-up	**Sunita Satyapal**, DOE, Office of Energy Efficiency and Renewable Energy, Director for Hydrogen and Fuel Cells Technology Office
11:10	**Keynote**	Thermal Conversion with CCS Summit Session Wrap-Up	**Sam Thomas**, DOE, Office of Fossil Energy and Carbon Management, Director for Hydrogen and Carbon Management
11:20	**Keynote**	DOE Hydrogen RFI Wrap-Up	**Tim Reinhardt**, DOE, Office of Fossil Energy and Carbon Management, Director for the Division of Methane Emissions Mitigation Technologies
11:30	**Panel**	State/Utility Perspective on Fossil Energy Hydrogen Challenges	***Moderator:*** **Mark Berry**, Southern Co., VP of R&D ***Speakers:*** **Peter Hoeflich**, Duke Energy Corp., Director **Joe Del Vecchio**, National Fuel Gas Distribution Corp., VP and Chief Regulatory Counsel **Chris Kroeker**, Northwest Natural, Emerging Technology Program Manager **Anja Bendel**, Wyoming Energy Authority, Program Director
12:30	**Lunch**		
1:30	**Panel**	Industry Strategies on the Hydrogen Value Chain	***Moderator:*** **Poh Boon Ung**, BP, Manager - Hydrogen & CCUS Advisory Services ***Speakers:*** **Michael Ducker**, Mitsubishi Power, Vice President of Renewable Fuels **Krish Krishnamurthy**, Linde, Head of CE Technology NA and CCS **David Edwards**, Air Liquide, Director
2:30	**Breakout**	Questions to be provided	Four breakout groups
3:30	**Break**		
3:45	**Report Out**	Report out and discussion from Day 1 Breakout Sessions	Session Moderators
4:15	**Wrap Up**	Highlights of today, Plan for tomorrow	NETL/GTI
4:30	**Adjourn**		

Exhibit 6-2. Day 2 Agenda

TIME (EST)	STRUCTURE	THEME	SPEAKER/MODERATOR/FACILITATOR
10:00	**Welcome**	Day 2 Welcome/Introduction Day 1 Review	**Brian Anderson**, NETL, Director
10:10	**Welcome**	Day 2 Welcome/Introduction Day 1 Review	**Mike Rutkowski**, GTI, SVP of Research & Technology Development
10:20	**Keynote**	Defining the Carbon Intensity of Hydrogen	**Shannon Angielski**, Van Ness Feldman, Principal
10:40	**Panel**	Challenges for Fossil-Based Hydrogen Production	***Moderator:*** **John Marion**, GTI, Senior Program Director ***Speakers:*** **Dan Williams**, Wabash Valley Resources, Managing Director **Perry Babb**, 'KeyState To Zero,' KeyState Natural Gas Synthesis & CCS, Chairman & CEO Rob Hanson, Monolith Materials, CEO
11:30	**Panel**	Challenges for Hydrogen and CO_2 Pipelines & Storage	***Moderator:*** **Jared Ciferno**, NETL, Technology Manager ***Speakers:*** **Michael Tritt**, Lane Power & Energy Solutions, President **Seth Levey**, Equinor, Director, Government. Relations & Public Affairs **Jason Ketchum**, One Gas, VP, Commercial Operations **Angela Goodman**, NETL, Senior Researcher
12:30	**Lunch**		
1:30	**Panel**	Challenges for Hydrogen Utilization	***Moderator:*** **Brian Weeks**, GTI, Senior Director, Business Development ***Speakers:*** **Brett Perlman**, Center for Houston's Future, Inc., CEO **Josh Martincic**, Long Ridge Energy Terminal, Chief Sustainability Officer **Trevor Brown**, Ammonia Energy Association, Executive Director **Bernhard Winkelmann**, Nikola Motor, Global Head, Technology & New Product Development
2:30	**Keynote**	Role of Public Private Partnerships	**Bryan Morreale**, NETL Research & Innovation Center, Executive Director
3:00	**Breakout**	Questions to be provided	Four breakout groups
4:00	**Break**		
4:15	**Report Out**	Report out and discussion from Day 2 Breakout Sessions	Session Moderators
4:45	**Next Steps/ Wrap-up**	Summary and Conclusions from the Workshop. Identify next steps to continue workshop momentum	NETL/GTI
5:00	**Adjourn**		

6.3 Appendix C – Participants

NAME	AFFILIATION
Amer Akhras	Linde
Timothy Allison	Southwest Research Institute
Brian Anderson	National Energy Technology Laboratory
Shannon Angielski	Van Ness Feldman
Perry Babb	KeyState to Zero
Peter Balash	National Energy Technology Laboratory
Jeffrey Becker	U.S. Steel
Anja Bendel	Wyoming Energy Authority
Mark Berry	Southern Company Services
Erin Blanton	Columbia University
Trevor Brown	Ammonia Energy Association
Klaus Brun	Elliott Group
Jared Ciferno	National Energy Technology Laboratory
Kristen Cooper	Duke Energy Corporation
David Dankworth	ExxonMobil
Debalina Dasgupta	National Energy Technology Laboratory
Joseph Del Vecchio	National Fuel Gas Distribution Corporation
Richard Dennis	National Energy Technology Laboratory
Michael Ducker	Mitsubishi Power
Colin Dyroff	U.S. Environmental Protection Agency
David Edwards	Air Liquide
James Ferguson	National Energy Technology Laboratory
Patrick Findle	Gas Technology Institute

