Angeles Link – Phase 1
Quarterly Report (Q3 2024)

For the period of July 1, 2024 through September 30, 2024

Appendix 2 - PAG and CBOSG Written Comments

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July 19, 2024

VIA EMAIL TO
ALP1_PAG_FEEDBACK@INSIGNIAENV.COM

Emily Grant
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Re: Angeles Link Planning Advisory Group (PAG) Feedback of Air Products and Chemicals Inc. on Plan for Applicable Safety Requirements (June 2024 Draft)

Air Products and Chemicals, Inc. ("Air Products") submits the following feedback concerning the June 2024 draft Plan for Applicable Safety Requirements ("Draft Safety Plan").

Air Products expects that the below feedback will be addressed in the final Studies and in Southern California Gas Company's (SoCalGas) quarterly reporting. Air Products also welcomes any response that SoCalGas may wish to provide to the comments below.

Experience with Natural Gas Systems Does Not Necessarily Translate to Hydrogen

Air Products safely operates 10 hydrogen production facilities and about 30 miles of hydrogen pipelines within California and has been doing so for over 40 years. Worldwide, Air Products operates over 1,800 miles of industrial-gas pipelines. In light of this experience, Air Products has concerns about the Draft Safety Plan's blithe assertions throughout the report that Southern California Gas Company's ("SoCalGas") experience with natural gas systems will inevitably translate to a hydrogen pipeline system. For example, the Draft Plan asserts that:

> A clean renewable hydrogen system (gaseous hydrogen) can leverage many of the existing requirements of an analogous natural gas system. Where hydrogen's physical and chemical properties differ from natural gas, influence from SoCalGas's existing natural gas system plans including safety system, specifications, procedures and training will provide a basis for designing, constructing and operating Angeles Link.[1]

The Draft Plan also asserts that "SoCalGas is well positioned to build, operate and maintain a clean renewable hydrogen pipeline system due to its long-standing experience operating and

[1] Draft Plan at 7.

maintaining a highly developed gas transmission and distribution system, existing highly trained and qualified workforce, and a comprehensive established integrity management and emergency response procedures."[2] The Draft Plan goes on to contend that "there are many similarities between hydrogen and natural gas operations and gas handling. *While there are some differences in their properties and characteristics*, a variety of existing practices can be modified to manage these differences."[3]

While it is understandable that SoCalGas might wish to claim that its experience with natural gas somehow qualifies it to operate a hydrogen system, Air Products cautions that experience with natural gas does not necessarily translate to the operation of pipeline systems for other industrial gases such as hydrogen. Assuming that existing practices regarding natural gas will apply to hydrogen pipelines can lead to the adoption of practices and procedures that are not appropriately adapted to hydrogen. The Safety Plan should specially address why the contemplated practices and procedures appropriately apply to hydrogen systems. In addition, the Safety Plan must include some type of hazop interface review with all the end-use markets/customers to ensure that they understand the safe handling of hydrogen the project intends to deliver. While the Safety Plan describes public outreach generally, more detail is needed on the interface with the intended industrial, power generation, and transportation fuel supply customers.

The same applies to the applicability, if any, of existing Commission pipeline regulations. The Draft Safety Plan cites to Commission General Order ("GO") 112 F, Subpart E, which supplements Federal Pipeline Safety Regulations. As Air Products has pointed out previously,[4] Commission has yet to determine that the Angeles Link, or hydrogen transportation generally, would be subject to Commission jurisdiction.[5] It therefore is at best unclear whether GO 112 will be applicable to Angeles Link; furthermore, it is unclear whether the Commission, if it did assert jurisdiction, would apply GO 112 as currently drafted to hydrogen pipelines. In its response to Air Products' October 13, 2023 Feedback, SoCalGas stated that "potential safety considerations *may* be derived from GO 112-F and should be appropriately evaluated as it *may* apply to a clean renewable hydrogen transportation system."[6] Yet the Draft Safety Plan lists GO 112 F as part of the "hydrogen-specific industry standards that provide best practices that should be considered for hydrogen pipelines."[7] As SoCalGas conceded in its Q4 Quarterly Report, GO 112 F does not directly apply, and must be appropriately evaluated, like other natural gas practices and procedures, to determine the extent to which such requirements can and should apply to hydrogen pipelines.

Odorization Issues

[2] *Id.* at 11.
[3] *Id.* at 21 (emphasis added).
[4] *See* Air Products' October 13, 2023 Feedback Letter at 4-5.
[5] D.22-12-055 at 8; D.24-07-009 at 30. (TCAP decision).
[6] SoCalGas Angeles Link Q4 Quarterly Report Appendices (Phase One), Appendix 3 at p. 5.
[7] Draft Safety Plan at 24.

The Draft Safety Plan notes that "an odorant *may* be required under 49 CFR §192.625," and the Plan's initial review of several studies on the feasibility of odorizing hydrogen and the options for doing so.[8] However, there is a significant amount of additional work that should be performed to determine whether odorization is appropriate, and the appropriate odorant for a hydrogen system, and the Draft Safety Plan fails to fully address this issue.

The Draft Safety Plan notes that due to the disadvantages of using tetrahydrothiophene (THT) such as for fuel cell systems, alternative sulfur-free odorants were investigated for hydrogen distribution. The Draft Safety Plan selectively states that the odorant 2-hexyne was found not to have an adverse effect on the performance of fuel cells and "was able to maintain stability in hydrogen, therefore appeared suitable for use as a sulfur-free odorant in hydrogen."[9] However, as the cited report shows, sulfur-free odorants, including 2-hexyne, can be vulnerable to hydrogenation when in contact with uncoated steel cylinder surfaces. For example, 2-hexyne in uncoated steel cylinders can be hydrogenated to hexane, which has a very different odor profile which is likely not suitable as a hydrogen odorant. The same is true of another odorant mentioned in the report, Gasodor S-Free, which is comprised of ethyl acrylate, methyl acrylate and 2-ethyl-3-methylpyrazine, as it is also vulnerable to hydrogenation, resulting in odor changes that would likely render it ineffective as a gas odorant.

Conclusion

Air Products appreciates the opportunity to provide this feedback concerning the June 2024 Draft Safety Plan.

Respectfully,

Miles Heller Director, Global Greenhouse Gas,
Hydrogen, and Utility Regulatory Policy

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[8] *Id.* at 28-29.
[9] *Id.* at 29.

Comments Regarding SoCalGas' Phase 1 Plan for Applicable Safety Requirements for the Angeles Link Project

Submitted via email to alp1_study_cbo_feedback@insigniaenv.com

Physicians for Social Responsibility - Los Angeles submits the following feedback letter in regards to the Phase 1 Plan for Applicable Safety Requirements for the Angeles Link project. Given the speed and intensity of the feedback process, all feedback should be considered partial, as there is not enough time to adequately address all of the issues with these reports.

That being said, our main concerns with the report are the following:

1. **That the report ignores SoCalGas' own history with mismanaging leaks, indicating that lessons have not been learned**

Given that SoCalGas is responsible for the Aliso Canyon methane leak that lasted over 100 days and resulted in 100,000 metric tons of methane into the atmosphere, as well as other issues in Pacoima and Wilmington, we believe that it is necessary to be critical of the existing policies and procedures that allowed for these issues to happen in the first place, and to be skeptical that they will adequately prepare for other potential disasters. Instead of an introspective and self-critical analysis of how SoCalGas can learn from their mistakes and thoughtfully tackle the complicated and specific challenges that hydrogen poses, the report painted a rosy picture of SoCalGas' methane infrastructure, and glossed over the differences between managing hydrogen and methane.

2. **The assessment of potential risks is overly simplified and fails to address several key risks**

The assessment of risks is simplified and fails to account for potential losses if the system fails, including disrupting critical infrastructure like power plants. Additionally, given the collocation of hydrogen and methane pipelines proposed by SoCalGas in the Routing Analysis, there is shockingly little information about what risks exist from the combination of these fuels in close proximity. While the report occasionally mentions a persisting challenge or unknown, the report concludes that the problem is solvable without demonstrating how (for example stating the issues with odorants and mentioning that research is ongoing). Additionally, given SoCalGas' own estimation of a leakage rate of .02-1% (which in our estimation is optimistic), there should have been mention of how these leaks could potentially lead to health or safety risks. The report also fails to mention that the project itself will contribute to climate change by way of hydrogen leakage.

3. **The report defaults to recommending existing guidelines for methane whenever possible, thereby ignoring potential issues that could arise for hydrogen**

The report claims that much insight can be drawn from SoCalGas' experience with managing methane infrastructure, and seems to default to assuming hydrogen and methane will operate similarly, and therefore only slight modifications are needed to existing practices. Instead, SoCalGas should thoroughly consider hydrogen implications on their own, rather than through the lens of methane, and additionally do research on the risks of transporting two fuels side by side. Hydrogen's flammability and volatility are big considerations that require much more robust planning and community education if hydrogen is ever to be considered safe.

4. **The report mentions that there are unknowns about hydrogen and that harmful incidents are possible and have happened, then concludes that it is possible to safely deliver 100% hydrogen**

It is surprising to see that after listing some of the many hydrogen incidents that have occurred, and outlining some of the many unknown issues concerning hydrogen, and after glossing over their own shortcomings in managing methane infrastructure that SoCalGas could confidently conclude that “as illustrated above, the safe transportation of 100% clean renewable hydrogen by pipeline is feasible.”

Feedback submitted by:

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July 19, 2024

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COMMUNITIES FOR A BETTER ENVIRONMENT
established 1978

Submitted via email to ALP1_Study_PAG_Feedback@insigniaenv.com

Feedback for Southern California Gas Company on the Plan for Applicable Safety Requirements Draft Report

Communities for a Better Environment (CBE) submits this letter of feedback to Southern California Gas Company (SoCalGas) on the Plan for Applicable Safety Requirements Draft Report (the "Report") provided on June 21, 2024. This letter discusses serious oversights and omissions that the final report must remedy. Although SoCalGas has repeatedly assured PAG and CBOSG stakeholders that draft reports would address shortcomings and gaps in earlier "preliminary data and findings" slide decks, this report still lacks fair discussion of several important issues surrounding hydrogen safety. California Public Utilities Commission (CPUC) Decision 22-12-055 emphasizes the importance of stakeholder engagement. Meaningful engagement is impeded where key information is either omitted or presented in a misleading manner. Particularly, the Report:

I. Glosses Over Unknowns about Hydrogen
II. Draws Faulty Conclusions about Angeles Link's Safety
III. Overly Relies on Safety Measures for Existing Natural Gas Infrastructure as a Proxy for Safety of New Hydrogen Pipeline Infrastructure
IV. Omits Key Details of Hydrogen Related Accidents
V. Mischaracterizes SoCalGas's Safety Management System

I. The Report Glosses Over Unknowns about Hydrogen and Fails to Discuss International Hydrogen Safety Standards Apart from Vaguely Referencing Them

The Report is characterized by an absence of clear hydrogen safety data and an insistence by the SoCalGas team that safety concerns are well in hand. Nowhere does the Report adequately address that the Angeles Link Project (ALP) is a first of its kind project without real world study to inform assumptions. The serious safety concerns associated with carrying unprecedented volumes of hydrogen gas along key infrastructure corridors and past sensitive receptors require substantially more precaution than the Report suggests. Furthermore, the ALP would bring hydrogen into communities like Wilmington and Pacoima, long plagued by hydrogen and methane system failures. The explosions, flares, and leaks those and many other communities experience are a strong reminder that the status quo does not provide adequate safety for many polluted neighborhoods. Hydrogen unknowns cannot be brushed aside.

The Report glosses over unknowns about hydrogen, including identification of a specific odorant for hydrogen gas to be used in Angeles Link. The Report notes that like natural gas, hydrogen is odorless and that mercaptans are used to odorize natural gas. The Report states that assessing and finding an appropriate odorant for hydrogen "to indicate the presence of hydrogen is an important consideration in the development of applicable safety protocols." We agree that odorizing agents are important for the public and emergency responders to detect the presence of a hydrogen gas leak that could threaten peoples' lives. But the Report also concedes: "Industry research on the implications of odorant in a pure hydrogen system is ongoing and should be monitored during the development of Angeles Link to identify industry best practices." CBE finds it alarming that SoCalGas has not identified or included in the Report even one specific odorant appropriate for the safe transportation of hydrogen gas. To ensure the safety of our community members, it is vital that SoCalGas address this major unknown about hydrogen.

Further, the Report fails to discuss important international safety standards for hydrogen in any detail. The Report mentions organizations with experience in hydrogen safety education and training, such as the American Institute of Chemical Engineers (AICHE) and the International Association for Hydrogen Safety (HySafe). It also notes: "Various resources for education and training are available for both pipeline operators, emergency and first responders, and the public." But rather than provide specific examples of safety standards or in-depth discussion of them, the Report only describes what these organizations do in very general terms and provides URLs for them. CBE thus believes the Report lacks necessary discussion of existing hydrogen safety standards.

II. The Report Fails to Commit to Maintaining Safety Teams for Hydrogen Distinct from Those for Natural Gas, Draws Faulty Conclusions about Angeles Link's Safety Despite the Lack of Hydrogen-Specific Federal and State Laws and Regulations, and Fails to Examine Safety Measures of Any Specific, Existing Hydrogen Pipelines in the United States

In both the Report's Executive Summary and Conclusion sections, SoCalGas states it might consider implementing separate safety teams for the Angeles Link hydrogen system and existing natural gas network. Due to the differences between hydrogen and natural gas and heightened risk of hydrogen accidents, CBE contends that SoCalGas should definitively commit to maintaining distinct gas controllers and emergency response teams for the Angeles Link pipeline system.

The Report acknowledges that federal minimum safety standards for gas pipelines "do not specify differences and considerations for hydrogen specifically versus natural gas (and other gases)." Given this lack of differentiation in federal law for hydrogen despite its numerous differences from natural gas, CBE finds it troubling that SoCalGas makes a "Key Finding" promising that some combination of existing regulations and industry standards (only some of which may be hydrogen-specific) "will help promote safety." To its credit, the Report discusses hydrogen-specific standards like American Society of Mechanical Engineers (ASME) B31.12 and National Fire Protection Association (NFPA) 2. Yet, the Report admits these standards "are not specifically incorporated into" Title 49 Code of Federal Regulations (CFR) Part 192 or CPUC General Order (GO) 112-F" by direct reference." CBE's communities have not been adequately protected by industry best practices for decades, even when federal and state laws and regulations directly apply them. Because these hydrogen-specific standards (CFR Part 192 and CPUC GO 112-F) are not directly incorporated into federal and state laws or regulations, only best practices provide for this necessary, but insufficient layer of protection.

Furthermore, SoCalGas makes multiple references in the Report to the roughly 1,600 miles of hydrogen pipelines that already exist and currently operate in the U.S. The Report claims the "industry experience" derived from operation of these pipelines "makes the properties and risks associated with hydrogen well known." Even if self-regulation by "industry standards" were sufficient to ensure safety, the Report completely fails to examine the supposed safety standards of the existing 1,600 miles of hydrogen pipelines because it does not discuss *any* specific, existing hydrogen pipeline anywhere in the country. With the sparse level of detail provided in the Report, SoCalGas's conclusions about hydrogen safety are not substantiated.

III. The Report Overly Relies on Safety Measures for Existing Natural Gas Infrastructure as a Proxy for Safety of New Hydrogen Pipeline Infrastructure

CBE appreciates the inclusion of the table comparing the properties of hydrogen and natural gas. It is important that the Report describes hydrogen's wider range of flammability and 500 °F higher flame temperature than natural gas, "which requires considerations for proper materials and mitigating potential increases in oxides of nitrogen (NO_x) emissions." However, we disagree with SoCalGas's statements minimizing the differences of hydrogen and natural gas and concluding that simply modifying existing safety practices for natural gas will be sufficient to address the safety risks associated with hydrogen.[1] After all, SoCalGas's review of approximately 1,600 of its own existing specifications, standards, and procedures (SSPs) revealed that roughly 21% of SoCalGas's existing SSPs do not apply to hydrogen, 34% of current SSPs apply to hydrogen but may require modifications, and 15% of existing SSPs "may

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[1] Report at 21 ("In summary, there are many similarities between hydrogen and natural gas operations and gas handling. While there are some differences in their properties and characteristics, a variety of existing practices can be modified to manage these differences.").

require a new SSP specific to hydrogen service." Therefore, by SoCalGas' own count, 70% of current SSPs either do not apply or need to be updated for hydrogen, and only 30% are applicable to hydrogen service but would not require changes. CBE believes it is deceptive for SoCalGas to gloss over these significant differences between hydrogen and natural gas services by relying on its existing natural gas network infrastructure and current SSPs.

IV. The Report Fails to Include Examples of Hydrogen Related Accidents Involving Serious Injuries or Fatalities and Includes Misleading Descriptions that Omit Key Details

The Report's Lessons Learned cherry-picks less severe hydrogen incidents from the H2Tools.org database and excludes key details about more severe accidents, thereby failing to include accurate descriptions involving serious bodily injury or death. Although this section of the Report describes 11 hydrogen-related accidents between 1969 and 2019, none of them involved serious injuries or fatalities. Yet the Report contemplates the potential for serious bodily injuries and death since the term "Serious Injuries and Fatalities" and the corresponding abbreviation ("SIF") are included in section 1.0 List of Abbreviations and Acronyms. In fact, only one incident description about an explosion in 1980 at a National Aeronautics and Space Administration (NASA) facility even mentions the word "injured."[2] Although it is fortunate no one was injured by that explosion, that outcome was only possible because, as the Report itself acknowledges, nobody was present at the NASA facility when the explosion occurred. Further emphasizing the need for greater study, NASA facilities are regulated by the Federal Aviation Administration's much stricter safety standards, in particular requiring physical separation requirements not mandated for standard gas transmission pipelines.[3]

To portray the risks of hydrogen more fairly, the Report should have included the following incident whose description is readily available in the H2Tools database. In a 1992 incident titled "Technician Fatally Burned When Leaking Hydrogen Ignites" in that database, experiments with hydrogen gas resulted in the death of a laboratory technician and serious injuries to three other individuals.[4] Leaked hydrogen gas interacted with liquefied petroleum gas to ignite a flash fire that "engulfed the people in the room."[5] It appears that the hydrogen gas leaked into the laboratory via "a pump seal or pipe union."[6] This is an extremely serious hydrogen-related incident, which should have been included in the Report.

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[2] Report at 52-53 ("Firefighters and emergency medical personnel were sent to the area to verify that no one was injured and to extinguish small residual fires.").
[3] 14 CFR § 420.
[4] Hydrogen Tools, Laboratory Technician Fatally Burned When Leaking Hydrogen Ignites, https://h2tools.org/lessons/laboratory-technician-fatally-burned-when-leaking-hydrogen-ignites (last accessed July 19, 2024).
[5] *Id.*
[6] *Id.*

The Report also omits key details about some of the incidents it does partially describe. For example, regarding an accident from January 8, 2007, the Report by SoCalGas states (in its entirety) the following: "On Jan[.] 8, 2007, an explosion occurred during a delivery of compressed hydrogen gas at a coal fired power plant. Evidence pointed to the premature failure of a pressure relief device rupture disk, which had been repaired by the vendor six months before the explosion." However, according to the H2Tools database incident description, the explosion "killed one person and injured 10 others."[7] The database adds further detail about the fatality: "The blast killed the delivery truck driver who was unloading compressed hydrogen gas."[8] Given that SoCalGas chose to include the January 2007 explosion event in the "Pressure Relief Device Incidents" section of the report, CBE finds it very troubling that SoCalGas either intentionally or negligently chose not to include any details about the fatality and serious injuries that occurred due to this incident. If the Report cannot directly confront the sort of incidents which impact CBE's communities and many communities like them, it will struggle to identify solutions to such catastrophes.

V. The Report Misleadingly Characterizes SoCalGas's Safety Management System as Strong Without Adequate Context

SoCalGas makes misleading statements about the maturity of its safety management system (SMS). The Report states that in 2021:

> SoCalGas engaged the American Petroleum Institute to perform a maturity assessment of SoCalGas's SMS. At that time, SoCalGas's SMS scored a 3.06, which indicates SoCalGas's SMS is "Implemented: Organizational structures are in place, processes are fully developed, and procedures and programs documented and functional." Since that assessment, SoCalGas has and is implementing improvements to continue maturing its SMS.

And that:

> SoCalGas is well positioned to build, operate, and maintain a clean renewable hydrogen pipeline system due to its long-standing experience operating and maintaining a highly developed gas transmission and distribution system, existing highly trained and qualified workforce, and comprehensive established integrity management and emergency response procedures.

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[7] Hydrogen Tools, Hydrogen Explosion at Coal-Fired Power Plant, https://h2tools.org/lessons/hydrogen-explosion-coal-fired-power-plant (last accessed July 19, 2024).
[8] *Id*.

There is no question that the personnel and expertise devoted to maintaining the safety of SoCalGas' transmission pipelines are an integral part of any hydrogen safety system. The company itself, however, has many long strides to make with respect to safety and basic hydrogen learning before making such claims in its report. SoCalGas's score of 3.06 (on a 1 to 5 scale) net's it a "Conformance" ranking while scores of 4 to 5 indicate "Effectiveness."[9] Adding the volatility of hydrogen along with the unknowns of untested safety equipment, the need for new safety procedures, and an outdated regulatory structure raises severe doubts about SoCalGas' ability to safely "build, operate, and maintain" the ALP.

VI. Conclusion

Due to the Report's omissions and misleading discussion outlined above, CBE strongly objects to SoCalGas's magical determination in the Report's conclusion section that: "[P]ipeline transportation of clean renewable hydrogen is feasible and can be safely achieved through compliance with Federal and State codes, standards, regulations, and procedures identified within this document."

Sincerely,

Jay Parepally
Theo Caretto

Communities for a Better Environment

CC:
Emily Grant, SoCalGas
Chester Britt, Arellano Associates
Alma Marquez, Lee Andrews Group
Angeles Link service list

[9] Pipeline SMS, Resources: Pipeline SMS Maturity Model, April 15, 2018, https://pipelinesms.org/pipeline-sms-maturity-model/ (last accessed July 19, 2024).

July 24, 2024

Informal Comments of the Public Advocates Office on Southern California Gas Company's Angeles Link Draft Report for Plan for Applicable Safety Requirements

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) provides these comments on Southern California Gas Company's (SoCalGas) *Angeles Link Draft Report for Plan for Applicable Safety Requirements* (Safety Requirements), which was issued on June 21, 2024. The Safety Requirements report discusses the safety regulations and industry standards with which SoCalGas must comply regarding hydrogen transmission, storage, and transportation as required by the Commission's Phase 1 Decision.[1] Cal Advocates comments on two issues regarding the Safety Requirements:

1. SoCalGas should clarify whether the Class Location of its hydrogen pipelines will be different from the existing Class Location of its natural gas pipelines due to differences in the two gases potential impact radius (PIR) calculations, and if so, cite to supporting regulations;
2. SoCalGas should design the Angeles Link pipeline to a more conservative, safety-oriented standard beyond the <u>minimum</u> requirements set by PHMSA's OPS TTO Number 13; given that:
    a. The consequence of pipeline rupture zone with the currently adopted Heat Intensity Threshold has come under scrutiny;
    b. New scholarship and real-world rupture data questions the simplified point-source rupture assumption and promotes a new standard for calculating the PIR which includes jet ruptures; and,
    c. PHMSA, the NTSB, and other safety advisor and regulatory bodies who are publicly addressing the seeming inadequacies of the current TTO Number 13 standard for calculating PIR may soon look to update the calculation.

<u>Class Location Definitions are Based on Population Density and Do Not Change with the Potential Impact Radius</u>

49 Code of Federal Regulations (CFR) 192.903, defines the PIR as "the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property."[2] The PIR is based on the

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[1] *SoCalGas Angeles Link Draft Report for Plan for Applicable Safety Requirements* (Safety Requirements) at 7.

[2] In 49 CFR 192.903, the potential impact radius is fully defined as "the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula r = 0.69* (square root of (p*d2)), where 'r' is the radius of a circular area in feet surrounding the point of failure, 'p' is the maximum allowable

calculated threshold where fatality due to the rupture is likely.[3] The Pipeline Hazardous Materials Safety Administration (PHMSA) has included as reference in 49 CFR 192.7 the 2004 American Society of Mechanical Engineers (ASME) B31.8S standard for calculating PIR for natural gas and other gases.[4] Section 3.2 in ASME B31.8S describes the relationship as follows:[5]

$$\boldsymbol{r = 0.69 * d\sqrt{p}}$$

where **r** is the pipeline impact radius in feet, **d** is the pipe diameter in inches, and **p** is the operating pressure of the pipeline in pounds per square inch. The coefficient **"0.69"** is a gas factor for natural gas.[6]

SoCalGas states in its Integrity Management section that it plans to utilize PHMSA's Technical Task Order (TTO) Number 13 to inform its PIR calculations.[7] PHMSA's Office of Pipeline Safety (OPS) commissioned TTO Number 13 in part to determine the gas factor for other fuels, and established that the appropriate gas factor for hydrogen gas would be **"0.47"**.[8] SoCalGas states that once it has finished its PIR calculation, its definitions around its class locations, high consequence areas (HCAs) and moderate consequence areas (MCAs) will vary between its natural gas and hydrogen pipelines:

> Once the PIR is calculated, the HCAs and MCAs can be determined for the hydrogen pipeline using the same methodology as for a natural gas pipeline.
>
> To note, the factor for hydrogen (0.47) is lower than the factor for natural gas (0.69), which results in lower PIR than a similar pipeline carrying natural gas. This could result in fewer HCAs and MCAs identified for a hydrogen pipeline versus a natural gas pipeline, and potentially differing class locations along the pipeline route.[9]

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operating pressure (MAOP) in the pipeline segment in pounds per square inch and 'd' is the nominal diameter of the pipeline in inches.

Note:
0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use section 3.2 of ASME B31.8S (incorporated by reference, see § 192.7) to calculate the impact radius formula."

[3] C-FER October 27, 2022 Presentation titled "The Potential Impact Radius Formula Background to Development and Validation" to the Transportation Research Board at 11.

[4] The original derivation of the PIR calculation can be found in a Gas Research Institute (GRI) report by C-FER Technologies (C-FER), "A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines".

[5] ASME B31.8S shows a formula with fifteen variables, many of which differ depending on the gas being transported in the pipeline.

[6] *See* Reference 2 for full definition of PIR from 49 CFR 192.903.

[7] Safety Requirements at 36-37.

[8] Office of Pipeline Safety (OPS) Technical Task Order (TTO) Number 13 "Potential Impact Radius Formulae for Flammable Gases Other Than Natural Gas" - Equation 4.30 at 37.

[9] Safety Requirements at 36-37.

Cal Advocates agrees that the change in PIR between natural gas and hydrogen pipelines will affect the size of HCAs and MCAs as these are both in part defined by PIR calculations.[10,11] However, PHMSA does not define class location in terms of PIR. Instead, class location is solely defined by the density of a region given the number of buildings intended to be used for human occupancy per class location unit based on a radius of 660 feet from the pipeline, which means that class location will not change with changes in PIR.[12] SoCalGas should clarify if it intends to use a different definition of class location for its hydrogen pipelines than natural gas pipelines due to a different potential impact radius or other regulations and, if so, it should provide its rationale and cite to supporting regulations.

Fatalities Outside of the Potential Impact Radius Mean that Assumptions in Technical Task Order Number 13 are Inadequate to Capture Real World Conditions and Raise Equity Concerns

Cal Advocates agrees with SoCalGas that PHMSA's OPS TTO Number 13 establishes the hydrogen gas factor at 0.47 based many variables including the "Heat Intensity Threshold". TTO Number 13 details how the Heat Intensity Threshold value was chosen and states:

> The exposure time adopted as the reference was 30 seconds based on the premise that an exposed person would stay in place for 1 to 5 seconds to evaluate the situation and then run at 5 miles per hour (7.3 feet per second) to some type of shelter within approximately 200 feet of their initial position... The heat intensity threshold of 5000 Btu/hr-ft^2 used in the original derivation was chosen by defining a significant chance of fatal injury as a 1% chance of mortality.[13]

For its input on whether the 30 second escape period was appropriate, C-FER, the co-author of TTO Number 13, has since defended this decision as they indicate there is international precedent for such travel speed.[14]

Following a 2019 pipeline rupture in Danville, Kentucky where there were several injuries and one fatality, the National Transportation Safety Board (NTSB) issued Pipeline Investigation Report NTSB/PIR-22/02

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[10] In 49 CFR 192.903, the High Consequence Area is defined by the size of the PIR in several instances, including the instance when an otherwise Class 1 or Class 2 location has a pipeline with a PIR greater than 200 meters and a circle of radius equal to the PIR contains 20 or more buildings intended for human occupancy.
[11] In 49 CFR 192.3, the Moderate Consequence Area is defined by the size of the PIR in several instances.
[12] In 49 CFR 192.5, the definitions of Class location 1, 2, 3, and 4 are all defined in terms of number and distance between buildings intended for human occupancy, not by PIR.
[13] OPS TTO Number 13 at 15.
[14] "International precedent (BS PD 8010-3:2009) for 2.5 m/s travel speed and sheltered within 50 to 75 m." C-FER October 27, 2022 Presentation titled "The Potential Impact Radius Formula Background to Development and Validation" to the Transportation Research Board at 10.

with recommendations that PHMSA implement changes to its PIR calculations due to concerns around the feasibility of human response in the event of pipe rupture.[15] The NTSB notes:

> We also found that the Pipeline and Hazardous Materials Safety Administration's (PHMSA's) equation for determining the potential impact radius of a pipeline rupture is based on assumptions that are inconsistent with findings from recent natural gas ruptures and human response data; thus, high consequence areas determined using the equation do not include the full area at risk.[16]

PHMSA has since acknowledged the NTSB's recommendation, suggesting that it was something the agency would consider addressing. On December 14, 2022 as part of its Public Meeting, Director of Program Development at PHMSA, Max Kieba, acknowledged the NTSB's recommendation. Mr. Kieba stated:

> There are a lot of aspects and questions we will come up in this panel are the baseline of the PIR is it reasonable for some of the timing aspects… the ability for a member of the public to respond following a gas pipeline rupture may be complicated by, for example, sleeping, being in interior room where one may not be immediately aware of a pipeline emergency or evacuation or evacuating other household members who cannot self-evacuate the speed with which the member is assumed to run is not general population including very young elderly, mobility impaired or those with preexisting medical condition. Two of the evacuees rescued during the incident by sheriff were both elderly mobility impaired I would say this part of the recommendation does also align with if it hasn't been mentioned yet among DOT strategic goals is looking at areas of equity… But we hope to go into a lengthy discussion about do we need to reconsider particularly align with the NTSB recommendation but also expand from there.[17]

PHMSA is interested in mitigating the risk to the mobility-impaired and people with pre-existing medical conditions posed by the adopted Heat Intensity Threshold, which underpins both the currently designated natural gas and hydrogen gas factors of "0.69" and "0.47", respectively. Adopting a new Heat Intensity Threshold standard to address these concerns would impact both gas factors.

There are also real-world events where fatalities have occurred outside of the calculated pipeline impact radius. In addition to PHMSA's equity concerns around the current PIR calculation, analysis of pipe ruptures in the twenty years since the PIR was first described has found damage outside a circle of radius equal to the potential impact radius (also known as a potential impact circle, or PIC).[18] Investigations of recent rupture

[15] "As a result of this investigation, we made a recommendation to PHMSA to revise the regulations regarding potential impact radius methodology based on data from recent natural gas pipeline ruptures and human response considerations." NTSB/PIR-22/02 at 9.
[16] NTSB/PIR-22/02 at vii.
[17] PHMSA Director of Program Development Max Kieba at PHMSA's Day 2, December 14, 2022 Public Meeting Transcript. day2 (onlinevideoservice.com). (Last accessed 7/16/2024)
[18] The potential impact circle (PIC) is defined in 49 CFR § 192.903.

events, including Danville, Kentucky in 2019[19] and Sissonville, West Virginia in 2012[20] have shown evidence of blast damage exceeding the PIC for how the pipeline was being operated. In its Pipeline Investigation Report, the NTSB noted several high-profile cases of rupture damage exceeding the calculated PIR:

> Past accidents have also demonstrated the insufficiency of the PIR calculation. In 2000, a pipeline rupture in Carlsbad, New Mexico, killed 12 people camped about 675 feet from the rupture crater; the PIR would have been calculated at 598 feet by current federal regulations (NTSB 2003). A pipeline that ruptured in San Bruno, California, in 2010 had a PIR of 414 feet, but homes were damaged up to 600 feet from the rupture origin (NTSB 2011). A rupture in Sissonville, West Virginia, in 2012 displayed evidence of thermal damage up to 610 feet from the rupture origin, but the PIR was calculated as 567 feet (NTSB 2014).

One reason for the discrepancy in finding damage outside of the pipe's PIC is the manner in which the pipe ruptures. C-FER noted in an October 2022 presentation on the matter that the original PIR calculation was designed by modeling the fire as "…a time-varying large-scale fire as a steady-state, ground-level, *point-source heat emitter* for the purpose of hazard zone estimation"[21] (emphasis added). This means that the PIR currently assumes that everywhere in a given distance of the rupture will be affected equally. Recent evidence shows that instead of point-source cratering at the rupture location, in certain circumstances pipeline ruptures have the tendency to create *directed jets*. For a directed jet rupture, such as is anticipated if a hydrogen pipeline ruptures,[22] C-FER explains that the "hazard area is comparable to that of crater fire, but generally width is reduced and length is increased."[23] This means that for a directed jet rupture, the heat and damage experienced in the direction of the jet exceeds the PIR circle as currently calculated. This is further evidence that the current PIR calculation fails to accurately define a threshold for the consequence of a pipeline rupture. Newly published research in January 2024 attempts to develop a new PIR calculation formula, validated against real pipeline rupture data including jet ruptures, to more accurately capture a threshold where damage is experienced during a pipeline rupture.[24]

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[19] "The PIR at the rupture site calculated under PHMSA regulations was 633 feet. Physical evidence at the accident site and from the Lincoln County Coroner's report showed that the PIR of the accident site was larger than what was calculated. The deceased individual was found 640 feet south of the pipeline failure and natural gas fire, and damage to homes was found up to 1,100 feet from the rupture crater." NTSB/PIR-22/02 at 37.

[20] C-FER October 27, 2022 Presentation titled "The Potential Impact Radius Formula Background to Development and Validation" to the Transportation Research Board at 18.

[21] C-FER October 27, 2022 Presentation titled "The Potential Impact Radius Formula Background to Development and Validation" to the Transportation Research Board at 2.

[22] "The existing methodologies employ a single point source model to estimate radiation and the potential impact radius. However, these approaches overlook the jet fire shape resulting from high-pressure leaks, leading to discrepancies between the calculated values and real-world incidents." "A Model for Assessing the Potential Impact Radius of Hydrogen Pipelines Based on Jet Fire Radiation" at 1.

[23] C-FER October 27, 2022 Presentation titled "The Potential Impact Radius Formula Background to Development and Validation" to the Transportation Research Board at 8.

[24] "A Model for Assessing the Potential Impact Radius of Hydrogen Pipelines Based on Jet Fire Radiation" Equation 10 at 7.

There are potential safety implications of designing the Angeles Link pipeline in accordance with PHMSA's TTO Number 13. Given the uncertainty around the future of the PIR calculation and the "0.47" gas factor for hydrogen calculated in TTO Number 13, SoCalGas should prioritize safety and adopt a more conservative value for the design of its proposed Angeles Link pipeline. In previous PAG meetings, Cal Advocates has advised that the hydrogen pipeline be designed to natural gas standards, to a gas factor of "0.69". To demonstrate that SoCal Gas can safely construct its first hydrogen transmission line, the safety requirements report should also explicitly discuss who and how SoCalGas consulted with in determining the engineering and design parameters for a hydrogen transmission pipeline. At a minimum, SoCalGas should consult with PHMSA and the NTSB given the concerns around the PIR calculation as currently described by TTO Number 13. SoCalGas should then explicitly describe how and where it included the advice and recommendations of these other safety advisory and regulatory bodies.

Conclusion

In summary, SoCalGas' decision to adopt PHMSA's TTO Number 13 should be tempered by broader consideration of the PIR that exceeds the minimum safety standards established by PHMSA. Cal Advocates recommends that SoCalGas:

1. Should clarify whether the Class Location of its hydrogen pipelines will be different from the existing Class Location of its natural gas pipelines due to differences in the two gases potential impact radius (PIR) calculations, and if so, cite to supporting regulations;
2. Should design the Angeles Link pipeline to a more conservative, safety-oriented standard beyond the <u>minimum</u> requirements set by PHMSA's OPS TTO Number 13; given that:
    a. The consequence of pipeline rupture zone with the currently adopted Heat Intensity Threshold has come under scrutiny;
    b. New scholarship and real-world rupture data questions the simplified point-source rupture assumption and promotes a new standard for calculating the PIR which includes jet ruptures; and,
    c. PHMSA, the NTSB, and other safety advisor and regulatory bodies who are publicly addressing the seeming inadequacies of the current TTO Number 13 standard for calculating PIR may soon look to update the calculation.

APPENDIX

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The Potential Impact Radius Formula
Background to Development and Validation

prepared for the

Transportation Research Board

Committee on Criteria for Installing Automatic and Remote-Controlled Shutoff Valves on Existing Gas and Hazardous Liquid Transmission Pipelines

presented by

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Information Gathering Meeting, Washington, DC

October 27, 2022

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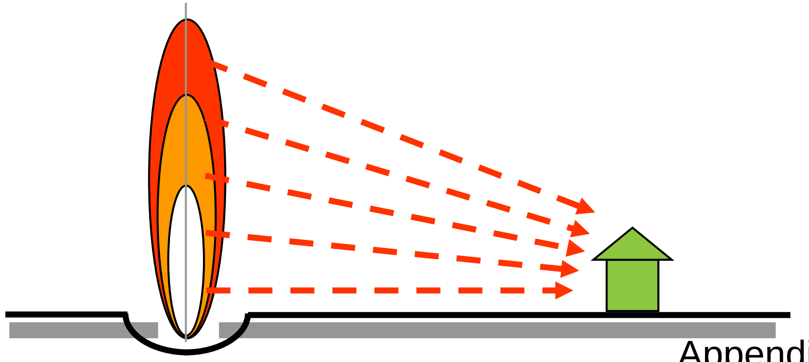
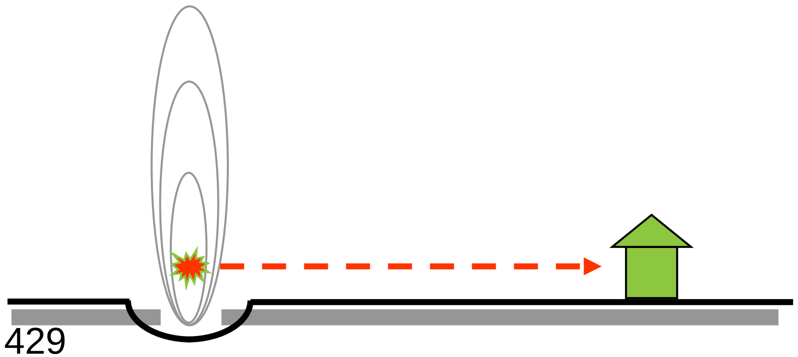
The Potential Impact Radius (PIR) Formula

- A formula developed by C-FER (Stephens 2001) for estimating the extent of the significant thermal radiation hazard zone resulting from an ignited rupture of a natural gas pipeline
  - The underlying models idealize a time-varying large-scale fire as a steady-state, ground-level, point-source heat emitter for the purpose of hazard zone estimation
  - A concerted effort was made to develop and describe a modelling approach that would
    - be as simple as possible (to enhance understanding and promote acceptance), but also
    - incorporate factors the reduce conservatism inherent in the adopted modelling approach





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Overview of the Model Components

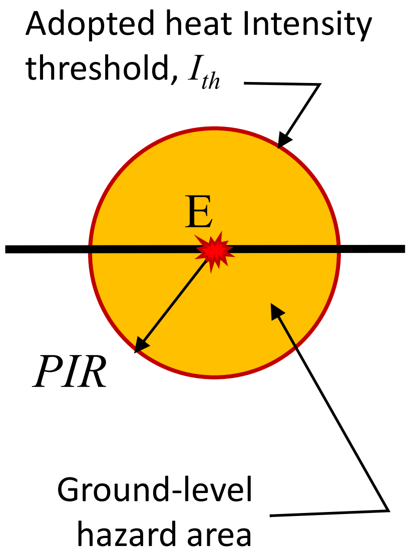
- Effective release rate, Q_{eff} (kg/s)
  - λ = release rate decay factor
  - C_d = discharge coefficient
  - d = pipeline diameter
  - p = internal pressure
  - φ/a_0 = flow factor/sonic velocity
- Emissive power, E (kW)
  - H_c = heat of combustion
  - χ_g = emissivity factor
- Heat intensity, I (kW/m^2)
  - r = horizontal distance
  - η = efficiency factor

$$Q_{eff} = 2\,\lambda \boxed{C_d \frac{\pi d^2}{4} p \frac{\varphi}{a_0}}$$

Orifice discharge

$$E = Q_{eff}\, H_c\, \chi_g$$

$$I = \frac{E\,\eta}{4\pi r^2} \longrightarrow r = \sqrt{\frac{E\,\eta}{4\pi I}} \longrightarrow PIR = \sqrt{\frac{E\,\eta}{4\pi I_{th}}}$$



$$PIR = 0.69\sqrt{pd^2}$$

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PIR Model Components Subject to Concern

- Effective release rate, Q_{eff} (kg/s)
  - λ = release rate decay factor
  - C_d = discharge coefficient
  - d = pipeline diameter
  - p = internal pressure
  - φ/a_0 = flow factor/sonic velocity

1

$$Q_{eff} = 2\,\lambda\,C_d\,\frac{\pi d^2}{4}\,p\,\frac{\varphi}{a_0}$$

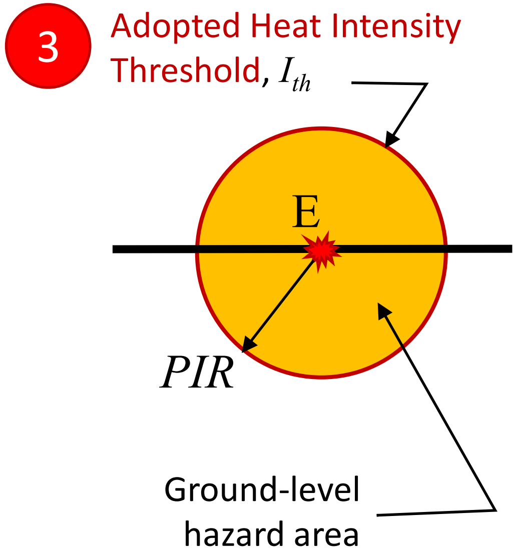
- Emissive power, E (kW)
  - H_c = heat of combustion
  - χ_g = emissivity factor

$$E = Q_{eff}\,H_c\,\chi_g$$

- Heat intensity, I (kW/m^2)
  - r = horizontal distance
  - η = efficiency factor

2

$$I = \frac{E\,\eta}{4\pi r^2} \qquad r = \sqrt{\frac{E\,\eta}{4\pi I}}$$

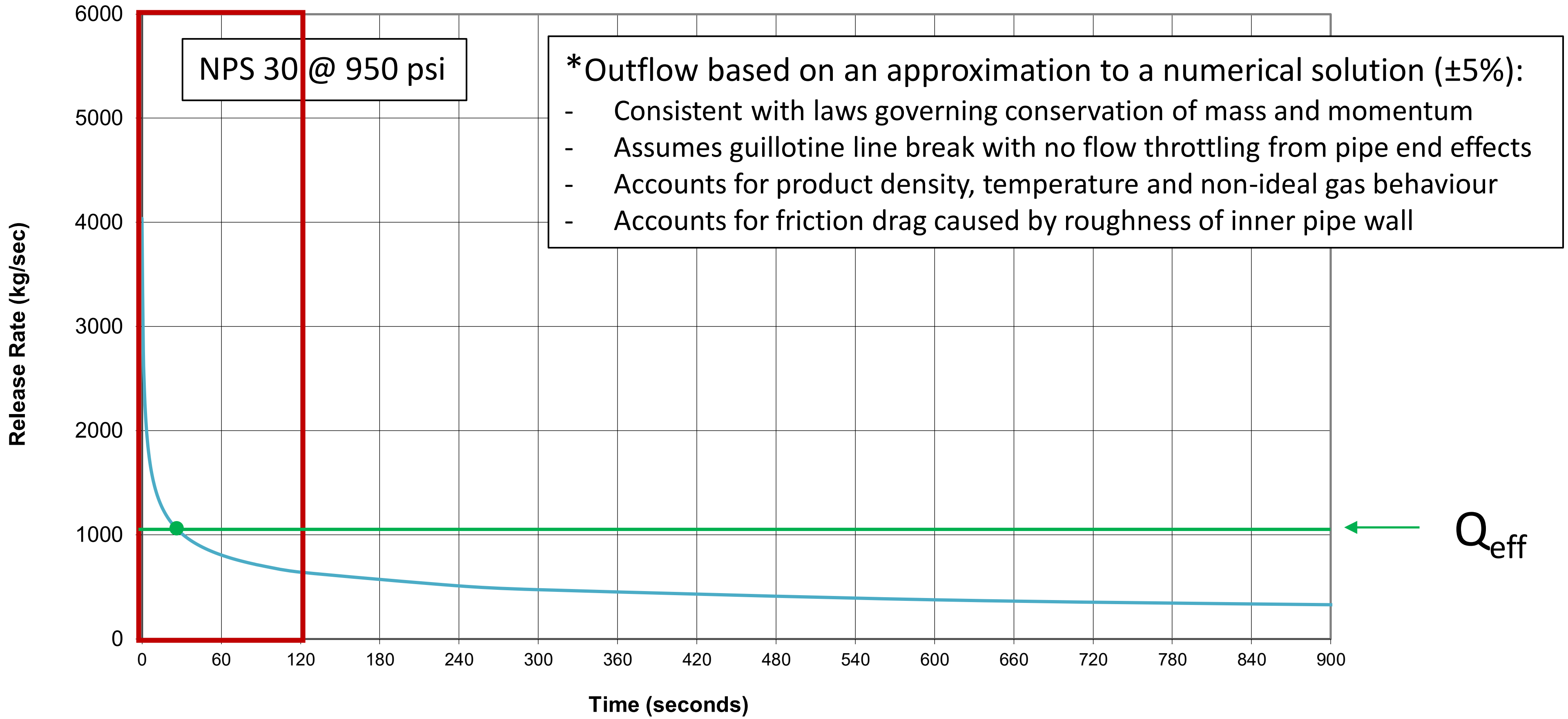


$$PIR = \sqrt{\frac{E\,\eta}{4\,\pi\,I_{th}}}$$

$$PIR = 0.69\sqrt{pd^2}$$

Effective Sustained Release Rate, Q_{eff}

- Comparisons to transient release rates – TNO (1982) rupture blowdown model*



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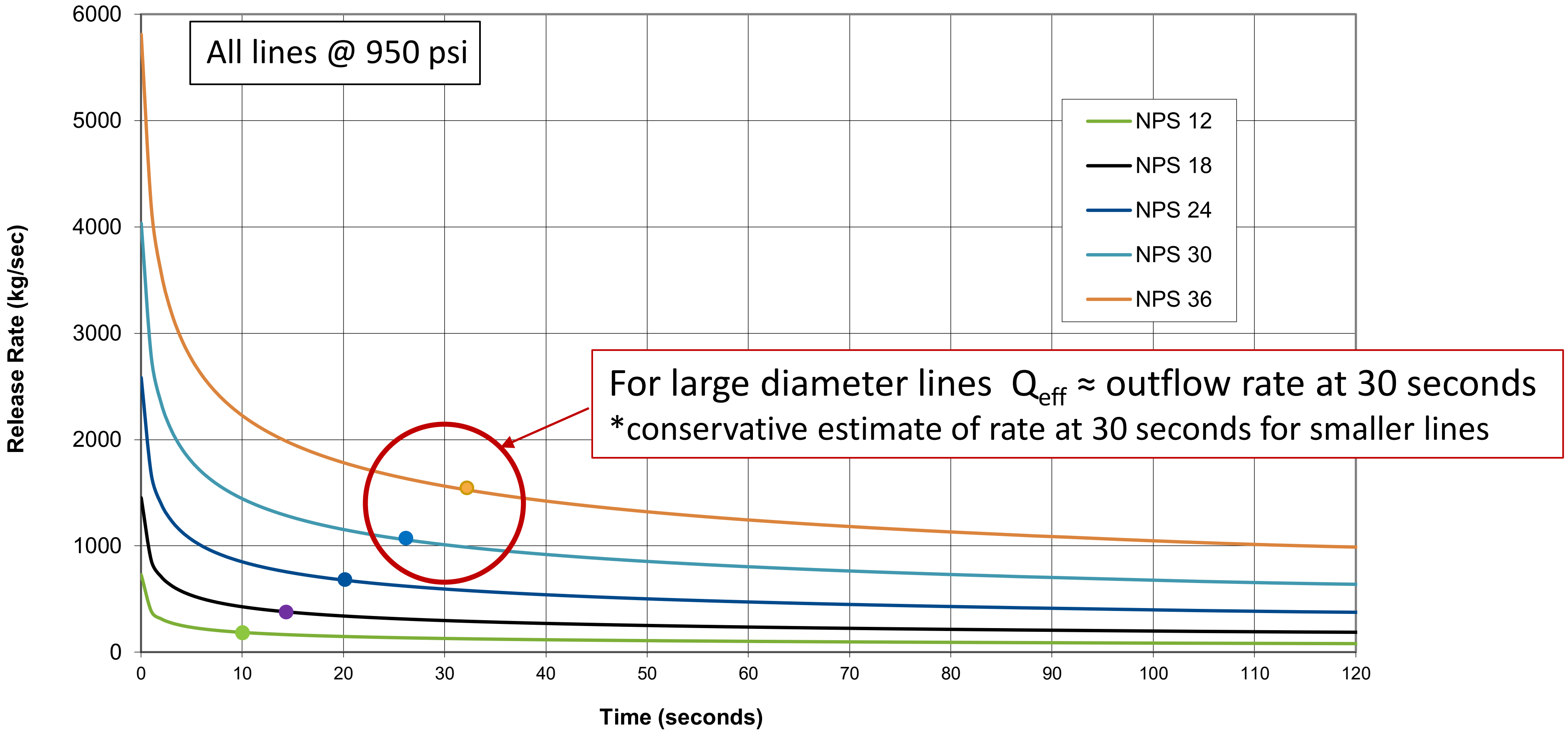
Effective Sustained Release Rate

- Comparisons to transient release rates - TNO (1982) rupture blowdown model



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Efficiency Factor, η

- The efficiency factor incorporated in the Technica (1988) fire model as adopted by C-FER addresses conservatisms inherent in the simplified form of the model used to estimate radiation intensity as a function of horizontal distance from an elevated fire source

- As discussed by Baker/C-FER in a report commissioned by PHMSA (Baker/C-FER 2005), the factor can be shown to effectively account for the following:
  - The effect of high-speed jetting on emmisivity —— a knock-down factor on the order of 0.75 [Chamberlain (1987) and Cook et al. (1987)]
  - The effect of atmospheric absorption on radiant heat reaching receptors —— a transmissivity factor on the order of 0.7 [Bagster and Pitblando (1989)]
  - The effect of fire geometry and flame opacity on the effective view factor —— a view factor adjustment on the order of 0.65 [Cook et al. (1987)]

- Efficiency factor, $\eta = 0.75 \times 0.7 \times 0.65 = 0.34 \approx 0.35$ ← Technica factor

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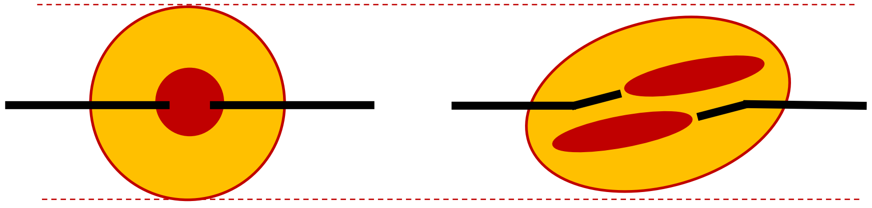
Applicability of Fire Model to Real Rupture Fires

- Models underlying the PIR formula are a defensible basis for estimating radiation intensity from a crater fire associated with near-immediate ignition as a function of horizontal distance
- A crater fire develops when opposing gas jets impinge upon one another and the crater walls redirect flow upwards, effectively creating a vertically oriented flame
    - For such a vertical flame, the hazard zone is circular and centered on break point
- What about a rupture resulting in directed jets?
    - If opposing pipe ends are significantly misaligned, impingement of opposing jets does not occur, jets are still directed upwards by crater walls but two distinct jet flames can develop
        - For directed jets, the hazard zone is more elliptical
        - Total hazard area is comparable to that of crater fire, but generally width is reduced and length is increased



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Heat Intensity Threshold, I_{th}

- Adopted heat intensity threshold is 5,000 Btu/hr/ft^2
  - Impact on people
    - A 1% chance of lethality for individuals subject to approximately 30 seconds of sustained exposure
      - Based on a widely recognized dose-response relationship (i.e. a lethality probit function)
    - Basis for 30 second reference exposure time
      - Individuals assumed to pause for 5 s then travel at 5 mph (2.5 m/s) and find shelter within 200 ft (60 m)
        - » International precedent (BS PD 8010-3:2009) for 2.5 m/s travel speed and sheltered within 50 to 75 m
  - Impact on property
    - Highly unlikely that wooden structures will ignite and burn in the event of extended exposure
      - Adopted heat intensity threshold requires about 20 minutes of exposure to result in piloted ignition (no potential for spontaneous ignition) based on widely recognized dose-response relationship
    - Implications for people indoors — wood-framed dwelling will afford indefinite protection to occupants

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Implications of Adopted Heat Intensity Threshold that Defines Extent of PIR

- It does delineate
  - the area within which fatal injury is a significant possibility
  - the area within which wood-framed dwelling destruction is possible

- It does not represent
  - the safe distance beyond which people and property are likely to be minimally affected
  - the perimeter of the emergency response planning zone or the safe approach distance

- Implications for validation by evaluation of historical incidents
  - It does not delineate the extent of the 'burn zone' (due to lower heat intensity required to ignite some vegetation and the potential for fire spread)
  - However, the burn zone is often the only available basis for the evaluation of model accuracy

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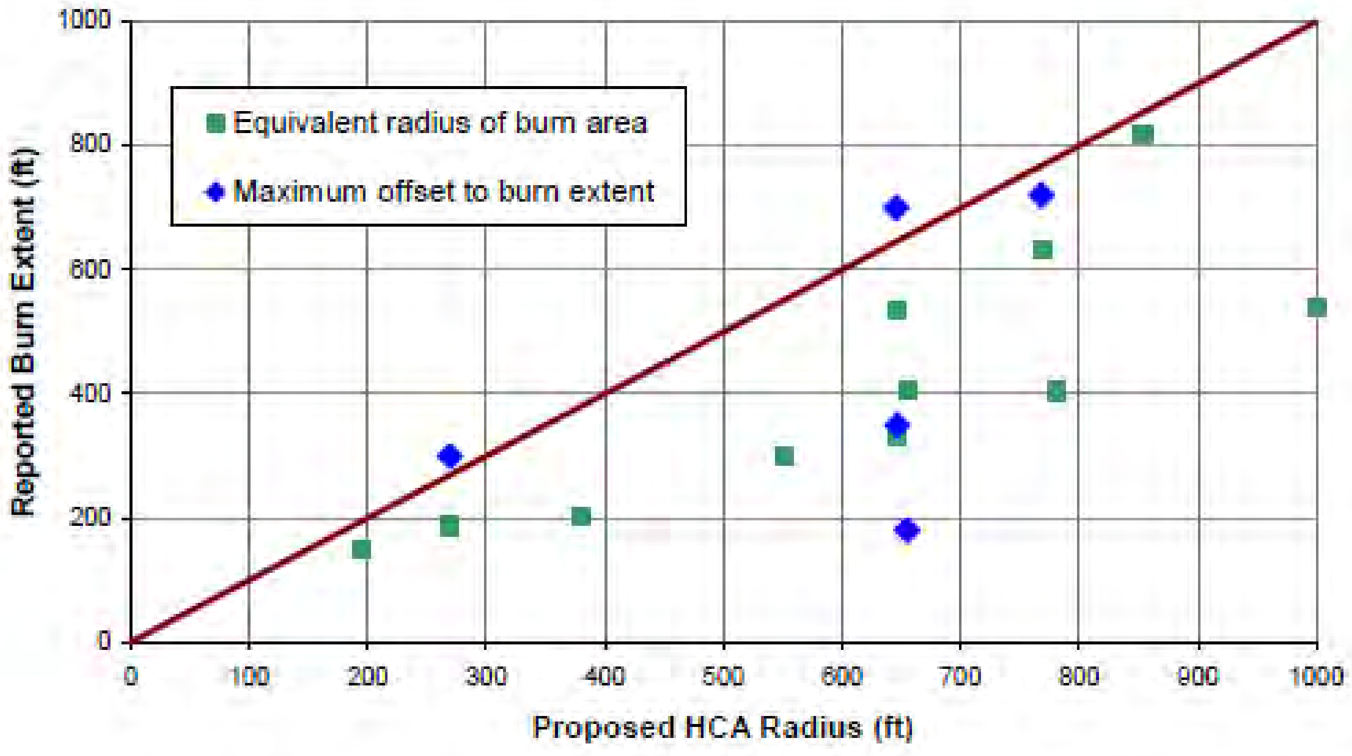
Original Model Validation – Comparison of Burn Zones

- From GRI Report (Stephens 2001)



Other Validation Effort – Safety Risk Focused

- A set of safety-related failure consequence analysis results were compared to those obtained from state-of-the-art consequence modelling (Rothwell and Stephens 2006)

- The study compared results obtained from the C-FER models, using an adaptation of the models underpinning the PIR formula, against those obtained using PIPESAFE, a proprietary pipeline risk analysis software tool initial developed under a joint industry project, now maintained by DNV UK
  - PIPESAFE contains a suite of interlinked consequence models specifically developed for gas transmission pipelines that have been validated by tests at scales up to 914 mm OD and 76 km in length
  - PIPESAFE is capable of taking into account many factors reflecting the attributes of the pipeline, its surroundings and contents, the nature of the failure, the meteorological conditions, and the presence and behaviour of potential receptors (see Acton et al. 2002)

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Comparison of C-FER Model to PIPESAFE

- Individual risk

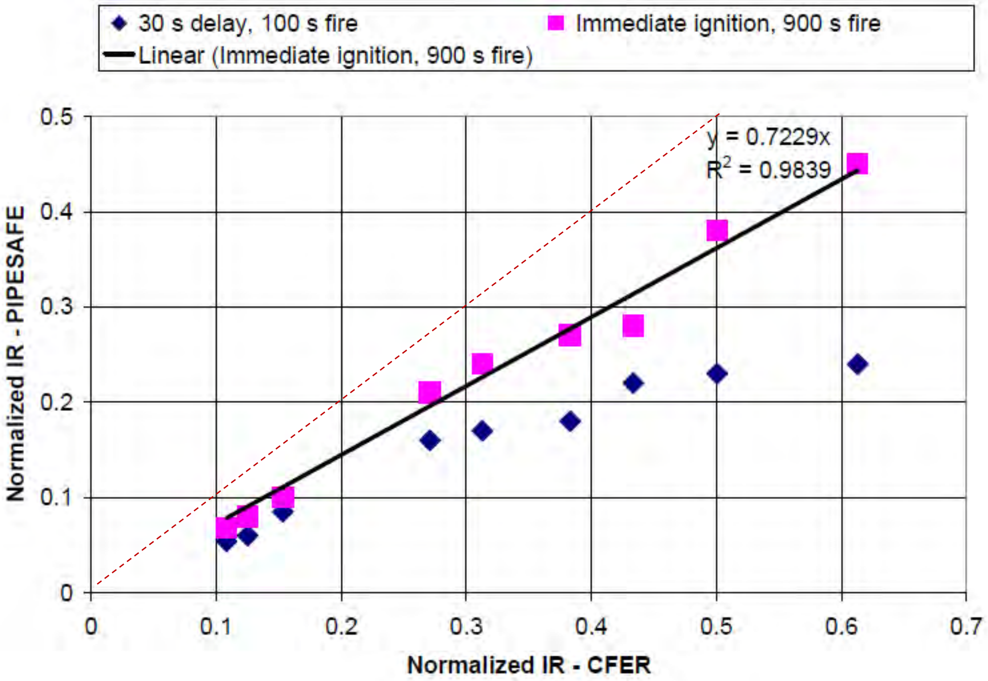

Figure 6 Relationship between normalized individual risk calculated by PIPESAFE and by the C-FER approach

Results from C-FER model plot to the right of the unity line (i.e. dashed red line) indicating conservatism compared to PIPESAFE results

Comparison of C-FER Model to PIPESAFE

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- Societal risk

Pipe diameter		NPS 48	NPS 48	NPS 24	NPS 24	NPS 12	NPS 12
Pressure, psi		1,500	750	1,500	750	1,500	750
Normalized fatalities per rupture	PIPESAFE	14	7	3	2	0.7	0.4
	C-FER	12	6	3	1.5	0.76	0.38

Fatality estimates very similar

Table 2 Normalized societal risk calculated by PIPESAFE and by the C-FER approach

Summary

- C-FER's position on the current PIR formula:
  - The models used and assumptions that underpin the PIR formula are a reasonable and defensible basis for hazard zone estimation
  - The predictive capability of the PIR formula as currently defined is considered fit for general purpose consequence screening
    - The development focus was to delineate the likely extent of the fatality and property destruction zone for typically populated and developed areas
  - The PIR as currently defined
    - Is not be interpreted to represent the distance beyond which no impact on people or property would be expected

Danville, KY, 2019

NPS 30 @ 926 psi
(MAOP 935 psi)

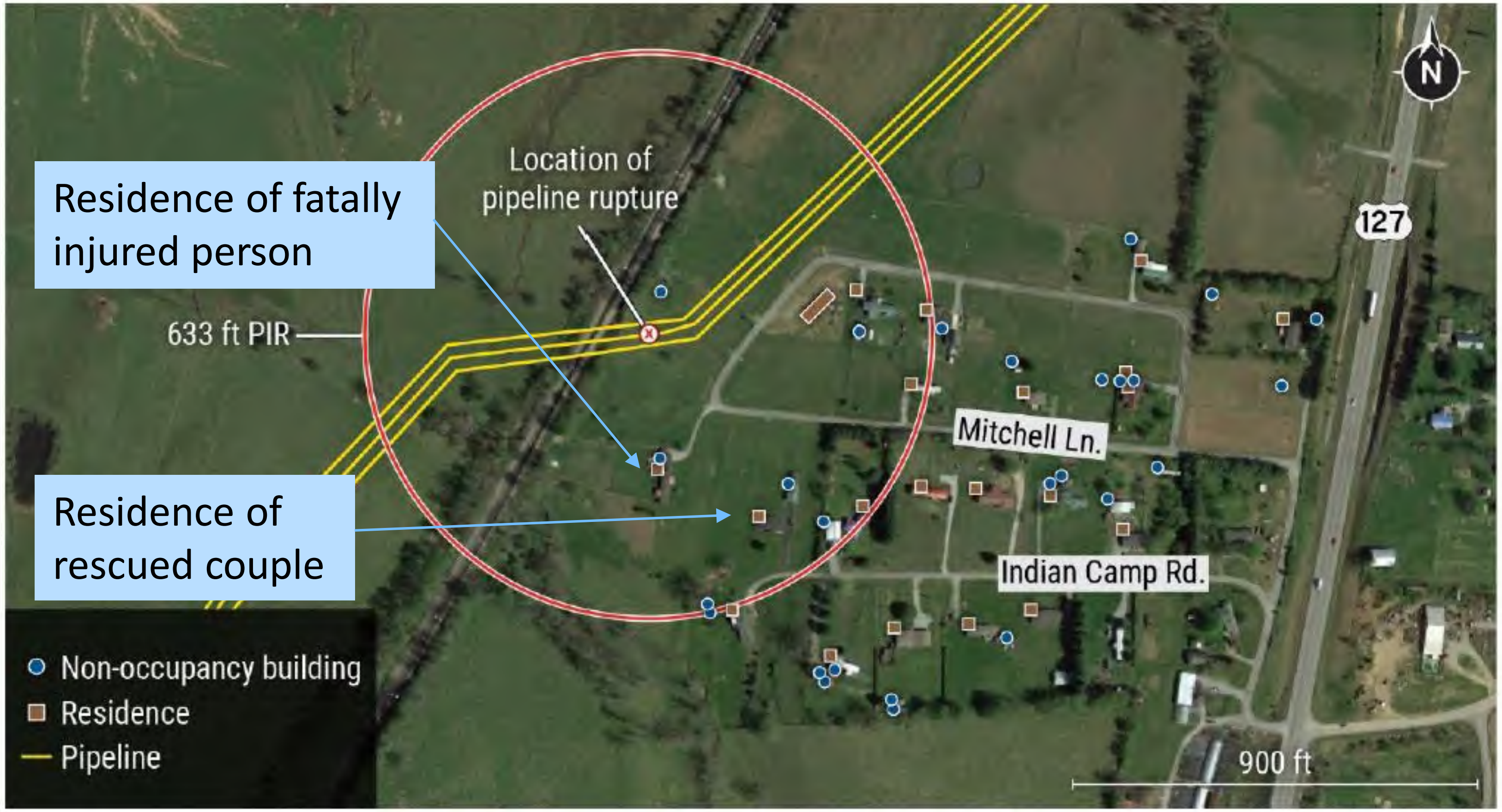

Figure 11. Human-occupancy buildings within the potential impact radius. (Courtesy of Enbridge.)

<u>Comments</u>
- Residence of deceased and all destroyed buildings fall within PIR

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Sissonville, WV, 2012

NPS 20 @ 929 psi
(MAOP 1,000 psi)

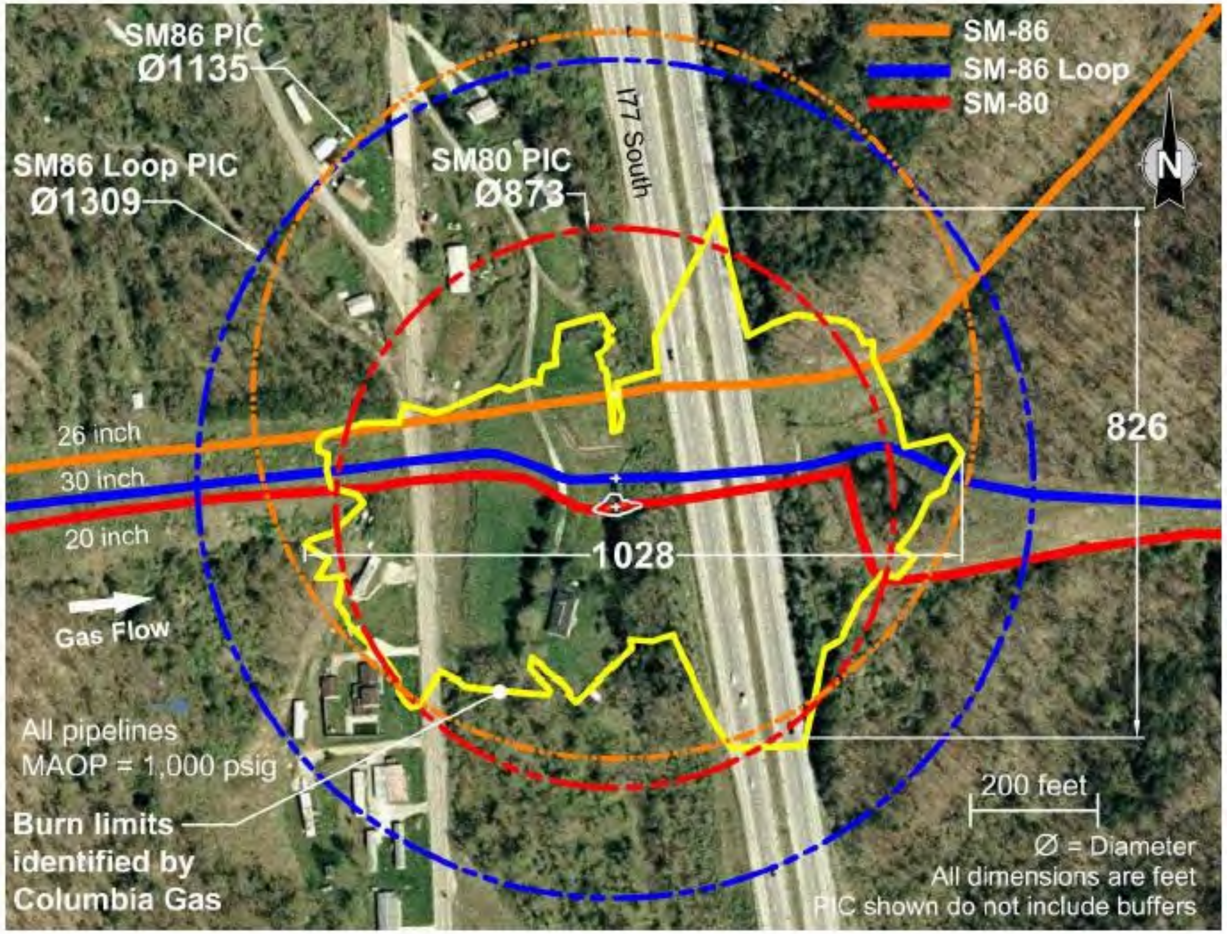

Figure 11. Potential impact radius circles for each pipeline in SM-80 system at rupture location.

<u>Comments</u>
- Area enclosed by PIR (red circle) comparable to area of burnt ground (yellow outline)
- Slight axial burn zone extension attributed to directional jetting

San Bruno, CA, 2010

NPS 30 @ 375 psi
(MAOP 400 psi)

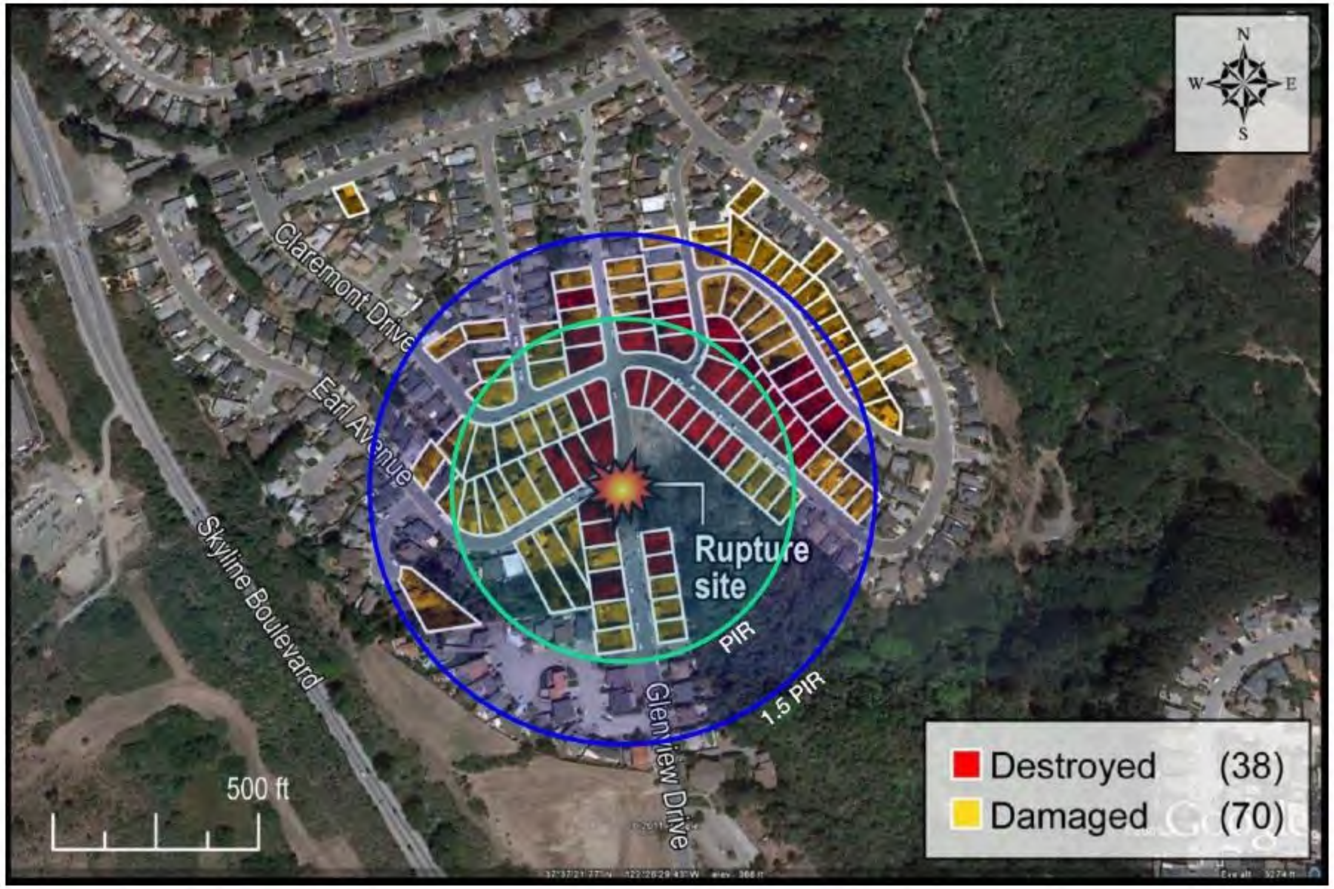

Fig. 3.69. Aerial view of the September 9, 2010 San Bruno natural gas pipeline release showing residential properties damaged and destroyed.

<u>Comments</u>

- extended distance to extent of building destruction and damage likely due to wind driven fire spread
- fire suppression was significantly delayed (water mains damaged; information suggests no water available for firefighting for about 1 hour)

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Carlsbad, NM, 2000

NPS 30 @ 675 psi
(MAOP 837 psi)

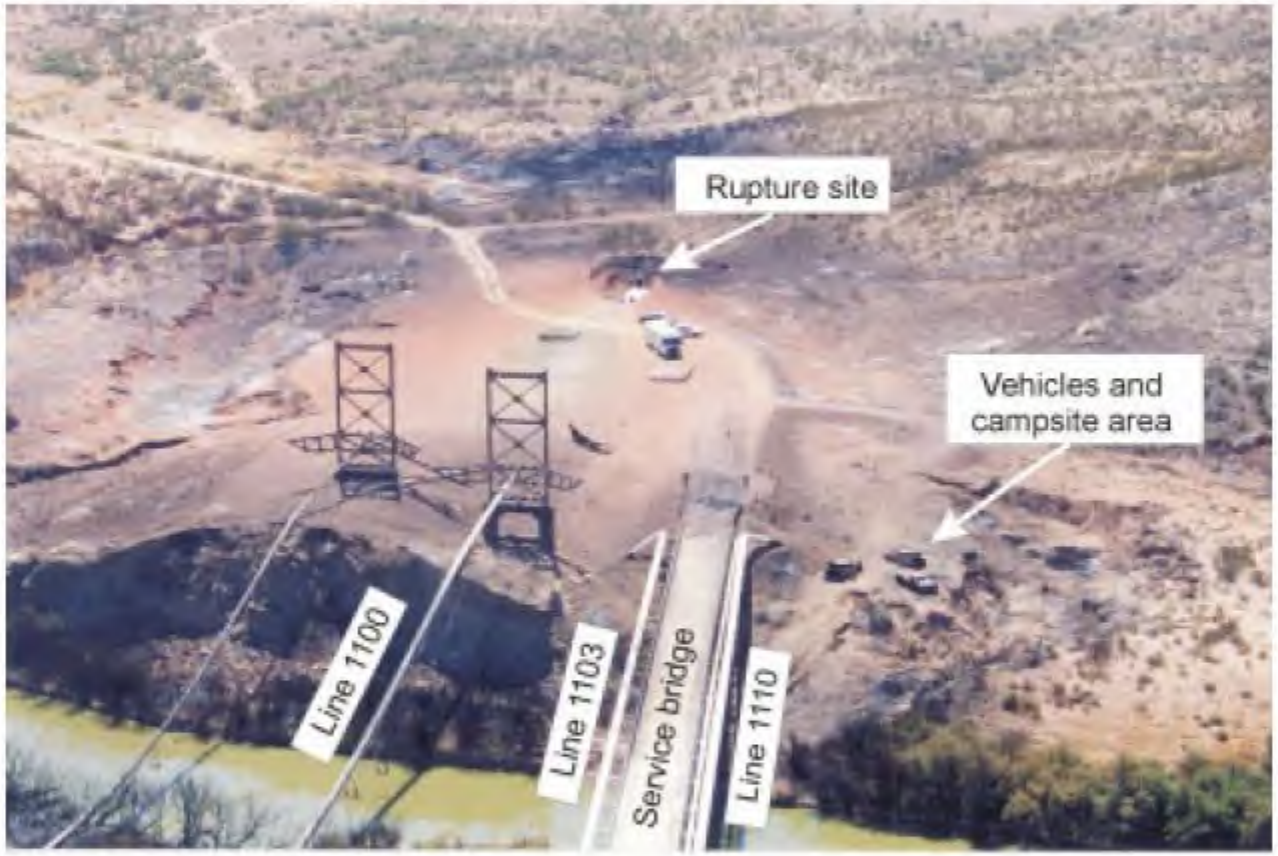

Figure 4. Aerial view of accident site looking east.

<u>Comments</u>

- Circumstances and specifics unclear from report narrative
- Causalities possibly sleeping unsheltered at camp site approximately 675 ft from crater (PIR = 599 ft)
- Fatality beyond PIR potentially attributed to slow reaction time and thereby extended exposure

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fire

Article

A Model for Assessing the Potential Impact Radius of Hydrogen Pipelines Based on Jet Fire Radiation

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Abstract: The accurate determination of the potential impact radius is crucial for the design and risk assessment of hydrogen pipelines. The existing methodologies employ a single point source model to estimate radiation and the potential impact radius. However, these approaches overlook the jet fire shape resulting from high-pressure leaks, leading to discrepancies between the calculated values and real-world incidents. This study proposes models that account for both the mass release rate, while considering the pressure drop during hydrogen pipeline leakage, and the radiation, while incorporating the flame shape. The analysis encompasses 60 cases that are representative of hydrogen pipeline scenarios. A simplified model for the potential impact radius is subsequently correlated, and its validity is confirmed through comparison with actual cases. The proposed model for the potential impact radius of hydrogen pipelines serves as a valuable reference for the enhancement of the precision of hydrogen pipeline design and risk assessment.

Keywords: hydrogen leakage; hydrogen jet fire; hydrogen pipeline; potential impact radius

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1. Introduction

Hydrogen pipeline transmission stands out as a highly efficient and cost-effective method for transporting hydrogen over long distances, particularly when compared to alternatives such as tube trailers and liquid hydrogen tankers [1,2]. Safety concerns within the international community arise due to the increased risk of leakage associated with hydrogen embrittlement [3]. In the event of a leak, the ignition of hydrogen poses a potential threat, as its low ignition energy, high flame speed, wide flammable limits, and elevated combustion heat make it susceptible to fire or explosion. Risk assessment has become a widely employed approach for evaluating the hazards associated with hydrogen systems, with numerous studies focusing on hydrogen stations, vehicles, pipelines, and other high-pressure hydrogen systems [4–12]. While many prior investigations concentrated on hazard analysis, some delved into quantitative risk assessment (QRA). It is crucial to recognize that quantitative risk assessment for hydrogen stations or vehicles differs fundamentally from that applied to long-distance hydrogen pipelines. In the quantitative risk assessment for stations or vehicles, the probability of equipment-specific leakage remains constant. In contrast, the probability of leakage for long-distance pipelines is influenced by diverse factors, including equipment impact, external corrosion, internal corrosion, stress corrosion cracking, manufacturing defects, construction defects, geotechnical hazards, equipment failure, incorrect operation and maintenance, and seismic hazards, among others. Consequently, the probability of leakage is not uniform throughout the hydrogen pipeline.

Moreover, pinpointing the location of hydrogen leaks in stations or vehicles is relatively straightforward, while the evaluation of an entire pipeline, spanning hundreds of kilometers, is less efficient. Therefore, the concept of a high consequence area (HCA) is introduced. A high consequence area is defined as an area where a gas pipeline accident could lead to significant consequences, causing considerable harm to people and property [13]. Given that the primary hazard of gas pipeline leakage is thermal radiation from a sustained jet fire [13], the potential impact radius is established to determine the high consequence area. This radius is associated with the heat flux of a sustained jet fire that ignites immediately after a pipeline rupture; it is based on the single point source heat flux model, which assumes that the flame is a single point and ignores the influence of the flame shape.

A collaborative effort by C-FER Technologies, the Gas Technology Institute, and the El Paso Pipeline Group has proposed a model for calculating the potential impact radius of natural gas pipelines [13]. In the quantitative risk assessment of high-pressure tanks, the pressure is sometimes assumed to be constant during the whole process of leakage in order to provide relatively conservative results. However, in the quantitative risk assessment of hydrogen pipelines, the pressure inside the pipeline decreases with time. Thus, the initial mass flow rate is calculated first; then, an equivalent mass flow rate is obtained that takes the pressure drop into account [13]. More details of the mass flow rate are given in Section 2. One should note that two aspects are taken into consideration with regard to mass flow rate calculation:

(1) The pressure inside the hydrogen pipeline decays with time;
(2) The rupture leads to a double-ended gas release.

With the further use of the release rate decay factor λ (λ = 0.33) and the constant 2, representing the pressure decay and double-ended gas release respectively, the equivalent mass flow rate is 2λ times the initial mass flow rate. It is to be noted that more details of λ are given in Section 2. By further applying the equivalent mass flow rate to the single point source model and using 15.8 kW/m^2 as the radiation threshold, Equation (1) and the value 0.099 are derived [13]. It is to be noted that the single point source model takes the jet fire as one single point and neglects the influence of flame shape on radiation. The previous model for the potential impact radius (Equation (1)) was validated by the data from the National Transportation Safety Board (NTSB) of the United States and the Transportation Safety Board (TSB) of Canada. In total, 12 practical cases were validated, and Equation (1) shows the reasonable and conservative results. One possible explanation is that Equation (1) assumes immediate ignition. While in real cases, the actual time for ignition is longer. Thus, the mass flow rate in Equation (1) is more conservative than the real cases [13]. It is to be noted that Equation (1) is limited to natural gas pipelines and is not applicable to hydrogen pipelines. The pipeline diameter (d, m) and operating pressure (p, Pa) are utilized in Equation (1) to determine the potential impact radius (r, m):

$$r = 0.099\sqrt{pd^2} \tag{1}$$

Other studies have similarly correlated the potential hazard area with the pipeline diameter and operating pressure of natural gas pipelines [14,15]. However, there is a scarcity of research specifically addressing the potential impact radius of hydrogen pipelines. The American Society of Mechanical Engineers (ASME) has put forth a model for the potential impact radius of hydrogen pipelines, as articulated in Equation (2a,b) [16]:

$$r = 0.47\sqrt{pd^2} \tag{2a}$$

$$r = 0.068\sqrt{pd^2} \tag{2b}$$

It is to be noted that the only difference between Equation (2a) and Equation (2b) is the units. In Equation (2a), the unit of r is ft, the unit of p is psi, and the unit of d is inches. In Equation (2b), the unit of r is mm, the unit of p is MPa, and the unit of d is m [16].

It is essential to recognize that the previously mentioned models for the potential impact radius are predicated on the following assumptions [13]: (1) The direction of leakage is assumed to be vertical; this takes into account the fact that high-pressure hydrogen encounters obstacles such as soil, leading to the formation of a crater in the ground. This directional assumption is made because the impingement on obstacles dissipates some of the momentum, redirecting the jet fire in a more vertical manner. (2) A single point source model is employed to calculate jet fire radiation. This model simplifies the jet flame as a single point and neglects the influence of flame shape on radiation. It is to be noted that radiation is highly influenced by the flame shape. In the single point source model, the radiation is determined by the heat release rate and the distance from the jet fire to the point receiving the radiation. This means that as long as the heat release rate is the same, for the same position, the radiation from a relatively tall jet fire is the same as the radiation from a relatively short pool fire, which deviates from practical cases. Therefore, the assumption of the single source point is beneficial in terms of a quick calculation; however, it introduces inaccuracy in the radiation calculation, particularly for the near field. It is important to note that Equation (1) considers factors such as the incomplete combustion of the gas escaping from the leakage and the emissivity factor of the fire. (3) The potential impact radius model considers a hazardous event involving pipeline rupture, resulting in a double-ended gas release that triggers a fire immediately upon leakage. One should note that in real cases, it is possible that a fireball happens after pipeline leakage. And the assumption is that immediate ignition takes the fireball into consideration by calculating the sustained jet fire immediately ignited after the pipeline leakage [13]. However, the high-pressure leakage of the pipeline leads to a large jet fire which cannot be understood as one single point. And previous works demonstrated that a high-pressure hydrogen jet fire in the vertical direction is long in length and narrow in width [17]. Moreover, the accuracy of the single point source model diminishes as the target approaches the flame. Recognizing this limitation, various researchers, including the American Petroleum Institute (API) and Sandia National Laboratories (SNL), have employed a weighted multi-source model to predict the radiation from gas jet fires [18,19]. The weighted multi-source model takes the flame as a 2-dimensional flame which is similar to the shape of jet flames in real cases [17,19]. Compared with the single point source model, the weighted multi-source model divides the whole flame into parts and calculates the radiation of each part separately. The sum of all the parts is the radiation of the whole flame. Additionally, the combustion intensity varies in the parts, and a weight factor is used to consider the different contributions of each part to the radiation of the whole hydrogen jet fire. It is to be noted that in addition to the heat release rate and the distance from the flame, the radiation of the weighted multi-source model is determined by how many parts are divided and the weight factor of each part. Some researchers used a convergence study to determine the number of parts. Others used empirical values. The distance from a single part to the flame is influenced by the flame shape. In summary, by dividing the flame into parts, assigning the weighted factor, and calculating the radiation of each part individually, the weighted multi-source model allows for the flame shape.

Although the weighted multi-source model considers flame shape, it introduces complexities in the radiation calculations, impeding its widespread industrial applicability. Compared with single point source model (Equations (1) and (2)), which uses a linear calculation, the weighted multi-source model introduces integration and adds complexity. One should also note that many CFD methods incorporate the discrete ordinate method or the discrete transfer mode and the weighted sum of gray gases model to calculate radiation; these models are more complicated than the weighted multi-source model.

Therefore, as the potential impact radius is determined by radiation, there is a need for a new model to assess the potential impact radius to determine the high consequence area (HCA) for hydrogen pipelines. This study simulates the potential impact radius of hydrogen pipelines under actual conditions and proposes a simplified model based on the weighted multi-source model. This new model aims to enhance the risk assessment of hydrogen pipelines and to serve as a valuable reference for industry design.

2. Radiation Threshold for Potential Impact Radius

Based on previous work on the high consequence area, when the radiation is below the radiation threshold of the potential impact radius [13]:

(1) The people located outdoors when failure happens would be exposed to a low and finite chance of fatality.
(2) The property represented by a typical wooden structure would not ignite and burn, thereby providing indefinite protection for people indoors when failure happens.

The radiation threshold for a potential impact radius is 15.8 kW/m^2, accounting for the impact on the effect of thermal load on both people and property [13]. Assuming an individual is exposed to radiation for 30 s and would remain in position for 1–5 s to evaluate the situation and then run with a 2.5 m/s speed towards a shelter, the estimated distance of people traveling within this period is 60 m. It is assumed that a shelter is located within 60 m of individuals. Then, under 30 s of exposure, 15.8 kW/m^2 is the significant threshold leading to a 1% chance of fatality [13,20,21]. And when a wooden structure is exposed to 15.8 kW/m^2 radiation, spontaneous ignition is improbable, and piloted ignition will only occur after approximately 20 min of exposure [20]. Therefore, it is posited that when the radiation is below 15.8 kW/m^2, the wooden structures would not be destroyed and would provide indefinite protection for the individuals [13]. This 15.8 kW/m^2 threshold of radiation is applicable for hydrogen pipelines, as indicated in ASME B31.12 [16].

3. A Model for Assessing Potential Impact Radius

3.1. Equivalent Mass Release Rate

In contrast to other high-pressure hydrogen systems, the mass release rate of hydrogen pipelines diminishes over time as the pressure difference between the leaking pipelines and the atmosphere gradually decreases. For example, in the quantitative risk assessment of a high-pressure vessel of hydrogen, some researchers assume no pressure drop in order to provide conservative risk results [18]. However, in the long-distance pipeline quantitative risk assessment, the pressure drop cannot be neglected [13]. To account for this pressure decay, an equivalent mass release rate model is introduced. Initially, the mass release rate resulting from hydrogen pipeline leakage is calculated using Crane Co.'s model [22], which considers high-pressure leakage leading to sonic or choked flow, as shown in Equation (3):

$$(\dot{m}_{RG})_{max} = C_d A_h \left[\gamma P_1 \rho \left(\frac{2}{1+\gamma}\right)^{\frac{\gamma+1}{\gamma-1}}\right]^{1/2} \tag{3a}$$

$$\frac{P_2}{P_1} \leq \left(\frac{2}{1+\gamma}\right)^{\frac{\gamma}{\gamma-1}} \tag{3b}$$

where $(\dot{m}_{RG})_{max}$(kg/s) is the initial mass rate; C_d is the frictional coefficient and has no unit; A_h (m^2), which is calculated as $\pi d^2/4$, is the area of the leakage hole of the hydrogen pipeline cross-section; d is the diameter of the rupture, namely the pipeline diameter in the present work (m) [13]; γ is the adiabatic constant; $P_1(P_0 + P_a)$ (Pa) is the absolute pressure inside the pipeline; $P_2(P_0 + \rho_w g H_0,$ Pa) is the absolute atmosphere pressure; P_0(Pa) is the effective gauge operating pressure; P_a (Pa) is the ambient pressure; ρ (kg/m^3), which is calculated as $\frac{(P_0+P_a)M_w}{RT_1}$, is the ideal gas density; M_w (kg/mol) is the molar mass of hydrogen; R (Jmol^{-1}K^{-1}) is the ideal gas constant; and T_1 (K) is the temperature of hydrogen. By further considering the pressure drop and the double-ended leakage of hydrogen pipelines, as well as the integration of the release rate decay factor $\lambda = 0.33$ [13,23], the equivalent mass release rate $(\dot{m}_{RG})_{equ}$ is obtained, as shown in Equation (4):

$$(\dot{m}_{RG})_{equ} = 2\lambda(\dot{m}_{RG})_{max} \tag{4}$$

One should note that the decay factor is likely to represent a steady state of pipeline rupture when λ is in the range of 0.2~0.5, and some researchers report the decay factor of 0.25. More recently, the decay factor of 0.33 was used to provide more conservative results to ensure that the sustained jet fire radiation, as well as the potential influence of a fireball, was not underestimated. The value of 0.33 has been widely used in natural gas pipeline quantitative risk assessment [13].

3.2. Flame Radiation Model

The weighted multi-source model involves dividing the entire flame into N points and assigning a weight w_i to each point. The heat release rate P (kW) is calculated using Equation (5). The radiation of each point is understood as an independent part, and the radiation of part i is calculated individually, as shown in Equation (6). As shown in Equation (7), w_i is used because the intensity of each part is different. The total radiation of the entire flame is the sum of each point, as illustrated in Equations (5)–(9) [24,25]:

$$P = \chi(\dot{m}_{RG})_{equ}\Delta H_c \tag{5}$$

$$q_i = P\frac{w_i cos\beta_i}{4\pi D_i^2}\tau_i \tag{6}$$

$$w_i = \left\{ iw_1, i \leq 0.75\text{N} \middle| n - \frac{n-1}{\text{N}-n-1}, i > 0.75\text{N} \right\} \tag{7}$$

$$q = \sum_{i=1}^{N} q_i = P\sum_{i=1}^{N} \frac{w_i cos\beta_i}{4\pi D_i^2}\tau_i \tag{8}$$

$$\begin{gathered}\tau_i = 1.006 - 0.01171(log_{10}X_{H_2O}) - 0.02368(log_{10}X_{H_2O})^2 - 0.03188(log_{10}X_{CO_2}) \\ +0.001164(log_{10}X_{CO_2})^2\end{gathered} \tag{9}$$

where χ is the radiation fraction, ΔH_c is the combustion heat (kJ/kg), τ_i is the transmissivity, and β_i and D_i are the angle and distance between the point and the observer. Therefore, the flame geometry, including flame length and flame tilt, is accounted for as the flame geometry influences β_i and D_i. X_{H_2O} and X_{CO_2} are the proportional amounts of water vapor and CO_2 in the path. One should note that the transmissivity is constant through the whole flame in the present work. Equation (1) considers the incomplete combustion of natural gas, whose main component is methane. The minimum ignition energy and the flammable limits of methane are 0.28 mJ and 5% to 15%, while the minimum ignition energy and flammable limits of hydrogen are 0.017 mJ and 4.25% to 75%. Compared with methane, the minimum ignition energy of hydrogen is low and the flammable limits of hydrogen are wide; therefore, the combustion efficiency of the hydrogen jet fire is 1.

Various researchers employ different values for N. The American Petroleum Institute (API) uses N = 10 for hydrocarbon jet fires, while Miller et al. use N = 30 for hydrogen and syngas jet fires [19,26]. On the other hand, Sandia National Laboratories (SNL) follow the approach of Lowesmith et al., utilizing N = 50 [18,24]. It is to be noted that the values of N are given directly in previous works [19,24]. In this study, N = 50 is employed to ensure a more accurate and detailed result. It is to be noted that Figure 1 shows the validation of Equation (8). Figure 1 compares the radiation calculation results of the weighted multi-source model with the experimental data from previous works [27,28]. The x-axis is the non-dimensional length, which is defined as the ratio of x and the visible flame length. x is defined as the horizontal distance to the leakage point. And the y-axis is the radiation heat flux (kW/m^2). The hollow triangles in Figure 1 indicate the experimental results of Schefer, with the leakage diameter of 3.175 mm. The initial temperature is assumed to be 294 K, and the initial pressure is 15.3 MPa [28]. The solid dots in Figure 1 indicate the experimental results of Schefer regarding different times after leakage, with the leakage diameter of 7.94 mm and the initial pressure of 15.5 MPa. The gas temperature at the jet exit is predicted to be 258 K to 284 K. The radiation changes with time as the pressure changes with time [27]. In previous work, the visible, infrared (IR), and ultraviolet (UV) digital images of the flame were used to obtain the flame shape. The average flame length over five successive frames was then taken to discuss the flame properties and to provide quantitative data, and the visible flame lengths from the averaged visible digital images were used for the radiation calculation [28]. The curved lines indicate the results calculated by the weighted multi-source model. In total, 59 experimental data points from previous works are used to validate Equation (10). Nineteen data points are derived from the experimental condition when the leakage diameter is 3.175 mm and the initial pressure is 15.3 MPa [27]; these are the black hollow triangles in Figure 1. Additionally, 40 data points are derived from the experimental condition when the leakage diameter is 7.94 mm and the initial pressure is 15.5 MPa [27]; these are the green, blue, purple, pink, and yellow solid points in Figure 1. This comparison demonstrates that the weighted multi-source model effectively captures the characteristics of high-pressure hydrogen leakage.

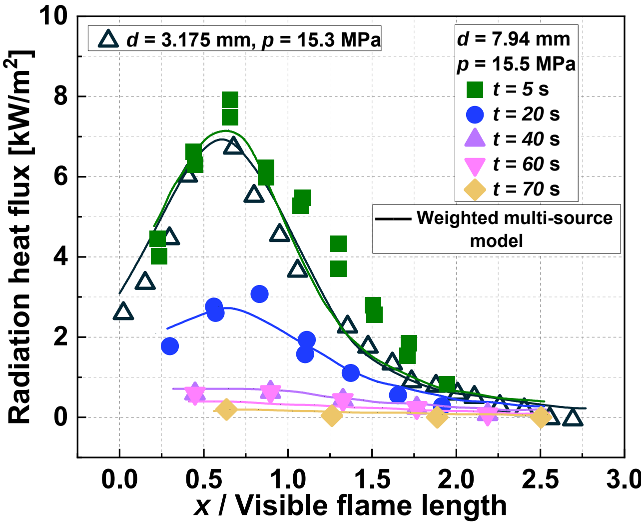

Figure 1. Comparison of weighted multi-source model and experimental results [27,28].

3.3. Potential Impact Radius for Hydrogen Pipelines

The potential impact radius (r) for hydrogen pipelines represents the horizontal distance from the leakage point to the location where the radiation reaches 15.8 kW/m^2. The radiation is calculated with the aforementioned model in Section 3.2, with the pipeline diameter varying from 300 mm to 610 mm and operation pressure from 2 MPa to 6.3 MPa. And the temperature inside the hydrogen pipeline is 294 K. A total of 60 cases were computed with Equations (1)–(9), as depicted in Figure 2. It is to be noted that these conditions encompass real-world hydrogen pipelines. All the conditions are shown in Table 1. The calculated values of the potential impact radius increase with the increase in pipeline diameter and operating pressure, affirming the applicability of Equation (8) for the potential impact radius calculation.

Table 1. Calculated conditions.

Operation Pressure (MPa)	Pipeline Diameter (mm)
6.3, 6, 5.5, 5, 4.5, 4, 3.5, 3, 2.5, 2	610, 600, 500, 450, 400, 325, 300

However, Equation (8) is relatively intricate compared to Equation (2), making it less suitable for swift industrial calculations. Consequently, a new correlation is proposed, as

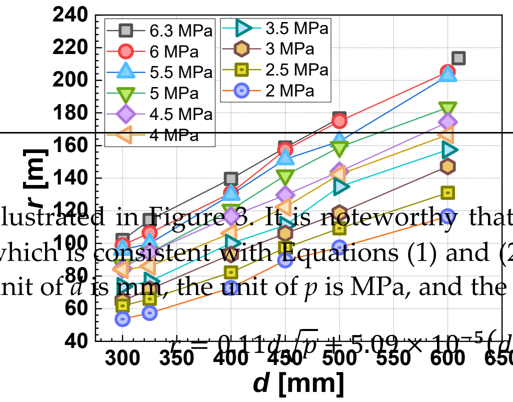

Figure 2. The potential impact radius calculated by Equation (8).

Table 1. ...ons.

Operation Pressure (MPa)	Pipeline Diameter (mm)
6.3, 6, 5.5, 5, 4.5, 4, 3.5, 3, 2.5, 2	610, 600, 500, 450, 400, 325, 300

However, Equation (8) is relatively intricate compared to Equation (2), making it less suitable for swift industrial calculations. Consequently, a new correlation is proposed, as illustrated in Figure 3. It is noteworthy that the characteristic factor $d\sqrt{p}$ is employed, which is consistent with Equations (1) and (2). It is to be noted that in Equation (10), the unit of d is mm, the unit of p is MPa, and the unit of r is m.

$$r = 0.11d\sqrt{p} + 5.09 \times 10^{-5}\left(d\sqrt{p}\right)^2 - 2 \times 10^{-8}\left(d\sqrt{p}\right)^3 \tag{10}$$

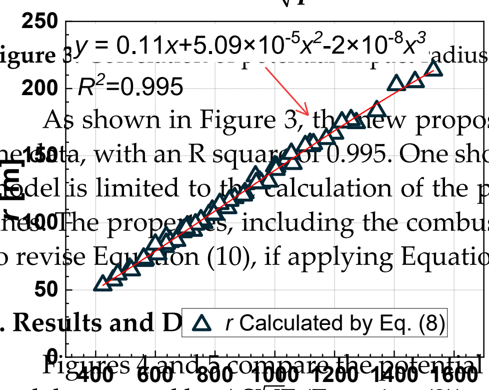

Figure 3. Correlation of potential impact radius (r) for hydrogen pipelines.

As shown in Figure 3, the new proposed correlation Equation (10) agrees well with the data, with an R square of 0.995. One should note that the applicability of the proposed model is limited to the calculation of the potential impact radius for the hydrogen pipelines. The properties, including the combustion heat and density of methane, are needed to revise Equation (10), if applying Equation (10) to natural gas pipelines.

4. Results and Discussion

Figures 4 and 5 compare the potential impact radius based on the single point source model proposed by ASME (Equation (2)) with the proposed model (Equation (10)). The x-axis is the diameter of the pipeline rupture. The y-axis is the potential impact radius calculated by the previous model (Equation (2)) or the proposed model (Equation (10)). Notably, no other work has been reported on the potential impact radius of hydrogen pipelines other than Equation (2). It is evident that regardless of the model used, for a given pipeline diameter, the potential impact radius increases with the rise in operating pressure. Similarly, for a given operating pressure, the potential impact radius increases with the augmentation of the pipeline diameter. Notably, the potential impact radius calculated by Equation (2) appears consistently smaller than that obtained from Equation (10). It is pipelines other than Equation (2). It is evident that regardless of the model used, for a given pipeline diameter, the potential impact radius increases with the rise in operating pressure. Similarly, for a given operating pressure, the potential impact radius increases with the augmentation of the pipeline diameter. Notably, the potential impact radius calculated by Equation (2) appears consistently smaller than that obtained from Equation (10). It is worth mentioning that the potential radius calculated by the single point source model has been reported to be significantly smaller than the potential impact radius in real-case pipeline leakages [29]. Given the absence of reported incidents of long-distance hydrogen pipeline leakage, the proposed model for the potential impact radius is validated using data from a natural gas pipeline incident published online. In this case, an Enbridge Corporation natural gas pipeline, with a diameter of 762 mm and a maximum operating pressure of 6.45 MPa, experienced a leak. The potential impact radius calculated using the point source model was 192.9 m. It is to be noted that the data were collected and measured by the National Transportation Safety Board, and the information on the incident was reported in Natural Gas Transmission Pipeline Rupture and Fire (Pipeline Investigation Report: NTSB/PIR-22/02) online [29]. However, the reported fatality occurred 195 m south of the leakage, and the furthest distance from a damaged structure to the leakage point was 335 m—both significantly larger than the calculated 192.9 m with Equation (1) [29]. Figure 6 compares the reported data with the potential impact radius calculated using Equations (8)–(10). In Figure 6, the y-axis is the reported or calculated potential impact radius. From left to right, the four bars in Figure 6 represent the calculated results of Equation (2), the calculated results of the proposed model Equation (10), the furthest distance causing a 1% fatality reported, and the furthest distance causing house damage reported. It is important to note that the properties of methane were employed in the proposed model to calculate the potential impact radius for the natural gas pipeline. Figure 6 illustrates that the results from the proposed model are closer to the accurate values compared to the previous model based on the point source model. As the definition of the potential impact radius is the distance where: (1) the fatality is 1% and (2) the structure could provide infinite protection, 335 m (orange bar in Figure 6, indicating the position where the structure could provide infinite protection) is used as the potential impact radius for the previous incident. And the accuracy of the potential impact radius is improved by 38%. This validation indicates that the proposed model aligns well with actual incidents, offering a simplified approach for calculating the potential impact radius for hydrogen pipelines. The results agree well with real-case scenarios and contribute to the improved risk assessment of hazard zones and pipeline design.

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By proposing models for the equivalent mass flow rate and utilizing a weighted multi-source model for radiation, a simplified model for quick industrial calculation is obtained to access the potential impact radius for hydrogen pipelines. The improvement and novelty of the present model are due to the consideration of the shape of the hydrogen jet fire, as well as the increase in the accuracy of the radiation calculation and the improved potential impact radius calculation. And one should note that Equation (10) is applicable for hydrogen pipelines. With more models and incident data reported for hydrogen pipelines, the further validation of Equation (10) would make an interesting future work.

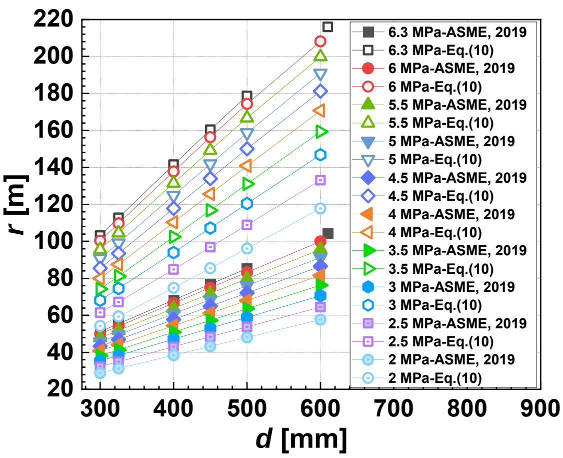

Figure 4. Comparison of ASME [16] (Equation (2)) and new proposed model (Equation (10)) for hydrogen pipeline leakage with the same pipeline diameter.

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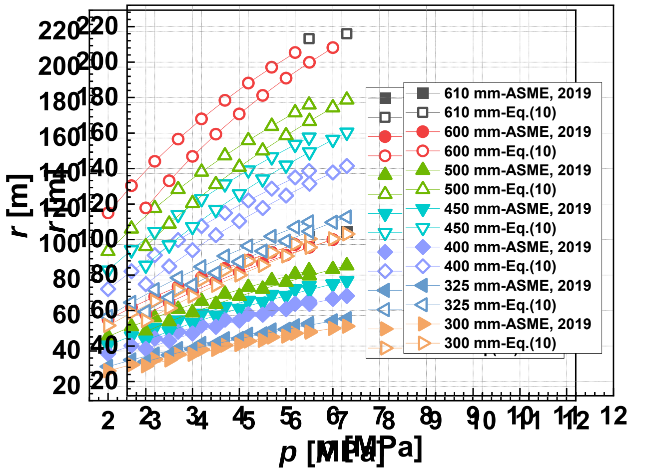

Figure 5. Comparison of ASME [16] (Equation (2)) and new proposed model (Equation (10)) for hydrogen pipeline leakage with the same operation pressure.

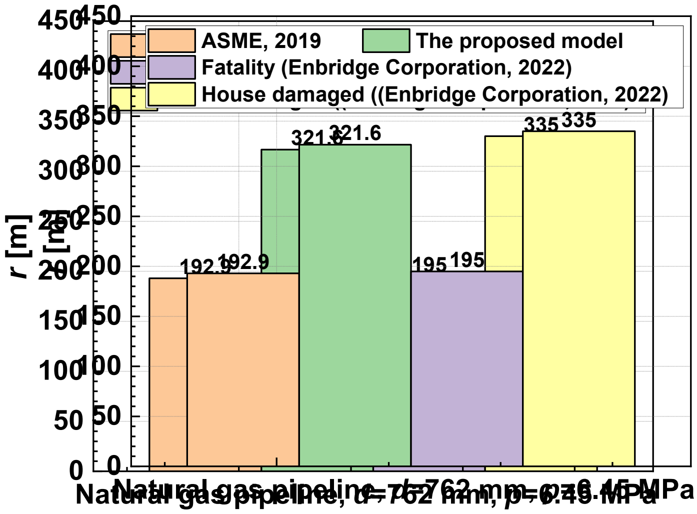

Figure 6. Comparison between the actual pipeline incident and the proposed model.

using models for the equivalent mass flow rate and utilizing a weighted multi-source model for radiation, a simplified model for quick industrial calculation is obtained to access the potential impact radius for hydrogen pipelines. The improvement and novelty of the present model are due to the consideration of the shape of the hydrogen jet fire, as well as the increase in the accuracy of the radiation calculation and the improved potential impact radius calculation. And one should note that Equation (10) is applicable for hydrogen pipelines. With more models and incident data reported for hydrogen pipelines, the further validation of Equation (10) would make an interesting future work.

5. Conclusions

The potential impact radius (r) serves as a crucial parameter in the risk assessment of hydrogen pipelines, delineating the horizontal distance from the leakage to the point where the radiation reaches 15.8 kW/m^2. Previous methodologies relied on the single point source model to calculate radiation, overlooking the impact of the flame shape. This study, encompassing 60 cases, introduces a novel model for the potential impact radius and considers the geometric characteristics of the jet flame induced by high-pressure leakage. The key findings include:

(1) A model for assessing the potential impact radius is proposed, including an equivalent mass release rate that considers the pressure drop of the hydrogen pipeline leakage, and a radiation model based on a weighted multi-source model;

(2) A simplified correlation (Equation (10)) is proposed to calculate the potential impact radius and to provide a reference for industrial use. The proposed model consistently yields more accurate results than the single point source model. The validation

(1) A model for assessing the potential impact radius is proposed, including an equivalent mass release rate that considers the pressure drop of the hydrogen pipeline leakage and a radiation model based on a weighted multi-source model;
(2) A simplified correlation (Equation (10)) is proposed to calculate the potential impact radius and to provide a reference for industrial use. The proposed model consistently yields more accurate results than the single point source model. The validation against an actual pipeline leakage demonstrates good agreement with real-world scenarios.

This work presents a model for assessing the potential impact radius of hydrogen pipelines based on jet fire radiation, supporting safety design and risk assessment in hydrogen pipeline applications. With more hydrogen pipeline information reported, more validation of the present work will be necessary in future works.