NAME	AFFILIATION
Julio Friedmann	Columbia University
Evan Frye	U.S. DOE, Office of Fossil Energy and Carbon Management
Eric Gebhardt	Wabtec Corporation
Joe Giardina	KeyLogic Systems, Inc.
Jeffrey Goldmeer	GE Gas Power
Angela Goodman	National Energy Technology Laboratory
Alison Gotkin	Raytheon Technologies Research Center
Eric Guter	Air Products and Chemicals
Janette Hansen	U.S. Environmental Protection Agency
Rob Hanson	Monolith Materials
Peter Hoeflich	Duke Energy
Vincent Holohan	U.S. DOT, PHMSA, Office of Pipeline Safety
Michael Hopkins	Bakken Energy
Nicolas Huerta	Pacific Northwest National Laboratory
Will Jordan	EQT Corporation
Glen Jukkola	CURC
Rich Kaelin	Gas Technology Institute
Shannon Katcher	Gas Technology Institute
Jason Ketchum	ONE Gas
Jai-woh Kim	U.S. DOE, Office of Fossil Energy and Carbon Management
Krish Krishnamurthy	Linde
Rainer Kurz	Solar Turbines
Karl Lang	KeyLogic Systems, Inc.
Markus Lesemann	Gas Technology Institute

NAME	AFFILIATION
Seth Levey	Equinor US
Robie Lewis	National Energy Technology Laboratory
Tony Lindsay	Gas Technology Institute
John Litynski	U.S. DOE, Office of Fossil Energy and Carbon Management
David Lyons	National Energy Technology Laboratory
John Marion	Gas Technology Institute
John Marra	Siemens Energy
Josh Martincic	Long Ridge Energy Terminal
Richard McKenna	KeyLogic Systems, Inc.
Bryan Morreale	National Energy Technology Laboratory
Sheena Murphy	West Virginia University
Brett Perlman	Center for Houston's Future
Jenna Peth	VNF
Brenda Petrilena	U.S. Steel
Matea Pranjic	KeyLogic Systems, Inc.
Jeffery Preece	Electric Power Research Institute
Massood Ramezan	KeyLogic Systems, Inc.
Timothy Reinhardt	U.S. DOE, Office of Fossil Energy and Carbon Management
Eva Rodezno	U.S. DOE, Office of Fossil Energy and Carbon Management
Michael Rutkowski	Gas Technology Institute
Sunita Satyapal	U.S. DOE, Office of Energy Efficiency and Renewable Energy
Robert Schrecengost	U.S. DOE, Office of Fossil Energy and Carbon Management
Anna J. Siefken	Carnegie Mellon University - Scott Institute for Energy Innovation
Kelli Snedegar	KeyLogic Systems, Inc.

NAME	AFFILIATION
Ronald Stanis	Gas Technology Institute
Josh Stanislowski	Energy and Environmental Research Center
Don Stevenson	Gas Technology Institute
Ganesan (Subbu) Subbaraman	Gas Technology Institute
Cynthia Sweet	University of Pittsburgh
Michael Tennyson	KeyLogic Systems, Inc.
Sotirios (Sam) Thomas	U.S. DOE, Office of Fossil Energy and Carbon Management
Michael Tritt	Lane Power and Energy Solutions Inc
Poh Boon Ung	BP
Shailesh Vora	National Energy Technology Laboratory
David Voss	Solar Turbines
Paige Wagner	KeyLogic Systems, Inc.
Valika Wan	GE
Malcolm Webster	KeyLogic Systems, Inc.
Brian Weeks	Gas Technology Institute
Nathan Weiland	National Energy Technology Laboratory
Michael Weiner	Van Ness Feldman, LLP
Joshua White	Lawrence Livermore National Laboratory
Jennifer Wilcox	U.S. DOE, Office of Fossil Energy and Carbon Management
Kristine Wiley	Gas Technology Institute
Daniel Williams	Wabash Valley Resources
Bernhard Winkelmann	Nikola Motor
Matthew Wisotzky	National Fuel Gas

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NATIONAL ENERGY TECHNOLOGY LABORATORY

1450 Queen Avenue SW
Albany, OR 97321
541-967-5892

3610 Collins Ferry Road
P.O. Box 880
Morgantown, WV 26507
304-285-4764

626 Cochrans Mill Road
P.O. Box 10940
Pittsburgh, PA 15236
412-386-4687

Program staff are also located in
Houston, TX, and Anchorage, AK.

CUSTOMER SERVICE
1-800-553-7681

WWW.NETL.DOE.GOV

POINTS OF CONTACT:

NETL:

Nathan Weiland (Nathan.Weiland@netl.doe.gov)

GTI:

Patrick Findle (pfindle@gti.energy)

Ganesan Subbaraman (gsubbaraman@gti.energy)

Kristine Wiley (kwiley@gti.energy)