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Transcript

PHMSA Public Meeting 2022

Houston, Texas

Day 2

Tuesday, December 14, 2022

>> All right. Good morning, everyone. Or good afternoon depending where you are in the world. I understand we'll have some folks coming in from UK at least virtually. Want to welcome you if this is your first time here today. I know many of you were here yesterday to Houston. My name is Max Kieba. Director of program development. This morning we're going to start about a discussion of potential impact radius before we do for those in the room emergency rooms out in the hall. Silent your phones, bathrooms outside to the left near the big mirror. Let folks know particularly virtually we have just give a sense of numbers we have roughly well over 800 registered. Probably the bulk of our folks are dialling remotely so thank you to those that are on the webcast. Roughly just over 300 on the webcast. We probably have, give or take, 150 here in the room on any given time. And those on the webcast and many questions we've been asked here in person, the presentations will be available and recordings roughly within a week or two or so so they will be available. Those dialling via webcast, there is a link on the webcast for asking questions and please do. We are intending this to be interactive portion which we had some yesterday. We'll try to balance it out between questions here in the room and also on the webcast. And we'll do our best to answer as many questions as possible. But we also have a pretty hefty agenda overall. So we may need to cut it short at some point. But again we'll try to do as much as we can to answer questions. With that the first session is impact radius. Those here yesterday you heard from Sara at NTSB. This is particular portion, PIR initiated most recently from Danville Kentucky incident. Those that weren't here yesterday 30inch natural gas pipeline rupture August 31st, 2019. Out of that and many things NTSB does looks at a number of other incidents that perhaps has some other issues related with the potential impact radius or PIR. But out of that recommendation or out of that report came a recommendation to revise the calculation methodology used in PHMSA's recommendations to determine the potential impact radius of a pipeline rupture discussed in the report. Feedback is always a gift. Unfortunately, this feedback sometimes does occur when there are fatalities. In this case there was a fatality. 14 others damaged, fire burned, 30 acres of land. We don't always talk about the victims directly. But there is still a people aspect to this. One thing when I read the report was the human response part of it. And we'll talk about it in context of the calculation of PIR at least the baseline of it. But to that end I did want to acknowledge the one individual that did perish, Lisa Denise Derringer was 58. Semi truck driver. She enjoyed dancing. Being outside, working on her home, riding horses, caring for her dogs and donkeys, enjoying home improvements. But perhaps most importantly she was especially loved being with her grandchildren. So if you haven't had a chance to look at that report, please do. There are a lot of aspects and questions we will come up in this panel are the baseline of the PIR is it reasonable for some of the timing aspects. For instance, part of that report talked about aspects and Sara mentioned this yesterday but again if anyone wasn't here yesterday and this is in the report as well, but from NTSB's perspective PHMSA model assumes one percent

chance of mortality with one person finding shelter this mortality rate assumes a individual would take five seconds after fire to analyze the situation, decide to evacuate, run for 25 seconds at 2.5 meters per second and successfully find sufficient shelter from the ongoing natural gas fire. Determining the probability of human errors complicated when faced with a circumstance like a gas pipeline rupture. There's reference to Idaho national laboratory 2005. Also in the report the ability for a member of the public to respond following a gas pipeline rupture may be complicated by, for example, sleeping, being in interior room where one may not be immediately aware of a pipeline emergency or evacuation or eevacuating other household members who cannot self evacuate the speed with which the member is assumed to run is not general population including very young elderly, mobility impaired or those with preexisting medical condition. Two of the evacuees rescued during the incident by sheriff were both elderly mobility impaired I would say this part of the recommendation does also align with if it hasn't been mentioned yet among DOT strategic goals is looking at areas of equity. So hopefully part of this I will say honestly in the beginning we will probably give you a slow death by PowerPoint but part of that is we're hoping to give you at least a baseline discussion of where the PIR came from and kind of how at least PHMSA is implementing it currently. But then the next part we will also talk. So we'll talk natural gas first. There have been questions, it was brought up yesterday some other commodities like hydrogen are of interest, carbon dioxide. We'll talk about impact circle for for some of those. But we hope to go into a lengthy discussion about do we need to reconsider particularly align with the NTSB recommendation but also expand from there. Alan was here yesterday and mentioned part of why we do these public meetings are to help, one, help share some lessons learned which we hope to do that today but also kind of help building a record where we think we'll be going potentially, particularly in this case to help address an NTSB recommendation. So with that, we will get into the presentation portion. The first portion will be a gas PIR development background. It will be by Mark Stephens, senior engineering consulting with MJ Stephens Consulting to CFER technologies and Mark is affectionately called the father of PIR. I'll let Mark introduce himself more but he'll go to the background of potential impact radius PIR. Mark. And to our speakers, there's a clicker up here and also we will have timers in the back that look for signs that go up on different times five minutes to go, et cetera. Mark.

>> You're assuming I can figure out how to use this.

>> Big green button. Good morning. Thanks for the introduction, Max, I think you referred to what I'm going to say as slow death by PowerPoint. I will try to speak quickly and loudly to offset for that. Yes, my background is I've been working in the area of pipeline risk and reliability since the 1990s. And my company focus my previous company, my employer before I retired, CFER Technologies, did a lot of groundbreaking

development work in the area of quantitative failure frequency, prediction and consequence modeling, and the potential impact radius model that I'm going to talk about today was some of the modeling work that we had done back in the late 90s that lent itself to development of this simplified screening model that we're going to talk about in the presentation. I'm going to take you through.

So with that, I'll get started. So just to frame this, the Potential Impact Radius formula was something I developed at CFER technologies around 2000, it was for estimating the hazard zone resulting from a natural gas pipeline rupture and ignition.

Now, the models that I'm going to talk about are trying to idealize something that's pretty complicated. It's a timevarying largescale fire, and we're trying to turn that into a steady state, groundlevel point source heat emitter for the purpose of developing this model. So we're trying to take something very complicated and simplify it.

In the context of simplification I want to point out when the model was developed and the report that was produced, I worked hard to try and develop a model that would appear simple and easy to understand, because the idea was if people can follow it and understand directionally what it's trying to do, they're more inclined to maybe perhaps accept it. But I do want to emphasize that it does incorporate some factors that try to reduce the conservatism inherent in using this really simplified modeling approach to analyze something that's pretty darn complicated. And this is where the slow death by PowerPoint comes in. I'm going to subject you to a few equations. You are not to worry about the details of those. I'm just trying to paint a picture and then highlight certain aspects. So let it wash over you and let's go through it. Really three parts. There's a model that tries to figure out what the release rate. The gas coming out of the pipeline when it ruptures. By rupture, we mean fullline break where both ends every time pipeline are discharging gas into the sphere. And the release releases over time release rate. We want to take that and predict what the power or the heat energy per unit time is that's being released and lastly we want a way to relate the heat intensity to the heat you feel as a function of how far you away you are from the pipeline rupture. Starting with the effective release rate. There's an equation with bunch of factors let's not get too tangled up in it. The simplest way to talk about it within the rectangle is a equation classic formula for the mass flow release rate of gas coming out of an orifice. And that was our starting point. You'll see it depends on D, the diameter and P the pressure, and a bunch of other constants we won't worry too much about. Outside of that basic orifice discharge equation we multiply it by a factor of two because we've got two ends that are feeding gas into the atmosphere. And then there's this lambda factor. It's called release rate decay factor we're trying to take the initial release rate scale it back to a release rate that would be an effective representation of the release rate that feeds the fire over the longer team. Actually feeds the fire in the initial stage. Once we get that release rate we

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drop it into this other equation to work out the socalled emissive power. We take the release rate, multiply it by the heat of combustion, which says theoretically how much heat gets produced when this stuff burns. And then there's there's factor we tack on the end scales it back accounts for the fact that not all the heat that could theoretically be emitted gets radiated and felt by receptors at distance. We take that emissive power and stick it in a formula you'll get out of an undergraduate physics book predicts heat intensity I as a function of how far away you are from the point of release are.

And all the terms are defined except we've got this efficiency factor that we've attached, which scales back the heat intensity. And we're going to talk about where that comes from. But the idea is if you can get this equation that relates heat intensity and corresponds to the heat intensity threshold you're worried about. If we tick a particular heat intensity threshold to define the zone we get the PIR formula. And because all the terms inside this sign are constant except for science and pressure it collapses to this simple formula.

Now this slide, maybe not that easy to see, but some of the factors are highlighted in red. These are the coefficients or constants that over the past 22 years have received pushback from people saying where did that come from and why is that so low and that seems wrong.

What I want to do is go through first the factors that fiddle the release rate to get an effective release rate. I want to talk about this efficiency factor that scales down the heat energy. And last I want to talk about the heat intensity threshold that forms the basis for how you're supposed to use this equation. If you'll bear with me I'm going to hop through three things that will give you a better feel for how this thing was developed and what it's taking into account and what it's not.

So this plot on the vertical axis has release rate blue is time. Blue line starts high falls quite rapidly the units are seconds. 900 seconds is 15 minutes. So the first quadrant is the first minute. And you can see within the first minute the release rate falls a long way. It falls rapidly then it starts falling at a slower rate and it kind of tails off with a much more slower release rate decay. That blue line is a representation of what the actual release rate would be. It's using the model that's in the original GIR report from 2001, and I won't belabor it. But it is approximation to a numerical model that takes into account the stuff that matters if you're trying to predict a release rate coming out of a long tube. It accounts for the opening, assuming that gas is coming out of both ends without obstruction. It accounts for the density and temperature, the product. It accounts for the friction drag of the gas as it's trying to shoot along the pipeline that comes out. The drag slows it down. It affects the release rate, and it satisfies the equations of state that matter when you're trying to predict this kind of outflow. It's not the only model. I like this one because it's the one I originally referenced. You can look it up you can code it up in a spreadsheet and use it yourself because some of the newer models are really fancy and sometimes fancy just looks confusing.

What I just do now is the effective sustained release rate that the fire model uses. And notice it's not the release rate at the very beginning. It's not the release rate towards the end. It's the release rate within the first minute give or take. If I zoom in on the first two minutes, this is a plot what the release rates would look like over time for pipelines running at 950PSI at different diameters. Top line 36inch, 30, 34, et cetera. The dots are what we assume to be the release rate. The dots are the effective sustained release rate that the model uses. And what we were looking for is a constant that we could multiply the initial release rate by to get an effective release rate that would be equal to 30 seconds because generally these fires, when they ignite, do the most harm to people within the first minute because that's the time when people are trying to find shelter if they're outdoors or that's the time period steady state fire biggest and does the most time. What I'm suggesting here is by multiplying the initial release rate by the decay factor we've got a relays rate for big inch lines it's about the release rate 30 seconds in it conservative for smaller lines we could have come up with a fancier factor but we didn't we tried to keep it simple. Jumping to the thing that figures out how much heat energy gets radiated once we've got a release rate and we know the product. Now the model we used incorporates this thing called an efficiency factor comes out of another study by a company called Technica. That simple model was adopted by CFER, and it tries to address some of the conservatisms inherent in this simplified point source emitter model we built. Where the initial GRI report tries to stay high, talk about things in simple terms, not be labor things with details. The lack of detail has been a problem in terms of the feedback we've got in the model. But we had an opportunity in a report that I coauthored with Michael Baker Jr. company 2005 report with PHMSA looking at PIRs for other gasses. And what that report explains is that the efficiency factor accounts for three things, the fact that a highspeed gas jet doesn't radiate heat the same way that a flare does, and there's a reduction to account for that because most models are based on flaring. It accounts for the fact that the atmosphere, or more specifically, the moisture in the air absorbs some of the heat radiated so people don't feel all the heat because the moisture in the air is absorbing it. And last it accounts for the fact that what you see is what you feel and people do not see the entire fire. Large scale fires are opaque. You can't see the flames all the way through and you see things up in the air geometry effect is the view factor and this accounts for the fact if you modeled this as a fancy multipoint source radiator you would get a different answer than a single point source emitter to the ground. When you chain together all those factors you come up with something that is very close to the efficiency factor that's in the report it wasn't something that we made up. It was something adapted from a model that accounts for these things in a systematic way and it's explained in that 2005 report. If I stop there and say all right that's how we get the fire model, what's it good for in general terms. And we're suggesting that the models that I've talked about so far do form a defensivible basis for estimating the REIT intensity from a crater fire near immediate emission the line ruptures ignites almost right away. And it can be used to estimate the heat intensity as a function of distance. And the thing is I said crater fire, what's a crater fire. A buried pipeline if it ruptures, generally a joiner pipe gets blown out two ends sitting inside a crater discharging gas in opposing directions. So the gas jets impinge upon one another. Chew up some of the momentum and kind of get directed upwards. The crater walls redirecting the gas that's going sideways. So basically you get a vertically oriented fire. And the hazard zone for a vertical fire is a circle which is why the PIR is the radius of a circular hazard zone. But what about fires that don't look quite like that and the reality is that sometimes when you get a pipeline rupture, the ends of the pipeline get misaligned a little bit. Opposing jets do not impinge directly. They bypass each other. They hit the crater walls. They still go up. But you can still get a couple of distinct jets, which is a little bit different from the crater fire which is what the model is all about.

But what happens is if you get misshrinement and you get distinct jets, when you look at the thermal radiation hazard zone, it's more elliptical in shape. The areas about the same because there's the same intensity heat feeding the fire but the lateral extent is often reduced but the axial extent is extended because those jets have length. And in that sense, assuming everything is a crater fire is conservative when you're interested in how far property is away from a pipeline in a perpendicular direction but potentially it's not conservative if you're interested in the length of the hazard zone. But it's worth noting that the way that the PIR formula is used to delineate an HCA, addresses that to a certain extent if you go to HASMEB34AS or the regulations that shows you how to use the PIR to figure out what length of pipeline is in a highconsequence area it says you start from the beginning of the first circle and extends to the end of the last circle. I've drawn a bunch of circles where the assumption enough dwellings within each of those circles to qualify as an HCA. The assumption is the circles to the left or right of those do not have enough houses they would not be HCAs the black shading from the beginning of the first to the last circle is the qualified length of HCA. When you think about it from a theoretical perspective suchling hazard zones are circles and the high consequence is the center of the first circle to the center of the last circle. Not the start to the end of the circles. And that extra length extension effectively accounts for any axial extension you might get from directed jetting that effect is accounted for in how the PIR formula is meant to be used for delineating a highconsequence area pipe. The last thing I want to talk about which is something that Max has already introduced is the heat intensity threshold and where it came from and what it means. And the value adopted is 5,000 BTUs per hour per square foot. I realize that's a pretty abstract quantity. But what it is, based on some recognized models that assess the likelihood of fatalities, function of the thermal radiation dose received, is a 1% leeth a letter meaning one in 100 people exposed to that level of radiation would succumb assuming a 30 second exposure period. Which invites the question where does 30 seconds come from, Max suggested correctly the report says that it assumes five seconds to gauge the situation, figure out what's going on and decide to take action then a decision to move quickly at about five miles per hour two and a half meters per second. And the shelter will be found within about 200 feet. And if you're wondering where did all that come from the literature at the time, which was used for developing quantitative risk assessment models typically in the UK in the Netherlands and other places where people have studied this kind of suggested that two and a half meters per second was defensible escape speed for the average, an average member of the population and in developed areas that shelter would typically be found within 50 to 75 meters. We basically adopted that assumption of travel speed and distance to be traveled again based on national precedent for this modeling. It is not a conservative representation. It's meant to represent typical developments and typical populations. Now in terms of what does that heat intensity mean for property. The idea is that heat intensity means if you're at the edge of a circle a wooden structure is unlikely to ignite and burn and therefore will afford indefinite protection to people that are indoors. In fact, it assumes it will not catch fire for 20 minutes in the presence of a flame. And by 20 minutes, if your house starts to burn and you leave. The fire will be much smaller when you go outside and you'll likely be able to escape the area. Again it's based on a recognized model for how what heat intensity is required to cause wood to ignite and burn as a function of the relevant parameters. The implication is that people indoors are going to be afforded protection by the dwelling variant. If the heat intensity is at or below that. What does that mean in the end that this model is predicting? I'm suggesting it does suggest it's the area within which fatal injury is a significant possibility. And beyond which fatality is not a significant probability for typical members of the population. It's the area within which wood framed structures could be destroyed by fire. It is not the safe distance beyond which people and property are going to be minimally affected. And it is not the perimeter of an emergency response planning zone where you could stand and watch the event. If that's what you wanted it to mean obviously a different heat intensity would be employed. So that's kind of my pitch on what we developed what it's meant to me. People ask how accurate is it? What have you done to validate it? And typically the only information you've got after the fact is the extent of the burn zone. You go to measure it compare it to the radius try to decide whether it's a reasonable characterization. But the burn zone is not necessarily the perimeter of the PIR because some materials will catch fire or burn and discolor and die at heat intensity's lower than the adopted on heat intensity threshold which is meant for people escape and wooden structures. So vegetation might discolor or vegetation might catch fire but as you know if you light a brush fire and you leave it, it can spread. So a problem with using the burn zone is that it delineates the extent of the fire spread not the extent of the zone that was caused to burn by the fire from the pipeline rupture. However it's pretty much the only thing you've got to work with but you've got to keep it in mind when you look at incident results. And the original study we took the incidents that were available at the time, took the hazard areas, turned them into equivalent circular areas with an effective radius and we looked at the maximum perimeter distance to the burn zone and we compared actual to predicted. And without belaboring this plot, there's a unity line, the red diagonal line, if the data points for the real incidents plot to the right of the curve, the model is conservatively overpredicting the area if they plot to the left of the curve they're underpredicting. What it showed is the model consistently overestimated the total impact area or the total burn area but occasionally it underestimated the maximum extent of the burn zone but again keep in mind fire spread is an issue. And we felt that that correlation between actual and predicted suggested we had a defensivible model. It wasn't overly conservative. But we felt it was reasonable for the intended purpose. Now Steve is going to talk about fence's recent experience going out measuring recent experiences and comparing a more recent incident. I'll leave it to Steve. I'll mention one validation effort that I think is important. It's kind of hard to figure out exactly what's going on from looking at incidents after the fact. So what we thought we would also try to do is compare the models I've described in fact slightly modified version of those models that could be used for life safety risk estimation to what you would get out of a really fancy stateoftheart consequence model that accounts for all the things that this simple model doesn't. So we compared results obtained from the models I described which we'll call the variation on the CFER model to the results obtained from a program called Pipe Safe. Pipe safe the pipeline risk software it's now maintained by DMV out of UK. Pipe Safe contains a suite of models developed specifically for natural gas pipeline failure investigation calibrated against largescale tests, including, this is important, two simulated rupture events where they took a 36inch diameter pipeline 50 miles long, set off a shape charge in the middle measured everything how everything varied with time as a function of distance and that model predicted those two release events. So to my way of thinking the Pipe Safe suite is pretty much the gold standard for this kind of prediction. We wanted to compare what that model would predict to what this simple model would predict. Again, without going into a lot of detail we used it to assess two things. One would be the individual fatality risk for someone living very close to a pipeline model using the simple CFER models versus the fancy pipe safe software. It's normalized to account for the fact that, well, failure has to occur let's assume the failure likelihood ignition likelihood is the same for both models. We compared the results for the fancy analysis with pipe safe to the simple analysis with the CFER models. Again without going into painful detail on this plot, that diagonal red line the slope of 45 degrees, if the results plot to the right it means the CFER model was conservatively overestimating the individual fatality risk if it plotted to the left of the line it would be underpredicting. You can see with respect to individual risk, this model, the CFER model approach, was overestimating the individual fatality risk for someone living very close to the pipeline. The other thing we did was measure the total societal risk in expected amount of fatalities in population density. This table shows the results of three diameter pipeline with the pressures and the predicted number of fatalities from the fancy Pipe Safe and the models from CFER. You can see the expected fatality counts are actually very close. So this validation that we did about 2005 led us to think the modeling approach is defensible surprisingly reasonable in comparison to some other fancy other models. So I guess my position on this the models used and the assumptions made that underpin the PIR formula as it currently exists are a defensible basis for generic hazard zone estimation. We don't think there's anything wrong with the models or the approach. It comes down to the assumptions that you make and what you wanted to predict. And we're suggesting as well that the predictive capability of this formula is fit for purpose if your objective is general purpose consequence screening. And again the development focus was to delineate the extent of the fatality and property destruction zone for typically populated and developed areas. It is not to be interpreted to represent the distance beyond which no impact on people or property would occur. And if you want to account for that, you obviously need to change the heat intensity threshold which would impact the PIR. But it depends on what you're using the PIR for. What I want to conclude my slow death by PowerPoint with is to provide some comments on the four incidents that are managed in the NTSB report on the Danville incident, starting with the Danville incident itself and then talking about the other three incidents that are specifically mentioned in the NTSB report. So for the Danville incident, the yellow lines of the gas pipelines the center one is the one that ruptured. The pinkish reddish are PIR, and pinkish cells are occupied buildings and blue circles are nonoccupied buildings. And I guess my takeaway on this is when you look at the dwellings that were destroyed by fire, they all fell within the PIR. And if you look at the residents of the individual who succumbed to the event that person was located at about 300 feet from the pipeline at the start of the rupture event. So they were well inside the circle and unfortunately that, I think, contributed significantly to the fact that they did not survive. There were no fatalities obviously beyond the PIR no property destroyed beyond the PIR but there was property damage and there was injury to animals that were trapped where they were and could not get away. So again the model does not predict no impact beyond. It simply says this is the area within which the impact would be significant and fatality would be a significant concern. The report also talks about the assistantville rupture this figure is hard to interpret focus on the horizontal red line, this is the 20inch line that ruptured. There is in the middle a dashed red circle, that's the PIR for that 20inch line. And the yellow outline is the perimeter of the burn zone that was actually experienced. And from my way of looking at this, the area captured by the

PIR is pretty darn close to the area captured by the footprint of the burn zone. You'll notice it is a little longer than it is high. That's the axial extent due to the fact that there was directional jetting here. But it wasn't all that significant. And I think you'll notice as well it wasn't as wide as it is long, which is what I suggested would be the case for a directed jets as opposed to a crater fire. But on balance, I think the PIR's doing a good job of estimating the area within which significant damage and destruction occurred. The one incident that generates a lot of discussion about the PIR is the San Bruno pipeline rupture that happened in the suburbs of San Francisco in 2010. Eight people died in this event. It was a 30inch line that ruptured in a densely populated residential area. The PIR is the green circle. The white lines outline the property boundaries for all the residences. If they're red, the property was destroyed. If it's yellow, it was damaged. You'll notice destroyed housing extends outside the PIR zone, which raised some eyebrows and led to people to be concerned about whether the model is missing something. But when I looked at this, the key takeaway I found from the information on the incident is that when the pipeline ruptured it took out the water lines. So the fire department, which was within this circle was there within minutes but they could not fight the fire. They had to stand and watch the houses burn got to watch the debris from burning houses be blown by the wind in a northeasterly direction on to the roof of adjacent houses catching them on fire. The extent of the destroying fire by property there was no extent to fire spread because in this situation they couldn't get water on the fire for over an hour. And that is a significant contributor. And of course the model doesn't account for fire spread. It begs the question, should it? And if you wanted to account for that, how would you account for that in a way that's reasonable? Last incident very tragic pipeline rupture incident in Carlsbad, New Mexico, in 2000. 12 people died. The narrative in the report not entirely clear but the assumption is that those 12 people were camping where these vehicles are located. Which is outside the PIR. None of them survived. So this was a red flag that those people died outside the PIR. When you think about what happened, the PIR formula is meant, was originally developed based on generic assumptions about population. If there's houses there and the fire starts when they're inside, the dwellings will afford some protection for at least a certain amount of time. These people were thought to be sleeping outside. And at the time of the rupture they would have had no shelter. So their ability to figure out what's going on, react and move away is perhaps different from the assumptions that were made in the generic screening model. The reality is, if the situation is different, it invites you to revisit the underlying assumptions. But again it depends on what you want this model to do. And again it was set up for generic screening under typical conditions. If you want to set it up to approach things from a conservative perspective, it's going to dictate, perhaps, a desire to have the hazard zone delineated by a bigger circle, but frankly from my perspective if you're within the PIR you're at most risk. If you're worried about affording additional protection, perhaps the most effective way to achieve that is not make the circle bigger but lower the threshold for what's inside the PIR that would trigger the HCA status. And that's exactly what a moderate consequence area that PHMSA has introduced does. It lowers the dwelling count that triggers proactive integrity management. I think that's a more cost effective way to target areas that need higher levels of integrity. I'll now stop. I don't know if I put you to sleep but hopefully not. But if you have any questions or comments, I would appreciate them. I hope we've got some time for that, Max.

>> Yes, we do.

>> We do have a question online. Question comes from Michael Bets how many had spontaneous ignition compared to delayed ignition and how dramatically does the delayed ignition affect the PIR discussion?

>> Good question. I think the working assumption is that if a natural gas pipeline is going to ignite that ignition is almost instantaneous. Within seconds or tens of seconds. The process that causes ignition is not well understood but it's known that pipelines in the middle of nowhere will ignite. So the gas is not encountering an ignition source. It's spontaneous. It's either friction and sparking from debris or it's a buildup of static electrical charge or another phenomenon that's not well understood.

I think the frequency with which a pipeline ruptures has been teased out of the historical data but whether it's immediate or delayed has been very hard to determine because the information at the time is anecdotal. But I think most people would agree that ignition, if it's going to happen, is within the first few seconds or tense of seconds because natural gas goes up into the air unlike propane that might drift downwind encountering ignition sources gas pipelines don't ignite because they find an ignition source, they create their own. And delayed ignition would be associated with a smaller fire, and a smaller hazard zone.

>>

>> Thank you for the presentation. Linda Daugherty, I'm with PHMSA. I have to tell you that some of the pictures brought back some hard memories. I was at some of the incidence, Carlsbad being one. If you've been to an incident set like that. It has an impact on you. It sticks with you for a long time. My question has to do with one of the core intent as I understand it of the NTSB recommendation is the ability of people to evacuate. And so when you look at I notice your presentation original calculations were based on you said a European standard or a European approach people getting my question is, have we gone back and evaluated the truth of that because demographics change, people change. I'm just wondering, I think you present a very strong case that the radiant heat burn calculations are very have been truthed over time. My question

is, has the people aspect, the ability of people to evacuate has been that truth and more of a comment if I was in a house I saw through my front window a huge fire and shaking the ground would shake, I don't know that I would think, oh, I need to stay inside the protection of this house; I would probably book it, which would put me outside and subject to the heat. Just because your instinct is to run away, not to stay inside of a wooden house. Anyway. Thank you.

>> No, thank you for the comments. It's a very good point. In terms of validating the assumptions of how long it takes people to figure out what to do and what they do. I'm not aware of that being analyzed in a clinical basis for the incidents that have taken place. Just to clarify, the assumption is that if you're outdoors and you're awake, the assumption would be you will spend a few seconds to say there's a fire I'm going to run away. I think the assumption for people outdoors that they're going to start moving away within a few seconds is unreasonable. If you're indoors, your point is that, well, do they know they should stay? It's a fair point. I know that some people I'm familiar with in the UK who have developed the Pipe Safe software, which actually accounts for how long people as people move what dose do they accumulate, how long does it take them to get through doorways get downstairs, they too have thought about that a lot. And I shouldn't speak for them and I'm not sure all the information is in the public domain. But I think the assumption that they are making is that if you're looking out the window at a fire, if it's really close and your curtains are catching fire you're going to leave straightaway. But if you're indoors and it's loud from the rumble, it's getting hot, you're going to think about it for a while and you may or may not stay. I guess the reality, though, is if you think about it for a while, your house, even if it's going to burn, is going to afford protection for probably several minutes before you need to leave or become a fatality within your burning structure. But the assumption is that even if it gives you time to think and if your decision is ultimately to move then you will be experiencing a smaller fire than the fire that we're assuming here. But I don't want to suggest that the assumptions about five seconds two and a half meters per second shelter within seconds a few meters is the only answer. It's a construct that was meant to represent a set of conditions. If you want to acknowledge other scenarios, other exposure durations would be appropriate. But the human reaction component which is obviously important, I just don't have the information to point you to say five seconds is reasonable versus now that seems to be dated information. Although I don't know that Europeans would do things differently than North Americans. They do some things different than North Americans. But as for this I'm not sure. Not wanting to make light of that. But....

>> Wanted to piggyback on Linda's comment and let you know I enjoyed the presentation. Your last comment, when you discuss moderate consequence areas, obviously the code has been adapted to account for five structures versus high consequence areas. I'm not sure we did enough, though, to address outdoor activities. I

mean, we address roadways. We address reducing the structure count but we don't really change what we were previously doing on identified sites. Any thoughts on that? Do we need to go further?

>> Again, if you were going to do a detail risk assessment of an identified site, you would absolutely take that into account because that would be the prudent thing to do. If it's an outside area that doesn't have the shelter density that's assumed, those assumptions wouldn't be applicable. So a detailed locationspecific analysis would warrant taking that sort of thing into account. I guess it comes down to this screening tool uses a certain amount of information. If you want to refine it to account for different kinds of land uses and have different assumptions with respect to exposure period, that's fine. That puts a greater burden on people using this kind of approach to figure out what the PIR should be in that situation. It's simply I guess a tradeoff between the level of effort to collect the additional information and use it all the way along the pipeline versus something that's simpler for again general purpose screening, it all comes down to what you want this to do. Again I'm not standing here saying 30 seconds exposure is appropriate for everything. I think it's reasonable for typical developments, but there are certainly developments where it potentially isn't.

>> Anything else from the webcast. We're good. Thanks Mark for your presentation. It's great to hear from you on PIR again. And I was engaged the whole time so it wasn't death by PowerPoint for me. Couple of questions the first one it sounds like the PIR equation isn't addressing consequential events like damage to water main and fire spread but all are caused by the rupture itself. So when I think about PIR and the definition of PIR and the regulations intended to address significant impact to people or property and hearing from you that it's not considering those consequential factors that could take someone's home or take many people's homes it's a disconnect to me. I wonder how it should be addressed if it's not through the PIR equation.

>> Thank you, Sara. It's a difficult question. Thank you very much for that one. The fact that the PIR narrowly looks at what the pipeline rupture incident and what its heat does and doesn't account for what knockon effects might be or what other things might contribute I think stems from the fact that there's all kinds of things that could develop that would impact what the extent of the impact zone is. And I'm not smart enough to figure out what one could do to that to make it bigger by a certain amount to account for other stuff because it depends on what the other stuff is. The fire spread thing if you're talking about the spread of the grass fire if you capture the extent of the grass fire. And if you have fires in San Bruno, that's obviously a concern but to be in an urban setting where firefighting doesn't work, I would say is the exception rather than the rule. Do you want to revise the model to account for the exception or not. If you account for the exception, you are conservative. If you have the luxury of making conservative

assumptions and you can live with what the implications are of making that set of conservative assumptions then fine. But unfortunately because of cost and benefit associated with everything. So I don't want to suggest that nothing could make it worse because knockon effects can happen. But the situations that could precipitate various things that would make the impact a significant impact zone bigger are kind of hard to capture.

You'd either have to wing it and say we're going to make it such and such an amount bigger, and that's fine. I'm not sure how you justify the amount by which you make it bigger.

>> We have time for one more question I think on the webcast. Or give Sara a chance to

>> The other question, so a lot of the accidents that we've seen including well Danville and some of the recent accidents, they look like they were occurring near bends in the pipeline and in your earlier, the earlier part of your presentation, you talked about assuming linear structures which they're mostly linear but there are many bends. How do you reconcile that piece?

>> I guess the short answer is I don't. We assume that the majority of pipelines are linear. There are bends. And at those bend locations if you're unfortunate enough to be at a bend location, the potential for the directed jet to have a larger offset distance for impact, it could very well be. The model just is not that sophisticated or at least the way it was developed and what its intended use was wasn't to flag bends of areas that need additional protection. For the reasons you're alluding to, I think the argument could be made is yes, maybe more protection could or should be afforded there. But again, if you're going to say and we need extra bends and we need extras if the land use is this and that, it's going to get complicated. If you guys I'm not sure who the guys I'm talking, girls are, if that's the decision taken, then there's going to be a lot more work required to keep track of all this stuff.

>> A question online from Adele Dbiaso are your conclusions the same for hydrogen and hydrogen blends?

>> No. I think we're going to talk about hydrogen versus natural gas a little bit later. So if we could table that one, if that's okay.

>> Okay. Our next question is from Danyo Nivson in the Danville incident where does it occur in relation to the PIR?

>> Another good question. My understanding is that all the people that died were in or or around the rupture point. Sara might have more specific information but I think the NTSB indicated in some information I heard that everybody was well inside the circle.

>> Sara is shaking her head yes, so yes.

>> Thank you. Question from Carlos. Does the PIR model consider ambient conditions? Were the incidents discussed conditions of the day of the incident compared to the model assumed ambient conditions?

>> Right. So for jet and crater fires the ambient weather conditions are secondary. The air temperature doesn't have the big effect. The wind will tilt the flame a little bit but those are secondorder effects, kind of in the five or 10% one or the other. It assumes the typical set of assumption doesn't take into account location or doesn't take into account it could be windy cold or hot, those are secondary. If you look at vapor cloud dispersion and cloudy conditions then the wind speed and the wind direction and temperature matter but it's secondary for these fires which is why it's not part of the mix.

>> Last question I have, Nicole from Nicole Tebow. Yesterday we saw two incidents where ignition of the gas cloud was one or two hours after the initial release. Have we evaluated data on how soon the emission of a gas cloud usually occurs?

>> Right. So if the gas that is flammable is heavier than air, and that's when it drifts downwind and finds ignition sources and it can take time to ignite. But natural gas is buoyant, and it's being driven upwards by high momentum from the initial conditions. So the vapor that is flammable does not collect near the ground. It's up in the air. And so delayed ignition generally doesn't happen because the ignition sources that you're worried about would be in and around the ground but the flammable reach of the cloud is in the air. So again if you're talking about dense vapors that are flammable then delayed ignition is a significant concern. But for buoyant vapor like natural gas it's not something that's a concern. The biggest concern is ignition within seconds or is it delayed by tens of seconds or a minute or two. At least that's my understanding of where that's at. Am I dismissed?

>> For now. Thank you very much, Mark.
[APPLAUSE]
I do appreciate, I did die slowly a little bit there but I was reinvigorated by great questions and good discussion. And I appreciate Mark trying to convey what the PIR does and does not cover. We will have time definitely for more questions in the panel discussion. But the next presentation right now will be Steve Nanney, senior technical advisor with the Engineering Research Division is going to be talking about regulatory development and current implementation of gas PIR. If I didn't mention it earlier, too,

particularly folks on the webcast you might see some slight delays as we're transitioning. Now we have the new slides. I do want to say thanks to all the folks in the back supporting between the camera folks and the folks running the slides. I do appreciate it. Steve.

>> I'm glad you asked all the hard questions to Mark. And thank you Mark. One thing, just to say, Mark is from Edmonton, Canada. He had a long trip to come down here. I just want to say from PHMSA we're appreciating taking the effort to come. When I left here last night, I had something I had to do with my wife. That's go to a Houston Rockets basketball game. And I know we're talking about risk and all of that type stuff. And the Rockets haven't had a very good record over the past several seasons. But here lately they've been beating the top teams. So we've been talking about risk and reward and all of that type stuff. And I've been wondering, well, I was hoping for them to get the No. 1 draft choice. No you I guess I'm hoping for them to get into the playoffs since they've been winning. Last night they played the Phoenix Suns, one of the top teams in the NBA, and they beat them. The last time we went they played the Philadelphia 76ers and beat them. And then the game before that, they played the Milwaukee Bucks and beat them. After seeing so many losses over the past three years it's nice to see them win.

But with that, just to get to the more serious stuff, I'm going to be going over, as Mark and Max and some of the others have said, is just to give everybody an idea of what PHMSA's looking at on PIR. Just talking about a PIR and having a potential impact radius without having anything behind it, you don't really have anything. You just have a distance. It's like what Linda and Allen and others yesterday said where you've got a threelegged stool. You've got to have the public. You've got to have industry and regulators and in identifying anomaly or threat whatever you want to call it, you've got to have it in your program to go look for it, to indirectly assess it. What PHMSA has elected to do in the code as you go and look is to use inline inspection as the number one choice. That's also what NTSB and some of their recommendations has given to PHMSA. The other part is to assess it. You have to have criteria to go out and assess it. Whether that's a potential impact radius high consequence area, which is a higher bar, whether it's a moderate consequence area, or where it's criteria just if you're doing a dig and it's not any of those. You've got to have criteria of what you do when you go out. That you have a certain level for all three of those areas that when someone goes out and looks at it, they've got to meet that bar. And as you've heard others say, there's been recent rulemaking that we've done that we think from a PHMSA standpoint has raised that bar. We've also done things such as the valve rule that's come out, is when I hear Mark, I hear Sara from NTSB, and others, and we talk about how far it spread. Well, if you've got a fuel source and it just keeps being a fuel source, then you're going to have a fire that spreads. Isn't that correct, Mark? Fuel source. And so we've put regulations in place as far as having valves in place whether remote controlled, whether automatic shutoff valves that close in a certain timeframe. So PHMSA through rulemaking has tried to do things to address the issues on this topic. It may not be perfect, but it's a step process of getting there.

So what I'll be going through today is giving you have an overview of I think we've got a helicopter coming over [helicopter noise]

But giving you an overview of some of the ruptures that we've seen, what our accident investigation group has gone out, what they've measured as far as being the impact area where the pipe has actually gone. And how long it's taken to shut off this area, which we think are all of those are factors in assessing. So with that, I'm going to start and go through the presentation. It works. Good.

The first thing is I'm going to talk about is gas transmission ruptures. 2017 to present. The reason we started at 2017 is that's when the PHMSA A group was put together and they've started going out on accident investigations. I didn't try to change it because I was trying to not put something in there. The next item I will talk about is identifying high consequence areas. And the definition of a high consequence area and the methods, whether it's method one or method two. Then I'll talk a little bit about the potential impact radius, how you calculate it. The PIR versus pressure and diameter, and then gas transmission mileage. How much mileage is on HCA, how much in a moderate consequence area, versus all the other pipeline mileage, then we'll go back to the PIR and just do a summary of it. I hope everyone can see this slide. This slide sheer is sort of to show you from 2017 to present, as far as all the various accidents that PHMSA has gone out and evaluated, I do not have an operator associated with it. I mean, we have that information. But that's not the intent. Also I haven't listed whether it's a high consequence area moderate or no consequence area or it's out in the middle of nowhere with nobody around it. But here's the things I want you to see. I've heard a lot of various things. But let's just look at the line here that's got PIR. You see right here in green, I put it in a different color for the intent so you could see that. Well that's PIR based on what Mark and others have been talking about. Doing the calculation of pressure versus diameter, which in the code pressure means MAOP. The maximum allowable operating pressure of the pipeline. Then you come over and you can see the various PIRs. And then I also put in a PIR based upon the pressure at the time of the failure. And what I did is I went back to our aid group, and I said tell me where this is located. Tell me if you have a compressor station, it's a point A and it's going to point B as the next compressor station or the ending of the pipeline, where, between that, did you have the rupture? And so what we did is we estimated what the pipe pressure if we didn't have it at that point we estimated it based upon that length and the discharge pressure versus the pressure at the section site of the pressure station. So these

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numbers here are actually what we think the pressure at the failure point is. So there's also a PIR associated with that. And I've heard a lot today as far as Danville Kentucky. And let's just show Danville Kentucky. It had a PIR I think Mark said it was 633. I rounded it up said it was 634. That's very immaterial in it. But if you look at the pressure drop going out of the Danville compressor station, I think it was about just a few miles outside the station. I forget how far it was. You can see that it had an impact based on where it was located of 630. We're showing the impact area based upon measurements that our group took was 704 feet. That's about 10% greater than the 634, the 630. Also had a width of 645. And here's another key point. It ejected pipe about 600 feet away. And then you come on over. My point here would be the oscillation time was an hour and 52 minutes. And I just picked that one out because I've heard everyone talking about Danville yesterday and this morning to show you. But what I tried to do also is show you others where it's exceeded the PIR. If you look down, we've had two in 2022. One was Union Town Alabama one in Pennsylvania, and you can see they were slightly over. But less than 5% over for both of them. You can also see the pipe ejected on one 72 feet, the other 304 feet. So sometimes the pipe goes right, very close to what the PIR is. Most of the time it's a lot less. And the same thing of what Mark was talking about earlier, was on fire duration, oscillation time. If you look, the points here where we just got a dash, there was no fire. And you can see there's one, two, three, four, five, six six of these seven teams there's no fire associated with it. The others there was a fire and you can see what the fire duration was.

And I've looked at these to see if there was any correlation between oscillation time and fire duration. Sometimes it seems to be. Sometimes it seems not to be. Like here's one that the oscillation time was two minutes. But the fire duration was over two hours. So I just wanted to put this up to give everybody an idea of what PHMSA is seeing. If you look, about over 80% of these, the PIR estimated based upon the present calculation in the code, it was under it.

There was, like I said earlier, three of these that it was over, and just slightly. The Danville was the most. And it was about 11% over. The other thing is the potential impact radius was developed for high consequence areas. We're also now using for moderate consequence areas too as we've discussed. And again it was put in in late with 2003. And it's in part 192903 in the code. And also the PIR calculations were based upon the CFER model as we talked about earlier. And again, just going back to the others, if you look, I know Mark talked about the 5,000 BTU per foot intensity threshold. And also if you're looking at wooden structures, the 5,000 would either go down to 4,000 or 3500, something in that type neighborhood.

All right. The next item is Potential Impact Radius. I just want to talk for a minute as far as what a Potential Impact Radius is. If you look here, again, it's in subpart 0, and it's used for high consequence areas. And it's the radius of a circle within which the failure of the pipeline could have significant impact on people. And the Potential Impact Radius area uses the PIR. As far as identified site, I know I heard people talking about it. What is identified site. If you look, it's an area open structure that is occupied by 20 or more persons on at least 50 days in any 12month period. And again it's also a building that is occupied 20 or more persons on at least five days a week for ten weeks in any 12month period. And then it's a facility occupied by persons who are confined or of empowered mobility or would be difficult to evacuate. In other words, hospitals, prisons, schools, day care facilities, retirement facilities, places like that.

And I know I heard earlier someone asking, should we have an increased PIR for those areas because people probably cannot get out in 30 seconds. I think we've heard that comment. And it's a fair comment. And as far as the next item as far as potential impact circle or PIC, PIR, whatever term you want to use for it. For lead natural gas the radius is calculated by .69 times the pressure times the square root of the pressure times the diameter squared of the pipeline. With R being the radius of the circular area in feet. P being the maximum allowable operating pressure of the pipeline. The reason I'm pointing that out is as a natural gas pipeline moves from point A to B the pressure drops. The only way it would not drop would be if you had it closed in on both ends of the pipeline. But as it moves and it flows gas, the pressure's going to drop. Normally you're probably going to see about five pounds per mile pressure drop. That's why you'll see compressor stations on transmission lines being about 50 to 60 to 70 miles apart. They're looking at somewhere around a 300 or so pressure drop before you compress it back. So five pounds may be if you're feeding a city it may be ten pounds. But the point is you're going to have pressure drop as you go. And the diameter is the normal diameter of the pipeline in inches. As far as what does this use, there are other areas that are used as far as defining a high consequence area. If you look here you can see a class one, class two, class three, class four location. A class one location, which is here, and here at this area is 10 or fewer dwellings within a mile. In other words, a very rural area like what we're showing here. A class two location is 11 to 45 dwellings. And again it would be as shown here you would have subdivisions being built around it but more spacing than a class three or four. And then a class three would be 46 or more dwellings or occupied sites. And a class three would be an area where you may have schools. As you can see here and homes built around the pipeline. And then a class four is where you're in a downtown type area with buildings with four or more stories around it. This picture here is in Manhattan where there's a pipeline, transmission line that goes into Manhattan. That's what it's illustrating. So there are pipelines in class four. Not as much mileage but there are some. As far as identifying high consequence areas operators can choose from two methods. Method one is based on class locations and it includes all class three and four locations. Also any area in a class one or two location where the impact radius is greater than 660 feet and the area within the potential impact circle contains 20 or more buildings intended for human occupancy, or any area in a class one or two location where the potential impact circle contains an identified site. So an identified site would make a pipeline an HCA whether it's in a class one, two, three, four, area. Some other items to consider, this is just giving you an overview of examples of method one. Again, if you look here, where you've got more buildings, highrises and things built around, it would be a class three or four. In other words, 46 or more dwellings for human occupancy. A class one or two would be areas where again you would have 20 or more homes buildings around it. PIR and you can see identified sites around it. And three and four if you're using method one would be an HCA. If it's a class one or two you'd have to look to see if it's an identified site. Our method two is based upon using the PIR. And it's any location on the pipeline with a potential impact circle containing 20 or more buildings intended for human occupancy. Or identified site. And you can see, whoops... you can see here 20 or more buildings intended for human occupancy or identified site. And just an illustration of this is on the next slide. This shows you an identified site here. And how, as Mark had shown earlier, how the PIR for the HCA actually projects out. Also, for method two, when you're looking at the PIR and you're looking at 20 or more dwellings, this is an example here where, if you look at the top here, it's got the MAOP of 1200. The pipe diameter is 36 inches. We've calculated the PIR here is 861 feet. And again these circles slide as long as you've got 20 dwellings in this circle, then you just keep moving the circle out and it becomes the HCA. Another item to consider as far as PIR and the methods would be what would be the PIR for various pressures and diameters and also the class location unit. And I'll just start with the class location unit. If you look here, you'll see the red line. Again, that's the six hundred 60foot foot from the pipeline. You class homes for class one, two, three, four location based upon distance on either side of the pipeline for sliding mile going down the pipeline. So you're looking at that's what you're looking at when you're looking at class one, two, three, or four. But to give you an idea of what the PIR gives you, is what this is showing and let's just start with the 42inch. If you had a 42inch operating at a thousand pounds, you can see you would have here's the pressure, a thousand pounds. And here would be the PIR.

It would be about a thousand feet. Maybe a little bit under a thousand feet. Again, now then let's go down to 8inch. An 8inch at a thousand pounds would be somewhere under 200 feet. For these different sizes, we made this chart just to give you an idea of how the PIR changes based upon pressure and based upon diameter. And then going to talk about moderate consequence area. Moderate consequence area or MCA, again, it uses the potential impact radius. And it's five or more buildings intended for human occupancy. Right here. And then any portion of a paved surface including shoulders of a designated interstate, other freeway or expressway as well as any principal roadway with three or more lanes. And another item one 97210 if you look there requires applicable gas transmission MCA with maximum allowable operating pressure of over 30% specified minimum yield strength to be periodically reassessed every 10 years. So it does have in the code where you have an MCA you do have to reassess it every 10 years if it's FGL. As far as the mileage, as far as being in an MCA, HCA or in neither, this is a breakdown. If you look let's start, first of all, with the HCA mileage. You can see here we've got about 21,000 miles of HCA mileage. In the new rulemaking that's come out in the past two years, you can see MCA, whether it's allowable not allowable or RLI able here. There's about 19,000 miles of MCAs that you can run an LI tool through. So when you add these up, we're at about 40,000 miles of transmission pipe that would be evaluated on a periodic basis. Whether that was every seven years or every 10 years for threats. And you can see all the other that's outside of those, as you can see here it's about 257,000 miles of 301,000. But again the definition of MCA would be five dwellings or more. And HCAs, if you're using method two, would be 20. Just in summary, potential impact radius is used to determine high consequence areas. PIR is used to determine the mileage and moderate consequence areas. Again, there's two methods for determining HCAs for gas transmission. Either using class locations or using PIR. I know earlier we were having a discussion on various locations that had ruptures and fires. But the key part is how much was around them. I know like Danville that we were talking about, when it happened, I think HCAs was all that was in the code. Now we have MCAs, which is five dwellings or more. So areas that we were not picking up before, we will be picking up with this addition to the code. As far as again what I had gone through earlier, some of the other items you have to look at is just because you run an ILI tool, you've got to have a bar that's consistent for everyone. What PHMSA did, we went in, if you look here, seven 12 and 714, we strengthened the repair criteria for nonHCAs, if you look at the code previous before we strengthen 710 and 712 there wasn't a defined requirement of when and how to repair or remediate whatever term you want to use anomaly outside of an HCA. So what we've done is we've added requirements for MCA similar to HCA requirements were a couple years ago. The only thing we did we gave operators up to two years to do the repairs. Also we've added for MCAs to do assessments, if it's ILI applicable, every 10 years. After initial timeframe in the code. The other thing that we've done is on anomalies outside of HCAs and MCAs, we've got criteria there for remediation, which I think that's raised the bar for everyone. And then again if you look at the impact, as I've stated earlier, the impact for the HCAs and MCAs is about 40,000 miles. Again, just going back to what we talked about before, and I tried to highlight areas where we've seen, where it was from the potential impact radius based upon the MAOP, whether it was the length, versus the length of the impact area versus pipe ejected, and all of the ones that I've highlighted on the length of the foot, the pipe ejected on the impact area and the pipe, where it's been exceeded you can see again as I've stated earlier, three locations out of 17 and here where the pipe went further was two locations out of 17. And again this is going from 2017 to 2022 has been the case that PHMSA has evaluated. As far as fire duration, I know here we've got that. We have got the valve rule that has a 30minute or less timing as far as shutting off anomalies on new pipelines. You can see here some of the fire durations were quite long and also as far as oscillation times for some of the sections. If you look here here's an hour and 21 minutes an hour and 35 minutes an hour and 12 minutes, two hours and 12 minutes. An hour and 52 minutes. Three hours and 23 minutes. Two hours and 25 minutes an hour and 26 minutes. So we've got a lot of them that were over an hour to oscillate. The reason I was pointing that out is I know yesterday we were hearing about SMS. I think tomorrow Allen Mayberry will be talking about SMS. Operators that participate in SMS should be looking at items such as this and making where they've got areas such as this and looking at the oscillation times. They should not take the code to require you to do it where we have to put exact language. Operators should be doing that on their own accord when they do a risk profile of their pipeline. The reason I was pointing that out is again part of the three legged stool is everyone doing their part. So PHMSA expectation is for operators to be doing that. Again, thank you for listening to me. And if you have any questions, I guess I'll turn it over to Max and others. We have a question from online from Charlie Child's, what parameter are the impact area length and width burn area structures damaged?

>> Say that one more time. What parameters for the impact area length and width burn areas structures damaged?
>> First after all, the areas I have on impacted is actually what we measured in the field. When our inspectors went out it's actually the impact area that I'm showing on length and width is actually what we measured when we went out on the field and looked at it.
>> Thank you.
>> Can I sort of echo the question. When you guys were measuring those businesses did you measure to the edge of the burn zone or did you measure to anything that was damaged? Like what were those distances to?
>> I think it was to the edge of the burn zone.
>> Burn zone. Thanks.
>> Yes?
>> Thanks, Steve. Garrett. Just for wanting to make sure that we have all the right facts, the Danville incident, just right out of the NTSB report is actually 56 minutes for time to isolate on that section. So I wanted to point that out. Maybe there was an error on your slides.
>> Thank you.
>> Thanks. Okay.
>> Thanks for your presentation, Steve. It's really interesting to hear how the regulations apply and what role PIR plays there. You know, thinking back on the

Carlsbad accident that Mark mentioned earlier and the 12 people that died outside of the PIR, six found dead and six that survived initially, later circuming to their injuries. The PIR and regulations it seems to me there might be room for relooking at that definition but from your presentation I wasn't sure if that was your view as well or if you think MCAs cover the concerns with PIR there.

>> Well, first of all, if you look at HCA areas where it's 20 or more, what the five in the MCA does will extend out the evaluation area that you're looking at. So let's say if normally you had 20 and it would stop at some point, as it goes down that whole area that you'll evaluate and assess will be larger. So from a standpoint of what you'll be assessing, it will be increased and should get a larger area in the areas that Sarah that you've been talking about. So I think part of it, yes, will cover that. Whether PHMSA wants to go further with it, we'll have to go back and look at that and we'll be coming back to the public and everyone when we decide what we're doing there. So that will be something we'll be letting everyone know as we go forward.

>> This is Allen from PHMSA. One of the reasons we're talking about this today is, you know, certainly we not the least of which we recently received an NTSB recommendation related to PIR but, you know, here we're gathering information from you all having a conversation and it's fair to say while we don't have I guess an active rule making docket that includes this, you know, it's up for consideration. We're exploring options right now. So we're open is what I'm trying to say.

>> Thanks.

>> I have a couple of questions online. One is from Jason Lambert. But I believe his question is covered by Bill Norton's question. That is, Steve, on your slide showing PIR in impact area you note three areas with an impact length longer than the PIR. What do you mean by impact area or length? Is this the area where structures were destroyed by the direct influence of the failure or does this area include secondary damage such as fire spread?

>> It would be in the ones that I have here I don't think there was fire spread anywhere. It would be the burn area. You're talking about fire spread such as San Bruno. San Bruno was not included here.

>> Again. So, Steve, a question. I know that you've worked a lot with our European colleagues on a variety of topics and also our Canadian colleagues. I'm curious do we see similar types of regulatory approaches related to PIR in Canada and in Europe? Or maybe Steve or Mark or Max or anybody. I'm just curious what others are doing in this area.

>> Do you want to answer it?

>> I do have some perspective on what the Brits do. They have a concept of a building proximity distance, a BPD. They use that to determine development exclusion zones and there's another distance that's sort of what the Americans are doing with the PIR. It's not based on PD squared but it's very similar relationship and when you overlay the

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number of BPDs that trigger the kind of attention that the PIR does here, there are strong similarities. I'm not aware of other European jurisdictions that use that which is not to suggest that quantitative risk and explicit consequence analysis doesn't get used because it does certainly in Britain and The Netherlands there's an established precedence for rule making and decision making based on risk. So they are obviously looking at a consequence analysis that would be a fancier version of what the PIR does. More like what that pipe safe model does. But, again, it's not distilled down into this simple formula to side a circle. The closest analog is the distance in the UK.
>> A question online I believe was directed towards Mark. Could depth of cover be considered in revising one's PIR. For example pipelines and depths greater than 10 feet or HDD pipe.
>> That's a good question because the operating assumption is that pipelines are at a typical depth about a meter, yard below the ground. If they're deeper the tendency for the crater to redirect everything straight up goes up. And of course if it's a directional drill way down below the ground it's kind of hard to imagine how that rupture manifests at the surface. But we don't or people do not typically take into account the impact of deep burial depths on how the hazard zone looks. But, again, I think you would be more inclined to get a vertically oriented flame as the crater gets deeper. Which is what the crater model assumes anyway.
>> How is it going to burn with no oxygen. That was just a comment that was made.
>> Of course when it reaches the surface it makes it so the fire may not actually start until it comes above the ground.
>> I had a maybe Steve can help too. Maybe to educate the public a little bit too. A lot of what we learned this morning was definitely at a technical basis behind PIR and others. Steve can you touch on at the end of the day they become a negotiated rule making. Maybe Steve can talk about some of the aspects that might go into a rule making or maybe when PIR was first put into the rule but other considerations.
>> Well, as far as any rule making and when we put in the MCA we have to go back and look at what Max was saying, negotiated or cost benefit analysis and any time we put in rule making the valve rule, any of the repair rules, MCA, others, we go and look at a cost benefit as far as whatever standard we're trying to put in, whatever repair, remediation conditions, what that cost will be over a time period and what benefit it will be. So what he's asking is anything we do here whether we're increasing the PIR, whether it's 10%, 20% or some number, yes, we would do a cost benefit. It would have to go through a regulatory process where it would go through the office of management and budget. They would do an overview if it was cost beneficial and we would not be able to get anything through that did not pass that. So that's how we do on all our rule making unless Congress and the authorization makes it authorized in the rule making that we get from the law we get from congress.
>> Any other questions from the webcast? Or one here from the room.

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>> Good morning. Alan with AGA. This is a question for Mark, possibly. Within the model what's the relationship between that exposure time that we talked about at the heat intensity threshold and PIR? I think you talked about it being like a 30 second. So for sake of argument if that was to be doubled to 60 second I presume that would not double the PIR. What's the relationship there?
>> Yeah. It's not proportional so doubling one doesn't double the other. I'm probably not in a position to do the arithmetic on the fly but if you go to the GIR report there's a table that gives you what the dosages or the heat intensities would be for the assumed exposure time. So you can actually work that out from the table directly. But I guess obviously if one's contemplating a different heat intensity threshold tied to a different exposure period one would want to know what that translates to in terms of distances. It's raised to a power less than one I would think is what the answer is. So it's going to be attenuated somewhat just by virtue of how the equation is structured.
>> And just to add to that, if you go to the PHMSA website and how I get to it, I normally Google or one of the search engines put PHMSA pipeline technical resources, and I go to gas integrity management and to the technical page of that and it will have the paper that Mark is talking about. It will have the calculations and show you that if you're wanting to look to see what the variation would be. I know a while back ago I had looked at it. What Mark is saying is what I had come up with too. It wouldn't be one to one. It would be less than that. And normally if you're looking at doing that there's a table in there that has like whether it's 5,000 that you're looking at BTU or 4,000 for like a wooden structure. It has a listing of times as you go down the list. So there is a table that would answer your question.
>> I'm seeing no other questions. So we'll go into break. It will be slightly more than 15 minutes. We'll go to 10:00 central. Thanks to Steve very much for the presentation and questions.
>> [Applause]

>> If you're on a panelist for the next portion right after break just come ahead on the table and we'll talk about CO2 and hydrogen from Mark and then go into panel discussion right away.
>> [Break being taken until 10:00 a.m. central time]

>> Ladies and gentlemen, we begin in about two minutes. Could I ask you to please move back towards your seats. Thank you.
>> Just a reminder, panelists if you're on the next session please come up. We'll go into panel after Mark's presentation.
>> All right.
We have 10:00 central on the dot. Thanks everyone for coming back and the great questions in the first part. I want to let you know in the webcast if we're looking at the

floor there's a monitor here is we're not looking at Alan's shoes. We have a monitor so just so you know. There was a question about hydrogen and carbon dioxide pipelines, what we regulate with gases and other liquid phases. So we asked Mark to give perspectives on potential impact radius or potential impact area for both hydrogen and carbon dioxide pipelines and then we'll go right into a panel session with both covering additional topics from the morning and also more on this. So, Mark.

>> Thanks, Max. Hello again. Welcome to death by PowerPoint part two. Yeah, I'm going to give you sort of my perspective on things to think about when trying to develop or update PIRs for hydrogen and carbon dioxide. It reflects a lot of the work that I was involved in when I was with CFER technologies because we have been looking at quantitative consequence modelling for project. There was a project looking at building simplified models for fancy analysis for a wide range of carbon products for a new design approach going into the 2023 edition of the Canadian pipeline code. So that is going to inform the remarks I'd like to make today as well. To jump in, I'd like to paint a picture of hydrogen the product in contrast to natural gas and then I'd like to talk about carbon dioxide in comparison to natural gas and hydrogen. So starting with hydrogen, hydrogen like natural gas is lighter than air, so it goes up, doesn't want to stay in the ground. The hazards that you're worried that has simply implications for hydrogen like natural gas would be fires and explosion. The concentration range of hydrogen gas in the air that's of concern, between 4 and 75% hydrogen is a mixture that will burn in the presence of an ignition source. That's a wider range of concentrations than would burn for the case of natural gas. It's also important to note that hydrogen is classified as a high reactivity fuel in comparison to natural gas which is actually classified as low reactivity. The energy required to ignite hydrogen is way lower than the energy required to ignite natural gas which means it's going to be more susceptible to spontaneous ignition. And another important consideration is when you ignite a hydrogen flame the rate at which the flame speed runs through the flammable cloud is way higher than it is for natural gas and that has implications for over pressure. Turning my attention to carbon dioxide unlike the other two products it's heavier than air. So when it comes out of the pipeline it hugs the ground. It's not flammable which means what you're left with is an asphyxiation hazard and a toxicity hazard. The concentrations defends if you're talking about asphyxiation or toxicity. You have to cut it in half before the fatality risk becomes significant. Which means that you've got to have more than half of the mixture that you're breathing made up of carbon dioxide for it to pose a fatality risk. However, there's a body of literature that would suggest that in addition to being that it has to be a hazard. It's something we exhale, it's in the air but concentrations above the typical concentrations although way below the concentrations required to asphyxiate it has a physiological impact on the body. It will lead to unconsciousness and stop breathing. Which means the toxicity hazard is generally perceived to be the governing hazard. If you look at the Internet you can find sources to suggest that carbon dioxide is an

asphyxiant. There's other things on the Internet. It's a toxicity hazard is important. I believe the debate is not settled as to what concentration thresholds can lead to fatality due to the toxic effects to the asphyxiating. It's not flammable so the other parameters that I talked about for hydrogen don't apply. What I would like to do now is sort of compare and contrast the hazards that can develop when you get a rupture of a pipeline transporting natural gas versus hydrogen versus carbon dioxide. I want to do that using what's known as an event tree. But if I'm going to subject you to that I better tell you what an event tree. So an event tree is a graphical representation of a sequence of events that has to occur to lead to an outcome. If events do or don't happen the outcomes are different. You have an initiating event and other possible events that constitute branch points. If this happens then that. They call it a tree because if you look sideways it looks like a tree because the events downstream are branch points and hence the reference to an event tree. So if we talk about pipelines transporting flammable gases, natural gas and hydrogen the initiating event we'll say it's a pipeline rupture and the subsequent events that are of interest is does ignition occur and when does it occur. So in the event of pipeline rupture, if you have immediate ignition you have one set of outcomes, if it's not immediate ignition and you get delayed out come or delayed ignition then it's another outcome and if delayed ignition it's another outcome. Regardless of whether you're dealing with natural gas or hydrogen, in the event of a pipeline rupture you're going to get what's known as a rupture pressure pulse. It has nothing to do with ignition. It's simply the fact that this highly compressed gas is no longer confined by the pipeline. It comes exploding out of the pipeline and expands rapidly and that high speed release and expansion pushes the air out of the way and it effectively creates a pressure pulse that you can hear and you can feel. If you're really close it's going to knock you over or do even more harm but that pressure pulse tends to die out pretty quickly with distance. In the event of immediate ignition when the flame starts to burn and then runs through the flammable region of the crowd or cloud you're going to get an ignition pressure pulse. And if the immediate if the ignition is immediate you typically get this expanding ball of flame that rises into the atmosphere, that would be the fire ball which rapidly transitions to what's known as the crater or jet fire that you typically associate with this type of incident. If you don't get immediate ignition but delayed ignition there's now an established flammable vapor cloud up in the air which when it ignites and the flame runs through that vapor you're going to get an ignition pulse and a very short lived flash fire that collapses into the jet, the crater fire. And in the event of no ignition you get an elevated vapor cloud. If we're talking about natural gas, history has shown that that pressure pulse is not negligible but not a governing hazard. It's overwhelmed by the radiation from the jet fire or the crater fire and that's the hazard that's being addressed by the PIR formula that you'll find in federal regulations and in ASMBE318. In the case of hydrogen, the same stuff happens but if we skip straight to the end and ignore pressure for a moment, the fire ball

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decaying into the sustained crater fire or short lived flash turns into a crater fire. That's what people think you need a PIR formula for, and you do. I'm note sure if all of you are familiar with the fact that there is a PIR formula for hydrogen. It's in the ASME hydrogen pipeline design standard B3112. Now it's presented and called the PIR although the way they use it is slightly differently from the way it's currently used in the integrity management rules. They don't cite the source for that model but I am familiar with it because it's sort of my fault. Back in 2005 when I partnered with Michael Bacon, junior on a project to develop PIR formulas for other gases, that report included a model for hydrogen releases. And the hydrogen formula in the Baker report from 2005 is what's made it into the ASME B standard. That work was done on evidence that flame that was prior to 2000. The reality is that information is out of date. There were no large scale hydrogen fires, no attempts to simulate hydrogen releases from buried pipelines until the past 10 years. And that information paints a somewhat different picture of hydrogen in the event of high speed release in complete combustion, et cetera. The formula in ASME B31.12 is out of date and needs to be updated as it relates to crater and jet fire hazard. However I put question marks on the pressure pulse due to rupture and ignition. Shock tube tests have shown that the pressure pulse from the gas release because the velocity of the hydrogen coming out of the end is so fast, that pressure is bigger than it is for a comparable pipeline transporting natural gas and the ignition pressure pulse that you get is also going to be higher because, again, hydrogen is a highly reactive fuel and the flame runs through the flammable cloud way faster, the pressure pulse is going to be higher. That needs to be looked at. I'm not saying that it's going to govern. In fact I doubt that the rupture pressure pulse is going to be that big of an issue but the potential ignition pressure pulse might be big enough to have an impact on what the potential impact radius is. And I'm not saying that that will be the case, it's just I have not seen information in the public domain that clearly lets you dismiss the over head pressure for hydrogen ignition. When you get to carbon dioxide, you still get that rupture pressure pulse but it's going to be comparable to natural gas or less because typically the CO2 is being transported in a dense phase. It's the flashing from this dense phase fluid to vapor that is going to generate that pressure pulse and that pressure is going to be lower than it would be for natural gas. Because it doesn't ignite what you're left with is a vapor cloud but because CO2 is heavier than air that is going to hug the ground. You have a ground level vapor cloud where the concern is asphyxiation and toxicity. If we look at and compare the hazard zones you get from a sustained or crater jet fire, which is what you have for hydrogen and natural gas and compare that to the hazard zone you get from CO2 the cartoon is meant to highlight a few things. For thermal radiation hazard the release rate designs the size. The gas composition and the flame that results in the density of the fluid is going to effect things and your heat intensity threshold. One of the things we've been talking about this morning is going to be on the table. You have to have all that stuff to be able to work that out. If you're

looking at carbon dioxide, the release rate matters to diameter and pressure matters. The concentration threshold that you design as hazardous be it for lethality you have to look at is it toxic and what levels might lead to fatality as what might be the result from concentration to cause asphyxiation. You need to know where the cloud is because where the cloud is where the hazard zone is. That's very much influenced by wind speed and direction, very much influenced by the atmosphere stability class which is how the atmosphere mix the gas with air as it spreads downwind. You care about the terrain, in particular how rough it is. If you release this dense vapor on a Tarmac the downwind extent will be greater than if you release it into a field with tall grass because the tall grass acts as a friction drag thing to hold up the spread some the rougher spread. So the rougher the suffer face the less the vapor cloud spreads and the shorter the downwind distance is. Last but not least dense vapors seek low points. So the elevation profile is potentially a consideration. So there's unfortunately more stuff to think about if you're doing a hazard zone analysis for dense vapor clouds. Now with respect to wind speed and direction, atmosphere stability class and terrain roughness you can do a fancy site specific analysis but there is precedent for doing this at a relatively high level in a generic sense with typical assumptions about wind speeds, typical assumptions about atmosphere stability class and typical assumptions for terrain roughness. So you can do a fairly generic type of analysis for CO2 using representative values for those parameters. That would probably be the way you would carry out an analysis for, quote, screening purposes. I put an asterisks on there because we were involved in a study that looked at dense gas dispersion in the context of a consequence screening analysis for the development of the safety class system and I've referenced the paper that came out quite recently that talks about and compares and contrasts the hazard zones for CO2 pipeline dispersion and the hazard areas compared to the fire hazard zones. Even though fancy models, numerical models are run to do the analysis regression analysis was used to turn them into PIR type formulas so it might be of interest to look at. Dense gas dispersion models are complicated. If you try and take elevation profile into the mix it gets even more complicated. You have to use computational fluid dynamics to be able to count for the terrain elevation profile. So if you want to do the full meal deal there's lots of fancy analysis required and the terrain or elevation profile consideration really does complicate things and it's going to make it very location specific. Last comment I'm going to make before I turn things over to the panel is if you use the thermal radiation hazard zone models like the ones we talked about you get this, quote, radial distance. The assumption is the radius defines maybe a circle in which the bad things happen. If you look at the downwind extent to these vapor cloud hazard zones and you call that a radius, and if you then treat that as a circle, you're over estimating the impact area because it's not a circle, it's the pedal of a flower. So the actual hazard zone area is not figured out by using that distance as the radius of the circle. It's the downwind extent of this shape that looks more like a football. If you use it as if it means the same thing as

the PIR for thermal radiation it's apples and oranges. So when you're working out how you're going to use that information to build a, quote, PIR you got to think about flower pedals versus donuts. So I will leave you with that as a background. I'll turn it back over to Max and we'll go from there.
>> Thank you, Mark.
>> I stole that. Sorry.
>> If anyone does have questions we'll first do intros of our panelists that joined us but if you have a burning question, use a different term, about hydrogen or carbon dioxide Mark will definitely field it. With that we're going to into our panel portion. It do want to is introduce some additional panelists that have joined us on stage left, house right. Bill Caram, executive director of pipeline safety trust. We have John Wolfgram and then Andy Drake vice president of integrity for gas transmission and midstream. I want to give them five minutes to introduce themselves, their perspective on PIR for both natural gas specific but also potentially CO2 and hydrogen. So, Bill.
>> Okay. Is this on? Working now? Delay. How about now? The green light is on. There we go. Okay. Yeah. Thanks, Max. Thanks, Steve and thanks Mark for a great discussion. I introduced myself yesterday so I'll skip that introduction and the introduction of the pipeline safety trust. I want to, you know I do really appreciate the NTSB's recommendation on this by looking at PIR on this nonconservative nature and the human factors that play into it. I really appreciated that walk through from Mark this morning. It really is remarkable how such a complicated concept was distilled down to such a simple formula. It's really impressive. I would say from the public's perspective, you know, rather than the of course the math behind the calculation, the public's concerned about the definition that's in the regulations, the area where a pipeline's potential failure could have a significant impact on people or property. And I think the public's perception of what a significant impact could be is probably different than what the calculation is calculating. I think they would be surprised to learn of what would be expected of them in the event of a failure in the time it would take to recognize and how fast they would need to run and things like that. So I think there is room to look at those assumptions and the calculation from the public's perspective. And I think there's the potential for the to find a calculation that more accurately reflects that qualitative description in the regulations of significant impact. We're also realistic about the outcome of anything like that. We saw the mileage on HCAs and MCAs that are subject to those extra safety standards and integrity management and I think any adjustment to that calculation is probably going to have a pretty modest impact on that mileage that's under integrity management. So I think what it really comes down to from the public's perspective is really about public awareness and public engagement. I think both of those programs from an operator are probably going to look different to a member of the public who is within that potential impact radius versus outside of it. As far as CO2, I think, you know, there are much more dramatic effects possible with new

calculations on CO2 as Mark just outlined because it can move so far, so much further than what any kind of current calculation measures as we saw in Mississippi that I think we are talking about some more dramatic potential effects on mileage of pipeline that would be subject to integrity management and other safety factors. But it's also really important on public awareness and public engagement and then I think extremely importantly is emergency response and making sure that communities that would maybe otherwise be considered too far away from a pipeline to be potentially impacted are prepared for an emergency response. Yeah. So I think looking at PIR for gas is probably a relatively simple questioning of the assumptions. CO2 obviously much more complicated. So looking forward to the discussion.

>> Thank, Bill. John.

>> Good morning again everyone. John Wolfgram with the national association of pipeline safety representatives. Like any good conference you have some ideas when you show up and then you maybe come up with new questions as you continue the discussion. I think through the kind of the lens at least from the state perspective looking at obviously we're talking about PIR potential impact radius and that really kind of lands on the transmission pipelines as I kind of went through yesterday we do regulate those. Lots of those are often negotiated with distribution piping that we have in our states. I did a quick dive into data. Since 2010 states have experienced about 500 gas transmission related incidents. Around 12 of those are incidents where, you know, damages were seen outside the PIR area. So just a little perspective on where that is. You know, then that is certainly not minimizing the impact that all 500 of those can have on people, property and the environment. You know, one thing I took away this morning was we have that calculation, you know, that was based on data based on evidence, based on practice and I think maybe some of the questions I have as we kind of discuss this further is do you change the calculation, do you change kind of the basis on for how the PIR is defined or do you utilize the current definition or calculation and maybe change where you apply that. You know, do you change counts, do you broaden the area in which that definition gets applied to. We talked a little bit about that with the MCA, you know, definition that we have in the regulation. Thinking about accidents and incidents primarily we have integrity management, we have PIR calculations and all that good stuff but the end of the day we you know, we have gas distribution accidents that happen where it's a totally different side of the house but I think we can really have some equal comparisons there that, you know, go back to emergency response. So if you do have a release, you do have an accident, the amount of time you can minimize where you have glow blowing gas, where you have that product being released I think that's where you see a lot of impact as well. Certainly we see that in the gas distribution world with what we see in states. Certainly in the areas of CO2, I think a lot of the pipelines that states are going to be familiar with are going to be interstate pipelines. I still think at the end of the day there's a lot more questions, there's a lot more we need to look at

there as far as the impact that these can have on folks. Thank you.
>> Thanks, John. Thanks, Max. A little bit of background on me, why am I up here. I was the ASME chairman of the standards at the time with B document was developed. That was the document that actually drove the development of the PIR and Mark and I met each other 20some years ago when we were much younger trying to think through how to provide consequence guidance to operators. Inside if you you know, I think really from a standpoint of the ASME document, that document was written on how to manage integrity management, how to do integrity management everywhere. It doesn't differentiate between high areas. That became codified later. The document was developed in the context of trying to provide guidance to operators of how to do integrity management everywhere. It gave a PIR to help people quantify assessments so they could do assessments at some point. I sit on the advisory committee for rule making and have sat on that committee for quite a long time including at the time this was adjudicated back in 2000 when we were vetting about the section O document which the B31.8S became a heavy information base for what later became section O of the code. So those two are very closely related. So ASME was generated and used to fuel the conversation that became section O of the code. So I sat on the advisory committee to PHMSA about creating section O of the regulations. So those two are heavily interconnected. I think that the really interesting thing I appreciated Mark's conversation and Steve, I think you really get a sense of how deliberate the effort was to try to provide a credible consequence model that was practice and conservative. A lot of data was as Mark eluded to a lot of data was used to look at the fire patterns we had, litmus test the model. Steve indicated since then we've been doing kind of an on going check model, you know, so our PDCA model is working and I think this is a part of the PDCA model. Here we are again, we have more data. It's prudent for us to come back together and again and check it, check this data, do we need to act and make some adjustment to what we're doing. I think the thing that may help, it provides some context in this discussion is kind of back to B31.8S. The purpose of the PIR was really to help operators get a sense of consequence to try to provide some credible model of what impact might look like in the interest of working progressively through their whole system. So we've done ACAs and people said, okay, we're done. We're not done. There's MCAs. People go, oh, we're done now. No we have LCAs. It's just a series of tranches that we're going to go through to get to the whole system. The question that I think has to happen is how long will it be until we get to the next tranche, so 12 years ago when HCAs and MCAs and maybe take another 10 to get to the rest. So what's the value proposition, you know. Okay. We're going to get there. You know, is there a certain fingerprint that we're learning that we need to get to that's urgent I think is relevant in this conversation. I appreciate the effort to center on facts. Getting centered on what is the basis of the model, what is happening inside and outside, how it was designed to work. It was never intended as an exclusion zone. And I think that's really

important. I appreciated Mark's wrestling with the effect. At the time there was fires in California. We could burn down a county that starts a fire that keeps knocking, knocking, knocking. How do we model that? We can't because it would be chaotic and unhelpful to everybody. So we tried really to look very deliberately at the immediate impact and tried to make some conservative assumptions about radial damage and things like that. But I think that the sense that I have out of it is inside the PIR is a high consequence, high risk event in the face of a failure. There that's why we call them high areas. That's why we call it an area of concern is if you're in that zone that is a high risk event. So we need to be very focused on that. Outside that area is not a no risk environment. It is a different risk level where structures and time can give you some opportunity to, you know, prevent or mitigate lethality. But I think the real key in that conversation is heat intensity threshold. Okay. If we want to change heat intensity threshold what you're saying is how far outside the HCA do we want to look to get them in that higher consequence area, that higher lethality consideration. So it's really I think the delta that we're talking about here is in what I would say call LCAs if we say ACAs, MCAs, LCAs, the next, if we want to pass a revised PIR through the LCA we would just be saying how much further out do you want to look of I think the thing we want to lay out is is the juice worth the squeeze. We're going to get to LCAs next. It's just when and is that interim time not acceptable risk that we're carrying until, you know, we can get there with this revised criteria. So that to me is how I see this conversation sort of boxing out. But it's a great conversation. I do think hydrogen is a different animal on many fronts. Not just mylergically. We should be thoughtful in how we put hydrogen in steel structures and should be thoughtful how to model that impact or that consequence. Thanks.

>> Thanks, Andy. I'll start off. Any questions? I have a whole bunch. John has one.

>> Hi. Thanks. John Study with liquid energy pipeline association. Picking up on Mark's presentation as a foundational question is how to label this zone or area for CO2 pipeline. Potential impact radius is not only the wrong term but a bad word. If you had a radius of 100 yards picking up a number you would leave out the town down the road. No CO2 is going to flow a mile uphill. How do you when we're picking up on recommendations of encouraging people to do more and better modelling or to do more and better out reach how do you get the correct zone or area and you're not sending them to the wrong places or taking money from the right places to give to the wrong places if we're going to misapply the PIR term to CO2? What would you suggest we call a potential impact zone or potential impact area or how would you have us do this?

>> I don't have the acronym in mind but I'm certainly cognizant like I brought that point up and you amplified it. The maximum extend for a downwind vapor cloud is not the same reach for a fire hazard zone. When one does work out a PIR type of formula to get you to the maximum downwind extent there needs to be another later on top of that to figure out how to use it in the context that's consistent. I don't have the answer at this

point in time but I'm just concerned that it shouldn't be treated the same way. And I'm equally concerned about the fact that to the extent the elevation profile factors into it, and you eluded to that, it makes it even more complicated and location specific. And currently the standards try very hard not to impose too big of a burden on the pipeline designer or the operator at certain stages in the design and management process for fancy out flow modelling and consequence analysis whereas we're kind of getting into an area that suggests, well, if we want to change that it's really going to have implications. So I think care has to be taken in how you define that distance and how you use it to figure out what the area is and how you actually count houses in proximity because it's not a straightforward process. At this stage I'm simply saying that needs to be sorted out along with the modelling of the dispersion characteristics as well. So, yeah, very different for CO2. And I don't have the answer yet but we and others are working on it.
>> Yeah. I might just add in the next session this afternoon we'll have our colleagues from engineering research talk more about CO2 including one project we have on looking at PIR. So Lynda.
>> So thank you. This meeting but also a lot of policy decisions, discussions have just like opened up Pandora's box in my mind. I keep thinking, oh, what about this or oh, what about that. Mark one of your diagrams just kind of put a light on it. I don't know if we can go back but the slide in which you showed the PIR with the circle, the donut versus the pedal leafs.
>> Yeah.
>> So I immediately thought, oh, natural gas pipelines donuts and CO2 pedal leaf. Then I thought what about ammonia? What about CO2? What about propane? Propane has the if you have a rupture of propane you have a vapor cloud and it can move like CO2 does, you know. The whole setting off the flame to set off the vapor cloud. So then you've got PIRs, the whole question of what about PIRs for propane. So right now we're looking at what about PIR or PIR requirements that we currently have in place for natural gas, what about propane, CO2 and hydro's ammonia. Do we need to take a bigger picture look at all these different aspects?
>> Maybe I'll try and answer that first. It's a very good question. You brought forth an issue that we had to wrestle with in the joint industry research project. Remember I said we did consequence modelling to support the development of this new alternative design approach to go in the Canadian pipeline code. The idea was it was going to involve explicit consequence modelling everything covered by the code. Natural gas, propane, butane, sour gas, multiphased pipeline CO2. Natural gas has hazards that are circled on the break point. CO2 has flower pedals with the center of the flower centered on the break point. Propane is a mix. You can get a jet fire from propane. You can get a flash fire from propane. So one is the circle, one is the power pedal. So our approach is we need a weighted average of those that reflects the likelihood of having the vapor cloud fire or the vapor cloud explosion or the jet fire. And then what you end up with is

this weighted average hazard zone because the alternative is the outside worst extent. And if you have the luxury of doing this worst extent analysis, fine. But in practical terms, given the implications for managing the assets and correctly estimating how likely it is the weighted average for all the different shapes and hazards is what we ended up with which becomes a bit abstract because it's not the worst of the bunch, it's the average of the bunch based on how likely they are. Explaining that and selling it gets more complicated. But I mean that's the road we went down. So in the upcoming Canadian edition these zone area estimates are weighted averages of the hazard zones from all the hazards that could develop given the release and the distances for figuring out the house counts are also weighted averages. I guess devil's advocate some people are going to say isn't there a hazard that could be bigger. Yes. But in the context of how we're using this analysis, we're using this weighted average approach. So, yeah, HVPs, propane and butane are nasty because it's a mixed bag of what can happen and the hazard zones have very different shapes. It gets complicated.

>> From the general perspective we have lessons learned. For CO2 it's a different animal. It's not liquid, it's liquid like in transportation if you're talking super critical. If the public doesn't know super critical is a different pressure and temperature, above 1070 PSI and above 88. When you play with those numbers you would get into a gas state, you could get into a liquid state and solid state. So that point I might transition a question to Steve on plume modelling has come up. Can you talk about the regulations looking at modelling for HCAs in a liquid context that might be applied to CO2?

>> If I can get this to is this working?

>> Yeah, you're on.

>> I'm on. Okay. As far as in the liquid code which would be part 195, you have to look is it on?

>> It's off.

>> There it is. It's on now. You've got to look at the dispersion modelling. No matter what type liquid it is, whether it's CO2 or even in HVLs and things like that. I know some of the models that have been used and some that are probably being used for CO2 would be the aloha model would be one and DNB PHSAT model. There are other models being used for dispersion and everything. When you look at an HCA you have to look at the could effect area. So you may have an HCA and then you've got to go down and look at the whole area that the product can go to. So that's why if you look at the mileage and the liquid side about half of the pipeline mileage that's under part 195 would be an HCA based upon how the modelling is in part 195.

>> I got something.

>> If I could just point something out there too. On those models fast and I believe aloha2 do not take terrain into account which as we know is very important in modelling CO2. So it's a simple and inexpensive model but it does have some big draw backs.

>> And just to add to that, there are other models that can be used. I just there is

canary. I could list a whole bunch of them. There's more than just those two models.
>> I think Mark touched on, there are models available. It's technically possible but it gets really time intensive to then also expense. But, yeah, there are models out there.
>> If I can jump on that band wagon. I realize it's a topic to come up but there are lots of commercial dispersion models, some more accurate than others, I'm not aware of any commercial tools that handle elevation profile changes for dense cloud dispersion. They handle surface roughness which is really important but the up and down bit is where the computational fluid dynamic stuff comes in. That I would call more research than practical application. So the reality is it may be easier said than done to account for all of that with the technology that's currently available to most operators.
>> We have several questions online. Going back to Mark. It is a follow onto Lynda's earlier question. Mark, can you further expand on your thoughts about the hazard area for thermal versus vapor cloud being apples and oranges due to one being a circle and a flower pedal. Thinking about a vapor cloud's potential impact area as a circle defined by hazard distance radius seems to make sense from an individual risk standpoint. The area of the hazard only becomes important when we start thinking about societal risks. Where the number of people impacted are influenced by the area involved and all wind directions are possible. They don't occur with the same frequency. How can we address the differing possibilities for each pedal when we have nonuniformed structures around the pipeline?
>> Right. So the issues at play for dense cloud is the downwind extent depends on the wind direction and the wind direction isn't actually random, there's preference directions that depend on where you are. There are other issues around the terrain and similarly if the property density varies within the area the only way to do that strictly correctly that you would have to take do an analysis of at least 16 different wind directions, do the analysis for that wind direction, see which properties it engages and then pick another direction and another and then for societal risk you do a weighted average and for individual risk I guess you could do it for each wind direction and for each house. So it's doable that way but as you can appreciate if you're trying to generify it you have to make smearing type assumptions. So there's no easy way to get around the issues that the question invites. And I guess the people who are trying to implement this approach have to decide what level of rigor to employ to dumb this analysis down to something that will be practical in the context of what we're trying to use it for because you cannot do a site specific consequence analysis for every mile of pipeline I don't think in any practical way given the technology and the tools and the information that's current floating around.
>> Thank you. We have a comment more than a question from Kevin Ricks. PIRs for pipeline carrying pipelines other than natural gas may more resemble thermal than vapor at LNG facilities. The next question I have. Max, I'll direct it towards you as you kind of touched on this topic. It's from Cindy. What is a dense phase fluid, is this the

same as a super critical liquid or the pure CO_2 that is proposed to be transported from ethenol plants to be sequestered? Thus think natural gas is so much more dangerous than the proposed CO_2 pipelines. Where is easy to understand information I can share with them of the dangers we may be facing.

>> Yeah. So anything on Iowa I defer to the public record there. There's siting meeting going on now. We don't do siting. So the phases, so first super critical what's in regulations, typically it's above 1070 PSI, 88. But my understanding as part of part of that process, sequestration of getting out there's a production that wouldn't fall directly under us. My understanding, there may be different phases that differ from the out take to the injection portion to the intake. I have heard there might be cases where they will be just below the super critical point but Lynda is here and I think it's fair to say PHMSA won't play games if it's just below the critical point. We're going to treat it as regulations through super critical. I don't know if Lynda wants to add on that. Things are getting pretty darn close. There's some perception out there, is an operator doing it to try to get out of the regulations. Some might be super critical. I don't know if Lynda wants to talk more about that.

>> If there is any possibility that there's super critical in that pipe we will regulate it. So if you have mixed phase and let's say you see this sometimes on the gas line, natural gas where you may have some liquid entrained you're covered. On CO_2 if you have let's say even if you're at a point where you're in a gaseous phase it's covered, we will be out there. The other thing I want to be very clear on, congress has given PHMSA statutory safety authority over gaseous CO_2. We already had it for super critical CO_2. We have regulations that apply to super critical CO_2. But we also have safety authority over gaseous CO_2. So if we see a concern we can move to act. We have to know that there is an issue and we're going to keep our eyes on all these new projects being proposed. So it would be unwise for a company to say oh, we're going to keep it in the gaseous state and think that PHMSA won't be out to see them because we will. So I hope that helps.

>> Thanks, Lynda. We have another comment. It is from Jen. Just a comment on elevation and roughness. Out puts from models like Aloha can be over laid in products to account for elevation and roughness. We can take a question from the audience.

>> So CO_2 in gaseous, what part would that fall under?

>> [Inaudible]

>> It's a question was CO_2 for gaseous where would that fall in the regulations? Lynda said probably 195. I will say our rule making folks are looking at those contexts of do they all fall under 195, should they be broken up, 192, 195.

>> Russ Morris with air products.

>> Yeah.

>> Has anybody talked to CGA about how to build and operate hydrogen pipelines? Compressed gas association. I just wonder because it doesn't sound like it. Because

we've been operating hydrogen pipelines since probably the 60s with almost zero incidents. Other than small leaks. So I suggest somebody get in touch with CGA.

>> Yeah, I think we have experience with them in the past. I want to say even some of our former I want to say some of our former administrators had some experience with CGA in the past, yeah.

>> Yeah.

>> If I could add, I think some of the context that you're talking about is hydrogen specific pipelines. Some of the context that society is dealing with now is blended hydrogen into natural gas streams using the existing pipelines. That's a different animal. That's where you're getting some of the pensive response about we really need

>> True. But I think that there's been some studies that show that as small as 10% hydrogen in a natural gas mix is going to act like a hydrogen pipeline in operations. So, you know, I

>> I agree.

>> That's a small so it would take the hydrogen would take over in operations.

>> Yeah. I think a bigger concern and someone correct me if I'm wrong, it's not necessarily if you're building a brand new dedicated hydrogen pipeline, it's when we have questions are you going to repurpose an existing line that maybe wasn't intentionally built for hydrogen in the first place what happens when you start building with natural gas more and more. Those are the questions that get concerned. I don't know if Bill mentioned it but there's a public report out through TST that talks about some of those concerns. I think it's fair to say if anyone has not seen it the pipeline safety trust conference recently all the discussions are recorded now and publicly available. So good to hear some of the questions, concerns that are coming up in that context. Bill, do you want to?

>> Yeah. I encourage everyone to we have a white paper both on CO2 pipeline safety and now on hydrogen safety that just came out. There are also as Max mentioned was a really great discussion at our conference a couple of weeks ago and that's on our website as well. Under programs go to our hydrogen page to see the paper. You can also go to the conference page and you can watch the replay of that discussion which I thought brought up some great issues. We've seen I think we're getting beyond the PIR discussion here but we have seen, you know, integrity issues with blends as low as 1%. And I thought Mark's chart there of all the different physical characteristics between gas, hydrogen and CO2 was excellent and we have a lot of those features in our paper and it was really great to see it laid out that way. So I think issues like flammability range and yeah. All of those physical properties that Mark pointed out I think are really important. I was curious you said the PIR for hydrogen needs to be revisited. How would a PIR for a hydrogen blend be approached?

>> Right. I did want to make a couple of comments on the topic of blending because I didn't say anything about it at all, I talked about natural gas and hydrogen. And there is

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frankly more interest in blends than hydrogen pipelines. And if the hydrogen concentration if the proportion of hydrogen in the mixture is relatively low like you see numbers like 10 or 20%, I don't think the over pressure hazards that might be an issue for a pure hydrogen pipeline are on the table. It's more like how does the blend effect the crater fire hazard. And there's a process that you can go through if you treat hydrogen as a mixture component to work out what the release rates would be and what the theoretical heat energy would be and there's now more information on better information on the hydrogen. I think doing the jet crater fire analysis for a blend is not something that requires a whole bunch of research. It just has to be based on an agreed approach and followed. The issue is when does the hydrogen content get sufficiently high that some of the other hazards might become an issue. I don't think that transition happens at 10 or 20% I think it's happening at a higher concentration level. And there is a cook book of sorts in that Baker report from 2005 that talks about how you would treat a mixture with some adjustment it would I think work well for hydrogen blends as well.

>> Yeah and I think again this afternoon we'll get into a lot more technical thoughts and research beyond hydrogen and CO2. I did want to shift gears a little bit. I did appreciate Bill saying we're getting out of PIR. I want to put Andy on the spot just a little bit. To help well, let folks know too when these incidents happen it's not just NTSB coming out and you're hit with a report. I want to talk about the incidents at Danville, what the industry does, the info sharing. There's a lot of discussion on the need for info sharing, transparency sharing, things like that. I want to give Andy a chance to talk about lessons learned from the incident and where they went with it.

>> Thanks, Max. I thought there was really good presentations yesterday. Really good discussions around it. I think the key, again, facts on the table. These are things that, you know, investigation identified, opportunities to learn. We did a lot of work with pull through labs are known samples of hard spots and pulled every tool we could find on this planet in the testing schema to get a sense of what was their testing capabilities and try to better define technologies to go in the ditch. We also really looked hard at what we think drives certainty. We're moving over to quantitative risk management, what drives certainty in this threat. I think there was some really good points about reevaluating the data. When we look at facts, when we took the old tools and passed it through the algorithm it identified a lot of hard spots but did not characterize them as actionable. Including the one that failed were well below any actionable criteria. They were below 240. That's not going to cue anything for anybody to do. That's not helping raise the confidence that you will find the critical flaws. The tool capabilities of the old tools is particularly susceptible. It's not mature. We're looking at I think the question is the thing that we learned is the new technology that are out there.

We also really looked hard at what we think drives certainty. Moving over to quantitative risk and managing the threats. I think there were good points brought up about reevaluating the data. I think when we look at the facts, the facts are when we took the old tools data and passed it through the new algorithm, it did identify a lot of hard spots. It just did not characterize them as actionable. Almost virtually all of them, including the one that failed, were well below any actionable criteria. They were well below 240. That's not going to cue anything for anybody to do that's not helping raise the confidence you're going to find the critical flaws, the tool capabilities of the old tools is particularly susceptible. It's not mature. And we're looking at I think the question is the thing that we learned is the new technologies out there, particularly Rose and Tool, I'll give them credit, I think they have a good tool. The ability for that tool to characterize is significantly better than the old tools even with modern algorithms.

So the question becomes, do you spend your time reevaluating the old data with a low certainty of finding the outcome or do you run the new technology. And I think that's a really important pause for everybody is simple solutions to hard problems don't usually lead out. They lead back in. And I think that's really an important lesson that we learned. I think the other thing we talked a lot about CP system. I mean, hydrogen is a product of the CP system. Okay. So we don't want to be overvoltage. I think that is really prudent because it damages the coding system, which is bad. I mean, you're starting to disbond the hydro coding system but dialling in the CP system will not mitigate the risk of hydrogeninduced cracking due to hard spots in my opinion very seemingly. The work that Kevin Garrity has done recently that identified the environment is a huge player in creating is yous he thoughtibility that with the right or wrong environment, you can create absolutely enough hydrogen at .850 to drive failure that's been documented. Our CPC system was not overvoltage by any stretch. Trying to mitigate or someone asked the question, you asked the question, Linda, should we go after managing hard spots or should we go after finding them. I think when you introduce the uncertainty around the environment influence and the fact that you can have a failure well below overvoltage criteria, and have, managing them is very scary. Below certainty event. Finding them is better outcome on certainty. I think that's a really important thought to pass on. The other things are good but it's not yielding the certainty level that we're looking for to manage threat. I think the tool, driving the confidence around the tool is really important. And I think edified tool that was developed in particular in the ditch really helps validate or confirm the IRI finding. So if you go in the ditch and you have a new tool but you have old technology in a ditch you may never find it. Equitip is not going to help you narrow that down effectively. So I think using those in concert with one another is also important. I think finally, we talked this morning, someone here pulled me aside was asking about the comment we made yesterday about the pipe. There's all kind of distributions about susceptible pipe.

Well, susceptible pipe is interesting but the question is where did the pipe come from that's what's happening there's not enough happening in the pipe melt thermal temperature to create a hard spot. It's happening in the plate mill. So the real relevant question is where did the plate come from? And I think what you'll find is that very large majority of the pipe is affected particularly the pipe came from Sheffield, Baytown Mill. Right over here. The interesting thing was AO Smith tube mill 30inch pipe mill was right next door. So shipped the point from one to here. There's also AO pipe made not in bay town. If that pipe is not made in pay town doesn't have Sheffield pipe it implies low risk but there's other manufacturers buying Sheffield pipe, too. So I think that's a real centering data, really centering facts in your analysis. Don't look for the answers it's AO Smith. Not really. It's Sheffield plate. And the other plate could be at risk, too, but predominant lid we're finding that Sheffield pipe was important. I appreciate the opportunity putting me on the spot there I hope I answered the question or provided insights there.

>> Yes, sir.

>> I had a question for Andy as well as pipeline operator representative on the panel today. So I know my understanding, correct me if I'm wrong, Embridge you include not just those portion of your assets in HCAs integrity management program but you include other assets as well. But just for natural gas systems and Embridge specifically, if the PIR definition was changed and it was larger, say, how much of an impact or burden would that be for a company like yours?

>> Well, specifically for Embridge I can't speak for everybody but we manage our system in an integrity program regardless of HCA, MCA or LCA, we treat the whole system as under the same integrity program. And we do the same with facilities like storage and program facilities like compressor stations. I think the big impact would actually be can appreciate this from an audit standpoint, it's the paperwork. How much paper do we need to prove that we did this becomes quite significant, become quite the challenge, actually. When we convert it to a legal requirement. A regulatory requirement, it has to be demonstrable outside. And I think that becomes, can become significant. But physically not to us, not significant. And our pipeline integrity program director is back there waiting for him to jump up straighten out if I said anything out of bounds. But we're good. Curt says it's good so we're good.

>> So with the PIR, it's a good question because what is extending a PIR on it? Because the current PIR that we have didn't save those peoples' lives. So extending the PIR is just going to bring in more pipe that we're probably already assessing anyway because you're not just putting pig traps at the end of HCAs, right? You're doing miles and miles of pipe covered in the ILR or even in a well pressure test obviously. So the question is,

why are those, why are we having incidents in PIRs? It's something is wrong with the system that we keep having incidents of PIR. So that's what you've got to find out. You don't need to keep expanding the PIR because we're capturing that stuff anyway. So your question is, it's not going to be that much more of a burden. It could be for some people that their pipelines are unpickable if they would have to go do direct assessment on, obviously. But I don't know if the answer is more regulation. I think it's more being better operators than facing the problem that you have. And looking for the QRA's a very good tool to tell you in what spots out those threats and go after those threats. So I think more people utilize the QRE the way it's intended I think we could reduce a lot of incidents in my opinion.

>> Great comment. I think it's Andy do you want to

>> I think it's a great series of questions. I've heard about three, I think. I'm glad to opine on them or if you want to max. The thing that I think may be on the table here, we talked a little yesterday, as we're in the PVCA cycle we're looking at we have new data saying that the PIR could be changed, okay, I think we revisit that in earnest, look at that. Maybe that creates an interim tranche between MCAs and LCAs this little group we want to change it and look at that. So we get more attention there. I do think you're right. When we look at interior programs, typically run trap to trap. Or at least tools run trap to trap. So you're getting a large percent of the population, which is really the goal. You want to drive these programs to the whole system. And I think slowly over time we're getting there. But it's the slowly over time and the piece you missed that's the one you worry about it's the snake that bites you it's the one you didn't see. So I think continuing to push that is a good challenge for people. You comment, I do want to kind of opine on the thought of why are we having incidents in PIRs? It's a great question. I think that was the question we've wrestled yesterday. Seen the statistics aren't driving down. Well, I think we're casting broader nets. We're learning things. We're also starting to see where we have confidence interval issues on tools. We need to get more sophisticated how we talk and frankly how we even think. Sevenyear interval for inspection that applies to external corrosion it doesn't apply to cracks. It doesn't apply to hard spots. It doesn't apply to geo hazards. And as we start deploying these newer tools, they're not as mature as MFL tools. Okay. So we're learning in the case of some of these tools vertically. That tool's confidence interval isn't the same conclusions we draw are not as certain we may be technology limited quite frankly I'm not making excuses I think we're driving like crazy to places like PRCI and figuring out a better way to crack this nut we're seeing those things and some aren't regulated it's industry discretion, it's not a requirement and not everybody is doing it. I think it's growing pains. I thought what I would try to hit was three different thoughts and they're good thoughts.

>> It's a good comment, too. To what extent do we need regulations to move this forward, I think Steven made a comment but sometimes you hear operators say we can't go too far above them because if anyone does our code is the minimum safety regulations it is the floor nothing precludes an operator from going above and beyond. But there are some operators that make statements that we can't go too far above and beyond unless the floor is raised a little bit. So I think we heard yesterday PHMSA doesn't determine what the HCAs are, it's the operator determining. So what's the balance between PHMSA setting up the minimum and the flexibility the operator seeing what the aspect is. It's a comment. I don't know if we have answers. But any questions from the webcast? A few questions. This is from Ming. PAR used AOD for calculating but actual PIR the explosion fire ball from MOP and OD if it's much lower than OAD may we use MOP instead of MAOP?

>> No. The code says that you have to use MAOP.

>> Sorry. Steve can you repeat that.

>> Can you hear me?

>> Can you hear me?

>> The code if you go to part 192, the definition says you have to use maximum allowable operating pressure, MAOP you can't use a lower.

>> I know there were a lot of acronyms.

>> MOP maximum operating pressures. MAOP allowable operating pressure. Did we hit them all?

>> MAR.

>> Another couple of questions from Robin first question are there any efforts to support further development of models that include terrain for dense gas hazard modeling CL2 or other dense gasses?

>> We'll start with the marker at least what you're aware of. I think this afternoon you guys are going to be talking about a research initiative to explore just that kind of going beyond the state of the art in the current models. It's just that I'm not aware of commercial models that handle the elevation profile. But I understand that that's obviously something that's being explored.

>> Just add to that, this afternoon they will be going through a couple of R&D programs that PHMSA has. One was with Texas A&M for CO2 pipelines machine

learning. And another is within BMT fleet as far as welding on CO2 pipelines. I think Bob Smith will be going over that. Some of them in our group this afternoon.

>> Maybe over to Bill. A lot of statements made today about we have the MCA new part of the new gas rule that came out. Do you feel like that's a step in the right direction? Do we need to go further? Are there other aspects PHMSA to consider processes to help address any kind of aspects that aren't included in the underlying assumptions with PIR?

>> Yes. I do think the MCA establishment of the MCA and the programs under those is a great step. And as Andy mentioned I think that's just the next of more steps ahead of us. Expanding integrity management programs to more and more mileage of pipeline I think is just the direction we should be continuing to go. And that MCA is a good step in that direction. I do think that the gentleman's question earlier, some of the discussion we had yesterday, of not seeing the trend move in the right direction on HCAs versus outside of HCAs is a bigger question. And one we need to work on at the same time. So it's great to expand these areas that we're doing the higher safety standards. But at the same time we also need to be finding ways for those extra safety standards to start translating into lower trends.

>> One more on the webcast.

>> Question again from Robin. For HDD, natural gas pipelines, the PIR doesn't account for the potential migration of subsurface gas similar to migration from distribution releases into buildings. Has there been any discussion of addressing this threat pathway beyond PIR used for HDDs in developed areas?

>> What was the term used?

>> HDD.

>> HDD, horizontal directional drilling?

>> Yes.

>> So I'm assuming I'm assuming the question relates to the fact that if you get a line break deep under the ground in an HDD, the gas is necessarily going to come straight to surface of crater it's going to go along the direction of the drill. What's the PIR for that? And I don't have the answer for that beyond the fact that if the gas has to worm its way along the interface between the pipe and the ground, there's a whole lot of flow throttling going on and the behavior of the gas when it finds surface is going to be a lot different than would be currently modeled by a crater or a jet fire. So to the extent that

that refinement is deemed appropriate, then that would have to be looked at separately, I think.

>> I think you have the possibility with migration to gather in basements and structures as well.

>> Well, I guess the PIR to my mind was meant for transmission type pipelines which is sufficiently removed from places of business or residences. So it's the distribution network where you're worried about gas migration in, but if you've got a directional drill under a river on a 36inch line and that lets go, all the gas comes how we fail is one question but how it comes to surface would be another.

>> Another qualifying comment there is you're talking ruptures, not leaks. It's a full blown rupture of a transmission pipe migrating down the pipe is not likely the outcome.

>> I guess fair point. It probably does, is going to find a weaker path to surface.

>> Can I just add something? Normally HDDs are going to be less than 100 feet deep where it's going under. So whether it's soil or rock, it's not going to have much resistance to 500 pounds of gas coming out. So you would expect the rupture to be very close to where it is. If you've got an HDD and normally an HDD is going to be a couple of inches bigger in diameter of the pipe. You might get some migration that way if that bore hole hasn't completely collapsed in. But I would expect it to be minor. But we haven't had any ruptures or anything to actually see this phenomenon. But again if you just look at the soil pressure, unless it's in solid rock, where it would migrate, it's going to come up in the soil. And just one other thing on what Mark was talking about earlier. Is on the Baker study, on the PHMSA website, it has the actual PIRs as far as how to calculate it for hydrogen for rich natural gas, lean natural gas SIM gas it has criteria there if anybody wants to see what those figures are. Good to go there and look it will give you something to look at even if those numbers adjusted overall you'll see they're lower than rich natural gas.

>> That's the track we need. We need the dialogue and discussions back and forth. And this discussion will continue into next year. So we are started down the road to evaluate PIRs. Are they adequate? Do they need to be changed? We are down that road. What I'm struggling with based on the dialogue here where we are on the risk equation. Are we focused on prevention by changing the PIR and expanding the segments of pipe which I heard from a gentleman over here. I don't know where he went. Or as I heard from I heard people allude to is consequence side the impact on people and whether the change in PIR will have a significant impact on people. We're definitely going down the road on PIR but then we've initiated we have rulemaking out

there on valve rupture detection, valve response, all those. But the question is is there something we need to track on the side.

>> Are you tracking quizzical thoughts. Not to start a fight or anything, but one immediately the PIR was designed to prompt an intense effort to assess and mitigate. Lowering the consequence side. We're obviously looking at it to queue up valve automation things like that. What I heard was beyond that. Here's where the challenge match is if the issue is beyond the PIR that you're really talking about the heat intentionality, finding shelter, evacuate, whatever number you pick, the people in that zone outside need to be evacuated and find shelter. I think that's where I think potential discussions would come into play about zoning and public awareness. I think that if things build up around the pipeline, then people outside that area may be benefited by an explicit evacuation plan in the design of those facilities or the structures and I think that you would even perhaps want to have some sort of advisory if you want to talk about people that are not in structures, just gathering is there egress for them? Is there an awareness of the pipeline's presence. I think you start getting into other things that start managing consequence. That's the thought that jumped into my mind.

>> I know you're not the reason I don't want to start a fight, is some of those things are agencies beyond PHMSA. And I don't want to start a fight with them. Awareness for a longer discussion I absolutely agree. What triggered that thought was something that Bill Caram said you said it's right for public engagement or engagement and discussion so people know. You were talking about would people know to evacuate. What about engagement, what about understanding if you live in the vicinity of a pipeline, yeah, you get the flyers but do you understand that means go quickly, that kind of thing. The other thing I'll toss it out there. Deputy administrator Tristan Brown who we heard from although we did not see on Monday but we heard from him, he actually asked a question he didn't have an answer for I was stunned good idea for, he said it wasn't about this type of scenario in relation to another event he said if we know, if a pipeline has an emergency, why don't we have a system or why doesn't somebody have a system where they can send a text to landowner saying evacuate? So many systems to do it. How many get the amber alerts. Maybe get a notice I'm reaching out there. That's coming from somebody thinking outside of the box I'm thinking on the consequence side. And I think some can argue, I think time for one more question we have to transition to the 11:30 panel. But our existing regulations for public awareness one can argue, it's partly in that. I mean CO2 for 1950440 looks at identifying HCAs but maybe that helps you figure out who are your audiences you have to give regular intervals. Emergency response happens, who are the individuals you need to make sure you look out for that might be impaired. And you have the new RPA1185 in the works could potentially take that to another level. Mark, did you have if I could pile on to this discussion. As I heard the discussion in and around what should the PIR capture,

maybe it should capture more because people aren't aware beyond the PIR damage can occur. Maybe it's not death and maybe it's not destruction but it's damage. That's fine but what are you going to use that for? What I was thinking of was what you're really talking about is the emergency response planning zone. And there are jurisdictions that have those. And there are jurisdictions that have taken the PIR formula and modified it to lower the heat intensity threshold so that that would define the perimeter not that you could stand and watch the fire but almost that's a bigger zone. To the extent it's framed as an emergency response planning zone and those conversations happen. That might be a way to have your cake and eat it too. Insofar as you can make it hall the way out to where you could set up facilities for responding and define the area within which people ought to be aware of the area it could happen and plan accordingly. PIR the way it's being used is a little different from what that entails. That might be a way to approach things.

>> One more question webcast.

>> Question is from Michelle Slider has PHMSA evaluated what they can do to assist industry in getting local planning departments to enact development exclusion zones?

>> Good question. We have colleagues pipeline emergency security support division they are looking at things certainly drills and exercises. They do a lot on the oil spill response side for sure there's talks about to what extent do we look at trainings exercises particularly in these areas as well. I believe the answer is, yes, we're discussing it, but I would defer to the PES group for answering more on that. I don't know if Linda wants anything else. She's nodding heads. But if anyone doesn't know Tim Gaither is director. Chris Gerard helps lead some of the exercises there, either Tim or Chris could be good ones to reach out to.

>> I think with that, I'm getting the sign to wrap up. So thank you to the panelists, we're going to have some transition time between the panelists leaving and Bryan is going to come on to talk about Freeport. Thank you.
[APPLAUSE]
Is.

>> Good morning my name is Bryan Lethcoe regional director for the Southwest Region. And I'll present the review. Due to PHMSA's ongoing investigation, the information on in this presentation is all publicly available and my comments will be limited to publicly available information. I cannot comment on the ongoing investigation. On June 8, 2022, at 11:28 central time the Freeport LNG facility experienced a loss of primary canement and boiling liquid expanding vapor explosion resulting in catastrophic failure of the vacuum insulated piping. The explosion that took place was the result of the overvaporization of the piping causing it to fail and cascading

of series of multiple piping fail ierswhere it was located and the initial piping fail year and sploesh together with the damage to other process piping instrumentation, wiring, and pipe rack structures resulted caused severe damage to additional process equipment and associated piping P in adjacent areas within and near the pipe rack. The initial loss of primary containment event continued for nine seconds atmospheric result of a flammable videotape for with methane trace materials making up the balance. The initial release of methane and gas phase was released along with a smaller release of approximately two barrels equivalent of LNG into the pipe rack containment. The dispersion of this flammable vapor open atmosphere served as a fuel for the secondary vapor cloud explosion. And as it progressed release of mixed phase methane gas dispersed into the pipe rack in the area directly above the pipe rapidly rising into the air with dispersal aided by wind from the south southeast at 13 miles per hour and ambient air temperature 85 degrees Celsius the release of methane was not fwr a single point along the pipe but was unevenly released from various sections of the line as the piping failed. As a result, the full 10,500 pounds of methane was not available to fuel the vapor cloud explosion that occurred above the pipe rack. Given the large number of pipe section failures and their displacement from the pipe rack, propelled by escaping gas is believed no more than 50% or 5,300 pounds of methane was ultimately consumed in the visible fire ball with a balance of the fuel escaping into the atmosphere or consumed in a flash fry that was not observable on the available security cameras. The vapor cloud explosion in this event was fueled by the vaporized LNG escaping from the rupture generated minimal overpressure. The initial release of vaporized LNG was very buoyant and was ignited with visible fire ball. The vapor ball explosion was an event that failed to transition to detonation lack of fuel lack of confinement and lack of fuel availability to sustain combustion within the fire ball. The initial piping failure and explosion and subsequent displacement of piping and other structural and nitrogen. And observed secondary loss of primary containment involving vaporizing LNG escaping from pipe occurred until approximately 5:25 p.m. until it was terminated. Secondary LNG release did not ignite caused by a large failed section of pipe flying south from the pipe rack striking other piping in the area. On June 30th, PHMSA issued a notice of proposed safety order proposing that Freeport LNG take certain measures to ensure that the public property and the environment are protected from the integrity risk of the facility. The proposed corrective actions include requirements for written approval from the director of the Southwest Region prior to return to normal al operations. Selection of a qualified independent thirdparty to perform evaluations and assessments approved by the director. Completion of a root cause failure analysis by the thirdparty consultant. Submission of a complete plan of and schedule of inspection and assessment to determine the full extent of the damage caused by the explosion and subsequent fire. Submission of evaluation of operating procedures, control system procedures and assessment of personnel qualification and training performed by the independent third party. Submission of remedial work plan for director review and approval and delivery of monthly reports.

AAugust 3rd PHMSA issued a consent order and consent agreement to resolve the alleged integrity risks raised in the NOPSO. The agreed corrective measures included requirements for written approval from the director of the Southwest Region prior to return to normal al operations, selections of qualified independent third party to perform evaluations and assessments approved by the director. Completion of a root cause analysis by the consultant provided by the Freeport and director concurrently. Submission to the director review and approval complete plan of assessment to determine the full extent of the damage caused by explosion subsequent fire. In addition, Freeport was to implement the approved plan according to the schedule and provide weekly written reports. Submission of an evaluation of operating procedures, control system procedures and assessment of personnel qualification and training performed by the independent third party. Submission of a remedial work plan for direct review and approval. Delivery of monthly reports and written requests for any extensions of time, timely submitted demonstrating good cause for extension. On October 30th, the IFO group the independent thirdparty issued the root cause failure analysis report. By November 15th, PHMSA posted the root cause analysis report to the PHMSA FOIA library reading room. They identified the direct cause of the incident as the overpressure of vacuum insulated piping with no protection from overpressure. Removal from overpressure protection is believed to have occurred during annual testing of the connected pressure safety valve or PSV on April 26, 2022. The vacuum insulated piping line was heated by surrounding environment causing overpressure to happy the Bevy and loss of containment. Immediately following the loss of containment the group identified the cause of the fire to be contact between flammable vapor the methane and ignition source likely open and damaged electrical conduits and circuitry in the pipe rack following the loss of primary containment which resulted there the videotape for cloud explosion a small secondary pool fire on the northeast end of the pipe rack in the elevated LNG drainage trench. There was also the shortterm release of the vaporizing LNG from the 3inch piping that failed to ignite and was suppressed by fire water master streams deployed by emergency responders.

IFO group identified the root cause of the incident as a lack of PSV testing procedure and a lack of CARCIO program. Freeport LNG lacked formal written testing procedure to ensure they were put back into service without testing with CARCIO in open position in addition there was no formal car seal procedure or car seal training or no car seal checklist inventory process and no formal requirement to audit car seals in use throughout the units.

IFO group recommended that Freeport LNG develop a PSV testing procedure to also include the use of car seals. IFO group also recommended that Freeport LNG consider providing formal classroom field training in the use of procedures. IFO group also recommended that Freeport LNG consider developing a car seal program to include procedures for their use, a checklist to be maintained, evergreens, showing the status of all car seals. Formal classroom procedures used in the checklist and internal audits of all car seals upon agreed upon special. IFO group identified another root cause incident lack of safeguards to warn operators of vacuum insulated piping pressure. There are various leak detection temperature points installed in the piping but they offered no safeguard even if they had alarmed. The IFO group recommended that the group perform vacuum to identify audible alarms can alarm. And Freeport LNG analyze temperature data and perform repairs on temperature indicators to maintain effectiveness of the outer skin temperature measurements. IFO group recommended Freeport LNG revise to warn of vacuum insulated lines due to loss of flow. Another root cause IFO group identified is a lack of operating integrity of certain operating procedures. IFO group recommended that Freeport LNG consider a complete review of operating procedures for their tank farm area and the IFO group also recommended that Freeport LNG remove the designation of operator choice valves and these valves be temporarily changed to supervisory control valves until a solution could be agreed upon. IFO group also recognized a number of contributing causes. One contributing cause of the incident was the 2016 hazard operability analysis to not evaluate all the operating modes for the facility. The HAZOP study documented in the applicable report dated July 22nd, 2016 failed to evaluate the impact of operating modes and potential consequences caused by the intentional or accidental actions by operators that result in the overpressure of certain LNG lines caused by LNG heating and vaporization. As a result, the HAZOP study did not identify any current or potential safeguards against the consequences of this scenario and the current likelihood of success or failure in preventing the overpressurization of this line. In addition, the design change was made after the HAZOP that resulted in the line being designed as a vacuum insulated piping line. There's no record of management of change was signed off or as subsequent process hazard analysis was reconvened to consider this change. IFO group recommended that Freeport LNG consider performing a revalidation process hazards analysis for all vacuum insulated piping systems ensure the necessary safeguards are provided in their design based on severity of consequence including in particular identifying and avoiding or mitigating scenarios of this incident. IFO group also identified a contributing cause of the incident as failure to follow the Freeport management of change process for modifications to procedure, unit 18 tank management. Freeport LNG does have a written management of change policy intended to comply with 29CFR 1910119. IFO group reviewed a list provided by MCOs performed since 2020. There were no MOCs related to the changes in the operating procedures between the joint venture for Freeport and Freeport LNG for various valve settings for loads of evaluations. The completion of a compliant management of change would have provided an opportunity for the facility personnel to identify operational conflicts and risks within the operating procedures and prevent this incident. IFO group recommended that Freeport LNG consider using the MOC procedure for all changes in the unit as defined in the procedure. IFO group also identified a contributing cause of the incident as facility personnel failing to recognize an abnormal operating condition and related hazard. On the morning of June 6, 2022 a Freeport LNG operator noticed that piping had been moved. He reported this to a supervisor who in turn notified Freeport LNG operations and engineering personnel. The mechanical engineer sent out to the unit by supervisor to evaluate the pipe movement reported the issue as a possible failed spring can attached to the bottom of a pipeline on the side of a tank and the lack of a pipe support that was indicated in the design drawings. This engineer had very little experience with piping as his expertise was primarily rotating equipment pumps and pressures. However, he prepared a detail report which was distributed amongst senior Freeport LNG operations management team at the site on June 7, 2022. With none of these more experienced personnel went to the tank farm to evaluate the issue for themselves. Regardless, no one went to the site to recognize the cause for the cause movement for expansion increasing in pipe pressure applying forces to the expansion joints and other components of the line and the events continued unabated until the mechanical explosion and subsequent loss of primary containment. IFO group recommended that Freeport LNG engineering operations maintenance personnel should be trained to recognize abnormal operating conditions including those related to pipe movement and the recognition of pipe movement stresses as a result of the cause of the incident. Finally, IFO group identified the final contributing cause of the incident as operator fatigue. Operator fatigue is believed to have served as a cause of the incident probable design of the Freeport operator to restore to the connected PSV or pressure safety valve after it was tested on April 26, 2022. The facility had a long standing practice of calling in operators on overtime to provide staffing for PSV inspections and other related activities. The IFO group reviewed hours worked by operations staff for the first half of 2022 and some clear patterns of concern emerged. The following observation is a summary of the patterns of hours worked by operators at the plant in 2022 and the days and weeks before the incident. 23% of the staff worked between 110 percent and 119% of their scheduled hours. 54% of the staff worked over 120% of their scheduled hours. 20% of the staff worked over 130% of their scheduled hours. And there have been over 900 occurrences identified in the first half of 2022 in which operators worked overtime shift on one or more of their scheduled days off. During the assessment period of the first half of 2022, each shift averaged 12 hours plus on shift and operators generally worked 84 hours per pay period excluding unscheduled overtime. Operators and supervisors made numerous comments in interviews during the investigation and about operators feeling fatigued due to the number of hours work and routing scheduling. So as a result, the IFO group recommended that Freeport LNG consider a review of operator staffing and hours worked. So this concludes the main part of my presentation. Like I mentioned, due to our ongoing investigation, the information presented this morning is all publicly available and my comments have been limited to what's in that publicly available information. So I cannot comment on the ongoing investigation. But I would like to thank our team here at PHMSA including especially Mary McDaniel, Chad Hall LNG officer and entire Southwest Region LNG team and headquarters LNG engineering team for providing great support as we continue to work through the consent order and consent agreement and our followup activities that we have to continue to execute in order to ensure that Freeport LNG is a fit for purpose facility and safe to restart. Also like to recognize the efforts of our regulatory partners at FERC and US Coast Guard for efforts to return to facility activities and couple of the FERC engineers working tirelessly with our staff to assure that the facility is fit for purpose and safe to return to normal operation. Subject to your questions, that's all I have this morning. Thanks.

>> Yes, my name is Tony Marion. And you stated on October 30th PHMSA released a redacted version of the RCFA that redacted version was actually an approved redacted version submitted by Freeport LNG. My question is, do you or will PHMSA release a different version of the RCFA, a less redacted version or nonredacted version of the RCFA?

>> What I can say is there have been numerous FOIA requestses for the information to the incident and we're going through the process to understand what can be released what needs to be withheld at this point. That said, there are numerous FOIA requests for the information you're receiving. At some point likely information will be put out there through the FOIA process. Any questions from the chat? All right. No other questions, thank you, and turn it over to Max.

>> I think we I think we might go on to give you a little bit more of a lunch break, is that okay, Bill, I got a thumbs up. We still need to be back at 1:00 central time. Correct? 1:00 central, back in this room. Thank you, everyone.
[APPLAUSE]
[Lunch break]

[Lunch break]

>> We'll be starting in about one minute.
>> All right.
Well good afternoon, everybody and welcome back to our afternoon session. I hope

everybody enjoyed lunch. I'm Sentho White, the director of engineering and research at the PHMSA office of pipeline safety. We have a really full and exciting agenda this afternoon. It's going to cover some of our research program and the recent R&D Awards as well as some discussion on our success stories from our research investment as well as some discussion on successes and challenges related to technology development. And of course we're going to also follow on on our CO2 and hydrogen discussions with presentations from some of PHMSA's staff as well as our research partners and also stakeholders. And so with that I'll move into our overview. So I'll be providing some background on our research program, its vision as well as providing a summary of the recent R&D Awards that were funded in September of this past year and then also give you guys a few helpful links about how you can engage in our R&D program. So I'll first provide you with a bit of background on our research program and its mission. So PHMSA's pipeline safety research program sponsors R&D projects that are focused on providing near term solutions for the nations 3.3 million miles of pipeline systems and 400 underground gas storage facilities. The program's research results and solutions comprehensively address the mission as well as priorities through research that promotes safety and environmental protection, and equity for all communities. So our R&D program as I mentioned is very comprehensive in its research strategy and we partner with a very diverse group of stakeholders as shown here. So these partnerships are going to include our colleges and universities through our competitive academic agreement program, pipeline research organizations and technology providers through our core program, small businesses as well as with the national labs and federal partners and also international government bodies. And this diverse collaboration ensures the research is non duplicative and produce safety and environmental protection. We want to invite you to collaborate with our colleges and universities, Hispanic serving institutions. These partnerships are vital to ensuring the research objectives and the solutions are relevant to pipeline integrity challenges and it also provides the under graduate and graduate students with an opportunity and exposure to pipeline experts and also subject matter related to pipeline engineers to really encourage career placement within the pipeline sector. So we've had a really great track record since 2002 focusing on technology with over 120 technology projects. And as you can see our program has had a lot of success with 77 technology demonstrations as well as frequent patent activity. We've had over 35 commercialized technologies that provide solutions available for industry adoption that better meet our exceed regulatory requirements. So most of our areas in pipeline research solutions involve threat prevention, leak detection and anomaly detection. We're hoping to see some investments in the future with alternative energy, LNG and also underground gas storage facility challenges. So this slide just highlights a few of our performance metrics such as the number of website hits that we've had and downloaded reports. And we also provide all of these reports electronically for all of the projects that we funded and there's also a keyword search that's available for you on our electronic library. So now just to cover a few of our recent Awards starting with our CAAP program. Really all of the Awards that we've funded in September of 2022 are available and they have dedicated website pages. So you can go to each of those and definitely follow on on the research as it progresses. Starting with our CAAP projects for this past fiscal year we've awarded $4.8 and funded universities. These projects are focused on investments covering hydrogen. As well as material research on structural liners to rehabilitate damaged pipelines. Moving onto our core projects. Within our core program we've funded 15 projects and about roughly $7.54 million. Many of these are to investigate advanced solutions that support prevention and mitigation of climate change impacts through research focused on hydrogen and pipeline integrity challenges associated with that as well as CO2 pipelines and also projects that address methane detection and geo hazard risks. Just to follow on a bit more about our core projects, we are also looking at validating leak detection technology through field demonstrations to pinpoint leak location and for the first time ever we are actually awarded a project on corrosion challenges with respect to break out tanks. So through our core program we historically fund a research related to field demonstrations. Moving onto our small businesses funding. We collaborate with the department small business innovative research program and here we awarded two phase one projects. Phase one projects really focus on lab demonstrations. So this past year we worked with intelesense and oceanic laboratories. They are working to test out additional functionality of fiberoptic technology sensors. Oceanic are developing sensors using nano particles to plug gas well leaks. So very interesting projects. And last but not least we also have interagency agreement projects and these are projects that we fund with our national labs and also with NIST. This project actually I'm highlighting here is a follow on project that's focused on welding procedures for hydrogen pipelines and it's actually built upon some prior work that was done by NIST. We are also collaborating with the high blend initiative as part of DOE's program. And so this slide just really highlights the importance of our research outputs, their outcomes and impacts. And so I just wanted to convey how our program achieves these areas but our outputs really result in informative research through research reports. Again, all of our reports are available online and really they give stakeholders, the public the opportunity to find out about a lot of research solutions that will help to inform standards and policy development and future, you know, potential rule making that could come about. There's also opportunities here to look at, you know, technology adoption as well as commercialization into the marketplace of these technologies that we fund. And I will leave you all with a few links to our R&D web page. Again, as we mentioned earlier, all of our presentations are going to be available online and what I want to highlight here is the last link where you can actually sign up for alerts so you'll never be able to miss an opportunity about our R&D program as well as any webinars or report outs that come out. And so with that I am going to turn it over to Kandi Barakat, our operations research supervisor and thank you.

>> [Applause]

>> Thank you, Sentho. My that I mean is Kandi Barakat, I'm operations supervisor of the R&D team. I'll be providing an overview of PHMSA's most recent technology transfers and some of the success stories that we've had. But before I do that, I would like to give an overview, just a visual of PHMSA's R&D program and some of the collaborative process we have. We identify research gaps through stakeholder engagement and public forums. We develop research topics, offer research solicitation which occur around the beginning of the calendar year typically. After the comment period on the resource solicitation closes the merit row view panel reviews those proposals. Then we award state of the art research projects to help the environment. Research projects typically take around two to three years to complete and then we issue a final report. Some of the research projects advance the commercialization and that's the part I'm going to be highlighting right now. Since 2002 as Sentho mentioned 77 technology demonstrations have occurred as part of research projects scope, execution involving technology development and only 35 have commercialized to technologies that are being used in the industry. Our hope is to help this number grow more. Technology demonstration as part of the research and development activities at PHMSA play a key role from our program's success. I will present the last five technology transfer success stories in the following slides. These technology transfers were possible through the partnership of public, private entities in the research that utilize a combination of private facilities, academia and government laboratories. These research enterprises have enabled technology development to be conducted in the public domain and operating natural gas and liquid pipelines right of ways. For this first project this project succeeded in developing an electro magnetic transducer. The research project scope involves testing improvement capabilities into our robotic inspection platform and significant field testing and demonstration to validate its performance. PHMSA registered this technology in June of '22 and this tool is available to the industry through Baker Huggies and QI2 elements. This project succeeded in further developing and demonstrating a probe that can be inverted into an active natural gas pipeline and map from the surface. Once in an active operating pipeline the probe can be deployed in either direction up to 1,000 feet and capture accurate geographic. PHMSA register in '22 and it's available in the industry through reduct company. This project succeeded in further developing and demonstrating a laser sensor that can be very accurately measure mechanical damage effect in an active natural gas pipeline that cannot be detected. It was integrated into our robotic inspection platform. PHMSA registered this technology in February of '21 and it's available through the industry by technologies. This project yes, this project succeeded in developing and demonstrating advanced in ultrasonic technology. This sensor was applied to pipeline cracking threats for the first time as part of this project. This new sensor technology can be applied through tools

and ditch or through a deployed in line inspection or robotic inspection platform. PHMSA registered this technology in April of 2020 and this tool is available to the industry through Applus company. And last but certainly not least, this project succeeded in further developing and thoroughly demonstrating a methane leak sensor. It can identify a methane like from an automated mobile unit. The field demonstrations were primarily conducted in urban areas. PHMSA transferred this project in December of 2018 and this tool is available to the industry through heath consulting. So we've worked diligently over time to test out ideas and work with anyone with mutual interest to draft technology development and commercialization but what else can we do, what are the next steps. We will continue stakeholder engagement, conduct public meetings to highlight the program, work with field operators for feedback on some of the technologies and track the research results and commercialization technologies. We're also looking into conducting our out reach and maybe working with other DOT modes on their research programs and commercialization. You've seen this slide before for the R&D links. I highly encourage you to join the distribution list so you will never miss any announcement that's related to R&D. And this is the R&D team. We also have Colin who joined our team, his name is not listed here. We have four additional R&D team that joined that will start in January. Thank you.
>> [Applause]
>> All right. Thank you, Kandi. And now we're going to move to our technology panel in this next session. We are going to hear from a few of our research partners on their perspectives and their organizations research challenges in developing and deploying the best technology into the market. So I'm of course going to be moderating this panel. A few housekeeping instructions, we're going to go through three panelists and our third panelist is going to be joining us virtually and then after that we'll take Q&A. So with that I'm pleased to introduce our first presenter, Cliff Johnson who is the president of pipeline research council international. Cliff.
>> Well good afternoon. Sorry about that technology, pushed the wrong button. So what we want to spend some time on this afternoon is really kind of talking about technology, the way advances our future and maybe some challenge to putting it into practice. Some of the things we've talked about so far are really looking at the opportunities for what is next in our technology suite. Where do we go, how do we do more, how do we learn better to build a stronger, better mouse trap so to speak. Here is where we are today. PRCI is an organization that's founded to do just that. We started in 1952 to create the research that's needed by our industry to look to the next generation of technologies, tools, how to improve people and practices. We're very fortunate to have members from around the world that bridges in knowledge from all parts of the industry. Looking at the natural gas, the hazardous liquids, hydrogen, CO2, work that we've been doing for many, many years now, looking at the facilities associated with it. As we continue to push though one of the things is how do we move

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this technology into practice. Many of the operators who are involved with PRCI are ready to pick it up. However there's impediments from a regulatory or process point of view of how do you put technology into practice and where do you go. We want to spend some time talking about that today. As I mentioned the mission for PRCI is to look for that innovative applied research. Make sure it's utilized as soon as we can through direct adoptions, regular standards or industry regulations. As was shown yesterday this is kind of the make up of our slides that Zoe shared with you on what we look like an as organization proud to say the international aspect. We were able to learn from our members in Europe, Australia and around the globe on how we move key challenges. What I want to do today is give you two success stories and one story still in process. One where we're slowly evolving and still trying to make it happen. The first shows some nice wins. The first one is a maritime story, one of our corner stone research results and the next one on the integrity and service of our systems. The first one is a story about onbottom stability. It's pipe that's in the water and what we need to think about. This looks at the environmental impact and how to ensure the integrity and is safety. That was an industry standard globally to ensure the aspect and integrity of the sub sea assets. The next is an evolution, we've been talking about the safety and integrity there on B31S. The next revolution is the R string technology. This is a system how do we do fitness for system. PHMSA referenced it actually as a way for us to identify the fitness for service of our systems. These are examples of how we can move together as we work together as a collaboration bringing in that public and the industry together as a joint approach. This needs to be a partnership between all three legs that we saw on the triangle to further advance these opportunities. These great technology advances that we've had at PRCI that you saw in the previous slides at PHMSA really only work if we have people using the research. It's good to do research but if no one uses it what's the value of where we're trying to go. The next one I want to talk about is something that we've developed now that we've talked about R string as an advance, the next step beyond that now is to a claim called P square. A continued refinement of the opportunity for fitness for service, how do we know more about our systems to make more productive decisions. This is based off the data that we're able to pull together from our various tool runs and information to provide a wider, better sense of what we need to be doing. Right now this is completed back in 2019. We're still working through the regulatory and association adoption of this technology. This is something that can really help with more understand of our fitness for service around corrosion and the cracks. The process now from completed research to adoption is three years in. How do we shorten that window, how do we more productively move through this process. Through what we've been able to do at PRCI we're able to get a collaboration of a number of operators from around the world together to see how to test and verify these ideas. We need to look at and partner with our industry partners and the government and the public in showing how these technologies work so we can have a greater adoption of the technology we need to continue to advance our industry. When we looked at how do we begin to shift that story in PRCI, we built the technology center here in Houston. This actually came out of a recommendation from NTSB many years ago after marshall, Michigan. Part of that recommendation is aligning inspection tools as strong as they say they are. They asked PRCI to help validate that statement. To do that in partnership with PHMSA we actually built a pool test facility in Houston, Texas. The first one of its kind. To be able to allow the tools to get up to full speed, be able to test real performance. This was a collaboration between government and industry that really helped us say, yes, the tools are as good as we say they are but there's more to be done to improve them further. Through this investment we were able to test in line inspection tools in hydrogen, CO2 and the other opportunities we're going to be addressing for the next fuels of our feature. So this facility if you have the chance is here in town. We've one of the largest pipe sample repositories currently both of manufactured and real world defects from around the globe that really allow us to begin testing these tools and training the next generation of professionals on how to do this work. Right now we're able to put spools together of 6 inch and up to 40 inch to run the tools of various lengths. This is this way we help technology to move. As we complete research now we're able to get collective members together to show how these tools perform and move into industry adoption. This is the kind of activities we continue to push and think about. PHMSA pushed in Colorado to build a research development and technology center. Initially it was kind of following the same steps we just developed here at the TDC but on a larger scale. We're talking about hundreds of acres of facility, probably much more than we can think about. But really what they needed to begin focusing on from my point of view at least is how do we transfer into hydrogen and CO2. One of the largest needs is full scale testing. To begin looking at how do we push the boundaries on these pipes that we have in the ground, these assets that we've had in the ground for 75 years. How do we transition. To do that a full scale test facility similar to what they were considering in Pueblo is needed in the United States. This could be the next step for how our industry moves for safety, moves into the next really understanding of what these systems can abstain. Again, the current infrastructure we built never envisioned putting hydrogen in it. Not built with that in mind. Never having built the idea of super critical CO2 into it. We can do it, we just need the opportunity to invest and verify. It could be part of this solution. Unfortunately we can't have that facility at the TDC, I would love to do it here in Houston, I like to blow up stuff. Can't quite do it there. Not big enough of a facility to do that safely and efficiently. In a large scale situation where many of us can come together both government and industry together to partner begins to show the way how we can do this. Again, give us the facility that then leverages the public asset to it to see what are we talking about, where do we do. Bill mentioned on his website they have picture from what the CO2 looks like. Let's do that here in the test environment so we can see how that works in the possess.

It's how we transfer the knowledge we need to continue pushing for those zero failures we all want to get to to have that opportunity. The other thing that PRCI is embarked on is data. We've been talking about how do you use the data, how do we do that. As an industry globally we're not very advanced in this. Individual companies are doing really good with the data and are very short with it. As an industry we didn't developed a repository similar to the federal aviation administration to learn from our data systemically. There's an effort probably about five years ago, I believe Allen it was five years ago, the volunteering share information begin to be explored. That was on congressional direction on how to share knowledge and look at this more. PHMSA was not able to complete that activity. PRCI has begun down this path to begin pulling data together to help us become better, smarter in what we're doing. I'll close with safety is not something that we want to compete on. However, safety needs to be our number one priority for everything that we do. Safety is going to be the number one priority. To do that we have to get together as a group and it can't be us versus them, the public versus the industry, we all have to be in this together to push that. So with that, Sentho and Kandi thank you so much. If there's any questions I look forward to answering it during the panel. Thank you.
>> [Applause]
>> Thank you, Cliff. Next up is Dr. Samuel Ariartnam and he is the professor and chair of heavy construction at Arizona state university.
>> Great. Thank you. All right.
Does this oh. All right. Well it's a pleasure to be here and I'm going to give you kind of a perspective of technology and technology transfer from an academic perspective. As someone who has been involved in a couple of PHMSA projects that resulted in technologies that are being currently used in industry as well. So to talk about what technology is, what are the drivers of technology transfer, you know, why do we do this type of thing. It's really looking at discovering new knowledge and taking that knowledge, protecting the intellectual knowledge through copyrights and patents. It was mentioned before some of the patents that came out of some of the projects in the past. Developing that commercialized strategy to you can license for companies or create startups. A lot of startups do come out of academic institutions. Why does an academic institution in general end up looking at technology transfer? Well, there's a couple of reasons. You know, what we do is we provide learning discovery research and public service and economic development. That's what coming out of academic institutions from a research perspective. What technology transfer does is it provides a easier way to support this mission through commercialization of this knowledge that was discovered or done through university research avenues and that. What it does and it enhances, it helps us to attract better researchers or more world class faculty to come to your institution if you're really engaging in research. It improves the local economy. A lot of those offshoots that come out of research end up being local companies that are

driven by academic personnel. We attract the industry sponsors for research. That's really important that industry engagement or stakeholder engagement is critical and I'll talk more about that as I continue on. And then obtaining licensing and technology transfers and things like that can end up in economic gains too as well. Like, for example, at Arizona state university we have a technology office and if you develop something that's patented through the university then there's a third, third, third split. So the professor would get a third, the research group would get a third and the university keeps a third after expenses. So we have to keep those expenses down I guess in that office. That's how they sort of try to incentivize academia to file patent processes and go through those. I want to point to something. I was going some research. This bayhdole act. I don't know if you're familiar with it. It was instrumental because it provided this legislation in 1980 that basically enabled academia or small businesses or research institutions to maintain the patents from federally funded research. That opened the doors to a lot of innovation. That's where a lot comes out with industry or federally funded type research. Some of the inventions that can come from academia, I just want to put things that you heard of, blackberry, bar code, Google, that's what came out of academia. A lot of these have been from a societal perspective very, very important aspects of it. Talking about some of the challenges, you know, I'll let you in on a little secret. Academia is pretty good at doing research but we're not really that good at business. So when you're looking at any of this type of thing understanding real world versus theory, we can develop these technologies in that but we don't know that whether they will be applicable to industry. Will industry like those things. That's why I'm a really big proponent of stakeholder engagement. You have to have the end user from an academic perspective. Even partnership with technology providers in developing the technology which I'll show you in the next slide is very, very critical but we don't really typically know how to market things in that. The time between disclosure and patents can take too long.

I know cases where you go to the office, technology office, you say, here, I have an idea, and maybe two years later you'll get a result -- an answer back that says, yeah, actually, this is good, let's pursue the patent.

And in the meantime, somebody developed something new, right?

And so that's part of the problem.

And making that business case, right?

We don't understand -- most academics don't understand valuations and marketing and those types of things, and oftentimes a new and better tool comes along, along the way.

But one of the things that we do very well in academia is that we do a lot of presentations, and when we take our research that we've done, a lot of the PHMSA research and that, we're presenting that, so we're marketing that in a way that maybe industry doesn't have that opportunity to do as well.

We're going to different conferences, talking about the successes, talking about the projects, and that is a really important benefit that comes out of working with academia on these types of research projects and that.

Tying into a couple of projects that I was involved with here, the one on the top is the innovative free swimming acoustic tool for leak detection, that's about 10 years ago with a company called pure HM, now they're required by, and leak detection obviously is a really big issue and doing that.

We helped develop this technology, pure had already had patents that were done, they just brought in Arizona State, we worked together on this and had partners, and that was really important.

In this particular project, Enbridge, trans-Canada pipelines were major partners of ours, we were using their systems, demonstrating it.

Our program manager from PHMSA had it pretty good because when we did the demonstration for the project, it was in Puerto Rico, so he got a nice trip down to Puerto Rico, and it wasn't Bob, he wanted to go but -- it was good.

And it really demonstrated the real life applications.

So today this technology is being used all over the world, actually, and it's commercialized and that.

The second one just finished a year ago, in August.

And that was looking at river scour monitoring.

And a lot of that came out of, back in 2011, the ExxonMobil, the 63,000 gallons of product in the Yellowstone River and a break that happened.

Then in 2015, the pipelines, the oil spill that had 40,000 gallons.

So with this type of project, and once again, we had Enbridge and we had -- Pipelines as partners so we actually were installing, working with their teams, installing these sensors in there, and what it does is it looks at river scour over time, and it helps to -- in preventing these spills into rivers, right?

And I think we just had one last week, which was about 500,000 gallons or something like that, in Kansas?

That happened.

So these are kind of applications that we did and we utilized that, and through academia, industry and government, these are kind of the success stories that we can bring.

But academia alone can't do it.

We have to have the industry stakeholder and partners to be able to be successful in our R&D mission and that.

So thank you.

[applause]

>> All right, thank you, Dr. Sam.

Next up, our third panelist from the technology panel, she is joining us virtually.

Please welcome Sonal Patni, and she is Vice President of operations technology development.

>> Thank you.

I just want to check that everyone can see and hear me.

Yes?

Okay.

Thank you for the introduction.

Happy to be here virtually.

Thank you for helping set this up.

A lot of great conversation, a lot of different topics touched on.

I'll be walking us through a few commercialized projects from OTD and then just some general considerations for R&D.

If we could go to the next slide.

OTD is a not-for-profit corporation led by 28 member utility companies who serve over 70 million natural gas consumers in the United States, Canada -- yes.

>> Can you give us a few minutes and we'll have your slides up.

>> Okay.

It's kind of tough to just be doing it blind.

>> Okay, and we're up.

>> Okay.

Are you on the second slide?

>> We are, yes.

>> Okay.

Great.

So I'll just start again.

So, again, we are a not-for-profit corporation, made up of 28 member utility companies in the United States, Canada, as well as France.

We focus on continuous improvement and developing solutions through innovation and research.

Next slide, please.

Here you'll see that there's the different GTI member companies.

One thing I want to touch on, sorry that I didn't cover on the last slide, was, at the bottom there's a few different branches of GTI that focus on end use technologies, end use technologies with new products, and a low carbon initiative that we also have.

OTD is primarily focused on pipeline and pipeline infrastructure that's owned and operated by local distribution companies.

Next slide, please.

Hopefully you can see on the screen OTD's missions and goals, which really answers the question of why do we need R&D and why does the industry need to continue on focus on R&D.

A phrase that was threaded throughout the discussion yesterday was continuous improvement, and that's what OTD aims to do.

Through our work, we work on enhancing processes and practices to enhance safety, finding efficiencies which can result in a cost savings to our customers -- to the customers that our members serve, discovering new technologies that tell our members more about their system -- you're sick of hearing us say this, but you don't know what you don't know.

Number four, enabling the deployment of cleaner energy within the pipeline infrastructure that maintains the same level of energy and reliability natural gas companies are used to.

I heard Linda during the morning session yesterday emphasize the synergy that PHMSA as well as deputy administrator Brown see with pipeline safety and the environment.

Providing solutions for deploying alternate fuels and decarbonization is of high interest to OTD members.

Next slide.

So hopefully you can see on the screen a few examples of how we've leveraged technology to move the industry forward.

We're going to be going through a few recently commercialized projects.

I'm going to touch on some of these projects, I'm still pretty new in my role at OTD, so if you do have any follow-up questions, my email address is on the last slide of this presentation.

Feel free to shoot me a note and I can definitely connect you with the right people that know more about these projects than I do.

The first project is the HALOVALVE, a breakaway fitting attached to a meter set that stops the flow of gas.

There's a lot of incidents, if you've reviewed incident data, that relate to either cars running into a meter set or snow pile-up.

When we're thinking about, for example, the snow pile-up, it's really important that we look at this event because in some cases, even if operators are sending field personnel out to report, sometimes they don't even have access to those roads and it could take them hours, so this is really a way to quickly and safely turn off the gas and keep that house and customer safe.

The next technology I want to talk about are remote methane monitoring sensors which can help operators better quantify concentrations of natural gas.

And also if these are installed in the field after a pipeline repair is made, it can also supplement the -- of the leak.

In the top right you'll see a technology, the Kleiss flow stopping system.

This technology was actually developed initially internationally.

We worked to retrofit, and I'm sure several people at GTI and OTD would say further improve this technology for the United States and our pipeline infrastructure.

And this is also another important point that I heard brought up as well, it's really important for us to try to leverage technologies, lessons learned, and studies, to see what their applicability is here in the United States.

This is something that OTD members are also very supportive of.

There's been a lot of discussions that we've been having about understanding how gas utilities internationally are actually integrating alternative fuels.

So just a little more about this technology.

The fitting within this technology really is useful for, for example, for performing larger excavations, so instead of having to excavate a larger area, this technology reduces the size of that excavation and helps operators isolate the flow of gas.

And then in the bottom right-hand corner, you have the virtual reality training.

Now, this is really intended to help supplement both training -- obviously when I first came on board and saw this or even in my prior role when I saw this, this was really very useful during something like Covid.

I'm sure several operators experienced the same situation where it wasn't always safe to go in and get training, and this provides that additional supplemental reminder if you need it.

Another great use for this technology is, and unfortunately we're seeing more of these, is those larger weather events where you are having to call for mutual aid.

And so as other operators are coming to your service territory, it's a great way to refresh them with how you do things in your service territory.

Next slide, please.

And these are some projects that OTD has partnered with PHMSA on.

I do want to say we really appreciate working with PHMSA to help develop new ideas and solutions, so thank you.

On the top left you'll see the small diameter electromagnetic acoustic transducer, that is a mouthful to say, so again it's just using a different tool, it's a little different than your typical MFL tool, to gain more data.

You don't know what you don't know, right?

And specifically this really helps identify more details about potential cracks in welds and helps operators just learn more about their system.

In the bottom left corner you'll see the orifice project.

This is not fully deployed yet.

The pilots were delayed due to Covid.

But this is a really important technology, and I know we're really excited to further the research here.

This is a radar system that identifies obstacles, horizontal directional drilling.

And this can actually be more broadly applied than just for gas utilities, so anybody that's using this technology to install, whether it's fiberoptics or a water pipeline, can use this to just be made aware of what else is in the ground.

And I do want to remind everyone that excavation damage is still the leading cause of incidents.

So really important technology for us to understand more and identify and leverage.

Lastly, there's the 3M locatable plastic pipe, which is an alternative to tracer wire which can also be damaged through weather and just normal wear and tear.

Next slide, please.

So let's talk about some factors to consider to develop and deploy successful R&D work.

First, you just have to understand that technology development can take a long time.

We need to walk before we run, and we have to do this safely.

Number two, understanding your constraints and understanding your variables.

You're not going to be able to create a solution every time for every variable, and sometimes that's okay.

For example, the mobile methane leak detection technology, which has been out for a few years, was at the time more accurate than a hand-held detector, but it doesn't work in every system, and that's okay.

That doesn't make it an ineffective technology or that that innovation should not be promoted where it makes sense to deploy.

Number three, work to identify commercial partners early in the process and get them involved in the deployment.

We need support from regulators to build the confidence and funding and supporting innovation.

I really like that a few moments ago Sam distinguished the difference between the need for both R&D in academia and the marketing of that end product.

There was a comment earlier this morning and somebody said that nothing precludes operators from going above and beyond code, but in fact business decisions -- that in fact business decisions and changes to work, including if you're trying to implement new technologies or R&D, need to be approved by the commission.

Providing regulatory support and this isn't always through a formal rulemaking or regulation, it can be through an advisory bulletin or just having conversations with -- to say we really support this technology or focus -- for operators to focus in these specific arenas, really provides some of that support that we need for deployment R&D.

More simply stated, you just need to develop a solid business case that can bring your product to market.

Lastly, you just have to understand the impact of implementing new technologies.

Like I said at the start of this slide, implementation is always going to have unknown challenges.

And you also need to understand how this affects your specific system as you're looking to deploy new R&D or a new technology.

And then I just want to point out, it's also really important that you communicate with your external stakeholders, whether it's your customers, whether it's your policymakers, just so you all understand the benefit and the potential changes that are coming your way.

Next slide.

Also as PHMSA and other governing agencies look to develop new regulations, regulations should allow for alternative or new technologies, that spurs innovation, and also new technologies may provide more system knowledge, helping how operators can leverage R&D and be more proactive in their risk management.

New technologies may also provide a solution for different types of pipeline systems.

Again, one size does not fit all.

And then ultimately, this just enhances safety to the public and the environment.

And then the last that I want to leave you with is this: The success of an R&D program cannot be represented solely patents or technology in the market.

White Papers, updates or new codes and standards, even failures and lessons that you learn when you're trying to deploy a pilot, are incredibly valuable to the industry.

So how you measure success is key.

Thank you, and you will turn it over to Sentho for what I think is the final.

>> All right, thank you, Sonal.

>> You're welcome.

>> Am I on?

And now we'll go ahead and open it up to the participants in the audience first for any Q&A they have for the technology panel.

>> We do have one question online.

That question comes from Terrence Peterson.

Can PHMSA provide an update on its implementation of the technology pilot program in the 2020 Pipes Act?

>> The question is related to section 104 of the pipes act of 2020 where we were required to establish safety enhancement testing programs to evaluate innovative technologies.

As of now, we have not received any applications for that program, but we are -- there is a report that was issued that provides information about how you can file your application with PHMSA, and so definitely please reach out to contact us if you have any questions or any interest in the program.

>> I can yell.

It's on, okay.

>> We can hear you.

>> Good afternoon.

Rick, ExxonMobil, technology and engineering.

Really appreciate y'all being here and talking about one of my favorite topics, which is technology.

One of the concerns I have is siloing.

As we develop technology, particularly with relationship to CO2 and hydrogen infrastructure, how do we avoid siloing our technology development efforts?

Specifically I'd like to address this to the federal agents, but what role might DOT and DOE play in coordinating with largely a federal effort of how do we capture, transport, and sequester CO2, and how do he effectively transition to alternate lower carbon intensive energy sources like hydrogen?

What do DOT or the federal agencies see as their role in helping to effectively coordinate those efforts and avoid siloing of technology development?

>> I can probably take that one.

It's a great question, and as I mentioned earlier, our efforts with our R&D are definitely collaborative.

We partner with DOE and specifically fossil, energy carbon management office, and we have a DOE representative, actually, several representatives that will be presenting later on about their efforts related to hydrogen and CO2, but, again, I will say, in terms of siloing, we definitely have a broad stakeholder base.

And we really try to encourage partnerships and encourage really a diverse set of input.

We have forums that we put on and they're very collaborative, we have working groups, but we also have an open solicitation, really, to hear about input about how research can really help to inform our agenda.

In terms of a federal effort, we have been working, again, with the Department of Energy, FECM, as well as the office of hydrogen, and internationally as well, we have joining us U.K. health and safety executives, so there has been definitely a broader effort to make sure there isn't any duplication with research.

>> Another thing that PRCI is doing that we had embarked on is creating the online community for research, we call it the research clearinghouse, which will be available in the first half of next year.

And the idea is to reach out to other organizations and provide a transparent place for everybody to go to find knowledge.

And so we're looking to other industry partners, look to the OTDs, European members research groups and others to be able to putting out information that's available.

It may be the titles and abstraction extracts of the work that links back to the organization so we can find because this environment we're in, the pace of change is rapid.

We have to keep up with it.

And everybody is doing something, and we need to make sure that we can strategically allow everything to flourish and provide the solutions in the right time and the right place.

Ideally, with the clearinghouse coming online in the first half of next year, we'll be able to provide a community space where anybody, whatever role you play, can find what's going on in the industry and hopefully can be able to do that, like I said, on a very wide basis.

To complement what PHMSA is doing with their outreach but from the industry point of view as well to create this visual of what is being done because there is so much happening at this current time.

>> Hi, Jon with liquid energy pipeline association, following up on the tech pilot question.

Do you have any ideas or thoughts on how PHMSA -- what PHMSA could do more to facilitate the demonstration of technology we saw in the case of the tech pilot, the legal and regulatory Congress requires effectively preventing operators from -- considering that a viable program and thus we've got no application?

Do you have any thoughts on what PHMSA could do assuming that it wants to leverage technology for the benefit of pipeline safety, what we could do to make it easier to use technology, not harder?

>> Well, I definitely would encourage a lot of dialogue with staff, with PHMSA, and I would also, you know, really highlight, a lot of our program is based on technology demonstration.

And so definitely having that confidence, that today, really having confidence in the data to be able to actually promote out and adopt technology is really key for us.

>> One thing, actually, I want to add to that one is, yes, have those discussions among the industry and stakeholders.

If one company is utilizing one technology, share that success, share some of maybe the concerns that you have with another company, so feedback can be provided.

While we cannot endorse certain technologies, I think the feedback among the industries might be very helpful.

>> And with that, we're going to have to move to our next panel, which is on hydrogen, and Kandi Barakat will be moderating.

Thank you, and thank you to all the technology panelists.

[applause]

>> Thank you, Sentho.

So I will be the moderator for this next discussion, and the Q&A following this panel.

As a reminder, please hold all your questions until the very end, after all presenters have had an opportunity to speak.

The objective of this panel is to discuss opportunities and challenges on hydrogen and hydrogen blending.

It's now my pleasure to introduce Vincent Holohan, senior engineer for the engineering and research division at PHMSA, who will discuss what PHMSA regulates, safety challenges, expectations, and will foreshadow future possibilities on hydrogen research awards.

The floor is yours.

>> Thank you, Kandi, appreciate it.

Let's see if I can get the technology moving.

Well, you guys are all in for a real treat here.

My name is Vinny Holohan, as Kandi said, I work in the engineering and research group for -- I want to make brief comments about PHMSA's involvement with hydrogen gas.

A couple things about past performance of the pipelines we have in our repertoire, and then a little bit about what the research and development program is doing in that space currently.

I'll be moving pretty quickly, but we'll have the Q&A afterwards.

As a quick aside, any time I have family or friends coming, visiting the DC area, they want to see the national treasures or natural mall, monuments, museums, each time I come here to Houston, I come to the Galleria mall.

I'm not sure if that's a parody.

You've heard enough about who PHMSA is.

By now you know our function.

I'll remind you that between us and our state partners, we regulate about 3.3 million miles of gas and hydrogen liquid -- I'm sorry, hazardous liquid pipelines, the majority transporting natural gas.

We regulate underground natural gas storage and certain liquefied natural gas facilities.

Of those 3.3 million miles, right now there is a little bit more than 1500 miles of hydrogen gas transmission pipelines.

Since 2010, we haven't seen a market increase in that mileage, but we expect that to be changing in coming years.

This is a map of the hydrogen pipelines as of the 2021 data.

The 1500 miles of hydrogen transmission pipelines are operated by about 36 different operators in the U.S.

So far there is no regulated gas distribution systems carrying hydrogen that we're aware of, and these pipelines are generally more of a local fractured nature, maybe that's not the right term for it, but shorter nature than most of our other infrastructure on liquids and gas and they concentrate around the gulf, Louisiana, and Texas areas.

So hydrogen pipelines are currently regulated under part 192, transportation of natural and other gases, and they have been since 1970.

As it stands today, the regulations are largely the same for natural gas and they are for hydrogen gas, the differences being mostly in performance language, that requires the operator to design and operate the pipeline for the commodity that's being transported.

Performance based requirements include considerations of materials compatibility for the components, differences in the PIR, which we talked about quite a bit today, for integrity management, and the hydrogen, if it's used as feedstock in certain cases can -- doesn't have the requirement for odorization.

It should be noted that currently PHMSA is not capturing information having to do with blends, there's not a choice for that -- or annual data, so more than likely if you had a small amount of hydrogen blended into gas, natural gas would probably be listed as natural gas in that data, or as other, but from what we know, communicating with stakeholders, we're not currently aware of any regulated pipelines operating with blends.

And if you know different, I'm here, please come talk to me.

So a little bit about past performance.

Since 2010, there have been a total of five incidents on hydrogen-carrying transmission pipelines, all five were transmission -- because there are no distribution currently.

None involved injuries or fatalities, and none of them appeared to involve hydrogen, assisted cracking -- meaning the transportation of hydrogen was not a contributing factor to the failure itself.

Taken overall, that's not a lot of data, doesn't seem to provide significant evidence to support or to refute any integrity concerns with those pipelines.

Out of order here.

This is a slide that highlights our research investments in the space of hydrogen gas, supporting the administration's clean energy initiatives and outlines the past research we've done on hydrogen pipelines.

Previously the projects began in the lay 2000s, 2007, 2008, and led to some early successes supporting the development of ASME standards for those pipelines, which was talked about a little bit today.

Those projects mainly focused on integrity management and materials properties issues.

Go back here.

There we go.

More recently, the end of 2021, the R&D program hosted this event which has been talked about.

Some of you were in attendance there.

Basically it was talking about hydrogen and emerging fuels and going through and prioritizing research that is in campus tense, these were used for the recent solicitations which went out and we have a total of seven projects that are starting in the space this year.

I'm going to very briefly highlight these.

This information has been noted on the website.

There's a lot of depth there.

This is too much to read through in the two or three minutes that I have here.

Essentially, MC Squared, they'll be researching integrity threats and threat assessment of pipelines transporting hydrogen gas and blends as one of their projects.

And another, the same company, MC Squared is also going to be considering how existing pipelines can safely be repurposed for hydrogen and hydrogen blends.

I apologize, I know I'm going a little fast here.

GTI is studying the impacts of leakage and how current leak detection could be affected by the presence of hydrogen and what's needed to go forward.

GTI will also be looking at underground storage facilities for suitability of storage of hydrogen gas.

University of Oklahoma, they have a project they'll be developing an assessment model, and then a tool looking at the compatibility of existing pipelines to transport hydrogen and hydrogen blends.

And North Dakota State University will be developing AI based software tool that may aid in decision making when considering the repurposing of natural gas pipelines for hydrogen gas service.

Finally, the national institute of standards and technology will be considering steel weld qualifications for new hydrogen pipelines as well as performance of modern steel welds and the assessment of vintage steel welds for hydrogen service.

You've seen this a few times today, some links in the presentation for anyone that's just tuned in to get a little more in-depth in the program.

With that, I thank you for your time.

Appreciate it.

[applause]

>> Thank you, Vinny.

Now I would like to well R welcome Evan Frye, physical scientist with the division of methane mitigation technologies at the Department of Energy, and mark Richards, technology manager with the hydrogen and fuel cell technologies office, also the Department of Energy.

They will be presenting on hydrogen production, transport, storage, and research, and development opportunities and challenges.

And they are presenting virtually.

Mark and Evan?

>> Thanks, Kandi.

I'm a technology manager with the hydrogen and fuel cell technologies office.

My primary focus in that office is on hydrogen infrastructure.

I would like to cover a little bit of why hydrogen first and then get into things related to hydrogen infrastructure.

Next slide.

On the left of this slide, you can see that renewables only represent about 15% of U.S. primary energy consumption.

The Biden administration has set goals to decarbonize the electric sector by 2035, and to reach net zero economy-wide by 2050.

The administration also has concurrent objectives to address domestic jobs in environmental justice.

Next slide.

DOE sees hydrogen as one component of a multi-office effort, as indicated on the right, to reduce carbon emissions.

Recent documents outlining the hydrogen aspects of the effort include the 2020 hydrogen program plan, and the 2022 draft clean hydrogen strategy and roadmap.

Next slide.

Looking at overall CO2 emissions, some end use sectors can be addressed by electrification such as heat pumps and battery electric vehicles.

Others are difficult to electrify, such as heavy duty vehicles and industrial processes.

Hydrogen can help address these end uses.

Next, please.

Two recent pieces of legislation included hydrogen-related support.

The bipartisan infrastructure bill provides nearly $10 million of funding for hydrogen research development and deployment, with 8 billion of that for hydrogen hubs.

DOE has solicited concept papers for these hubs already, and these papers are currently under review.

The second item is the Inflation Reduction Act, and that includes provisions for a clean hydrogen production tax credit of up to $3 per kilogram.

Next slide.

One challenge DOE is trying to address is the cost of hydrogen.

This graphic shows the market clearing prices need for hydrogen to be competitive across several end use sectors.

For hydrogen to help address the decarbonization of industrial usage, costs need to be reduced to around $2 per kilogram at the point of use.

DOE's hydrogen shot goal is to reduce the cost of clean hydrogen production at the point of production, $2 by 2026, and $1 by 2031.

Next slide.

To help guide RD&D funding, the DOE develops targets for various cost components across the production and delivery chains.

The middle two boxes on this graphic outline current costs, estimated high volume production costs based on current technology, and 2030 targets for clean hydrogen production and distribution.

Next, please.

I'm going to touch on hydrogen production pathways briefly here.

We break down hydrogen production into three groups, electrolysis, thermal conversion, which includes reforming and -- and advanced pathways such as thermochemical, photo electrochemical and others.

We're working to identify RD&D pathways to reach the $1 per kilogram target but it should be noted that advanced pathways are lower TRL at this time and these pathways can be more challenging to identify.

Next slide, please.

Aside from adjusting costs, DOE is working to ensure that materials and components needed for hydrogen production and distribution are developed and suitable for use.

Hydrogen is known to affect the properties of many materials, such as strength, ductility, et cetera.

Hydrogen effects do not necessarily pre-conclude the use of a particular material.

Design and operation conditions for a material in hydrogen service play a role in determining suitability.

A multi-lab consortium is performing cross-cutting R&D on the effects of hydrogen on metals and polymers.

The green highlighted items on the right are work areas that may be of interest to the pipeline community.

These include improving the fracture toughness of high strength steels, developing master curves for pipeline codes to simplify new material adoption under those codes, and examining pipeline materials relative to blends of hydrogen in the natural gas network.

Next, please.

To help assess the potential to blend hydrogen in the natural gas network, DOE established a multi-office initiative called Hugh blend.

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The first effort in the initiative is a cooperative R&D project consisting of six national labs and over 30 industry partners, and that effort is to investigate various aspects of hydrogen blending, the effort is undertaking material testing in various blends, developing integrity models to help identify operating conditions and establishing analysis and lifecycle analysis models that will be publicly released for economic assessments of blending.

Next, please.

Finally, the hydrogen fuel cell technologies office maintains the safety codes and standards subprogram that supports the development of codes and standards to enable the use of hydrogen.

The subprogram focuses on developing the scientific data needed to establish requirements for hydrogen deployment and use and to disseminate this information as well as safety practices to the broader community.

Thanks for your attention, and I'll hand it over at this point to my DOE colleague, Evan Frye.

>> Many thanks.

Apologies, this is my first slide showing.

Hey, everyone, appreciate you coming virtually and thanks to PHMSA for organizing this.

My name is Evan Frye, program manager for the natural gas decarbonization and hydrotechnologies program.

Second slide, please.

Here I present FECM division of methane mitigation technologies.

We support administration goals including a 50% emissions reduction by 2030, a CO_2 emissions repower system by 2035 and net zero emissions economy no later than 2050.

Our division is organized into four primary program areas, methane emission mitigation is focused on eliminating future emissions.

Quantification works to measure and quantify methane emissions across in natural gas value chain.

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My program, the natural gas decarbonization and hydrogen technologies program, functions to decarbonize the natural gas supply chain and support a clean hydrogen-enabled economy.

Finally, our newly established undocumented orphaned well program is tasked with locating undocumented orphaned wells.

This presents DOE's H2 scale framework which highlights an energy economy.

When we think of hydrogen as a carbonless fuel, at FECM we explore how fossil resources and infrastructure assets can be leveraged to provide clean hydrogen at scales necessary in meeting administration goals.

Thus the NDGHC program focuses on three areas of interest around transformative hydrogen production, transport and storage.

Fourth slide, please.

In thinking of a net zero economy by 2050, FECM's program mission falls cause challenges and opportunities.

With respect to current R&D for production, activities include developing processes that produce clean hydrogen and hydrogen carriers from fossil feedstocks in support of the hydrogen energy.

Specifically, we are assessing processes that convert methane to clean hydrogen while capturing and converting carbon in marketable, solid carbon products.

With respect to transportation R&D, we are characterizing the long-term impact of hydrogen on piping and pipeline materials within natural gas infrastructure.

We are also developing advanced sensors for hydrogen leakage detection and blend monitoring in real-time.

To further validated the carbon-free proposition, we need to conduct lifecycle analyses from equipment transporting natural gas and hydrogen blends.

Finally, we conduct technoeconomic analysis to understand lower, more reliable hydrogen and blended national gas transport pathways.

With respect to storage needs, FECM will determine the viability, safety and reliability in storing pure hydrogen or hydrogen natural gas blends in subsurface environments.

I'll speak to this subsurface storage portfolio in later slides.

Next slide, please.

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This slide provides a high level overview of potential, near, mid and long term R&D opportunities for FECM.

In the near term we continue to work across DOE offices to understand market opportunities in various regions of the United States to best deploy federal resources.

In the mid-term, scaling of subsurface storage of hydrogen is of specific interest and we welcome your inputs on this subject.

I'll identify a way to connect with us in later slides.

In the long term, understanding FECM's role is critical towards maintaining and achieving administration goals and providing safe, reliable and secure resources to the American public.

Next slide, please.

So a major component of our storage portfolio is our subsurface hydrogen storage and technologies acceleration program, known as SHASTA.

Subsurface hydrogen is limited to storage facilities.

SHASTA is composed of four national labs.

SHASTA works towards expanding the footprint for subsurface storage, which is crucial to enabling the widespread utilization of hydrogen via bulk storage.

This team will identify and address key technological hurdles and develop tools and technologies to enable broad acceptance for storage with natural gas or pure hydrogen storage in the subsurface.

As we've established in the update, this data knowledge, SHASTA and our stakeholder working groups will determine the viability, safety and reliability of pure hydrogen or blended gas storage by conducting field demonstrations.

Next slide, please.

So I'm going to present some preliminary workout of the SHASTA group.

Underground hydrogen storage has the potential as a long duration energy storage option for low carbon economy.

Using PHMSA's underground natural gas storage facility reports, our investigators assessed 399 underground gas storage facilities in their working gas volumes.

They considered blended, hydrogen methane storage scenarios and estimated the working gas energy of these mixtures in domestic facilities.

If these facilities could be converted to 100% hydrogen storage, the total working gas energy of underground gas storage facilities in the United States is estimated to be 327 terawatt hours.

We estimate the transitioning domestic facilities from natural gas to pure hydrogen storage would reduce the collective gas energy by 75% from 1,282 terawatt hours to that 327 terawatt hours.

Because of hydrogen's volumetric density compared to methane, approximately 73% of the 399 underground gas storage facilities can store hydrogen blends up to 20% and continue to reliably meet their current energy withdrawal demands.

Presented here are facilities by storage reservoir type, their working gas energy capacities, and then the cumulative storage potential organized into regions.

Hydrogen demand projections suggest that hundreds of new storage facilities may be needed to meet reliability demands.

Next slide, please.

Other work within the SHASTA portfolio.

The previous analysis will improve on our principal -- the previous analysis will improve as our investigators integrate higher fidelity inputs into meteorologist which consider biological, geological to assess domestic storage facility.

Because there are only a few hydrogen storage data points and limited examples of blended natural gas and hydrogen stored at scale, the SHASTA team is continuously updating our analyses to inform infrastructure planning.

Ultimately it is the team's goal to describe components of the hydrogen natural gas storage chain as a function of storage facility type capacity and end use demand.

We hope to develop tools using existing DOE analyses and national labs, delivery scenario analysis model, HDSM, to inform policymakers of existing and future storage potentials by providing metrics on costs of stored hydrogen.

Next slide, please.

As mentioned, SHASTA can leverage assets and expertise to clarify operational risks, develop enabling tools and technologies, and demonstrate a collaborative test plan in partnership with a network of stakeholders.

This last point is especially critical as I encourage those interested to reach out to our team via our SHASTA page on the NETL energy data exchange to join our stakeholder working group.

Next slide, please.

2400, fossil energy based production storage transport and utilization of hydrogen approaching net zero or net negative carbon emissions.

Thanks for everyone that submitted applications for this funding opportunity.

It was highly competitive.

Applications are currently under review, four AOI's, two within the area of 14 one respectively to each AOI 15 and 16.

We hope to make selections and announcements next spring, but for future areas of interest, please seek out our FECM solicitations page for ways or opportunities of doing business with DOE.

Next slide, please.

Finally I present the NGDHT, the natural gas decarbonization hydrogen technologies programmatic timeline.

The program was established within the FY22 omnibus, however, we've leveraged insight from our programs, but ultimately the NGDHT program collaborates with the larger system as we work together to transition energy infrastructure and systems into a more decarbonized energy economy.

I think that's my last slide and thank you for your time today.

Please reach out to FECM and our research partners.

Take care, everyone.

Thanks.

>> Thank you, Mark, and Evan, for your presentation.

[applause]

>> Now I would like to welcome Dr. Simon Gant, he is with the health and safety executive science and research center based in the U.K.

Dr. Gant will be presenting on H2O research initiatives, challenges and opportunities, and also joining us virtually.

>> Thanks very much, Kandi.

It's been a great meeting so far and thanks for the opportunity to come and present here.

Slide 2, please.

Yeah, I'll give a quick introduction to HSE and talk about our net zero strategy, talk about ongoing activities and some recent publications that I thought might be of interest and end with some knowledge gaps.

Slide 3, please.

HSE is the U.K. regulator for health and safety, which includes all onshore and offshore pipelines as well as other bits of infrastructure.

Our activities cover -- some of the things awesome as PHMSA, consultation, regulation, incident investigation and enforcement.

Regulatory regime is slightly different in that it's a bit more risk based than based on codes and standards.

I work in the science and research center, about 400 staff, and we've got test facilities to support the agency and other government departments as well as joining in projects in consultancy.

Slide 4, please.

Net zero plans in U.K. these are centered around two main areas at the moment.

We've got regional hydrogen and CCUS industrial clusters, there's two of them.

I'll talk about them on the next slide.

And we've also got a big program of work on hydrogen for heating, looking at using 100% hydrogen for domestic, commercial and industrial heating.

And there's a lot of work going on at the moment that's in support of a cross-government policy decision on hydrogen heating that will take place in 2026.

And in the run-up to that, there's various trials ongoing.

So in the next year or two, there will be a neighborhood trial with 300 properties in Scotland, running, and cooking on hydrogen, using a new distribution network, and after that, there will be a village trial with up to 2,000 properties, including a school and hospital, running 100% hydrogen using a repurposed gas distribution network, and then after that, there will be a town pilot probably -- 2026 and going on into rollout.

Next slide, please.

So like I mentioned, one of the areas of work is the industrial hydrogen and CCUS clusters, there's two of them.

HYNET and the East Coast cluster, both of them involving new or repurposed hydrogen and CO2 pipelines.

They received funding last year, and there's a second phase of funding being announced next year, related to those two industrial clusters.

These are projects that are looking at incorporating CCS so there's a number of projects, some hydrogen production plants and industrial installations like refineries and cement factories.

Next slide, please.

The second part of the work is a hydrogen heating program.

This is an area of work funded by BEIS funding industry consultants and regulators, to deliver a range of research projects and testing work looking at putting 100% hydrogen into the domestic heating and commercial and industrial heating.

So within HSE, we've convened 11, what we call evidence review groups, they're listed on this slide.

And each of them have got about a dozen scientists, regulatory and policy specialists.

What's happening is that we're receiving various documents from industry and consultants that we're reviewing and you'll go into some examples in the next few slides.

Next slide, please.

Slide 7.

This is just covering the areas of work that we're reviewing.

It covers everything from materials performance to risk assessment, different types of equipment and procedures and training.

Next slide, please.

So for an example, a bit of work we've been looking at, this is work run by the gas company SGN, looking at using the polyethylene distribution pipe systems for 100% hydrogen, the scope of that work, the standards, looking at failure modes, fracture toughness, crack proper a graduation, leak tightness and various different squeeze-off welding and repair technologies.

They also funded some experiments looking at accelerated lifetime testing, so that was one large report that we reviewed and gave some feedback on.

Next slide, please.

Second example here, this is some work in support of using hydrogen in the gas transmission network, which in the U.K. is operated by the national grid.

And they've given us various bits of work to review, so they've done a fair amount of working looking at potential impacts on materials, also looking at due points, barrier coatings, looking into deblending, this is mixing hydrogen within natural gas at different points in the network.

Looking at what information is required if you're going to repurpose pipelines, so the design standard of that pipeline and its history, also looking at in-line inspection and repurposing.

Reviewed some of that.

Next slide, please.

The third example is, there are a number of studies that have been done at various facilities, industrial sites looking at the implication of switching from natural gas to hydrogen.

So issues around area -- some materials issues, things like that, so we'll review reports on that.

Next slide, please.

Slide 11.

So we've been very busy over the last few years, looking at qualified risk assessment methodology for hydrogen distribution platform that works, so this includes pipeline distribution network and also within domestic buildings, the internal pipeline system, and the modeling work includes the whole gamut of things from the pipeline release frequency, hole sizes, how the gas tracks through the ground, ingress into buildings, gas cumulation, and explosion, fire, consequences, and various experimental studies to support that modeling work.

And this is aimed at looking at what are the relative risks between 100% hydrogen and the current system of natural gas, and also looking at different mitigation measures to reduce the risk with 100% hydrogen, things like excess flow valves, gas detection, and so on.

And barriers to see what mitigation measures are needed in order to make the risks equivalent to hydrogen as they are for natural gas currently.

Okay.

So, the next few slides, slide 12, sorry, talk about some of the previous slides work that we're reviewing.

Agencies also carried out some research of its own that Adam banister has headed.

I thought this was relevant to what Vinny was mentioning, was it Iowa, looking at material compatibility for 100% hydrogen and developing methodology there.

Next slide, please.

This is looking at assets on the gas network and their suitability for hydrogen, and the work looks at assets, the component -- if you're looking at a valve, looking into educator use different component parts of the valve, and the quantitative methodology is looking at the individual component sensitivity to hydrogen degradation, how that component is loaded, and the consequences of failure of that component.

And then it gives a ranking system or score for the threshold assigned to it.

And the idea is that if the component fails in some way, this work also looks at mitigation options for how you can deal with that.

And it's also codified into a spreadsheet tool.

Next slide.

Slide 14, please.

And there are examples here, I won't go into the details, but this is what single band repair clamp on the distribution network -- the top part of it is looking at its current risk situation for natural gas and the bottom part of the spreadsheet that is shown is the various scores that are given for different component parts of it for hydrogen and it's given a green mark at the end as a pass.

Next slide, please.

And this is the same thing but for a different asset, so building entry tee.

You can see it's got more components there.

This one is in process.

Next slide, slide 16.

That methodology was tested by the gas network company on a range of assets on their network, and you can see the chart here is showing -- passes or fails, it highlighted them -- pressure regulating devices and slam shut valves were areas they needed to look at in a bit more detail.

Next slide.

Slide 17.

Cast iron is a bit of an issue we're looking into at the moment.

A number of U.K. gas network companies are doing further work on material testing of cast iron for 100% hydrogen and we'd be very interested to learn about any work that's ongoing in the U.S. or elsewhere on cast iron hydrogen surface.

There is a replacement program that's ongoing in the U.K.

Next slide, please.

I didn't know to what extent the energy institute is visible in the U.S., but they're coordinating a number of studies in the U.K.

I don't know whether it's just the U.K.

I think a number of international organizations are involved.

They've published a couple of interesting reports looking at repurposing of natural gas infrastructure for hydrogen, and something else on energy efficiency, and there's a number of ongoing projects that -- they've got a number much industry stakeholders and the agency often participants in their working groups.

It's just a highlight that that work is going on.

Next slide, please.

And there are a couple of other interesting publications that came out this year, not on the safety side as such but on the emissions side, so the one on the left there about atmospheric implications of increased hydrogen use, has something on the global warming potential of hydrogen, and the publication on the right on fugitive hydrogen emissions, emissions is a big area of interest, so this was looking at what it would be for hydrogen in the future.

Those are freely available reports.

And then slide 20, please.

To conclude then, I've got a couple of slides here on knowledge gaps and technological innovation needs.

I had a chat with colleagues to pull this list together.

These are things we're looking for some work on in the future.

Development of procedures and remote repair technologies for gas escapes on the distribution network.

Flow stopping equipment for hydrogen distribution pipelines.

There's been a fair amount of work going on on hydrogen pipeline purging, tests, but there's more needed there.

Gas detection for homes and smart excess flow valves for homes.

Two experiment points that I've got on this slide, one on ignition of hydrogen pipeline releases and one on response of buildings to internal hydrogen explosions.

So work that I'm aware -- projects are being put together on those two areas in the U.K., and if people are interested, I can put them in touch with the project leads for those.

There's also a need for work on explosion relief systems, governor kiosks.

Next slide, please.

And a need for work on -- further work, I guess I should say, on compatibility of gas network assets for hydrogen service, and also the performance of network assets, and finally erosion of pipeline systems for blends and 100% hydrogen.

So if you know of any work that's going on in that area, we'd be really interested to know more about it, the agency.

And the final slide, slide 22, is just my contact details.

Thanks very much for listening and thanks again to PHMSA for organizing this meeting.

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Thank you.

[applause]

>> Thank you, Simon.

We appreciate you joining after business hours.

We realize the time in the U.K. right now.

Thank you so much.

>> Okay.

>> Now you'd like to welcome Dr. SIARA so a, technology development manager, research, development and demonstration clean energy innovations.

They will be presenting on hydrogen composition, supply customer, design operations, locations, and safety considerations.

.

>> Thanks so much for the introductions.

And hi, thank you for having me today.

I've been work for SOCAL gas in 20 years, different capacities in the engineering area, materials testing, evaluations, failure natural circumstances, all kinds of interesting things.

And now I manage the low carbon research system on their project for research and development.

Basically our projects range from hydrogen production and renewable gas production, all the way to carbon capture utilization and sequestration.

Very interesting and exciting for me.

A great change after so many years.

While we wait for that Powerpoint to come up, I'm going to explain today specifically about our strategy at SoCal gas for hydrogen and hydrogen blending.

Basically we are focused on decarbonizing our system and reach carbon zero goals or zero -- okay, there we go.

I guess now it's on me to do this.

Yes, okay.

Going back to SoCal gas and their strategy, we're looking forward to becoming zero greenhouse gas emissions by 2045, a very ambitious goal, and we need to set up a clear strategy on how to achieve those lofty goals.

We are the largest gas distribution utility in the country, and we have over 22 million customers being served by an infrastructure that's relatively old, since our company's been serving the public for over 20 years.

Basically we're taking a serious look at all of the different options in terms of clean fuels and how are we able to have different strategies to decarbonize our system.

So with that, we defined specific goals on how we were going to approach this, and regarding hydrogen, we had defined two specific strategies.

One of these is what we call -- I'm going to go over this.

Angeles link is our proposal to the public utilities commission to let us have 100% hydrogen pipeline infrastructure.

This would be new construction, if you will.

There's many different phases to this proposal, and currently we have a decision by the CPUC to allow us to go forward and plug this effort in with the -- submitted by the state of California for the -- one of the hydrogen hubs that is opened by the Department of Energy.

How could this make sense?

Basically what we're trying to combine is the source of hydrogen with the end user, and for this to work, we need to use basically the renewable electricity from solar and wind that can be curtailed from time to time every day.

So based on that availability, we can use an electrolyzer to split water from hydrogen and sides where we have availability, transfer that to our end users that are hard to decarbonize and that could use the hydrogen, for example, for heavy duty trucks and the like or other industries like cement, for instance.

One of the key advantages of this process is that by using electrolyzers our hydrogen product will have a pure composition.

Different type of trace elements, maybe a little bit of moisture or oxygen, depending on the technology, working with very pure hydrogen.

Basically our customers, as we're planning at a high level, could be the LADWP electric plants that use electric generation facilities, in addition to those heavy duty fleets that I was talking about before.

The heavy duty fleets are very large in Southern California and that would be a significant impact in terms of the pollution reduction and emissions reductions.

This is an example of how we envision our industrial hub for hydrogen in terms of what would be our customers, basically by bringing that hydrogen from the areas where we have wind and solar that are in the desert, outside of our Los Angeles basin area.

So that's, when you make that connection, the transportation via pipeline makes sense.

Ideally, you will have a collocation, electrolyzer next to the end user, but for that to work, to have an impact, the renewable piece needs to be brought together.

It's definitely not an easy analysis, and that's part of why we're requesting the state to allow us to move forward to do all the evaluations in order to demonstrate a specific plan that will make sense.

Our second aspect of our hydrogen initiative to decarbonize our system is on blending.

We don't have a specific level of hydrogen to blend, but we're working on a significant amount of research, we're part of so many different consortiums with PHMSA, with the Department of Energy, with Europeans, if aliens would be doing hydrogen blend go, we would partner with them, too.

It's important for us to come together and make sure we can substantiate together, make sure we raise a flag to any other constraints that we need to consider.

This is a very important issue because hydrogen can have certain impacts on old infrastructure.

This is the basic idea that we have with our blending proposal and electrolyzer to split the water, using electricity, and going through our blending skid, inject that into our system.

And at a high level, these are the specific areas of focus that we're working on in terms of our studies.

Definitely that plastic and steel compatibility are critical.

We've heard today many people are already working on those type of projects.

Integrity of our pipeline is the number one concern, and we've all gotten into safety again because of the safety piece.

In addition to that, we're also part of the center for hydrogen safety.

I highly encourage anyone that has either safety concerns or safety questions about hydrogen or curiosity in terms of how to deal with it, is it safe or not and how will it impact me as a customer regardless if you're industrial or at home, go to the website, this is from the American Institute of Chemical Engineers.

I don't have a link there but I promise I will add it when I share the presentation.

These people are doing a fantastic job of making sure we're touching all the pieces and they're also reaching out to standards and codes organizations to ensure that everything that needs updated is updated.

They had a very large conference in Anaheim this past September, and they will be having another next year.

I'm not sure where.

But, again, they're a very, very large and reliable source of information.

I encourage anyone with that curiosity to go and reach out to them.

They also accept memberships.

We, of course, are members as well.

Again, I encourage anyone that's interested to reach out to them.

And I also wanted to put a few examples of some of the projects that we are collaborating with.

Definitely running those tests are a large period of time to substantiate that it works in the real life environment, modified demonstration type projects is something important for us.

So we have several efforts here, explaining we have this higher pressure or let's say medium pressure, not necessarily transmission but not -- this project with UC Irvine.

We also have another project with UC San Diego, I believe these are lower pressures.

I said we because SDG and SOCAL gas are sister entities.

Bodies from southwest gas are developing another plastic demonstration project.

Then these are more examples of what we're actually doing at SOCAL gas.

We have this training facility that we use for our employees that go into customer service.

And in one of their sites, one of their little homes that you see there, we developed a closed loop system with materials used by the residential system and the distribution system, and tested several blends of hydrogen and natural gas at different levels, over relatively long term.

This test was several years long.

And we wanted to see what could be potential impacts on these materials as well as also monitoring equipment, and we figured out with small leaks, trying to figure out how our monitoring equipment will work.

That's why it's indicated there by liquids.

We have a second version of this project that is called the living lab that is collaborative with a team and it's a two-year demonstration still in the plans.

So no pictures yet.

And this is yet another demonstration project.

This is a very large project, we just finished construction this year.

And we typically call this a hydrogen home, hydrogen innovation experience.

Over here we wanted to have another closed loop system to run appliances at a residential level for a long term, and running blends up to 20% of natural gas.

So the home is fully equipped, is very pretty if you ever are in Los Angeles and want to go take a look.

And it has its own system to produce their own hydrogen, which we'll see in the next slide.

It has some solar panels, and electrolyzer, so it's a closed loop system.

And it's aimed to demonstrate that all of this can work together in a home, like anybody's home.

This is the second project that we have on my R&D team, and this is a demonstration of technology that can separate and compress hydrogen from an initial blend.

So this is meant to demonstrate in case we want to retrieve the hydrogen after blending to use it for another customer that might need specifically only hydrogen, that is something that can be potentially and easily done.

This first project was made at a relatively low pressure, so I want to say under 6 PSI, but we have a second phase coming up that will be higher pressures, and this is European technology.

And last but not least, this is one of my favorite projects in hydrogen.

We are working with a company, a start-up that was funded by the Department of Energy.

They invested already, I want to say $12 million on this technology.

And this technology developed small, compact 3D-printed reactor to produce hydrogen from renewable gas.

So we're basically having these larger demonstrations installed in the sun line bus transit agency.

They have their buses all running hydrogen and they have an SMR but we're plugging in this reactor in order to test out their ability to scale up for larger volumes.

And with that said, thank you very much.

If you have any questions, we can discuss either at our Q&A or if you want to reach out to me either via LinkedInor at the end of this presentation, thank you so much.

[applause]

>> Thank you, Dr. Sosa.

I'd like to introduce Jay Meyers, vice president for engineering and technical services at Tallgrass Energy.

He will be presenting on hydrogen composition, supply customer, design operations, and safety considerations.

All yours.

>> Thank you, I appreciate the presentations.

It's nice seeing some of the real world applications that people are working on for hydrogen production.

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All right.

So today I'm going to be talking a little bit about some of the hydrogen initiative projects that we're working on.

below is a list of projects.

And I do have a couple other more detailed slides associated with each of these projects so I'll just touch on these briefly.

First project is up near Douglas, Wyoming, the initial engineering of CO2 capture on a unit, 220 million standard cubic feet today standard hydrogen production facility, in partnership with BASF, universities of Wyoming and others.

Second project is something that I think is very interesting and that's in northwest New Mexico, and that's the conversion of an existing 265-megawatt coal fired power plant to 100% hydrogen fired, which includes new hydrogen production with 95% of the CO2 capture in sequestration.

Then we have the Black Hills Cheyenne project, which is a demonstration of hydrogen combustion in a commercial natural gas combined cycle unit with the Wyoming Energy Authority, Black Hills, and others.

I do think that it's important to say that, you know, with a lot of these blue hydrogen projects, you're not going to have blue hydrogen without the capture and the sequestration of CO2 so they inevitably require CO2 projects.

We do have a project potentially our existing Trailblazer pipeline which runs from Cheyenne out to Beatrice, Nebraska, but it's an existing 36-inch pipeline and we're looking at converting approximately 390 miles of it from natural gas to CO2 with access to approximately 10 million tons per year of CO2 within 50 miles of the pipe.

That's not really related to the blue hydrogen.

There are ethanol plans where we plan to gather the CO2 from.

We're looking at the Eastern Wyoming CO2 sequestration hub which is the development of a 5 to 10 million ton per year sequestration hub, and also including characterization well drilling in a Class 6 permit application.

All right.

So first project, is DOE project up near Douglas, Wyoming, but it's the initial design of a commercial scale carbon capture system that would be installed and fully integrated with a 220 million standard cubic feet per day blue hydrogen facility, which will utilize ATR technology or auto thermal reforming.

Also the identification of potential pathways for CO2 and hydrogen, and it will also help us determine the levelized cost of hydrogen in cost-to-carbon capture.

As far as success criteria, we are, you know -- it's the development of the initial engineering study for the commercial scale of the carbon capture and underground sequestration system that separates and stores more than 100,000 tons per year of CO2 with 95% purity.

Then the carbon capture efficiency will be 90 plus percent.

Then there are other purification requirements and then the CO2 delivery pressure at 2215 pounds absolute.

ESCALANTE, an existing 265-megawatt power plant, coal fired power plant, that was originally commissioned in 1984.

It was retired on August 31stof 2020.

So this project involves the evaluation of large scale clean energy production facility in northwest New Mexico and the repurposing of the ESCALANTE power plant to use, you know, the clean hydrogen as fuel.

Greater than 95% of the CO2 from the hydrogen production facility will be captured and permanently sequestered, which means that we will now be using the CO2 for enhanced oil recovery, we will be permanently sequestering the CO2.

From a clean power standpoint, approximately 265 megawatts, very low greenhouse gas dispatchable power.

We do expect 60 plus per minute jobs to be created in the local community as well as 500 plus construction jobs.

We also believe that this will serve as the foundation for further development of clean hydrogen in the area.

Talking a little bit about the conversion of the power plant to hydrogen fuel, it's really not that much different than the conversions of, you know, coal fired power plants to natural gas, with the exception of you have to create the hydrogen, but you've got the coal handling that feeds the boiler, produces the steam and drives the steam turbine and you have your off sides for ash pond, et cetera.

You'll remove the coal handling, the off-sites, but you will bring in natural gas, produce the hydrogen, the hydrogen in turn will feed the boiler, produce the steam, drive the existing steam turbine which produces the power, but you do need to capture the CO2 as well as sequester the CO2.

From a reliability standpoint, you know, we believe that -- ESCALANTE will be capable of dispatching power at any time and provide decarbonized power, you know, when renewables are producing.

You know, the reliability will be very similar to what we have for natural gas generation except it will have very low CO2 emissions. From an affordability standpoint, we also believe that this will be a less expensive source of power capacity than solar or renewable growth as renewable growth continues. Then a lower cost than green hydrogen. From a decarbonization standpoint, 95% of the carbon capture from the production of the hydrogen will be permanently sequestered. Next project is with is black hill Cheyenne. This is a demonstration of a hydrogen combustion of hydrogen combustion in a commercial natural gas combined cycle unit with Wyoming energy authority, black hills energy, GE and black and beach. Black hills energy is the lead on this project and will be providing the technical expertise for the blue hydrogen production. The initial phase of the project is the front end engineering design for a blue hydrogen gas production for the facility with carbon capture. There's also conceptual engineering assessment of the equipment modifications for a GE LM600 combustion to combine the blend. I should have mentioned this, this is a blend of hydrogen and natural gas. And then, you know, finally there will be the demonstration of using that as a fuel but for the demonstration testing, the hydrogen will be supplied from tanker trucks. So it's going to be a testtype project. I will touch briefly on the trail blazer conversion project. This is the conversion of an existing 36 inch natural gas pipeline to gas CO2 services. So it will not be super critical. The MAOP of the pipeline is not such that we can move out in the super critical site. The pipeline hard to see runs from Cheyenne out to Beatrice. It over lays part of the trail blazer pipeline. You can see the converted piece of trail blazer in blue and then there are inner connects with recs to maintain the supply of natural gas to the customers. But the blue area is where it will be converted. Then, you know, we'll also be able to of course leverage the office and field personnel that we already have in the area. I do want to touch a little bit on hydrogen pipelines since I though this is a PHMSA conference and that's what I think everybody is interested in. But hydrogen pipelines, these are kind of our thoughts and what we see here. But hydrogen pipelines of course are regulated under part 192. Hydrogen is a flammable gas as defined in 192.3. It includes natural gas pipelines with hydrogen blends as well as pure hydrogen pipelines. Part 192 really doesn't say a lot on hydrogen. There's not a lot of specific guidance. You know, in fact the gas factor that's used for hydrogen in the PIR calculation for HEA determinations not mentioned of course .69 is typical for natural gas. I know there was discussion around that this morning. .69 is typical for natural gas. It references ASME B for gas. It doesn't have much guidance on hydrogen either. You know, it was mentioned earlier this morning ASME B 31.12, 31.12 does include a reference for the gas factor to use for hydrogen and that's .47. You know, as we as I think Mark brought up this morning, you know, he believes that that is out of date and really needs to be refreshed. I'll be interested to see where that goes. But then there's also ASME B31.12 for hydrogen piping and pipelines. I'm not sure how many people are familiar with it but it is a good standard. Very similar to B34.8 and 31.8 but t specific to hydrogen pipelines. It's not incorporated for reference within part 192 but applicable for pipelines containing more than 10% hydrogen. It does address a design construction and operation and then there are a couple of things that I think are interesting in there because it does include guidance on design factors which are typically lower than they are for natural gas service. You know, they include an option A which is a prescriptive design method. There you use a .5 design factor for class 1 through 3 and then a .4 for class 4 areas. They do have an option B which is more of a performancebased design factor and in there you get your more typical design factors for class locations like you do with natural gas or of course you can go with a .72 for class 1, .6 for class 2, .5 for class 3. There is also a separate material performance factor that can further decrease the design pressure as your, you know, pipe grade exceeds. The higher yield pipe there's a recommendation for a further D rate for the pipeline itself. And then last slide I do want to address a little bit on at least my thoughts on, you know, pipeline conversions, you know, whether I guess building new versus converting. So, you know, there of course have been a lot of conversion projects and a lot that have looked at that people have looked at. I think it was mentioned yesterday what was it 400something pipeline conversions, whether it's a conversion of service or, you know, change in product. So there are quite a few out there. New pipelines of course give the operator complete control over all aspects of the design and construction of the asset. You know, that's nice to have. Pipeline conversions, the repurposing of existing pipelines does make sense in some cases. You know, new pipelines are challenging to permit and the process can be lengthy. It does provide opportunities for underutilized pipelines and there's typically less environmental impact. You know, as far as steps for conversion, you know, we discussed quite a bit the PHMSA guidance for pipeline flow reversals, product changes or conversion to service. Great document if you're not familiar with it. But it does, you know, walk you through different scenarios, what you need to pay attention to and how to go about the conversion. Then I do want to mention that ASME B31.12 does address pipeline conversions in section PL3.21 for its steel pipeline service conversions. So what makes a good candidate for conversion? Every pipeline is unique and needs to be evaluated based on its unique characteristics. That really comes down to operators need to understand their pipeline, need to understand their assets and the specific risks associated with it. I do want to point out that a pressure that I guess I believe a pressure D rate will probably be required if you're following B31.12 to operate at no more than 50% SMICE. This is largely because of the prescriptive design factor where you have the .5 limitation for class 1, 2 and 3 areas. Then also, you know, potentially because of the material performance factor. Vintage pipelines, you know, pre1970 pipe, the good thing is a lot of times those are lower yield pipe that may not require that material performance factor for the further D rate. But we need to be aware of the historical issues associated with vintage pipe. Weld seams, load toughness, hard spots, poor coding, SCC, you know, we had quite a lengthy discussion yesterday morning on hard spots. You know, cathotic production providing a source of hydrogen that could further brittle the material. Same thing with putting hydrogen in service. You need to understand your assets and how to address it. Then you also need to you know, so really just understanding the abrittlement and the impact on these potential issues. As far as modern pipelines it voids some of the historical issues associated with vintage pipe which is a real plus and typically operators have much better records what they have on their newer assets. You know, half our modern pipe is typically a higher yield that might require further D rate due to the material performance factor. So a lot of times the pipes are X70 or so. So, you know that could require a further D rate. I guess thank you for your time. I appreciate you letting me speak. I look forward to the panel discussion.

>> [Applause]

>> We'll move on to the Q&A session right now.

>> We do have a couple of questions online. This question is from drew Gomer. Does PHMSA plan to incorporate ASME B31.12 in reference to part 192?

>> Currently we are evaluating and that's why we're having this PHMSA public meeting today. So I definitely encourage comments to the public meetings docket for consideration for potential future rule making.

>> I'll add to that that B31.12 is currently going through the revision process and look forward to reviewing the next version of that when it comes out.

>> Thank you. Next question is from Justin. Is there any estimate of when there will be comprehensive hydrogen regulations in place? It appears that some of the research mentioned here that would support that effort won't be done until late 2025.

>> I can take part of that at least. I think in some spaces there's already coverage for hydrogen. We did publish through San Diego national lab I believe it was earlier this year, it was called federal regulatory map I guess for hydrogen infrastructure that walked all the way through all of the different federal agencies that cover different aspects of putting hydrogen distribution systems in service. If I can dig up a link shortly I will I guess I'm not sure exactly where to send it but it's out there.

>> Okay.

>> Looks like now we have a question here.

>> Hi this is Bill Caram the pipeline safety trust. So I guess my question is mostly for

DOE. Given the known integrity issues with introducing hydrogen into pipelines, the safety issues that have been talked about of the flame ability range and the fact that hydrogen is a gene house gas with potential warming potential and leaks from infrastructure with the money that DOE has, how are you going to prioritize projects that don't put the public at added risk and meet our climate goals?

>> Well, I mean obviously safety is always a primary concern in any project we do we require safety plans from all of the projects that involve any kind of like beyond the lab or even beyond very small scale lab activities. In terms of addressing things like greenhouse gas effects or indirect greenhouse gas effects there is some work being planned in conjunction with folks like MIST that are going to examine and try and get better information because some of the information that's out there regarding this is not terribly refined. So we're going to try and get better numbers and better handle on that situation. We also currently got a solicitation that's that proposals have been submitted to that are going to be reviewed soon to develop sensors that can quantify PPB levels of hydrogen at facilities also to get a handle on how much is actually being released because just comparing hydrogen leaks to current methane leaks isn't necessarily fair if you're not careful about it. I don't know if I answered every bit of your question but I got pieces of it.

>> Okay. Thank you. We have another online question. This one from Shawn Wallace. Bear with me. As the speakers have discussed today the feasibility of hydrogen and hydrogen blending transportation from storage to gas transmission and gas distribution needs to be researched, modelled and tested to ensure public safety and system reliability. On site hydrogen production instead of hydrogen transportation for large volume customers like power generation appears to provide many benefits with less risks EG it's not typically transported through public space and it is maintained and operated by qualified industry professionals. However, I want to ask the question about in use feasibility and safety risks behind the residential meter. These piping systems are typically addressed by a variety of building, fire, fuel gas codes as adopted within each state and the piping systems contain a great variety of materials, components and the related that's span over many decades. Can one or more of the speakers discuss the concern of this weak link in the transportation network behind the meter and how we have a responsibility to work with our behind the meter jurisdictional partners to ensure public safety with these proposed increase blends of hydrogen in the gas blends that can increase leak rates and exposure limits? I will repeat the question.

>> That's fine. Let me answer from the standpoint of what I have seen over many years of many studies. You remember from our last panelist we had the someone representing the OTT group and that same token there's also a similar parallel group called UTD, that's for utilization technological development. They have over the years dedicated themselves to make sure they do a lot of testing in different not only equipment but also appliances. They are large programs in residential appliance

testing. One of the projects I showed is the hydrogen home. There's a lot going on in how the different codes are impacted by the use of hydrogen or hydrogen blend in the residential aspect. And the idea is to make sure that we do reach out an agreement with all subject matter experts and all different people from all the industry and the regulators in terms of what is it that we need to update in our codes in order to make this happen if this is doable at all. So all of that is still part of the conversations we're having as feasibility studies go further. Hope that answers the question. Not sure if you want to add anything.
>> I agree. I think there's a lot of joint efforts going around researching the issues as far as bringing hydrogen into the homes for power and all. I think there's a lot of studies taking place over seas as well in Europe. So maybe good coordination between the different entities I think will be beneficial.
>> Right. If I could add, certifying and standards and code organizations are all either already involved or getting involved folks like ICC and CSA and NFPA. This is all on their radar. Obviously we don't necessarily have all the answers yet but we're going to get at them.
>> Thank you. So this concludes our Q&A session this afternoon. I would like to thank all the presenters, both virtual and in person. We have a break I believe until 3:30. Thank you, everyone.
>> [Applause]
>> Thank you.
>> [Break being taken until 3:30 p.m. CT]

>> Ladies and gentlemen, we will begin again in one minute. May I ask you to please return to your seats.
>> All right everybody we're going to go ahead and get started. Good day everyone. I'm Robert Smith, bob Smith, I'm going to be the moderator for our final panel for today. On this panel we're going to talk about CO2 pipelines, carbon dioxide pipelines just like we did for the hydrogen panel earlier. We're going to have three speakers, three presenters for this panel. After the presentations we're going to go through a short Q&A session and entertain any questions from the floor and on line. I will announce a couple of corrections through the agendas. Without further adieu let's go to our first speaker. We will talk about the PHMSA regulation and what we regular visit. Vinny Holohan is going to talk about some of the safety challenges, some of the possible rule making that might be Afoot as well as some of the research that we recently awarded. With that Vinny.
>> Thank you, Bob. You're going to get a second helping. All right. Good afternoon again, working in the engineering and research group. Going to talk a little bit today about PHMSA's involvement with carbon dioxide pipelines including what regulations pertain to them, to the pipelines carrying soup critical fluid CO2. A few points regarding

pest performance and talk about what PHMSA is doing with R&D and projects in that space and regulatory development going on. I'll move quickly through this to keep with time. I like maps. This is a map of PHMSA's regulated CO2 pipelines, a little over 5,000 miles of super critical fluid, carbon dioxide pipelines represents about two and a quarter percent of the liquids pipelines that we regulate. Since 2010 the CO2 mileage just like hydrogen hasn't really increased marketably but we're feeling that an acceleration is coming. I know 15 to 20 years ago we thought the same thing but this seems to be maturing at a much faster rate. Most of these pipelines were originally built for enhanced oil recovery but different market forces are acting today. As far as regulations go, since 1992 when it was added to the code, CO2 pipelines have been regulated in part 195 transportation of liquid by pipeline regulations. Alongside other liquids, petroleum and products. They cover pipelines to move at the critical temperature in the super critical state. It's treated as a hazardous liquid but there's considerations that are a little bit different. These are a few highlights from the regulations that are specific to carbon dioxide. First the CO2 has to be 90% or more the fluid being transported. Has to be moved in super critical state to be regulated by part 195. There are compatibility requirements for the pipe in the facilities and your only material choice is seal. Let's see if I get to there. Pipeline materials and their design must take into account the potential low temperatures during operations. Design must also consider fracture propagation and valves must be considered for compatibility with the fluid being moved. As far as performance, these 21 years from 2001 to 2021 there were a total of 105 accidents reported to PHMSA on these slides. Zero fatalities resulted and one injury. Although that is one injury for in patient hospitalization. It was a contractor involved in the excavation damage. I'll note that injuries does not include out patient or people that were not staying in the hospital for treatment. Mississippi's incident that was discussed in more detail the last couple of days did have 45 injuries that did not result in patient hospitalization. I spoke earlier about this event. This generated some topics on carbon dioxide along with hydrogen pipelines to be looked at online. All right. A little bit of a shorter list. BMT commercial USA was awarded a project that is in progress. They will be looking at the design in weld requirements for new and existing pipelines for carbon dioxide. Texas A&M engineering experimentation will be looking at PIR. And finally carbon dioxide rule making. PHMSA's initiated rule thinking to update the requirements for CO2 pipelines including those related to emergency preparedness and response. Since the rule making started I'm not at liberty to discuss the areas that will or will not be included in the rule or considered for the rule. In my opinion we have a pretty good idea of what the gaps are out there and anything will be considered that can improve regulations down the road. These are the links that are in most of the presentations which I can skip over. And I think that's it. Thanks very much.

>> [Applause]

>> All right thanks for that. Once again we're going to hold questions until after the full

panel has presented. So our second presenter is Sarah Leung. She's the carbon transport program manager for the U.S. department of energy and correction to the agenda she's specifically going to talk about the CO2 transport, not production and storage research development and demonstration activities. Sarah.

>> Good afternoon. Thank you Bob. Thank you PHMSA for the invitation. I'm really glad to be a part of this forum alongside my DOE counter parts that presented earlier. I'll talk through what is carbon dioxide removal just to give some context for those who may not be as familiar and then talk into the RDND, to research, development and demonstration at the department of energy that we're supportive of as well as go into the provisions listed in the bipartisan infrastructure law, which is the other arm which is the funding opportunities that we have. So I find this interactive diagram really helpful to level set and give a sense of what the ecosystem for carbon management is. This is available on our website and it's meant to be an interactive helpful tool for stakeholders and, you know, if you were to go to the website and it's hyper linked here for this page when it's posted as part of this forum, but if you go to that website each of the ten blue dots you can find information on our research programs as well as fact sheets that we put out at DOE related tot aspects. CCUS and carbon dioxide removal, all of that is the umbrella term is carbon management. So essentially we're taking CO2 captured at point sources or captured and moving that from point A to point B being an end use of CO2 whether that be utilizing that for carbonbased materials like low carbon concrete, turning that into carbonbased chemicals like sustainable aviation fuels, turning that into other synthetic chemicals through fisher trops processes. It's in the permanent and safe geologic storage of safe CO2 in the under basically in the sub surface. And what you can see on the right of this diagram is what a class 6 weld would look like, which is regulated by EPA. So this is just a really helpful hint to show that CO2 transport is the intermediary that connects CO2 sources with CO2 end uses and permanent geological storage as a climate mitigation solution either on shore or offshore. So you heard from my counter parts earlier but fossil energy and carbon management, we added carbon management to our name. We've also been the name of fossil energy since the 1970s but this represents the new vision, you know, with the executive order 14008 when the U.S. rejoined the Paris agreement. Really what I want to take away from this slide if you look at the greenhouse gas emission pi chart you can see that industry and electricity represented by power plants of which fossil fuels is, you know, 60% today in the U.S. represents a huge opportunity for carbon management. It is going to be renewable energy and it's going to be carbon management on top of that. So it's not or but it's rather an and conversation. That's supported by the international energy agency, you know, the inner governmental panel on climate change AR6 working group 3. So all of that is, you know, if you take a look at that it's supportive of carbon management that's needed to meet net zero goals. Another thing too you should be aware of is our strategic vision that was put out earlier this year. That really represents the priority areas across

our office of fossil energy and carbon management. Of note, I want to point out, you've heard from the hydrogen and carbon management aspect but we also have domestic critical minerals within our office and what I'll be talking about mostly though is, you know, on CO2 conversion, CO2 removal and then CO2 transport that underpins, you know, being able to move CO2 capture to these end uses. So this is available online. There's a hyper link there too. Another important aspect that we put out, a road map for industrial decarbonization recently actually it's September of 2022 and really just underpins how CCUS is one of the strategic pathways for decarbonizing industry. It's one of four. These are the industries too that are the hard to abate sectors. So really just underpins that slide earlier that I showed which is the pi chart. So to get to the meat, to meet decarbonization goals CCUS and CDR is needed. We publicly have a goal, a target of catalyzing this growth for carbon storage. You can see these stage gate goals every five years, you know, right now we're in the validation phase and we do that through our flag ship program called carbon safe. But, you know, we have public targets that we want to get to one billion metric tons of CO2 injection by mid century. That's supporting the decarbonization goals. It's in the national climate strategy of the United States. It's a very, you know, universally acknowledged across multiple sources whether it be the national petroleum council, as you mentioned the IPPC, the national climate strategy, Princeton's net zero study. All these sources helped inform these targets for us. But I really want to point your attention towards the bottom of this slide which is the CO2 transport modelling that is shown. So as Vinny pointed out today we have 5300 miles of pipelines today. Mostly servicing enhanced oil recovery end uses and by the end of this decade what are we looking and projecting, it's 1100. So basically doubling CO2 pipelines. What I should note too is that this is not showing any offshore pipelines and so, you know, gulf of Mexico we've done a lot of storage characterization work as well as depleting gas reservoirs as well as saline formation. That represents another key opportunity of prolific storage resource in the United States. That's something that we work closely with the department of interiors BESI on who is doing regulations alongside BOEM for the continental shelf. Moderning for mid century showing looking at 2500 miles of pipelines. We are also looking at other modes of support in concert with pipelines. Talking about research, development and demonstration, you know, we have in this strategic vision our goal in the 5, 10, 15 for CO2 transport but what I relaxing wanted to dig into is, you know, what does that need to look like in the next five years and how do we do our DND at DOE. It's a complimentary arms looking at it from an early TRL to maturing that technology and demonstration and then deployment and we do that really heavily in an iterative process with our national labs, with academia, with industry and what we can see, you know, as we go to these first of a kind demonstrations to an endth of a kind we are proving and scaling up this technology. This technology existed since 1970, right. We've been doing this commercially, carbon capture and natural gas processing for decades. So we're building off that knowledge and taking it in different, you know, CO_2 capture sources now that we're capturing an iron and steel, cement, ethanol, different sources. The learning curve associated with these different sources so that you can collect the CO_2 and safely store it. So just wanted to point out here that offshore CCUS is definitely an area of research as well as transition of oil and gas infrastructure. Largely speaking, you know, at the 30,000 foot level what are we interested in. Interested in like I said transport is the intermediary but we're also very interested in understanding opportunities for other modes of connecting rail, barge, ship, truck and also in the repurpose of infrastructure as was mentioned earlier in conversation as well with hydrogen. So how do we do that? You know, as you mentioned that iterative approach between earlier stage TRL at the lab level and then demonstration projects funded by our funding opportunities. So this is the slide I want to focus a little bit of time on. Near term our RND. The near term next five years, these are three pillars in which I see a lot of potential in building something similar that mirrors the high blend initiative in hydrogen bringing together consortia of industry, academia, agencies bringing together public stakeholders as well as community is a huge demonstration. These three pillars are highlighted in origin. CO_2 and specifications and impact in integrity. How that differs today the CO_2 moved is typically from naturally occurring CO_2 and now we're talking about CO_2. So talking about how impurities that come from different sources impacts corrosion rate, how it impacts brittleness, two phase flow. Coming back to the principles thermal modelling that DOE can do is a integral piece of how DOE can contribute. Also on low temperature testing, what we do need to do to show brittleness and how we can impact operational procedures or guidance in operational procedures. Second one is CO_2 specific leak detection and emergency response protocols. So that was mentioned a bit in the PIR conversation. Completely agree. Thought that was a really great dialogue and we'll continue on with that work that was discussed. We are also very interested in how we can develop sensors that are sensitive to, you know, if there's an odor and additive added that is part of the OND that Bob shared earlier or Vinny shared looking at odor and additives and what that looks like and how a sensor at the PPB, part per billion, could detect this odorant and warrant a response in the span of seconds. The other component is cross cutting. So as I eluded to the other modes of transportation looking at how we can leverage other existing repurposing work that's done internationally and better understand the opportunity to repurpose infrastructure where it makes sense on a case by case basis in addition to natural gas pipelines but also product lines so ethaline and others. We do demonstration. I know I seem like I'm going quite past but we are under a limited amount of time. All these slides will be available after this as well. I just wanted to highlight a large view of the funding that was available in the bipartisan infrastructure law. The ones highlighted in green are the ones that CO_2 transport is integral too. Actually the regional direct air capture hubs recently dropped yesterday. So that's hot off the press. This is how we are going to catalyze the demonstration and such that it goes to commercialization and deployment. Over all some key facts is that $12 billion supportive of carbon management is part of the bipartisan infrastructure law. For those not generally aware cost share is 20% government, 20% industry or applicant and as how you get to higher levels demonstration is 50/50. That's typically how our cooperative agreements work in partnering with the department of energy. So zooming in particularly into the studies that's one of the provisions that we have. $100 million to support front end engineering design studies. This recently closed actually and it's supportive of new build out and repurposing. It's really to identify areas in which we are supportive of studies and we worked on this in concert with the department of transportation, FMSA. So we are aligned with specific provisions as well in there that are deliverables that are looking at pipeline set back, looking at odor and additives. Things that are critical for the delivery. It's going to be an interesting one. It's under review, expected probably in spring of next year. Another key component as well is in the build out of CO2 infrastructure we have what's called SIFIA, that is supported. That acts as the commercial arm. It helps with to bridge to bankability. They offer loan and loan guarantees on CO2 infrastructure ranging from pipelines to all other modes of transportation. So that one is live and the website to access that for those who are interested is listed there. And then the other part is actually on you know, the twoprong approach. We're anticipated future use of direct air capture and other sources come online, how do we develop infrastructure today with future sources in mind such that we aren't redigging. We dig once, we think about the capacity for the future today. So a bit of strategic planning there. The request for information is open right now and seeking input from all stakeholders. Another thing here that we're doing in concert with the department of transportation is on the CO2 transportation report and that's looking at the state of the art of where we are with moving CO2 today by rail, by truck, by barge, by ship and where are the efforts globally as well as the near term and the long term to provide cost effective service. So this was in our Congressional language in house report and Senate report. So this is something that we're working on right now and offered an opportunity to work not just with PHMSA but also with the railroad administration, office of the secretary federal high administration. So really working in concert with the department of transportation as we think about connecting CO2 transport networks on a regional and national scale. Just want to offer here the repurposing infrastructure, R&D priorities report is available on our website actually. It brought together 170 participants earlier this year virtually. We looked at regulatory and opportunities on repurposes not just pipelines but also wells for injection or monitoring for CO2. So this is my last slide. Really as we look towards building out infrastructure I think we need to be very thoughtful about infrastructure in the consideration of, you know, how the future uses are going to be, how do we colocate with renewable energy sources with hydrogen pipelines, you know, void stranded assets but also keep in mind centering environmental justice

considerations. We are working all of government in doing this in R&D and in deployment, you know, as seen as working very closely with the department of transportation, PHMSA in our fee studies and the roll out of that. A huge potential for intermodal pipeline transportation. A lot of activity is happening in ship transportation globally. Expect to see similarly in the United States especially around the gulf of Mexico. It's underpinned by not only the bipartisan infrastructure law that gives $12 billion for carbon management but the 45Q which raises credits for CO2 projects. Lastly we're seeing a lot of continued collaboration on R&D. We also have the college competition that we kicked off for workforce development. Anyone who knows anyone who is an undergrad or graduate students we have a challenge for students that can compete on proposing a CO2 regional network. That's how we're getting students to work on real world modelling and providing a feed study. The other thing I'll say is we're building up this network of infrastructure and storage is that there is some on going, you know, CCUS task force permitting task force that's being put together by the executive office of the president council of environmental quality. So I think that's another key aspect that's going to help streamline inner agency work, help support with R&D and help support with general permitting for CO2 infrastructure. So I think with that I'll open it up for questions at the end and thank you very much.
>> [Applause]
>> Sarah, thank you very much for the comprehensive presentation. There's a lot of important work going on in DOE. Excellent summary. Our third and final speaker Steve Lee, executive vice president for engineering and construction for the navigator CO2 project. He's going to give a summary of the project.
>> Thank you, Bob. That's kind of loud. First I'd like to thank PHMSA and the audience for giving me the opportunity to sit up and talk about the heartland greenway and some of the things that we're doing as a project team that's going to take a lot of the complex situations and processes we've seen throughout today and turn them into practical midstream development of CO2 transportation networks. First I'd like to go over just I've got a few slides here that I'd like to get through the first few slides pretty quick to leave a lot of time on the back end as we go to some of the practical aspects how we're implementing these design models, et cetera. So from high level standpoint, the heartland greenway started back in 2020 with around 5 million metric tons of, you know, capacity to support the ethanol plants in the Midwest. As the initiative of decarbonization and energy transmission the system has grown in the past 18 months to over 15 metric million tons per year equating to a 1300 mile system throughout the Midwest. We cover five states. We have permanent sequestration storage and formation in south central Illinois. Sequestration welds are class EPA6. We had 5 million metric tons. Looking at the future development, making sure there's enough storage the mount Simon formation was the ideal location. It's over a $3.2 billion capital investment and we are partnering with some of the leading ethanol producers

throughout the U.S. Some of the things I want to go through real quick is the economic benefits. We have a lot of the traditional pipeline infrastructure benefits of property tax, jobs, you know, the standard, you know, indirect aspects of economic development of large midstream asset installation. One of the things I would like to highlight here is the unique business model that navigator is using when it comes to the economics of our system. We are utilizing the common carrier tariffbased system when it's pretty much a dollar rate for the various metric tons that goes from point A to point B on our system. Coupled with some of the economic benefits very seldom are we able to talk about the environmental benefits of pipeline infrastructure. With the 15 million metric tons once the system is fully built out is equivalent to around 3.2 million vehicles annually off the roads or 18 million acres of reforestation throughout the country. One of the things that I did want to get into because there's been a lot of questions about, you know, details, data of the system as well as the CO2 transportation networks these days, you know, I like to use this timeline because one of the things that we're going through is there's no federal Nexis when it comes to the process. There's a lot of ambiguity. The state doesn't have the aspects for permitting, state by state, community by community, county by county. We started in 2020. What we did in order to help promote county and community engagement was mimic a process, get out in the community, talk to stakeholders, elected officials, landowners, energy responders of all things, on all their concerns. For the first two years we were in data acquisition mode talking to anybody that wanted to talk to us about some of their passions, fears, as well as some of the existing precedents of the 5300 miles of pipe that's already in service today. Right now as we've already submitted three out of the four PUC permits we're kind of rounding third base when comes to the front end cycle of the development where we're looking at the core permits. Wanted to make sure we're still early in the process.

We're not looking at going into construction until at least the middle of 2024 and that would be -- and in service somewhere in mid to late 2025.

So here's where I wanted to spend a little bit more time as we go through details of the system because there is a lot of ambiguity, a lot of passion out there that we're trying to do the right thing and be proactive in everything we do.

First of all, when it comes to the composition of our CO2, it is 98% pure CO2.

The remaining 2% is a makeup of nitrogen and oxygen.

The biggest thing is taking all the water out of CO2 and water creates carbonic acid.

As we take CO2 from ethanol in fertilizer plants, it's almost pure, it's just taking the water out and pushing -- compressing it and sending it down the pipeline.

One of the things, we talked about a lot with super critical, that's a defined term that is 88 degrees Fahrenheit as well as above 1,070 pounds per square inch.

Some of the other things we learned about was lined pipe.

Ductile fracture propagation, brittle fractures, you know, we're looking at starting with the current top industry standard of API5 Psl2 plus some additional aspects on the wall thickness and some of the toughness to mitigate fracture propagation just by using the certain line pipe characteristics.

Some of the things we also did when it comes to 195 is, we heard a lot of things about are there gaps, are there continued enhancements.

We looked at several different industry standards, regulations, but also reached out to the international community.

The biggest one that we started talking with is DNV, when there's 195 or additional guidance, looking at RPF 104, which is DNV's CO2 design and operation standard for recommended practice, I'm sorry.

The other thing is, as we talked PIRs this morning, there's things in 192 that might be applicable to CO2 as a best practice or that would promote public safety.

Some of the technical aspects of the system is, our normal operating pressure is between 1300 and 2100 pounds with a final MOP of 2200 pounds.

The pipe depth, as we talked about, reducing risks, we agreed and committed to being a lot deeper than most conventional oil and gas infrastructure.

Being below five feet means more protection from third-party damage.

Up in the ag fields and a lot of things going on, so as we get deeper, less third-party impacts plus in the event of a release, you have more overburden to help protect the flow of that.

The diameter of the system is between six and 20 inches, about half the system is eight and six, the other half is 12, 16 and 20.

But the operating temperature here, we changed lately, it was -- used to be 40 to 80.

That was more of the pipeline.

As we look at some of the characteristics of the capture locations, the compression and the pumps, we do have a range of 40 to 110 degrees Fahrenheit.

We've also already implemented our main line valves per the recent rule that came out in March, when it comes to looking at, you know, 20-mile spacing and non-HCAs, 15-mile within -- that's an environmental HC A's and seven and a half mile maximum spacing when it comes to populous areas from OPAsand HPAs.

We looked at the other thing we really took time, took us two and a half years just to develop our route, where a lot of the 195 pipelines, we look at minimizing the collective impact, and a lot of times that's routing that next to an existing utility to enhance public awareness as well as damage prevention.

However, when you take some of the other parameters of modeling, sometimes you have to deviate from those existing utilities in order to have a comprehensive route that does minimize that collective impact.

I think Vinny went through some of this stuff, but one of the things I did want to key in on, because there's a lot of people out there that are either saying that CO2 pipelines aren't regulated by PHMSA, I did put the definition back up, a fluid consisting of more than 90% carbon today dioxide models cools compressed to a super critical state, to kind of drive home the point, here are some of the carrots that we put up where we know we're rated by PHMSA and here are our interpretations that run that home.

When it comes to wear at 98% CO2.

The receipt points, the 21 capture sites, we will be above the 88 degrees Fahrenheit and the 1070 critical pressure.

As you start checking all the boxes, it is under PHMSA's jurisdiction from a navigator standpoint.

One of the things, maintaining the fluid state, you know, a minimum of 1200 pounds, again, when you look at the phase diagrams, it will always be a fluid or dense phase or super critical phase.

One of the things -- and this is where a lot of the opposition or the uncertainty comes into is the critical temperature, where any pipeline, unless it's insulated or heat traced, it will revert down to ground temperature a certain distance away from the pressure source.

And so we're coming out between 90 and 110 degrees, but eventually it will normalize to ground temperature, which would be below the 88-degree critical temperature.

We spent a lot of time this morning going over high consequence areas.

Don't want to regurgitate some of the definitions, but when it comes to HCAs, we as an operator have to take measures to mitigate all the consequences of the pipeline.

Not just within HCAs, could they affect HCAs, as well as they're growing, not just looking at the HCA maps that are generated.

It's getting out in the community and finding out from zoning individuals where these municipalities are growing, where are the developments moving as we develop this pipeline system.

I have listed some of the things here that we're doing when it comes to damage prevention, you know, cathodic protection, as well as leak protection.

We talked about absolutes.

There is no one size fits all to mitigate all risks.

Sometimes there's overlapping since that have to work together in order to have the proactive safety culture and public safety.

Okay.

Plume modeling.

Thanks to Mark for going through a lot of details.

It's very complex.

There's a lot of research going on.

Navigator ended up using two models to date, one, we used ALOHA, that is a recognized system, not only for modeling techniques but these are the ones that emergency responders use.

As we reach out and talk to some of these emergency response districts, this is the model that they're going to go to right off the bat.

As we used that for the first area to see these plume models and where they're going to affect, how they're going to affect, what's that concentration, et cetera.

After we did some initial routing, we did also use the DNV PHAST model, I think you may have heard about that earlier this morning, but this is the model that's proprietary, that, not only do they have the algorithms but this is also the reason for that -- the eight-inch plant rupture, to have instruments out there to validate their models that it can adequately predict the plume size and air dispersion of a CO_2 release.

How did we use these models?

I think Mark did a great job where it's not just a localized PIR, it's a -- one of the things with CO2 as he explained, it's toxic.

When it comes to the toxicity, it's mildly toxic by definition so you have to take concentration and exposure time to see the true effects of that CO2 plume upon humans and animals.

And so what we did at Navigator was, we took some of these models and brought them all the way up into the early stages of routing, and so to use this analogy of these petals, we had four different concentration levels and exposure times to have these different bands where we have initial routing where we're trying to avoid the risk altogether, instead of that being a reactive aspect under the 195 code, why not route the pipeline to avoid the risk.

What we get into, we have customers or ethanol plants that you can't always maintain that buffer and route around everything.

That's where we have the additional design and operation mitigation aspects, associated, to help maintain that same level of safety throughout the system.

The lessons learned from Satartia, was response, notifying the various responders, down in the Gulf Coast or in west Texas a lot of CO2 infrastructure, not much up in the Midwest so it's new to them, so training them and knowing who they call on.

We're reaching out to the counties as well as the mutual aid counties in order to have a comprehensive engagement with emergency response.

The last one here is the public awareness.

Again, you know, engagement, engagement, education, education, and it's tell them, tell them again.

We have a larger buffer to help reach out to the communities and educate them on what is CO2, what does it look like, how does it react, what are some of the risks attached with the CO2 pipeline, but what I would say from our different plume models, you know, we took one of those leaves and drew a complete circle all the way around to have a larger I'd say potential impact area on each one of these, and they grow in size.

The first one for routing was smaller, the second one was concentric circles getting out getting larger and larger as we go along.

So here is -- I want to go through -- basically when it comes to the initial routing buffer, this is what we used a lot of it for, is to identify direct HCA impacts.

And that's other populous areas, trying to wiggle around and avoid as much as possible.

When it comes to including the significant parameter to minimize, a lot of people aren't using plume models.

If you look back at the 5300 miles, they might not have used plume model.

When it looks at repurposing existing infrastructure, this is one of those parameters you might need to look at as you go through on the rehabilitation of existing infrastructure for CO2.

Additional design and operational mitigation buffers, this is where we looked at some of the things in 192 for guidance.

And 195, there is not a difference of design factors.

And so we look at as we encroach on some high population areas or HCAshaving different wall thicknesses, having more conservative design factors, also looking at the EFRD analysis to maybe put additional valves within the seven and a half miles from the new rule.

Also there we have enhanced leak detection, what we're seeing right now from leak detection is, you have a compressible fluid, and so you have computational mass balance, you have fiber, negative pressure waves, all those can work together to have a comprehensive leak detection system which would also help assist in response time and identifying a leak.

Some of the other -- we're talking about soil movements and surveillance.

This is what we look at, the areas that we would increase these inspections to make sure That we know what's going on, you know, along the pipeline route as well as some of the areas of impact and growth.

As we're getting into some of the emergency response aspects of it, this was the third buffer, this is where we looked at for indirect HCAs, when it comes to high population areas, so we think of a much larger potential impact area and band that goes language to do to make sure the people who live within that band and emergency responders know what's going on.

One of the things that we are doing already is CO_2 training, as we said earlier, about emergency responders in the Midwest don't know CO_2, and Q1 of 2023, we're having a comprehensive tour of every county we touch plus regional aid counties.

There's a lot of questions that we have.

Talking too fast.

Basically, you know, when we went -- what do we need as emergency responders.

We don't have the resources.

Help us understand what we need.

We don't know what they need.

We think we know but it's getting county by county, you know -- there you go.

And collaborative -- got it.

And so once we have the initial training, they can start thinking about their local communities, what resources do they have, what do they think they need.

And then also get some of the HAZOP districts to have that comprehensive engagement because it's not what Navigator thinks, it's what everybody thinks when it comes to not only emergency responders, police, fire, et cetera, you know, and one of the things that we did promote, it's our job to make sure those emergency responders are equipped that have the resources, so a lot of these communities, they're volunteer firefighters so sometimes we have to find strategic resources, third-party resources to place in order to address a potential CO_2 release in the community.

And so currently, you know, we are doing the training.

The next thing is developing a collaborative plan.

Next after we do the plan together, the resources to execute that plan.

Then we go back and we drill well before this pipeline goes into service to see the effectiveness of the plan and have that continual enhancement of these plans to ensure public safety.

One of the things I don't say -- probably run out of time but I want to get to some of the other things, one of the things on the public awareness that we're looking at is, you know, what we call the NAV 9-1-1 system.

There would be a polygon, similar to the A 11 polygons, when it comes to signing up landowners and emergency responders where in the unlikely event of a release they will be notified by text message, by phone, similar to how the Amber alerts work in Texas.

How much time do I have left?

I got a minute.

I'm going to jump all the way to this slide.

As we -- we've been hearing a lot about odorant.

One of the things from Satartia, they were confused for the first 30, 45 minutes on what was the product released.

Traditionally the gas industry uses the mercaptans that have

a rotten egg smell.

We're looking at developing in conjunction with the academic world as well as industry partners on a garlic smell, so basically enhancing the public awareness and the identification of that product because it does, it acts different.

It's not going to go up in the air.

It's going to basically follow the plume models and elevation.

As you look at some of the enhanced response to these events.

The last thing that I'd like to talk about is, you know, the leak detection.

In the past decade there's been phenomenal progress in quantitative leak detection systems, both from a real-time transient model, computational mass balance, the negative pressure wave, but one of the things that we're finding out is the fiber, you know, optics, is going to be a redundant system that can serve two purposes.

One, to have the acoustics for a leak, but you can also use it for intrusions to your right-of-way, as they have the quantitative aspects, finding out, is somebody digging on your pipeline that you weren't aware of.

All of these are proactive systems that have to work together to promote that public safety aspect of the Heartland Greenway.

That's all I've got.

Thank you for your time.

[applause]

>> Steve, thank you very much for that marathon.

I know you don't work for Marathon, but for that marathon effort there.

That's a great summary and it looks like you have a plan in place for just about everything we can think of.

It was great to see that effort.

With that, that concludes the presentation portion of the panel, and now we're going to go into a 10 mustn't Q&A.

It looks like we already have a question from online.

>> Sure.

Questions from online.

For PHMSA.

Several individuals were hospitalized per PHMSA's definition after the Satartia incident, with some victims in the hospital for several addition.

Deny berry new this and it's in our communication two days after the incident, it said two people are still at the hospital.

Shouldn't Denbury be required to revise its incident report to reflect the actual circumstances?

It seems important that injuries be reported accurately given the fact that these CO_2 pipelines are touted to be safe.

>> I won't be able to answer that question, so I'm looking to punt to Max or Alan.

>> This came up at Pipeline Safety Trust where there was -- that statement came up where they believed there was multiple individuals that were hospitalized overnight, multiple weeks.

We're having our data folks look into that, whether it's true or not, and if the operator needs to submit a supplemental report, but we are check on that.

>> Thanks, Max.

Another question?

>> Jon from Liquid energy pipeline association, thanks, everyone, for coming including Sarah from DOE.

One thing that struck me when I saw the lab opportunities slide, is, it looks like there's a potential for a lot of duplication between what DOE is thinking about, what PHMSA is doing, what PRCI is doing, even industry right now is working on best practices for emergency response, and I don't say that to be critical but to say that it's an opportunity, and we should all get together, especially given the different timelines, the research has their own timeline, industry standards will probably come out quicker, Congress is going to be there in the middle next year, so different stakeholders have an opportunity to deliver different products at different points.

So if we all sat down and I'm not saying divvy up but at least avoid duplication and know who's doing what and when things will come out, I think that would be great to coordinate because there is a lot going on by all the parties, whether it's addressing specific incidents in the past or proposed projects in the future.

It would be great if we could all get together and I'll certainly talk to you after the meeting.

>> I think I speak for the panel that we all agree but it looks like Sarah wants to add to the point.

>> Definitely thank you for the comment and we seek to be complementary, not to duplicative, so completely agree and look forward to chatting more.

>> Another question?

I'm sorry.

>> Go ahead.

>> Bill Caram, Pipeline Safety Trust.

There are a lot of regulatory gaps but also a lot of knowledge gaps that remain on CO2 pipelines as evidenced by the R&D program and the projects that have been approved recently that we won't have the results from for a couple of years.

In your plans, do you -- will you be incorporating what's learned from those -- it seems like you're pretty far along in the knowledge process so how will you incorporate what's found in those R&D projects?

>> I think I'll take that one first, for PHMSA, at least.

Bill, as you know in your participation in the program, where we started the pre-award process to try to bring everyone to design a project with the right kind of components of participation so we're just not creating a coffeetable book at the end of the project.

We want to be able to reach out and connect the knowledge to standards, if it's knowledge transfer, or if it's technology development project, bring in the right type of maybe technology service providers early into the process, demonstrate it thoroughly and hopefully be able to remove barriers for tech transfer.

So duly noted.

And it's really one of the hallmarks of our program, is to bring that collaboration, so we are successful, create the highest likelihood of success at the end.

Thanks for the question.

>> I'll add to it.

I echo what Bob just said.

Additionally, DOE hosts annual project review meetings that are open to the public, every August, and any of the funded projects will be reported out on there so I think that's a great forum to communicate to everyone, anyone who's interested on the knowledge gained from these funded projects.

I think the other component, too, for DOE-specific projects, we have a segment that's called societal considerations and impacts, and as part of that, projects going forward are having to consider and implement programs that look at how we can have two-way engagements with communities and community benefits plans such that communities have access to data at certain times of the project, but this is a forward look, and something that hasn't been done, you know, so much in the past, and we're living and learning at DOE but that's one of the integral ways in which I see that information just doesn't get siloed in research projects but is available and putting these procedures and structures in place such that data is accessible to communities is one of the key roles I see of our funded projects.

>> We have time for one more question.

Rick, ExxonMobil to respond to Jon's excellent question on the CO2 task force lead within PRCI.

We all work collaboratively with multiple agencies.

Happy to talk to you more about that afterwards but to my previous comment about siloing, we want to make sure that we try to prevent silo, particularly in the CO2 space and hydrogen space.

My question has to do with the odorization in future pipelines, and the one thing I haven't heard is whether they have any adverse impact on things like corrosion control, namely, through change in dewpoint and whether there's any impact --

>>

[inaudible audience comment]

>> You've been cut off.

[laughter]

[inaudible audience comment]

>> Steve, I guess I might want to start with you on that one.

>> Sure.

The answer is yes to all those.

One of the things that we look at with the impurities of CO2, especially in the dense phase, a small imputer makes it react very differently.

So we're utilizing the Binnel two methods as we look at the composition of the Heartland Greenway and the present of some of these odorant, but how does it deal in sequestration in the formations.

And so that's why we are working with Penn State and some of the industry odorants to do all this testing, we've been testing for almost nine months, but it's a process, as we find we had several we were reviewing, rear probably down to two or three, and we don't have the full answer yet but yes, it does impact several things, so it's not an easy yes or no at this point on what's the perfect one.

>> Everyone, thank you very much for your questions.

That concludes the Q&A.

Let's give a round of applause for this fantastic panel.

[applause]

All right.

And with that, we're going to move to the final presentation, I'm going to be giving it.

So convenient to be up on stage.

I think I introduced myself fully before, the research program manager for PHMSA's pipeline safety program.

And I'm going to talk to you a little bit about -- a short presentation.

We're going to look at some of the research topics that you all helped us derive, develop, and try to understand if they're still important enough as something we should look into, solicit and fund.

Take these off.

Just kind of in review, when we have these R&D forums, regardless if it's for other subjects outside of pipeline, gas storage or LNG, like the one we just held, this is an opportunity to bring everyone together to talk about developing -- identifying real gaps, gaps that are not duplicating something else that's going on by another federal agency, that's been noted, PRCI or others.

We want them to complement where possible and leverage opportunities from existing and ongoing research.

They're definitely intended to be a priority need that we should try to fund some research, solicit and fund.

But they are a snapshot in time and that's why we want to revisit some of these topics.

They're a form of peer review from the standpoint of a pre-solicitation review, to develop some of the subject matter experts that are in the room, and it really creates a wonderful opportunity for cross cutting, collaboration, all the goals that we really have in the program to make sure we create the highest likelihood of success.

So you can see the data over on the right.

We took a look at the 2020 and 2021 R&D forums.

The last two full pipeline ones that we did that had other subjects like LNG and gas storage.

From the output of these forums, we did solicit multiple topics.

We did actually combine some topics.

We had topics that weren't taken at that time that other federal agencies like RPE did in their repair forum, and the remaining topics you see there, five from 2020 and five from 2021, fall into some of these programmatic areas that we have, threat prevention, underground natural gas storage, anomaly detection/characterization, methane abatement and breakout tank corrosion.

So I'm not going to go through each one of those 10 topics, I'm going to leave you all with some homework.

If you're interested in participating, it's voluntary.

If you go back to the website that you registered, and also for the virtual attendees where your got the link to participate in the webcast, there's a file listed there entitled list of unfunded research topics from prior forums.

Take a look at that.

It has the 10 topics that I mentioned before that we haven't, you know, done anything with.

And we want to be able to see what the interest level still is, so we urge you to take a look at leaving a comment on the docket that was established for this public event, it's listed on the meeting page that you registered, it's listed right there in the presentation, you just have to go to regulations.gov type in the docket and it allows you the opportunity to leave a comment.

Review those topics.

We want to understand the remaining importance for our program to solicit.

Leave us a comment.

The docket is going to be open for at least another 30 days.

At some point we do have to take a look at what was submitted, make a call, pull together a full solicitation, and solicit for these research projects.

So next step is basically what I said.

We're going to look at pulling that together sometime early in January and look to hear from comments that are left.

And with that, thank you very much.

[applause]

With that, I want to reintroduce Alan Mayberry, associate administrator for pipeline safety.

He'll give the final remarks and close of day two.

Alan.

>> Thanks, Bob, and thanks to everyone who stayed.

I think we have about, what, 50 people in the room, maybe a tad shy.

And then today on the webcast, and thank you all on the webcast, we had about 285, so good participation.

A little bit less than yesterday, but, you know, the topics drive the attendance, and certainly today was a shift from yesterday where we talked about, you know, accidents and lessons learned from accidents, was the big focus.

But, yeah, we'll wrap up quickly here.

We started off the day talking about PIR for gas.

We brought in the father of PIR, Mark Stephens, who was on the original team who developed that, and it was great to hear his perspective on, you know, the background to PIR and give us some things to ponder related to what it considered, what it didn't consider.

And then of course we had the panel discussion that brought up, you know, the various issues related to that.

I will tell you one thing, from our perspective, and like I said yesterday, you know, from PHMSA's perspective, you know, we're doing this meeting here to learn and to establish a public record and be transparent in the deliberations.

We will address the NTSB recommendation related to PIR.

I think I mentioned that earlier, but I just wanted to reiterate that.

And we're open.

I think it's probably a good opportunity, a good time in the spirit of pipeline safety management systems to take a look and see where we may need to go on that, perhaps there are changes that need to be made.

Certainly we're serious about looking at and addressing the NTSB recommendation.

And getting better, it's all about getting better.

Then we had a great discussion after lunch -- by the way, we also talked about the PIR for CO2 and hydrogen.

I know we use PIR and CO2 in the same breath.

It's probably less about being a radius or a circle and more about maybe a blob or a shape that is less of a circle and more of a -- determined by topography of the area we're dealing with.

But nonetheless, it's a convenient term to use, PIR, which tends to be, you know, a circle that we calculate for gas pipelines.

But nonetheless, obviously there's a lot of work to do there, and the session we had in the afternoon, we heard a bit about some of the research projects we have and certainly learning more about how we need to determine the PIR, concept for CO2 pipelines is a topic of discussion -- or one project related to R&D.

We also talked about a lot of the success stories in R&D.

I think that's a great story and that's just our program, and then we heard from our partners, various research partners on success stories that they were mentioning.

We talked about hydrogen and hydrogen blending.

Vinny did a great job of just talking about our current framework, what we currently regulate related to that and I will tell you, related to -- I'll mention CO2 in a minute, but, you know, our usual -- the way we evolve the regulations, the federal standard for pipeline safety is, we address what we can address, we develop rule making, policy for what we can address.

With hydrogen, there are a lot of things we don't know, and a lot of research going on as evidenced by the great discussion we just had.

So I think we're going to need to see the outcome of that and apply the lessons from that to policy making as we go forward.

You know, kind of scratching our head on the next step, but, you know, it may be some sort of advisory to just recognize related to the -- you know, the difference in the properties of hydrogen and things you need to consider for emergency response, things that could be tightened up in that area.

So that's one area we're looking at.

Obviously, you know, we're considering possibly rulemaking in that area as well.

Just wanted to give a special thanks.

We had a kind of understated international component here but I appreciate the involvement of HSC, our counterparts in the U.K., and Dr. Simon Gant.

I thought his input and the advances they've made over in the old country were quite informative.

As you know, over there, they're a bit ahead of us related to the -- looking at hydrogen.

And then related to CO2 and similarly like Vinny mentioned, we are in rulemaking right now, we can't really talk about the particulars there, but in our usual model for developing national policy making, we're addressing what we can address now, I think it's fair to say.

I'm see that in the form of a proposed rule in the coming months.

I would hope it would be sometime by next year, but we'll see how that progresses, as you know, as many of you know, we have a very busy regulatory docket but it is a high priority for us and we do realize that there's some gaps we need to address, which are also being addressed with technology.

And just a bit on that, related to technology, you know, as we get the learnings from research, we'll apply them, you know, as needed to the oversight program that we have, and obviously in a very transparent way to make sure that we get the information out.

Two other things I wanted to mention related to CO2 is, our intent here this week was really to whet your appetite on CO2.

We recognize that probably not all the stakeholders that are out there that have a vested interest in CO2 were able to make it, so this is really to whet your appetite.

And we anticipate having a -- [no audio]

Gas pipelines explode. How far away is enough to survive?

By Mike Soraghan | 01/24/2023 06:56 AM EST

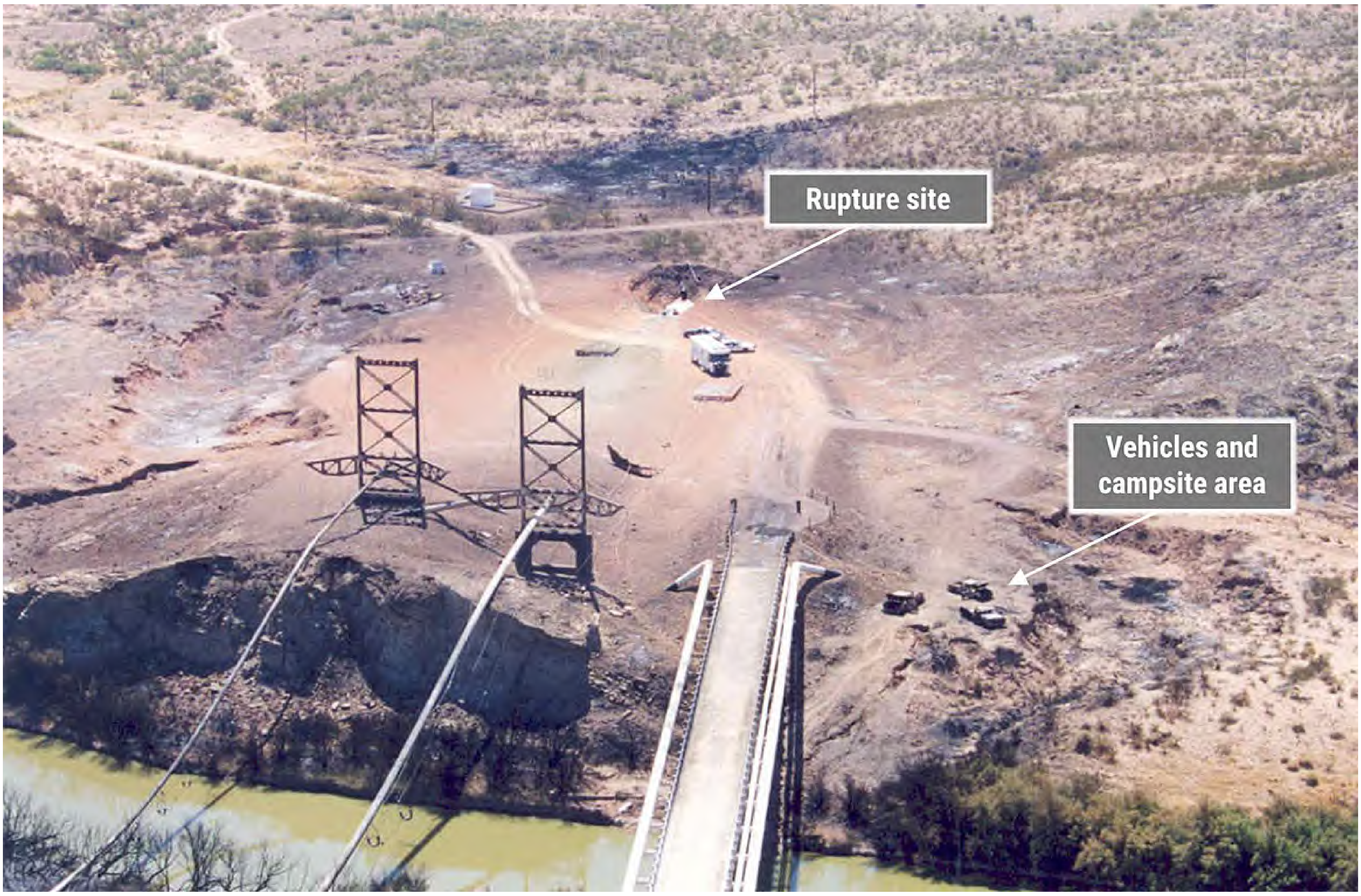
A federal formula assumes a person will flee from a pipeline explosion within five seconds. Pipeline safety advocates call that a "fairy tale" that results in a blast zone that vastly underestimates the reach of debris and flames.

The site of a 2019 gas pipeline explosion near Danville, Ky., that killed a woman in a mobile home nearby is shown. Investigators said the rupture was caused by defective pipe compounded by ineffective maintenance. Regulators found damage exceeded the "potential impact radius" predicted using an industry-crafted federal formula. NTSB

An extended family of 12 was sleeping on the banks of New Mexico's Pecos River on an August morning two decades ago when a nearby gas pipeline ruptured.

The explosion spit out three sections of severed steel pipe and opened a blowtorch 2 ½ feet wide. Flames reached across the desert terrain to the family's campsite, scorching their pickup trucks and melting sleeping bags.

No one survived. All 12 family members — linked by marriage and shared grandchildren — died at the campsite, or later at the hospital. That included 6-month-old twins Timber and Tamber Heady.



An explosion on a gas transmission pipeline in Carlsbad N.M., in August 2000 killed 12 people camping nearby. | NTSB

The blast was 675 feet from the campsite, not far enough to spare them. But federal regulators later adopted a formula, still in use today, that would have deemed the family safe at 600 feet away.

Now a federal safety watchdog is urging regulators to change the calculation, which sets what's called a "potential impact radius," or PIR. It has many other names: "blast zone," "incineration zone," "hazard area."

Whatever one calls it, the National Transportation Safety Board (NTSB) says the formula significantly underestimates the danger of gas pipeline explosions and called it "inconsistent" with evidence in arecent report (https://subscriber.politicopro.com/eenews/f/eenews/?id=00000183-3ead-dc0e-a9bb-7fefb92d0000) (*Energywire* (https://subscriber.politicopro.com/article/eenews/2022/09/15/feds-blame-enbridge-for-fatal-ky-gas-pipeline-explosion-00056803), Sept. 15, 2022).

Other safety advocates put it more bluntly.

"The whole thing was a fantasy story, like a fairy tale," said Royce Deaver, a pipeline consultant who worked for Exxon Mobil Corp. for more than 33 years. He has criticized the impact formula for years, and his research was cited in the NTSB report.

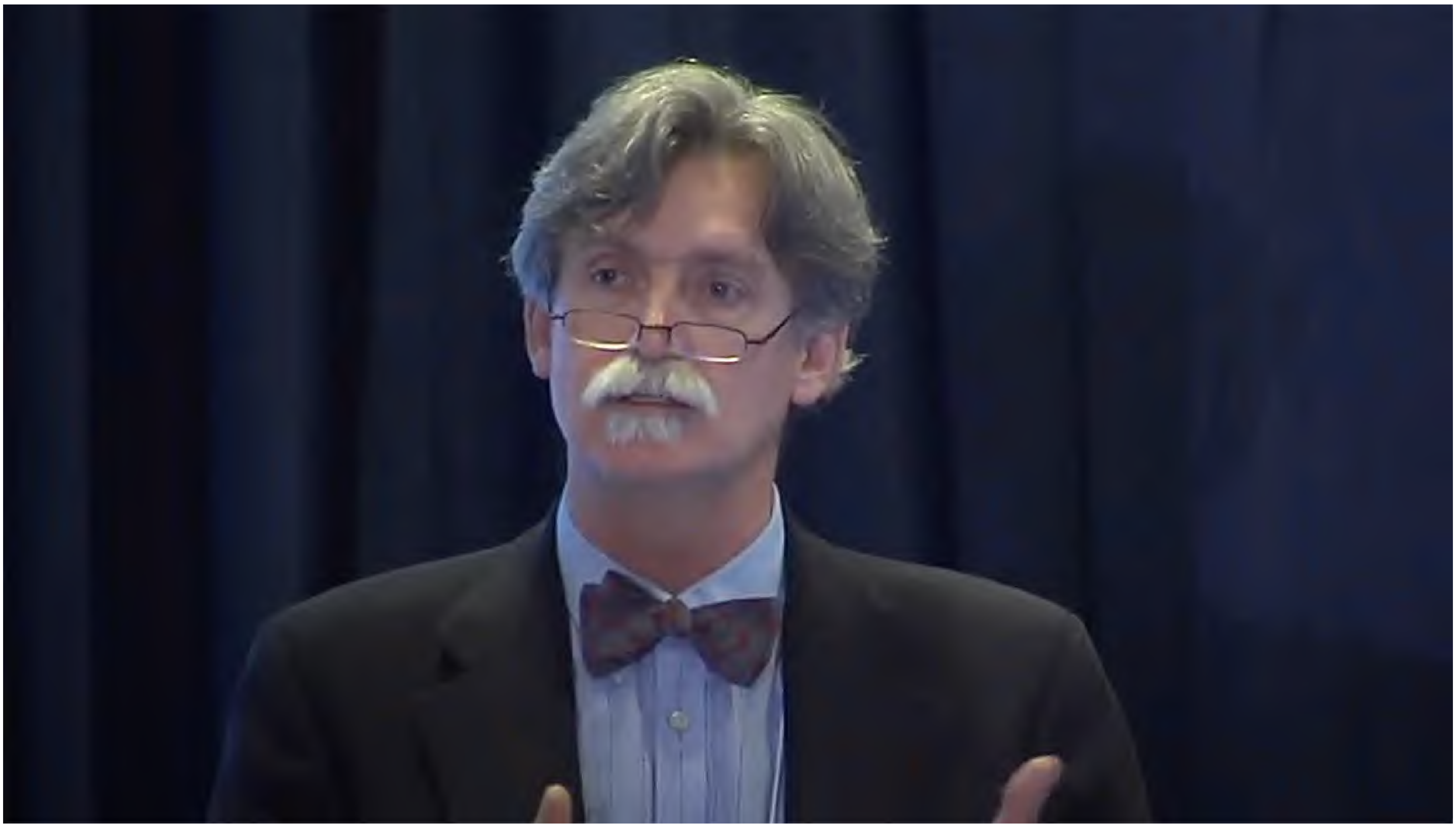
Critics say the industry-crafted formula shows how federal pipeline oversight is tilted away from safety in favor of pipeline operators. The Pipeline and Hazardous Materials Safety Administration (PHMSA) has indicated it is willing to change the formula, telling the NTSB it would "strongly consider" modifications to ensure bigger safety margins.

'You're gonna run'

Any increase in the radius of the blast zone could mean costly pipe upgrades for oil and gas companies. But even the engineer who devisedthe formula (https://subscriber.politicopro.com/eenews/f/eenews/?id=00000185-0369-d955-a1a7-1b7f72e10000) has acknowledged it has gaps.

"Don't assume that you can stand and watch this fire at the edge of the PIR," Mark Stephens told a Transportation Research Board (TRB) panel in October. "You can't. You're gonna run. You're just likely to survive."

Stephens alsodefended the formula (https://subscriber.politicopro.com/eenews/f/eenews/?id=00000185-0367-d955-a1a7-1b77fef60000), telling the panel it has held up pretty well since he put together the calculations in 2000 for a Canadian company called C-FER Technologies. The Department of Transportation, which houses PHMSA, later adopted the formula as its own.



Mark Stephens, recently retired from C-FER Technologies, a Canadian firm, developed the formula federal regulators use for the "potential impact radius" of a pipeline explosion, sometimes called a "blast zone." Here he appears at the 2016 conference of the Pipeline Safety Trust. | Courtesy Pipeline Safety Trust

Attempts to reach Stephens, recently retired from C-FER, were unsuccessful. C-FER also did not respond to calls and emails seeking comment on the formula.

NTSB pipeline accident investigator Sara Lyons told the TRB panel that regulators should add an extra "safety margin" to account for the many variables that come with a massive explosion.

Some safety advocates would like to see regulators go even further.

Bill Caram, executive director of the advocacy group Pipeline Safety Trust, said the NTSB's recommendation is a chance to do more than tinker with the formula. Regulators should look at the land planning around the impact zone, he said, including whether to prohibit pipelines near buildings and even ban building near existing pipelines. That, he acknowledged, might be beyond PHMSA's jurisdiction.

"Improving the formula probably wouldn't have a large impact on pipeline safety," Caram said. "It's time to revisit these old assumptions."

In late November, PHMSA Deputy Administrator Tristan Brown sent a letter (https://subscriber.politicopro.com/eenews/f/eenews/?id=00000185-311b-de47-a3e7-779b6a130000) to NTSB that said the agency has set up a team to consider changes to the formula. At a public meeting in Houston last month, Allen Mayberry, the top career pipeline-safety official at PHMSA, said there isn't an official rulemaking process underway, but added that "It's up for consideration. We're exploring options right now."

Creating or amending PHMSA rules, though, often takes many years.

The importance of five seconds

The use of the blast radius by regulators is oblique and not easily understood. It does not create a buffer or "no man's land" along the pipeline route. There are no rules restricting building homes or even campsites within the radius, or "blast zone." And companies can install their pipelines within the blast radius of a house or school.

Instead, the impact radius serves as a planning tool. PHMSA rules require companies to use it to determine if the area around their pipelines is densely populated enough to require extra safety measures, such as using thicker-walled pipe, testing the pipeline at higher pressures or operating the pipeline at lower pressures. The impact radius is also used in drafting emergency response plans to suggest places to start looking for damage and victims.

A gas explosion in 2019 in Moreland, Ky., killed one person and caused fires in several homes. | Somerset Pulaski County Special Response/KY Haz-Mat 12/Facebook

If the estimate of the impact radius is underestimated, Caram said, then many miles of existing pipelines were built and tested to insufficient standards.

The radius is supposed to predict the area that would be "severely impacted" if a gas pipeline explodes. Put a little differently, a person just outside that circle at the time of the blast should have a 99 percent chance of surviving an explosion.

But that survival rate rests on a set of assumptions that some safety advocates find unreasonable. It assumes that the person can decide within five seconds to flee, then run at about 5 mph for 25 seconds and find shelter within 200 feet. Stephens has said that he based that on previous research.

Safety advocates argue that elderly people or young children can't run that fast. And they note there are many reasons a person wouldn't be able to decide what to do in five seconds, starting with sleeping.

"They've got this little illusion of a story that people can do that in five seconds," Deaver said.

The NTSB also said the formula falls short by assuming that the flames and heat from a ruptured pipeline radiate upward. The agency said in its report that flames from high-pressure pipelines mostly shoot horizontally, toward buildings and people nearby.

The predicted zone also doesn't cover the complete extent of the explosion. Stephens told the TRB panel that the formula wasn't designed to predict the "peak initial" blast.

Instead, he said, it reflects the average reach of the fire for the first minute of the explosion, when people nearby are scrambling for safety.

Simple — and industry-preferred

At least twice since 2017, explosions have blown lengths of steel pipe beyond the impact radius, according to a PHMSA analysis.

That analysis looked at 17 pipeline explosions (https://subscriber.politicopro.com/eenews/f/eenews/?id=00000185-036a-d955-a1a7-1b7e65f40000) between 2017 and 2022. In three of them, the agency found that the "impact area" exceeded the potential impact radius.

One of them was a fatal explosion in Kentucky in 2019, which prompted the recent NTSB report that questioned the PIR formula. In that explosion, the formula predicted an impact area of 630 feet. But PHMSA said the damage extended past 700 feet.

The pipe section ejected by the blast landed 600 feet away from the rupture. The NTSB reported that an off-duty sheriff's deputy found an elderly injured couple 480 feet from the blast crater, and the intensity of the heat was more than he could handle. He could not reach the body of the woman killed in the blast, which was 640 feet from the crater.

The NTSB report on the Kentucky explosion cited three earlier instances with damage outside the blast circle: the New Mexico explosion; a 2018 blast in West Virginia; and a 2010 explosion in San Bruno, Calif., that killed eight (*Energywire* (https://subscriber.politicopro.com/article/eenews/2018/11/15/no-penalties-for-90-of-pipeline-blasts-035988), Nov. 18, 2018; *Energywire* (https://subscriber.politicopro.com/article/eenews/2016/06/17/pg-e-criminal-trial-begins-in-san-bruno-pipeline-blast-074402), June 17, 2016).

The formula dates back more than two decades, when Stephens and C-FER were hired to create it by an industry group called the Gas Research Institute, which is now part of GTI Energy. GTI, which is based near Chicago, did not respond to requests for comment about the formula.

The Interstate Natural Gas Association of America, the trade group representing gas transmission pipeline operators, declined to comment.

Stephens has said that he aimed to simplify what could be a very complex calculation. The result is fairly straightforward. Regulators take the diameter of the pipeline and the pressure used to move the gas and run it through the formula. The resulting number is the size, in feet, of the potential impact radius.

"The approach I took was to make it as simple as possible to understand," he said.

In his report for C-FER, Stephens wrote that his model is "preferred" because it comes up with a smaller radius than more generic models. It does this, the report said, by factoring in incomplete combustion of the gas and accounting for the heat absorbed by the atmosphere before it can reach buildings and people.

The most recent accident it looked at was in 1994, and the highest pressure on the list of "relevant" ruptures was 1,016 pounds per square inch (psi). Many new pipelines operate at higher pressures, such as Energy Transfer's Rover pipeline, which operates at up to 1,440 psi.

Stephens' formula was implemented in 2004 as part of a set of operating regulations for gas transmission lines known as "integrity management," or IM.

Deaver, the pipeline consultant, believes PHMSA chose to use an industry-commissioned formula in order to avoid opposition from pipeline companies. Pipeline regulators, he said, have long relied on industry resources because of underfunding.

To him, it's an example of the many complex ways that the oil and gas industry limits regulations. PHMSA officials say they stick with science and engineering principles with safety as the top priority. But safety advocates say the agency has less room to maneuver than other agencies because Congress imposed tighter limits, such as stricter cost-benefit analyses to ensure a regulation's cost to industry doesn't exceed its benefits.

"The pipelines," Deaver said, "control the cost and the benefit of it."

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Issued: August 15, 2022 Pipeline Investigation Report: NTSB/PIR-22/02

Enbridge Inc. Natural Gas Transmission Pipeline Rupture and Fire

Danville, Kentucky
August 1, 2019

Abstract: This report discusses the August 1, 2019, rupture of an Enbridge Inc. 30-inch natural gas transmission pipeline in Danville, Kentucky, which released about 101.5 million cubic feet of natural gas that ignited. The accident resulted in 1 fatality, 6 injuries, and the evacuation of over 75 people, as well as property damage in the surrounding area. Safety issues identified in this report include nonconservative assumptions used to calculate the potential impact radius, incomplete evaluation of the risks caused by a change of gas flow direction, limitations in data analysis related to in-line inspection tool usage, incomplete assessment of threats and threat interactions, and missed opportunities in training and requalification practices. Three recommendations are made to Enbridge Inc., and three recommendations are made to the Pipeline and Hazardous Materials Safety Administration.

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Abbreviations and Acronyms

API	American Petroleum Institute
CFR	*Code of Federal Regulations*
CS	compressor station
DEGT	Duke Energy Gas Transmission
HCA	high consequence area
HSMFL	hard spot magnetic flux leakage
ILI	in-line inspection
IM	integrity management
L15 VS4	assessment segment "Line 15 Valve Section 4"
LCFPD	Lincoln County Fire Protection District
MAOP	maximum allowable operating pressure
NTSB	National Transportation Safety Board
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIR	potential impact radius
P-PIC	Process Performance Improvement Consultants, LLC
psig	pounds per square inch, gauge
SCADA	Supervisory Control and Data Acquisition
STD	Standard
TET	Texas Eastern Transmission, LP

Executive Summary

What Happened

On August 1, 2019, at 1:23 a.m. local time, an Enbridge Inc. (Enbridge) 30-inch natural gas transmission pipeline ruptured in Danville, Kentucky, releasing about 101.5 million cubic feet of natural gas that ignited. The accident resulted in 1 fatality, 6 injuries, and the evacuation of over 75 people. Five residences were destroyed by resulting structure fires, and an additional 14 were damaged. A nearby railroad track was also damaged, and over 30 acres of land were burned.

At 1:26 a.m., numerous local emergency response agencies were dispatched to the accident; the Lincoln County Fire Protection District was the first to arrive at 1:37 a.m. The fire department and other emergency responders focused on evacuations and medical transport while Enbridge crews worked to isolate and shut down the pipeline. At 2:19 a.m., the ruptured pipeline segment was isolated. By 4:13 a.m., all fire suppression activities had concluded.

What We Found

We found that the combination of a pre-existing hard spot (a manufacturing defect), degraded coating, and ineffective cathodic protection applied following a 2014 gas flow reversal project resulted in hydrogen-induced cracking at the outer surface of the pipeline and its subsequent failure. We also found that the Pipeline and Hazardous Materials Safety Administration's (PHMSA's) equation for determining the potential impact radius of a pipeline rupture is based on assumptions that are inconsistent with findings from recent natural gas ruptures and human response data; thus, high consequence areas determined using the equation do not include the full area at risk.

Enbridge and Spectra Energy Partners LP did not effectively identify, investigate or manage the impact of a 2014 gas flow reversal project for the level of hydrogen evolution, or generation, in the pipeline surface, which ultimately contributed to the failure of the pipeline. The extent of hard spots on pipelines evaluated using the hard spot magnetic flux leakage in-line inspection tool is likely unknown because of the limitations of the tool and analysis techniques found during this investigation. Further, insufficient data were available to support Enbridge's classification of the threat of hard spots in the accident pipeline as inactive. Enbridge underestimated the risk posed by hard spots because its processes and procedures were inconsistent with PHMSA guidance and industry knowledge of hard spot threat interactions.

Enbridge also missed an opportunity to address a lack of knowledge displayed by the Danville compressor station operator in an emergency shutdown earlier in

2019; addressing this may have reduced the delay in the operator's response at the station on the morning of the accident.

We determined that the probable cause of the August 1, 2019, Enbridge pipeline rupture and resulting fire was the combination of a pre-existing hard spot (a manufacturing defect), degraded coating, and ineffective cathodic protection applied following a 2014 gas flow reversal project, which resulted in hydrogen-induced cracking at the outer surface of Line 15 and the subsequent failure of the pipeline. Contributing to the accident was the 2014 gas flow reversal project that increased external corrosion and hydrogen evolution. Also contributing to this accident was Enbridge's integrity management program, which did not accurately assess the integrity of the pipeline or estimate the risk from interacting threats.

What We Recommended

As a result of this investigation, we made a recommendation to PHMSA to revise the regulations regarding potential impact radius methodology based on data from recent natural gas pipeline ruptures and human response considerations. We also recommended that PHMSA advise natural gas transmission operators on the circumstances of this accident, the need to evaluate the risks associated with flow reversal projects, the impacts of such projects on hydrogen-induced cracking, the possible data limitations associated with the use of in-line inspection tools and analysis used in hard spot management programs, and the need to follow industry best practices when conducting in-line inspection data analysis.

We made recommendations to Enbridge to evaluate the effectiveness of its corrosion control equipment and infrastructure following a major change in operations, like a gas flow reversal; modify its integrity management program to better address threats and threat interactions; and require disqualification, remedial training, and/or requalification of covered tasks whenever an employee does not follow procedures when responding to an emergency shutdown, rupture, or other abnormal operation.

1. Factual Information

1.1 Accident Description

On August 1, 2019, at 1:23 a.m. local time, a 30-inch-diameter natural gas transmission pipeline, Line 15, owned and operated by Enbridge Inc. (Enbridge), ruptured near Danville, Kentucky.[1] As a result of the rupture, 1 person was fatally injured, 6 people were hospitalized, and over 75 residents were evacuated from the Indian Camp Subdivision, a residential community. The rupture released about 101.5 million cubic feet of natural gas and ejected a 33.2-foot-long section of pipeline that landed about 481 feet southwest of the rupture site. The releasing gas ignited and burned. Five residences in the subdivision were destroyed by fires, and an additional 14 were damaged. (See figure 1.) A nearby railroad track owned and operated by the Norfolk Southern Corporation sustained fire damage.

Figure 1. Aerial view of the Indian Camp Subdivision overlaid on Google Earth image.

Enbridge personnel completed isolation of the affected pipeline segment at 2:19 a.m., while a Lincoln County Sheriff's Office deputy sheriff and the Lincoln

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[1] (a) Visit ntsb.gov to find additional information in the public docket for this NTSB accident investigation (case number PLD19FR002). Use the CAROL Query to search safety recommendations and investigations. (b) The ruptured pipeline was one of three parallel pipelines traversing the area. The pipelines will be discussed in more detail in section 1.4.1. (c) All times in this report are local time.

County Fire Protection District worked to rescue and evacuate residents and minimize the spread of the fire. The grass fires in the surrounding area were extinguished at 3:20 a.m., and the structure fires were extinguished at 4:13 a.m.

1.2 Emergency Response

1.2.1 Enbridge Response

An Enbridge employee received a call at 1:23 a.m. about the event from a friend who lived near the rupture site. Enbridge's gas control center received an informational pressure rate-of-change alarm on the discharge (south) side of the Danville compressor station (CS) on Line 15 at 1:24 a.m.[2] This alarm indicated a pressure drop in the pipeline of about 105 pounds per square inch (psi) in 1 minute. At 1:25 a.m. the Enbridge gas control center received a second pressure rate-of-change alarm.

To isolate the affected pipeline segment, Enbridge personnel needed to close valves manually at the Danville CS (valve 15-393) and at a valve station located near Highway 49 (valve 15-382). (See figure 2).

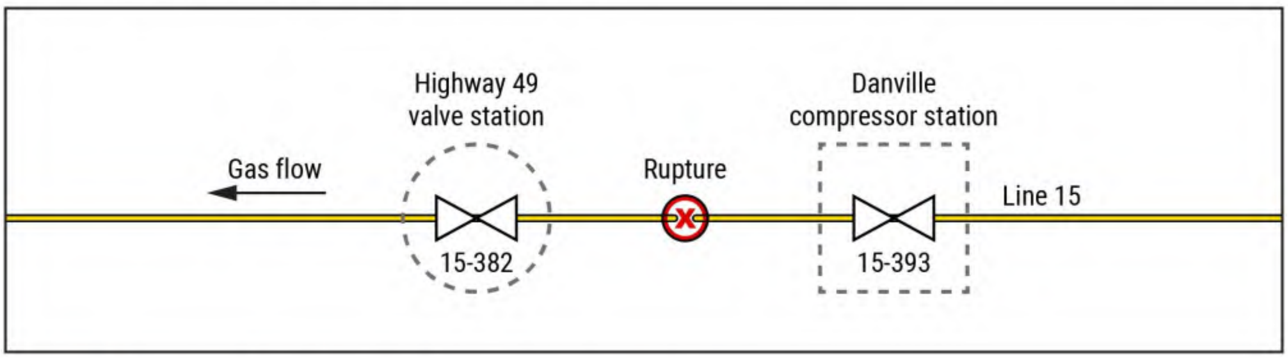

Figure 2. Process flow diagram for pipeline isolation.

At 1:28 a.m., the Enbridge's area supervisor received a call at home about the rupture from the employee first notified at 1:23 a.m. The supervisor directed that employee to the Highway 49 valve station to close valve 15-382. Then the area supervisor called the station operator at the Danville CS at 1:35 a.m. and instructed him to close valve 15-393 to isolate the damaged pipeline segment on the north side of the rupture. Although an on-duty station operator was present, saw a visible fire

[2] *Compressor stations* increase the pressure of gas in a pipeline by compressing it. The *discharge* side of a compressor station is the higher-pressure output side. The *suction* side of a compressor station is the lower-pressure input side. The Danville CS was the closest compressor station to the rupture site, located 4.1 miles to the north.

from the station, and saw a low-pressure alarm at the CS, he did not act to close the manual valve at the CS until instructed by the area supervisor. The station operator manually closed valve 15-393 at 1:39 a.m., isolating the affected pipeline segment on the north side of the rupture.

The Enbridge employee sent to manually close valve 15-382 arrived at the Highway 49 valve station at 2:13 a.m. and confirmed valve 15-382 was the correct valve to close by checking Enbridge's Stanford Area Emergency Response Manual (2015), which was in his company vehicle. The employee closed valve 15-382, completing isolation of the ruptured segment at 2:19 a.m. The total time from the rupture to isolation was 56 minutes. Table 1 provides a detailed timeline of Enbridge's emergency response actions.

Table 1. Enbridge emergency response actions

Time	Activity
1:23 a.m.	Enbridge employee receives notification of rupture from friend
1:24 a.m.	First alarm received in Enbridge gas control center
1:25 a.m.	Second alarm received in Enbridge gas control center
1:26 a.m.	Enbridge gas control center attempts to contact Danville station operator
1:27 a.m.	Enbridge gas control center receives report of accident from the public
1:28 a.m.	Enbridge area supervisor dispatches employee to Highway 49 valve station
1:29 a.m.	Danville station operator notifies Enbridge gas control center of fireball
1:30 a.m.	Enbridge gas control center shuts off compressors at an upstream compressor station
1:30 a.m.	Enbridge area supervisor notifies gas control center of valve closures required for isolation
1:35 a.m.	Enbridge area supervisor instructs Danville station operator to close valve 15-393
1:39 a.m.	Danville station operator manually closes valve 15-393
2:13 a.m.	Enbridge employee arrives at Highway 49 valve station
2:19 a.m.	Enbridge employee manually closes valve 15-382 at Highway 49 valve station, completing isolation

1.2.2 Local Emergency Response

At 1:23 a.m., Bluegrass 911 Central Communications Center (Bluegrass 911) received a call from a motorist traveling by the accident site, who reported an explosion and massive fire.[3] Shortly after, Bluegrass 911 requested emergency response to the accident site. At 1:35 a.m., an engine and a rescue/brush truck were dispatched from Fire Station 3 of the Lincoln County Fire Protection District (LCFPD), the closest station. Additionally, mutual aid was provided by several adjacent emergency services jurisdictions, including the Stanford Fire Department, Boyle County Fire Department, and Danville Police Department. The entire emergency response totaled 81 firefighters, 10 engines and 21 trucks. All structure fires were

[3] Bluegrass 911 received 71 additional reports of the accident from the public after this initial call.

extinguished by 4:13 a.m. Table 2 provides a detailed timeline of local emergency response actions.

Table 2. Local emergency response actions

Time	Activity
1:23 a.m.	Initial report to Bluegrass 911
1:26 a.m.	Bluegrass 911 requests response to the accident site
1:35 a.m.	Engine and truck dispatched from LCFPD Fire Station 3
1:37 a.m.	LCFPD arrives at accident site
1:39 a.m.	LCFPD Assistant Chief assumes incident commander role
1:40 a.m.	Command post established at Indian Camp Road and Route 127
2:19 a.m.	Ruptured pipeline segment isolated
2:56 a.m.	Suppression of grass fires begins
3:00 a.m.	House-to-house searches performed by LCFPD, no individuals found
3:20 a.m.	Surrounding grass fires extinguished
3:29 a.m.	LCFPD checks area for natural gas with gas detectors, none observed
3:57 a.m.	Suppression of structure fires begins
4:13 a.m.	Structure fires extinguished

A part-time, off-duty Lincoln County Sheriff's Office deputy sheriff also responded to the accident site. While approaching the source of the natural gas fire, the deputy observed a man lying on the front porch of a burning residence about 480 feet from the rupture site. The deputy placed the injured man and the man's wife, who he rescued from just inside the door to the house, in the police cruiser. In a postaccident interview with the National Transportation Safety Board (NTSB), the deputy described the heat in the area of the accident as "more than I [could] handle." The deputy also attempted to render aid to a woman lying on the ground nearby but determined she was deceased and, due to the intense heat, was unable to recover her. The deputy left the area with the two evacuees and transferred them to nearby ambulance personnel.

1.3 Injuries and Damages from the Gas Fire

After rescuing the two injured individuals, the deputy sheriff drove to a local medical trauma center to have a minor burn injury treated. Three other residents of the subdivision were also transported to the facility for treatment. All five of the injured residents and the deputy sheriff were subsequently released after receiving medical care.

The home of the deceased was located about 310 feet south of the rupture location. The deceased individual was about 640 feet south of the natural gas fire when she was found by the deputy sheriff.

Five residences were destroyed by resulting structure fires. Fourteen other residences suffered property damage to various degrees; some were 1,100 feet from the rupture crater. The gas flame direction, as shown by the darkened area of soil indicated with a black arrow in figure 3, was oriented along a true bearing of about 80°, or just north of due east. This flame direction was consistent with the direction of the pipeline at the rupture location.

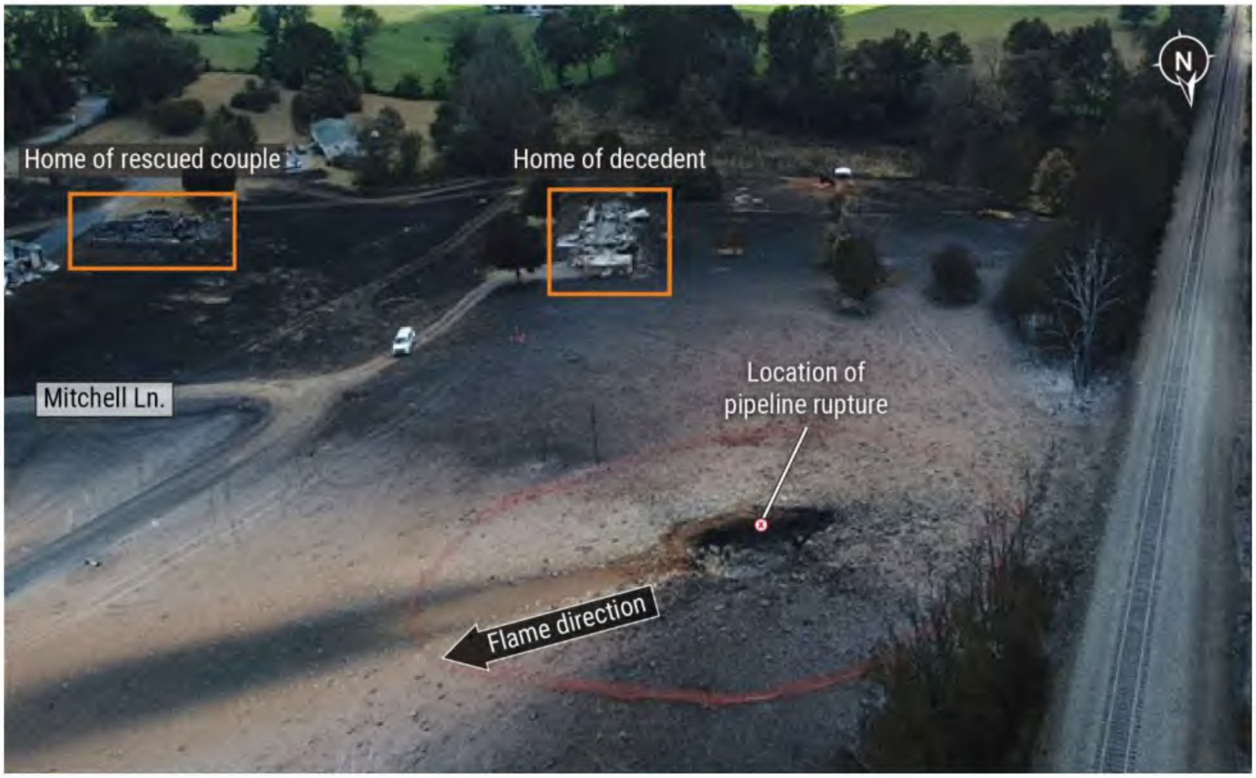

Figure 3. Homes of decedent and rescued couple, rupture location, and gas flame direction.

1.4 Enbridge Natural Gas Systems and Pipeline Specifications

1.4.1 Texas Eastern Transmission, LP, Line 15

The Enbridge asset involved in this accident, Texas Eastern Transmission LP (TET), a natural gas transmission pipeline system, connects the Gulf Coast with the northeastern United States. TET is a wholly owned subsidiary of Spectra Energy Partners LP (Spectra), which was purchased by Enbridge in 2017. Table 3 lists the recent ownership history for TET.

Table 3. Recent ownership history for Texas Eastern Transmission

Owner of TET	Time Period
Texas Eastern Corporation	January 30, 1947 – June 28, 1989
Panhandle Eastern Corporation	June 29, 1989 – July 28, 1994
Panhandle Eastern Corporation/PanEnergy Corp	July 29, 1994 – April 15, 2001
Duke Energy Gas Transmission Corporation	April 16, 2001 – January 1, 2007
Spectra Energy Corp	January 2, 2007 – October 31, 2013
Spectra Energy Partners, Limited Partnership	November 1, 2013 – present
Enbridge Inc.	February 27, 2017 – present

At the accident location, three parallel Enbridge pipelines (lines) transport natural gas through a common right-of-way: Line 10, Line 15, and Line 25. The rupture on TET Line 15 occurred at milepost 423.4.[4] The impacted TET section was known as Tompkinsville to Danville and was located within the Stanford Area. The Danville CS is located at milepost 408.5 and the Highway 49 valve station was located at milepost 427.5.

At the time of the rupture, gas in Line 15 was flowing south from the Danville CS to the Tompkinsville CS at 925 pounds per square inch, gauge (psig), which was less than the maximum allowable operating pressure (MAOP) of 936 psig.[5] According to Enbridge, the pressure on Line 15 between the Tompkinsville CS and the Danville CS did not exceed the MAOP in the 5 years before the accident.

The external protective coating type for Line 15 in the area of the rupture was coal tar enamel.[6] Other pipeline specifications for Line 15 are shown in table 4.

[4] A *milepost* is a unit of measure used to define the location on a pipeline relative to a chosen starting point in miles and fractions of miles.

[5] Title 49 *Code of Federal Regulations (CFR)* Part 192.619, Maximum allowable operating pressure: Steel or plastic pipelines, specifies how the maximum allowable operating pressure is determined.

[6] *Coal tar enamel*, also called coal tar wrap, was a coating commonly used in the 1950s. Hot tar formulated from coal tar pitches and inert fillers was applied to the pipeline exterior over a primer. Often, it was then covered with a fiberglass mesh and a felt wrap. Much of this original coating is still present on transmission pipelines across the United States, including on Line 15.

Table 4. Pipeline specifications of Line 15 at the rupture origin

Pipeline Specification	Value
Diameter	30-inch
Material	Carbon Steel
Grade/Specified Minimum Yield Strength[1]	X-52/52,000 psi
Long Seam Weld	Electric Flash-Welded
Manufacturer	A. O. Smith Corporation
Year Manufactured	1957
Year Constructed	1958
Wall Thickness	0.375 inches
Flow Direction (at time of rupture)	South
Class Location[2]	2
MAOP, south flow	936 psig
Operating Pressure (at time of rupture)	925 psig
CS Discharge Temperature (at time of rupture)	115°F
Soil Type	Shale
Cathodic Protection Method	Impressed Current

[1] American Petroleum Institute 5LX defines specific grades of carbon steel pipeline, each with a minimum yield strength. The higher the grade of the pipeline, the higher the strength of the steel used to manufacture that pipeline.

[2] Title 49 *Code of Federal Regulations* 192.5 defines class locations, with four class locations representing different population levels present near a pipeline. Class 4 areas have the highest populations around them and present the highest risk, while Class 1 areas present the lowest relative risk.

1.4.2 Danville Compressor Station

The Danville CS was the closest compressor station to the rupture site, located 4.1 miles to the north. The Danville CS is manned 24 hours a day, 365 days a year, by a station operator working a 12-hour shift. The station operator is supervised by an area supervisor.[7] Station operators perform physical walkthroughs of the station, evaluate Supervisory Control and Data Acquisition (SCADA) information at a computer, and respond to various types of emergencies, including emergency shutdowns or valve isolations of the system.[8]

1.4.3 Gas Control Center

Enbridge's gas control center for its natural gas transmission pipelines is in Houston, Texas, and is the central location for monitoring and control of pipeline

[7] The area supervisor oversees the Stanford Area segment of pipe and manages 15 employees, including 4 station operators.

[8] *Supervisory Control and Data Acquisition* (SCADA) is a computer system for gathering and analyzing real-time data. SCADA systems are used in the pipeline industry to monitor and control pipeline systems. Station operators control and monitor a large amount of data and systems at the station. There are almost 2,500 distinct SCADA inputs at the Danville CS.

operations. The gas control center is staffed 24 hours a day, 365 days a year, by six gas controllers working in 12-hour shifts and supervised by personnel within the gas control center.

Gas controllers monitor operating conditions, such as line pressure, flow rate, temperature, and gas composition. Depending on the data source, gas controllers can look at data on an instantaneous, per minute, or hourly basis.

Gas controllers have authority to take immediate action in the event of an emergency, including a pipeline rupture. They notify the public and emergency response agencies when a potential accident is reported through their central phone line. The gas control center also coordinates information to and from the field during an emergency response, keeping track of which personnel are responding, where they are, and what actions they are taking. Gas controllers are also able to operate valves equipped for remote closure from the gas control center. Most valves on Line 15 require manual operation, including valves 15-382 and 15-393 on either side of the rupture.

1.5 Postaccident Pipeline Examination and Testing

1.5.1 On-Site Visual Examinations

A crater was located in the area of the rupture; the crater and ground bedding under the pipe consisted of soil and broken pieces of shale. (See figure 4.)

Figure 4. Crater and ground bedding at rupture site.

The NTSB's on-scene examination of the ejected pipeline segment revealed that most of the external coal tar coating was consumed by fire, leaving large regions of the external pipe surface bare. The fracture face of the ejected segment exhibited chevron fracture features, helping investigators locate the origin of the fracture.[9] Figure 5 shows the origin of the fracture as indicated by the brackets; the arrows indicate the general direction of fracture propagation.

[9] *Chevron features*, also known as a river pattern, is a fractographic pattern of marks that look like nested letters "V" or herringbone. The points of the chevrons can be traced back to the fracture origin.

Figure 5. Ejected pipeline segment.

While on-site, the NTSB cut the ejected pipe section into three pieces to facilitate shipping and handling. The exposed fractured ends of the pipe, located within the rupture crater, were cut at the border of the crater. The pipe sections were crated and shipped to the NTSB Materials Laboratory for testing.

1.5.2 Microscope Examination of the Fracture Origin

The NTSB Materials Laboratory examination of the fracture faces from the ejected pipe revealed that the fracture originated at the outer surface, as indicated in figure 6. The origin of the fracture and an area extending below it contained a flat region with a rough texture, shown enclosed by a yellow line. Fracture propagation was in the general direction indicated by the arrows.[10] The origin of the fracture showed no evidence of a gouge or dent and did not originate from a weld. The length of the origin at the outer surface measured about 0.8 inches, and shear lips extended from both ends.[11] The fracture face at the inner surface (opposite the

[10] Details of the fracture examination can be found in the *NTSB Materials Laboratory Factual Report No. 19-064*, February 6, 2020, in the docket for this accident.

[11] A *shear lip* is a precise 45° lip of metal around the perimeter of a ductile overstress fracture area.

fracture origin) contained a minor shear lip, indicating the fracture did not start at the inner surface of the pipe. The fracture areas located outside of the north and south ends of the flat region were on a slant plane and contained a chevron pattern, consistent with overstress separation.

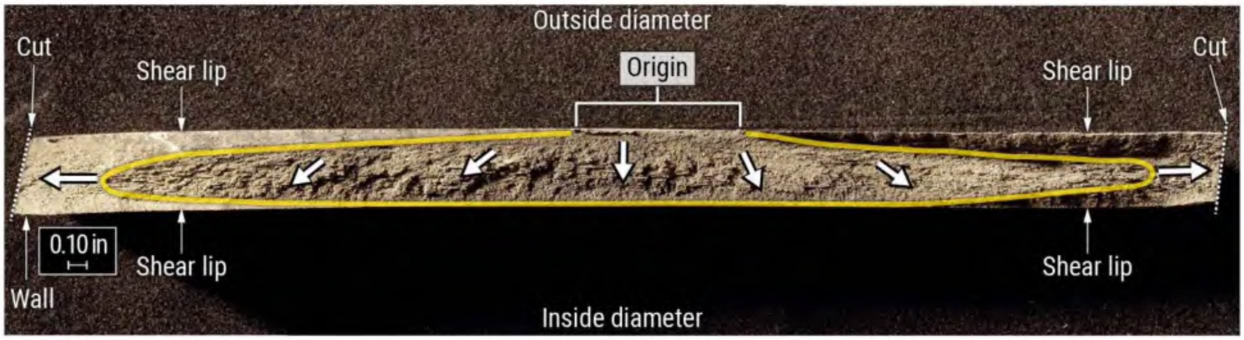

Figure 6. East face of the fracture origin.

A detailed scanning electron microscope examination of the fracture face revealed that the origin exhibited intergranular fracture features, which came from localized embrittlement caused by exposure to hydrogen.[12] The amount of intergranular fracture features decreased toward the inner surface of the pipe.

1.5.3 Microhardness Testing

Two metallurgical cross sections, one longitudinal and one circumferential, were made through the wall of the pipe in the general area of the fracture origin. Microhardness testing adjacent to the outer surface of the pipeline identified a hard spot (a pipeline manufacturing defect greater than 2 inches in size in any direction with a hardness equal to or more than 327 Brinell) that measured 5.85 inches by

[12] (a) *Intergranular fracture* is the propagation of cracks along the grain boundaries of a polycrystalline metal or alloy and involves little or no plastic deformation. Plastic deformation is when an applied force causes a material to change shape. (b) *Embrittlement* is the partial or complete loss of a material's ductility, thus making it brittle. An embrittled product fails by fracture without deforming.

3 inches and had continuous hardness values of between 362 and 381 Brinell.[13] Elevated hardness readings extended through the wall.

The pipe was manufactured in 1957 to American Petroleum Institute (API) pipeline standards in use at the time. The standards then did not specify rejectable criteria for a hard spot, such as hardness and length (API 1956). By current API 5L standards, this hard spot is considered a rejectable defect because of its size and hardness.[14] According to Enbridge, Line 15 had a hardness typically between 180 and 200 Brinell, which is within the standard range for this grade of pipeline.

1.5.4 Microstructure

Examination of the same two sections prepared for microhardness testing revealed the wall of the pipeline contained a microstructure of ferrite and banded pearlite, typical of hot rolled steel.[15] The microstructure of the hard spot contained martensite, which resulted from unintentional localized rapid cooling (quenching).[16]

1.5.5 Other Examinations

NTSB's examination of the fracture face origin revealed no evidence of branching cracks (multiple cracks initiating from a central crack that often indicate stress corrosion cracking).

The NTSB reviewed data from all the in-line inspection (ILI) assessments taken by Enbridge and its predecessors on Line 15 in the area of the rupture between 2003

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[13] (a) A *hard spot* is an area in a pipe with a hardness level considerably higher than the pipe's overall hardness, and it usually occurs during the pipe manufacturing process or during welding operations. Hard spots can vary in size, location on the pipe, and level of hardness, and can be more susceptible to cracking when other threats, such as corrosion, are present. (b) *Hardness* is the ability of a material to resist deformation from indentation. (c) Hardness tests assess the relative strength of a metal by measuring its resistance to deformation, generally using an indenter or probe. *Microhardness testing* is typically performed on cross sections of a material using smaller indenters and loads over a smaller surface area. (d) *Brinell*, or Brinell Hardness Number, is a scale for the measurement of hardness. It is also referred to in industry practice as HBW.

[14] American Petroleum Institute (API) Standard 5L, incorporated by reference into 49 *CFR* Part 192, discusses hard spot parameters and under what conditions a hard spot must be remediated.

[15] Microstructure examination was performed at the NTSB Materials Laboratory.

[16] *Martensite* is a microstructure of steel that is formed by localized quenching, or rapid cooling, that is harder than the ferrite and pearlite microstructures of standard pipe steel. Unintentional localized quenching can occur during the manufacturing process, creating hard spots in the pipeline.

and 2019.[17] These assessments found no dents within 500 feet of the rupture site that met Enbridge's criteria for repair. The assessments also identified no internal corrosion near the rupture origin.

1.6 Line 15 Incident History

The NTSB examined incident history with Enbridge's pipeline system involving Line 15. The history includes a 2003 rupture, an operational modification that changed the flow direction between 2014 and 2017, and an emergency Danville CS shutdown in 2019; these events are discussed below.

1.6.1 2003 Rupture

On November 2, 2003, Line 15 ruptured at milepost 501.72 near Morehead, Kentucky, between the Danville CS and the Owingsville CS, which is the station immediately north of the Danville CS. No fatalities or injuries occurred because of the rupture or resulting fire, and the parallel pipelines, Lines 10 and 25, were not impacted. The predecessor to the Pipeline and Hazardous Materials Safety Administration (PHMSA), the Research and Special Programs Administration (RSPA), issued a corrective action order to TET, then owned by Duke Energy Gas Transmission (DEGT), in 2003 because of the rupture.

As part of the corrective action order, TET was required to conduct a detailed metallurgical analysis to determine the cause of and factors contributing to the rupture (RSPA 2003). TET hired an engineering firm to investigate the rupture cause, including metallurgical testing. In its final report, the engineering firm found the rupture was "caused by hydrogen-induced cracking that initiated at the [outer] surface of the pipe in a hard spot that was coexistent with a mid-wall lamination" (Mesloh and Rosenfeld 2003).[18]

Both the hard spot and lamination were present at the time of manufacture in 1957, although this segment of Line 15 passed a hydrostatic test of 1,417 psig when it was first installed. The lamination and hard spot at the rupture origin also were not

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[17] *In-line inspection* (ILI) is an inspection method in which a highly specialized tool is passed within a pipeline to inspect the pipeline from the inside. ILI uses nondestructive examination techniques to identify, locate, and size various damages and defects, depending on the type of tool.

[18] A *lamination* is an abnormal structure in the pipeline wall that results in a separation or weakness aligned generally parallel to the work surface of the metal. Laminations are manufacturing defects that can be caused by several issues during the manufacturing process, including the formation of blisters or the inclusion of foreign materials.

identified during ILIs conducted in 1986 and 1999; the ILI tools used at that time were not capable of detecting hard spots.

In response to the 2003 rupture, DEGT initiated a new hard spot management program. As a first step, DEGT identified the areas on its pipeline systems containing pipeline vintages with a known history of hard spots, including 24.76 miles of pipeline on Line 15 manufactured by A. O. Smith Corporation.

On July 3, 2004, April 26, 2005, and April 29, 2005, DEGT completed three hard spot ILI runs on various sections of Line 15 and identified 22 hard spots with predicted hardness values between 235 and 340 Brinell. Based on predicted hardness and distance between hard spots, DEGT excavated 14 of the 22 hard spots and performed hardness testing.[19] Four of the excavated hard spots were recoated and backfilled, as the hardness values of each was below DEGT repair criteria. The remaining 10 excavated hard spots were removed for more extensive metallurgical laboratory testing, which generally showed close agreement between the field measurements and ILI predictions.

In 2006, DEGT hired CC Technologies Inc. to perform an evaluation of its hard spot management program. CC Technologies Inc. concluded that the ILI tool accurately and reliably detected and estimated the hardness of hard spots (Barkdull and others 2006). However, CC Technologies Inc. also recommended during its review that DEGT request that the ILI vendor provide additional details on how hard spots were identified. Overall, CC Technologies Inc. found DEGT's hard spot management program to be "consistent with industry best practices."

1.6.2 2014 to 2017 Operational Modifications

Line 15 flowed north when first constructed in 1957. From 2014 to 2017, modifications were completed on Lines 10, 15, and 25 to allow for reverse flow from Pennsylvania to Louisiana. This project changed all three lines from unidirectional flow to bi-directional flow. The conversion was completed at the Danville CS in late 2014 and at multiple other compressor stations and pipeline segments in the following years, with the entire project completed in 2017.

[19] None of the hard spots identified during these ILI runs were located near the origin of the 2019 rupture. Of the 22 ILI-identified hard spots, 8 were not excavated, as their predicted hardness values were under 327 Brinell (see section 1.5.3 for more information on hard spot measurements).

Spectra performed a management of change review for the flow reversal project.[20] During this review, Spectra assessed risks and performed mitigative actions.[21] One risk identified was an increased temperature on the discharge side of compressor stations that are in use. In the case of the Danville CS, flow south would result in an elevated temperature on the south side after flow reversal. Increased temperatures pose a higher risk to pipeline integrity because external corrosion can increase as temperature rises. To address this risk, gas coolers were installed at several compressor stations, including the Danville CS, in 2014 when the flow was reversed.[22]

From 2014 to 2017, gas flowed south, but the compressors at the Danville CS were not actively used; thus, only about a 5°F temperature increase was noted south of the Danville CS. In 2017, Enbridge began actively using the Danville CS, which resulted in an average 30°F increase in temperature south of the CS even with the gas coolers in use.

1.6.3 2019 Danville Compressor Station Emergency Shutdown

On May 8, 2019, the Danville CS experienced an unplanned emergency shutdown.[23] This event was caused by a shorted wire in a direct-current circuit, which indirectly caused a buildup of gas pressure at the station. When the emergency shutdown initiated, one of the block valves at the station failed to close properly, allowing gas to continue to flow out of the station. Because of the continued flow of gas, the gas control center in Texas believed there was a rupture near or within the Danville CS.

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[20] *Management of change* is a standardized approach for reviewing proposed changes to systems to ensure safety, health, and environmental risks are all assessed. It is part of a pipeline safety management system as outlined in American National Standards Institute (ANSI)/API Recommended Practice 1173. A pipeline safety management system is not currently required by PHMSA regulations, nor is ANSI/API Recommended Practice 1173.

[21] Spectra was purchased by Enbridge in 2017.

[22] *Gas coolers* are devices used in the pipeline industry to reduce the temperature of gas by heat exchange methods.

[23] PHMSA defines *emergency shutdown* as an abnormal operation in Title 49 *CFR* 192.605(c). An *emergency shutdown* is designed to protect a compressor station and its personnel from threats to safety and pipeline integrity. During an emergency shutdown, automated valves isolate the station from the remainder of the pipeline system and release the isolated gas to bring the pressure in the station down to atmospheric pressure (0 psig).

During the emergency shutdown, the Danville CS station operator (the same operator on duty for the August 1, 2019, accident), in response to a call from the gas control center, manually closed a valve at the station to try to isolate the station from the remainder of the pipeline system. This action did not halt the flow of gas because the release was from an open valve, not a rupture. Neither the station operator nor the gas controller reviewed the SCADA graphics during the response.

The Enbridge area supervisor was then contacted by the gas control center to assist the station operator with the response. The area supervisor reviewed the SCADA graphics, determined that the valve was still in the open position, and immediately closed it, stopping the flow of gas.

Enbridge's internal root cause failure investigation into the May 8, 2019, emergency shutdown found that had the station operator reviewed the SCADA graphics, he would have concluded the valve was open and needed to be shut. Enbridge's internal failure investigation report stated that the station operator displayed "a lack of understanding" of the emergency shutdown system by failing to confirm all valves had operated as intended. Additionally, the internal investigation found that the gas controller and station operator's communications resulted in the station operator "attempting to manipulate valves that were irrelevant to the event" (Enbridge 2019a).[24]

Between May 8, 2019, and August 1, 2019, the station operator was not disqualified or requalified for tasks related to the emergency shutdown system, nor did Enbridge retrain him. Enbridge's operator qualification program stated that, if an internal investigation of an accident finds the employee's performance of a covered task such as responding to an emergency shutdown has caused or contributed to an accident, that employee "will be deemed disqualified" for that task(s) until they are requalified.[25]

1.7 Enbridge Procedures, Operations, and Maintenance

1.7.1 Company Background

Enbridge transports about 20 percent of the natural gas consumed in the United States. The accident pipeline, TET, is an 8,580-mile transmission pipeline

[24] The Enbridge investigation found the gas controller and station operator did not reference the specific valve numbers during their communication.

[25] Per 49 *CFR* 192.801, a *covered task* is one that is performed on a pipeline facility, is an operations or maintenance task, is performed as a requirement of federal regulations, and affects the operation or integrity of the pipeline.

system that can transport up to 11.69 billion cubic feet of natural gas per day. (See figure 7.) TET is federally regulated by PHMSA.

Figure 7. Map of Texas Eastern Transmission pipelines. (Courtesy Enbridge.)

1.7.2 Emergency Response Plan

Enbridge's *Stanford Area Emergency Response Plan* outlined what actions the station operator should take in the event of a rupture or other abnormal operations. The plan included lists of valves requiring closure to isolate specific pipeline segments, including valve 15-393 (which was closed during the accident response), maps, and detailed schematics of the valve stations and compressor stations.

The *Stanford Area Emergency Response Plan* also provided specific details on the activities a station operator should take in response to an emergency shutdown for each compressor station. For the Danville CS, the plan listed which valves should be operated during an emergency shutdown, both automatically and manually. This procedure also required the station operator to contact the gas control center and the area supervisor in the event of an emergency near the compressor station.

1.7.3 Cathodic Protection

External corrosion is controlled on Line 15 by impressed-current cathodic protection and design elements such as coating.[26] Between the Tompkinsville CS and the Danville CS, there are eight rectifiers. The closest rectifier and anode bed north of the accident site is at Goodnight, and the closest rectifier and anode bed to the south is at Harris Creek.[27] (See figure 8.) The soil in this area is primarily shale. The Enbridge corrosion technician told the NTSB that "it takes a lot more [cathodic protection] with shale," and that shale "does lower the ability for [cathodic protection] to go through the rock."

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[26] Buried steel pipelines will corrode because of the presence of moisture and ground water in the soil. To prevent corrosion, the exterior of the pipe is coated with an insulating material such as coal tar so that the soil does not directly contact the pipe surface. Inevitably, there are unavoidable flaws and defects in the coating, and the exposed steel at the flaws may corrode. To minimize corrosion at the coating flaws, an electrical direct current power supply (*rectifier*) is set up between the pipe and an inert electrode (*anode*) buried beside the pipe. The power supply provides electrical current that prevents corrosion of the exposed steel at the coating flaws. As a byproduct, hydrogen also evolves at the exposed steel at the coating flaws. This process is called *impressed current cathodic protection*.

[27] *Anode beds* are a collection of interconnected anodes that work together to protect a pipeline system.

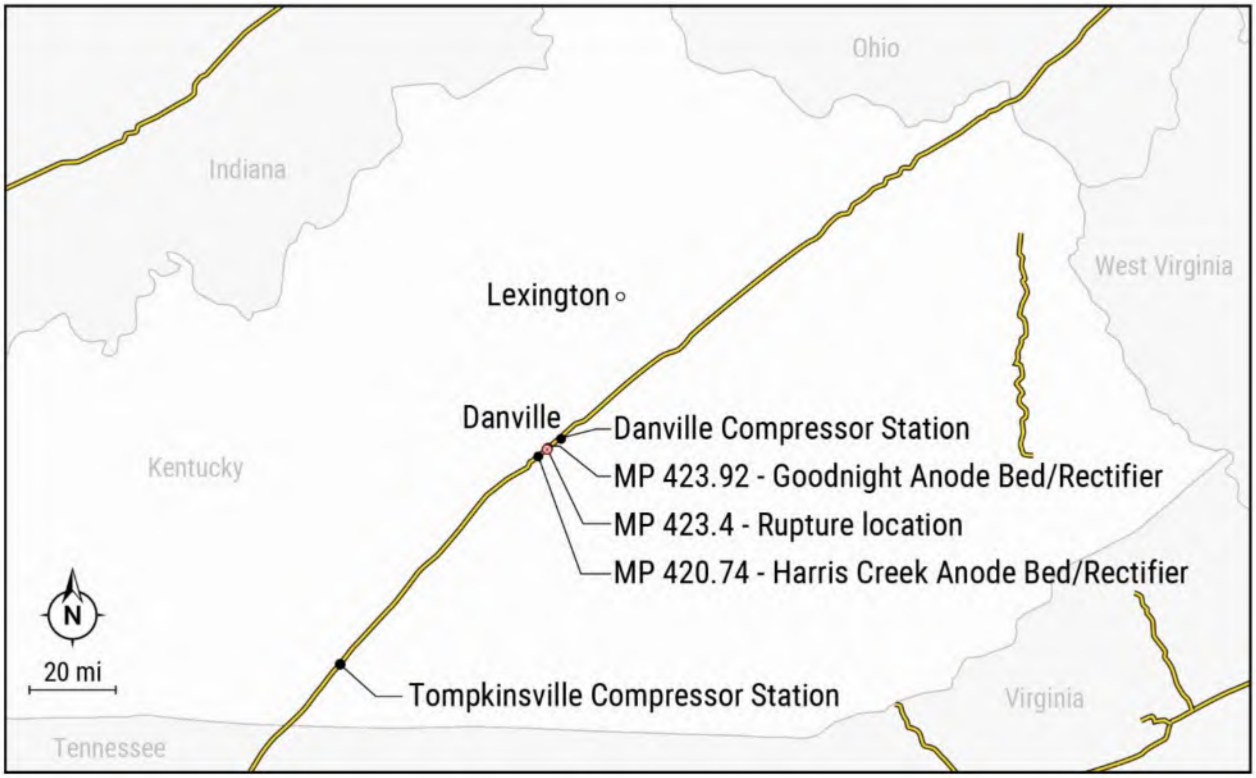

Figure 8. Map of the right of way for Lines 10, 15, and 25.

Investigators examined 10 years of maintenance activities related to cathodic protection at Goodnight and Harris Creek. In 2017 and 2019, the output from the Harris Creek rectifier was increased to address dropping potential readings.[28] These dropping potentials began in early 2014 after the flow reversal project was completed. Before the flow reversal, cathodic protection voltages were regular and consistent; after the flow reversal, technicians were unable to stabilize readings; at Harris Creek, voltages were increased by 18 percent, and the voltages at Goodnight increased by 58 percent. (See figure 9.) The plot in figure 9 shows the steady potentials up to 2013; after that, they became unstable. In 2018, a new anode was installed at Harris Creek, but it did not successfully raise potentials.

[28] When referring to cathodic protection potential readings, low potentials are those that do not meet PHMSA criteria and are more positive than −0.85 volts. When potential readings drop this means they become more positive and may not meet PHMSA requirements.

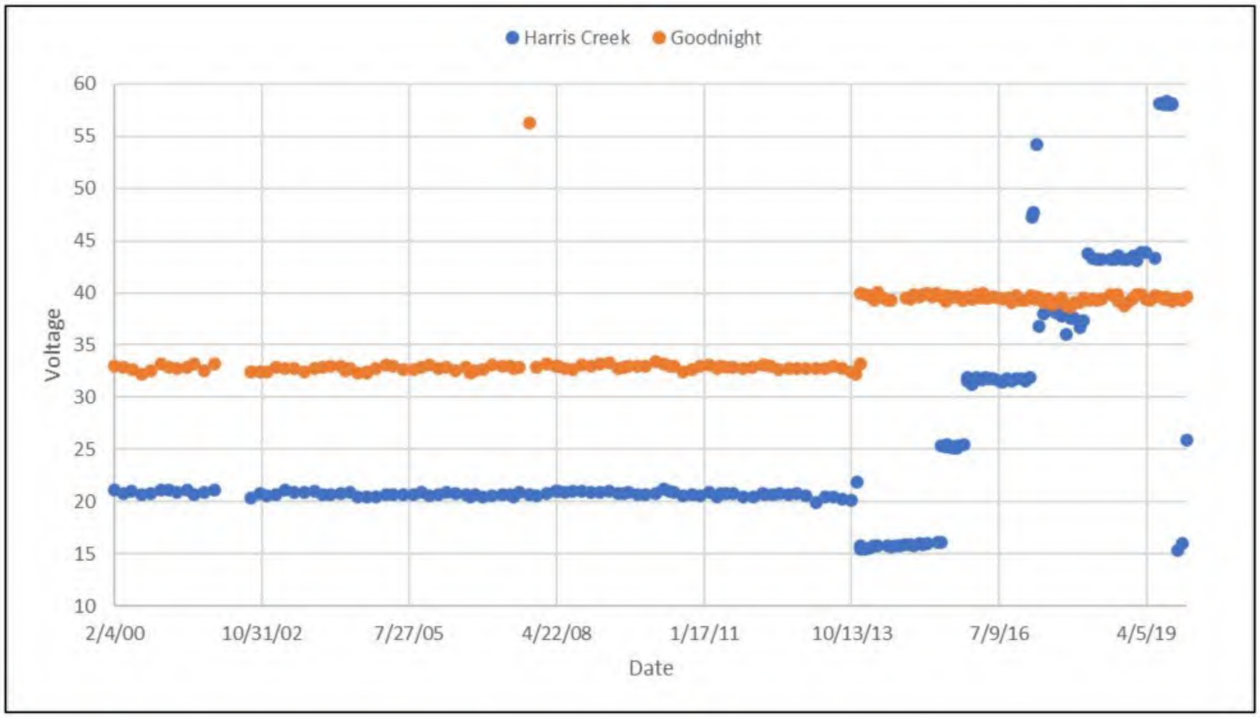

Figure 9. Voltage outputs at Goodnight and Harris Creek rectifiers.

Several inspections related to cathodic protection were also performed on Line 15 in the 10 years before the accident, including close interval surveys.[29] Specifically, a close interval survey that was performed between the Highway 49 valve station and the Danville CS by Allied Corrosion Industries Inc. on October 25, 2012, found 451 feet of the segment did not meet PHMSA's minimum federal safety standards for cathodic protection.[30] In response, in 2013, Spectra installed anode beds at three locations in the segment, and additional anodes were added at another location. These activities were performed to address the low potentials identified during the 2012 close interval survey.

Allied Corrosion Industries Inc. performed another close interval survey on the same pipeline segment on Line 15 on August 24, 2018, and on June 5, 2019. This close interval survey found that a total of 774 feet of the 19.02-mile segment did not

[29] *Close interval surveys* are part of a class of nondestructive above-ground testing methods. They are used primarily to evaluate the effectiveness of cathodic protection, but they also can be used to detect small coating defects and other issues.

[30] Title 49 *CFR* Part 192 Appendix D specifies PHMSA's minimum federal safety standards for effective cathodic protection. Five evaluation options are available to operators of steel pipelines.

achieve a 100-millivolt differential between on and off potential readings.[31] After the 2018–2019 close interval survey, anode beds were installed at three more locations on the pipeline segment to address the low potentials identified during the survey. No pipeline segments were recoated.

Enbridge's local corrosion technician told the NTSB that there was some disbonded coating in the area.[32] No internal or external corrosion was identified near the rupture origin during integrity assessments of Line 15 completed in 2010, 2011, or 2018 by the vendors listed in table 5.[33] However, external corrosion anomalies were identified at other locations on several magnetic flux leakage ILI runs conducted as part of the integrity assessments, with the number of anomalies increasing by 166 percent between 2010 and 2018. (See section 1.8.4 for more information on magnetic flux leakage tools and integrity assessment.) Table 5 describes the external metal loss anomalies identified during the ILI runs.

Table 5. External metal loss anomalies identified in ILI runs

Year of ILI Tool Run	Vendor	Location	Total Number of External Metal Loss Anomalies	Pipeline Joints Impacted (%)
2010	PII Pipeline Solutions	Tompkinsville CS to Danville CS	4,655	14
2011	NDT Systems & Services (America) Inc.	Tompkinsville CS to Danville CS	3,125	N/A
2018	PII Pipeline Solutions/Baker Hughes	Tompkinsville CS to Danville CS	12,376	31

1.8 Integrity Management

Integrity management (IM) has three goals: (1) to determine pipeline segments where the potential consequences are the highest; (2) to evaluate the soundness, stability, and reliability of pipelines; and (3) to address risk in a scientific, consistent, and prioritized manner. PHMSA's regulations on gas transmission IM fall under Title 49

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[31] Method 3 of PHMSA's criteria for cathodic protection in 49 *CFR* Part 192 Appendix D requires a voltage differential of at least 100 millivolts between on and off potential readings.

[32] *Disbondment* is when the coating applied to the exterior of the pipeline separates from the metal, causing a gap between the coating and pipeline, which can negatively impact pipeline integrity.

[33] *Integrity assessments* are evaluations performed by pipeline operators to determine whether their pipelines have adequate integrity to prevent leaks or ruptures under normal and abnormal operations.

Code of Federal Regulations (*CFR*) Part 192 Subpart O, Gas Transmission Pipeline Integrity Management.[34]

By design, IM is a cyclical, nonlinear process that continually feeds data back into other program elements, so that data collected during each part of the process are used to improve other elements. (See figure 10.) IM requires operators to identify threats to pipeline integrity, determine threat severity, validate data, allocate resources, conduct repairs, and evaluate the entire system, reassessing threats and revising system elements as new data or analyses become available.

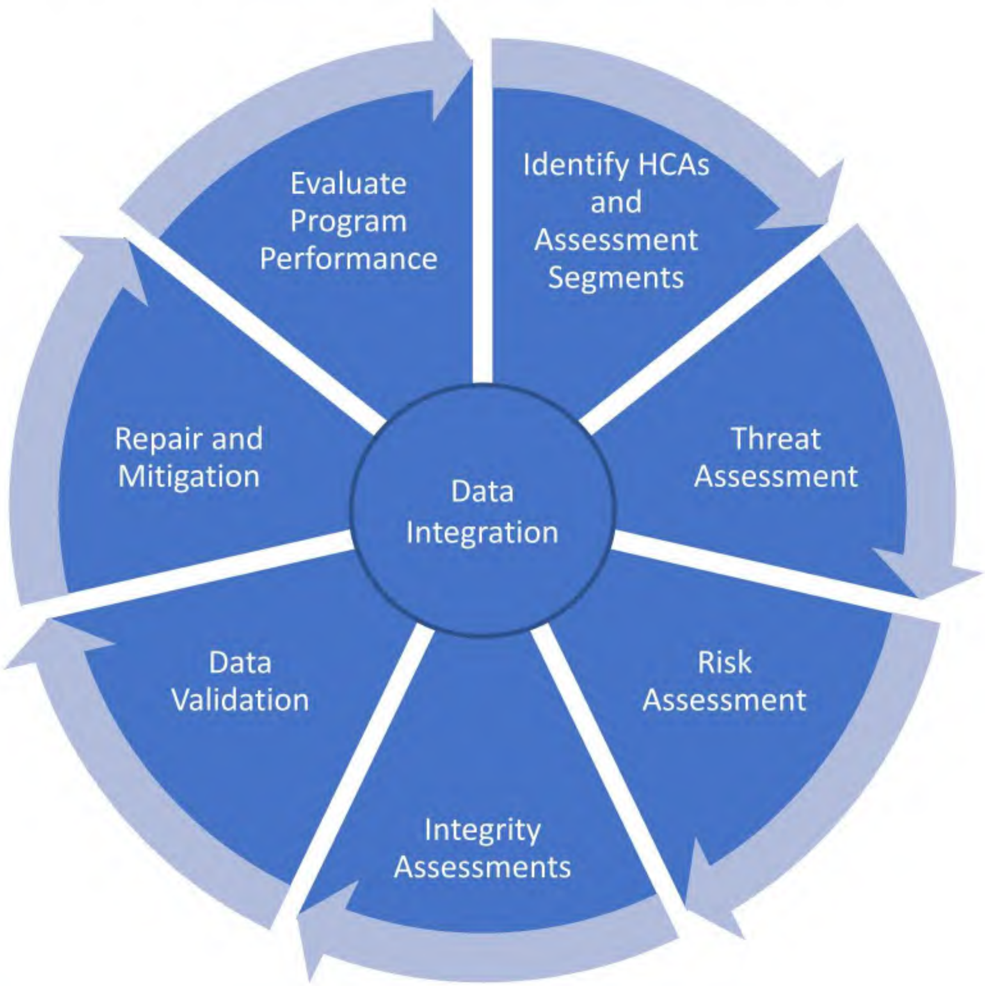

Figure 10. Integrity management process flow.

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[34] On December 15, 2003, the Research and Special Programs Administration issued its final rule on natural gas transmission integrity management (IM), setting the minimum regulatory requirements for pipelines in high consequence areas.

As in all IM programs, the various elements of Enbridge's IM program relevant to the 2019 accident did not necessarily proceed in a chronological order and are therefore discussed by topic in the following sections.

1.8.1 High Consequence Area Identification

To determine which segments of an operator's natural gas pipeline system are covered by 49 *CFR* Part 192 Subpart O, an operator must first identify the high consequence areas (HCAs).[35] High consequence areas help gas pipeline operators find "segments of their pipeline systems that pose the greatest risk to human life [and] property" by identifying more populated areas (PHMSA 2016).

Under 49 *CFR* 192.903, PHMSA requires pipeline operators to use one of two available methods to evaluate if a pipeline segment falls within an HCA. For most of its pipeline systems, including at the rupture site, Enbridge uses method 2, which defines an HCA as an area within the pipeline's potential impact radius (PIR) that contains either (a) 20 or more buildings intended for human occupancy (with some exceptions) or (b) an identified site.[36] PHMSA defines the PIR by a mathematical equation that includes MAOP and pipeline diameter.

The NTSB used this mathematical equation to calculate the PIR at the rupture site to be about 633 feet. Within 633 feet of the rupture site radially (indicated by a red circle in figure 11) were seven private residences as well as other structures not designed for human occupancy, such as garages and sheds. Because the number of buildings intended for human occupancy was below 20 and no buildings met the qualifications of an identified site under 49 *CFR* 192.903, the rupture site was deemed a non-HCA via method 2.

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[35] A *high consequence area* is a location specially defined in pipeline safety regulations as an area where pipeline releases could have greater consequences to health and safety or the environment.

[36] An *identified site* is a location intended for mass occupancy, such as a stadium or office building, or a facility with occupants who would be difficult to evacuate, such as a nursing home or prison. A full definition for an identified site can be found in 49 *CFR* 192.903.

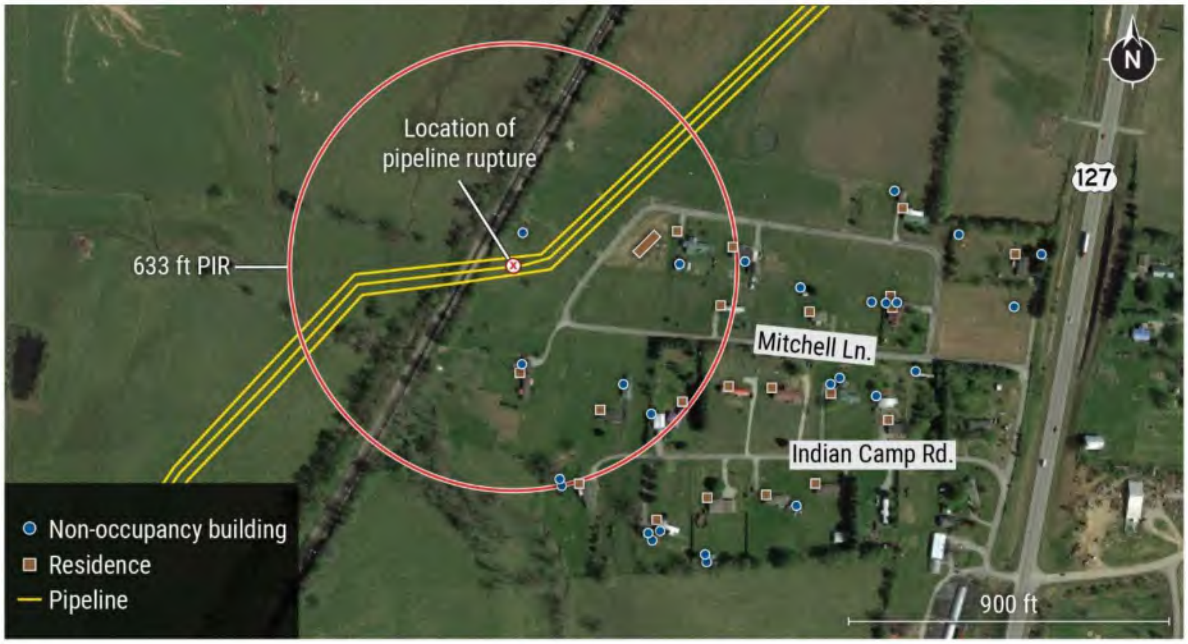

Figure 11. Human-occupancy buildings within the potential impact radius. (Courtesy of Enbridge.)

On the date of the accident, PHMSA's gas transmission integrity rule applied only to pipeline segments located in HCAs. As such, Enbridge was not required to implement any of the regulations in 49 *CFR* Part 192 Subpart O for the area containing the rupture site, including management of change, risk assessments, or integrity assessments. However, Enbridge voluntarily included pipeline segments that fell outside of HCAs in its integrity management program; these sections were called assessment segments. The rupture site was located within a non-HCA assessment segment known as Line 15 Valve Section 4 (L15 VS4). L15 VS4 extends from milepost 408.5 to milepost 427.5, which is all of Line 15 between the Highway 49 valve station and the Danville CS.

1.8.2 Threat Identification and Interaction

As part of IM, within each HCA and assessment segment, the pipeline operator conducts assessments to identify threats to pipeline integrity. The American Society of Mechanical Engineers standard B31.8S, *Managing System Integrity of Gas Pipelines*, which is incorporated by reference into 49 *CFR* 192.7(c)(6), divides the threats to pipeline integrity into nine categories (American Society of Mechanical Engineers 2012). Hard spots fall under the category of manufacturing threats. Enbridge also considered pipeline "segments that [had] not been [hydrostatically] pressure tested to a minimum of 1.25 times the MAOP, [contained] susceptible materials, or [had] a history of material related failures" vulnerable to manufacturing threats.

Following the 2010 rupture of an Enbridge hazardous liquids pipeline in Marshall, Michigan, the NTSB found Enbridge's IM program did not consider the interaction between threats (such as between corrosion and crack depths, among other issues) and recommended that Enbridge revise its program.[37]

In a March 16, 2017, advisory bulletin, PHMSA offered guidance to pipeline operators on how to classify the stability of various threats, noting that threats "may be considered active or inactive, but are never permanently eliminated" (PHMSA 2017). In PHMSA's classification, threats are active when an integrity assessment is required, and inactive threats can be considered stable and do not require assessment or reassessment as long as they remain stable. When a threat requires reassessment, pipeline operators must evaluate their systems for that threat on a regular basis, called a reassessment interval. The length of these reassessment intervals varies by threat and assessment method.[38] When manufacturing threats are active and ILIs are used, 7 years is the maximum reassessment interval allowed under 49 *CFR* 192.939. According to the 2017 advisory bulletin, manufacturing threats are stable threats that become active (that is, require assessment) when any of the following occur:

- The operating pressure increases above the highest operating pressure in the past 5 years.
- MAOP is increased.
- Stresses are increased that lead to cyclic fatigue.

In 2011, Spectra, and later Enbridge, considered hard spots eliminated as a threat on L15 VS4 after one in-line inspection, four excavations, and one repair on that pipeline segment.

[37] NTSB Safety Recommendation P-12-11 states, in part, that Enbridge must "develop and implement a methodology that includes local corrosion wall loss in addition to the crack depth when performing engineering assessments of crack defects coincident with areas of corrosion" (NTSB 2012). As of 2014, Enbridge had completed action on that part of the recommendation and was working to implement new IM procedures. The recommendation is classified "Closed—Acceptable Action."

[38] 49 USC section 60109(c)(3)(B) allows the Secretary of Transportation to extend the deadline for an additional 6 months to a maximum total of 7 years and 6 months if the operator submits written notice to the Secretary of Transportation with sufficient justification of the need for the extension.

1.8.3 Risk Assessment

After potential threats are identified, Enbridge assesses the risk from those threats to its pipeline system.[39] Enbridge used a risk algorithm from Dynamic Risk Assessment Systems Inc. (Dynamic Risk) to perform its annual risk assessments.[40] The algorithm assigns scores to risks from manufacturing threats like hard spots.

Hard spot scores ranged from 0 to 10, with 0 having the lowest probability of failure. Enbridge's average hard spot score for the ruptured pipeline segment was 1.53 for each year between 2010 and 2018. This yearly hard spot score was a function of various inputs: the susceptibility of the pipeline to hard spots (1.53 out of 10), coating condition (1 out of 1), and cathodic protection (0.97 out of 1), among other factors.[41] Each year between 2010 and 2018, Enbridge rated the overall probability of failure from all threats on L15 VS4 as "unlikely," Enbridge's lowest-priority category for performing integrity assessments.

In its risk algorithm, Enbridge defined the consequence of failure as the sum of potential impacts to public safety, economic loss, and environmental damage. Within public safety, the algorithm considered consequences from thermal radiation (heat and fire), blast overpressure, and flying debris. Each year from 2010 to 2018, the ruptured pipeline segment had an overall consequence score of 2.71 out of 10.

1.8.4 Integrity Assessment

Based on the calculated risk scores, pipeline operators perform integrity assessments to find potential weaknesses (anomalies) in the pipeline system. ILI tools are frequently used by pipeline operators to perform these integrity assessments.

Seven integrity assessments were performed on the L15 VS4 segment between May 2003 and May 2019 (2 months before the accident). These assessments looked at various threats, and each threat was assessed about once every 7 years. (See table

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[39] *Risk* to a pipeline segment is defined as the probability of failure multiplied by the potential consequences of failure.

[40] Dynamic Risk Assessment Systems, Inc., is a Canada-based pipeline integrity company.

[41] The value for the susceptibility of the pipeline to hard spots was based on the pipeline vintage and history, with the highest value, 10, assigned to pipelines with known hard spots over 327 Brinell, previous accidents on similar pipelines, and pipelines manufactured by A. O. Smith Corporation before 1953. Coating condition was evaluated on the frequency of external corrosion. Operating stress level was based on the average operating pressure relative to the yield stress of the pipeline. Cathodic protection was based on the percentage of potential readings that were more negative than -1.20 volts.

6.) Enbridge and its predecessors had determined the reassessment interval for all active (unstable) threats would be 7 years, which, as stated earlier, is the maximum allowable reassessment interval under 49 *CFR* 192.939.

Table 6. Integrity assessments performed on the ruptured pipeline segment between 2003 and 2019

Assessment Method	Vendor	Date of Field Assessment or ILI Tool Run	Threats Assessed
Magnetic flux leakage ILI	Tuboscope	05/12/2003	Internal corrosion, external corrosion, 3rd-party damage, dents, and other deformations
Magnetic flux leakage and caliper ILI	PII Pipeline Solutions	06/24/2010	Internal corrosion, external corrosion, 3rd-party damage, manufacturing defects (limited capability), dents, and other deformations
Hard spot magnetic flux leakage ILI with inertial measurement unit	NDT Systems & Services (America) Inc.	04/05/2011	Hard spots, internal corrosion, external corrosion, 3rd-party damage, location
Close interval survey	Allied Corrosion Industries, Inc.	10/25/2012	External corrosion
Magnetic flux leakage and caliper ILI with inertial measurement unit	PII Pipeline Solutions/Baker Hughes	05/01/2018	Internal corrosion, external corrosion, 3rd-party damage, manufacturing defects (limited capability), dents, and other deformations
Close interval survey	Allied Corrosion Industries, Inc.	08/24/2018	External corrosion
Caliper ILI with inertial measurement unit	Baker Hughes	05/29/2019	Dents and other deformations, location, geotechnical stress

Several of the seven integrity assessments used a magnetic flux leakage tool, one of the most common and versatile ILI tools. Magnetic flux leakage tools impose a strong magnetic field within the pipe wall and measure magnetic flux leakage and determine the amount of wall thickness loss. Readings from magnetic flux leakage tools can be used to look for most types of anomalies in which metal loss is present: external corrosion, internal corrosion, external damage such as scrapes and gouges, and voids in the pipe wall.

Hard spot magnetic flux leakage (HSMFL) ILI tools use magnetic flux leakage technology to detect hard spots. An HSMFL ILI tool has two sections: the first section contains sensors within a higher magnetic field, followed by a second set of sensors within a lower magnetic field. The higher magnetic field section will detect only metal loss anomalies, while the lower magnetic field section will detect both hard spots and metal loss anomalies. Analysts working for the ILI tool vendor then compare the data collected by each section of the tool to identify hard spots.

After the flow reversal in 2014, Spectra did not develop a new baseline assessment plan. Baseline assessment plans are not required by federal regulations when changing flow direction.[42]

1.8.4.1 Hard Spots

A. O. Smith 30-inch pipe manufactured in the 1950s was known by major industry organizations and PHMSA to have a history of hard spots (Clark and others 2005).[43] During the 2011 HSMFL ILI run, the segment of Line 15 between the Tompkinsville CS and the Danville CS was also evaluated for hard spots. Sixteen hard spots were identified; none were located near the 2019 accident site.

Enbridge's IM program manual stated that stable threats, such as hard spots, required assessment until "effectively mitigated." The manual required no specific intervals between assessments. Mitigation options listed in the accompanying procedure, *Threat Response Guidance Document 440*, *Manufacturing*, included eliminating or reducing stress on the pipeline segment, eliminating susceptible pipeline, and eliminating or reducing hydrogen generation.

Neither Spectra nor Enbridge re-inspected L15 VS4 for hard spots between April 5, 2011, and the accident on August 1, 2019.

1.8.5 Hard Spot In-Line Inspection Data Analysis

The NTSB reviewed the performance specifications for the tool NDT Systems & Services (America) Inc. (NDT Systems & Services) used during the 2011 HSMFL ILI run and found the report NDT Systems & Services provided to Spectra did not contain a statement regarding the minimum detection capabilities of the tool.[44] Further, the

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[42] A pipeline operator develops a *baseline assessment plan* to assess the integrity of all the lines included in its IM program. The baseline assessment plan must show when each line is to be assessed and the assessment method the operator will use. At a minimum, the baseline assessment plan (1) identifies all segments of a pipeline system that could impact an HCA, (2) identifies the specific integrity assessment method(s) to be conducted, (3) specifies the schedule by which those integrity assessments will be performed, and (4) provides the technical justification for the selection of the integrity assessment method(s) and the risk basis for establishing the assessment schedule (49 *CFR* 192.919).

[43] Historical pipeline vintages that are known to have a higher rate of certain defects are described in a 2004 report by the Interstate Natural Gas Association of America entitled *Integrity Characteristics of Vintage Pipelines*.

[44] In 2012, NDT Systems & Services (America) Inc. sold the majority of its assets to Weissker Molch LLC, which is now known as NDT Global LLC. It also discontinued use of the hard spot magnetic flux leakage ILI tool that year.

specifications were not complete: they did not clearly state if the probability of detection, location accuracy, and sizing accuracy applied to hard spots, metal loss anomalies, or both.

Specialized ILI tools, such as HSMFL tools, rely on proprietary processes for data analysis and interpretation. Spectra relied on the ILI vendor's contractual requirements, and confirmation using the vendor's quality checks, for validation of data coverage and quality.

Spectra's data on the total number of miles of pipeline on which NDT Systems & Services ran its hard spot tool in 2011 were incomplete, but according to documentation provided to the NTSB postaccident from NDT Global LLC (NDT Global), at least 1,320.8 miles were run, including 328 miles on TET pipelines. NDT Systems & Services' July 9, 2011, analysis of the data collected during the 2011 HSMFL ILI run predicted that the closest hard spot was located about 2.2 miles north of the accident site.

After the accident in Danville, the NTSB requested a re-analysis of the original data from the 2011 HSMFL ILI run. In August 2019, NDT Global used the raw data from 2011 to conduct a re-analysis that showed a total of 441 hard spots. Of these 441 identified hard spots, 9 were located in the pipeline joint that ruptured, including 2 at the rupture origin (with predicted hardness values of 241 Brinell and 245 Brinell).[45] These two hard spots corresponded with the hard spot at the fracture origin that was measured during NTSB testing. NDT Global reported that the large discrepancy in the number of hard spots identified between the analyses in 2011 (16 hard spots) and 2019 (441 hard spots) was due to significant improvements in computer hardware and software used in data analysis in the 8 intervening years (NDT Global 2019).

1.8.6 Data Validation

Enbridge standard operating procedure 9-3010, *Response to In-Line Inspection*, outlined its procedures for validating ILI data, including field measurements and direct comparisons of ILI runs. Hard spots were not specified in this procedure (Enbridge 2019b). Spectra used field measurements of the four hard spots that were excavated as a result of the 2011 HSMFL ILI run to validate the ILI tool performance. In a response to a postaccident NTSB inquiry, Enbridge concluded that the data for these four anomalies demonstrated generally good agreement between the HSMFL ILI and the field measurements.

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[45] A *joint* of pipe is a piece of pipe; multiple joints are welded together to form a pipeline. A standard joint is 40 feet long, but joints can be longer or shorter.

Enbridge had an additional procedure for ILI data validation: standard operating procedure 9-3040, *Enhanced Survey Analysis* (Enbridge 2018). It outlined how an Enbridge analyst would perform an additional, detailed review of the raw ILI data to verify documentation and would conduct a series of data checks, including data validation and integration. Procedures were specified for standard ILI tools but not for HSMFL ILI. These procedures did not require the use of statistical analysis methods for any ILI tools. Statistical analysis methods are an industry best practice and are recommended in the optional appendices of API Standard (STD) 1163.

1.8.7 Response and Repair

Enbridge standard operating procedure 9-3010 outlined the specific response, remediation, and repair activities Enbridge personnel should take when different anomaly types and severity levels were found during an ILI run. Procedure 9-3010 stated that hard spots only required excavation and repair when their hardness exceeded 300 Brinell and no cracking was observed. No repaired hard spots were located near the rupture origin. Reports from all excavations noted that the coating was mostly intact with small coating defects present.

1.8.8 Program Performance

In 2012, Spectra's principal metallurgist performed a review of Spectra's hard spot management program using the information gathered from the 2011 HSMFL ILI run and resulting excavations. He found that the hard spot tool data agreed well with field measurements.

The metallurgist also recommended ILI inspections of four other pipeline segments in 2013, including Line 15 between the Danville CS and the Owingsville CS, because these segments contained pipe vintages known to be susceptible to hard spots. Spectra stated that it experienced difficulties finding alternate HSMFL tool vendors after 2013. As of the 2019 accident, the pipeline segments recommended for HSMFL ILI in 2013 had not been inspected for hard spots.

In 2012, Process Performance Improvement Consultants LLC (P-PIC) performed an audit of Spectra's integrity management program. P-PIC found that over time, Spectra "did not evolve … as effectively or at the same rate as its peers" and "must improve … to keep pace" (P-PIC 2012). P-PIC found that corrosion control was one of the key areas where Spectra fell behind.

P-PIC stated Spectra's work planning and management negatively affected the use of data and lessons learned in risk assessment, process improvements, prevention measures, and evaluation of performance, and needed improvement. P-PIC also found that Spectra lacked a robust database to support its IM program, including threat identification, risk assessment, and data integration.

P-PIC recommended that Spectra increase its attention to interacting threats, including looking at industry research and past accidents. P-PIC recommended that Spectra perform an annual comparison of yearly pipeline segment risk scores to enable Spectra to show risk was decreasing every year and to identify areas with increasing risk. No evidence was found that Spectra or Enbridge completed these recommended comparisons.

Spectra's and Enbridge's annual IM performance evaluations from 2014 to 2017 did not recommend any changes to the IM program; however, the number of leaks increased over that time frame, while the number of repairs decreased. In 2018, Enbridge reviewers recommended consolidation of all IM programs and an independent IM program audit.

1.8.9 Recent Integrity Management Program Changes

In early 2019, following several accidents, Enbridge determined that its approach to IM was not resulting in expected performance.[46] Enbridge began transforming its organization, programs, behaviors, data, and support systems with the goal of no ruptures and proven pipeline integrity using a quantitative, as opposed to a qualitative, approach to risk assessments. Enbridge estimated this process would be complete around the end of 2023.

Enbridge contracted with Dynamic Risk to review its IM program and assess the integrity of Enbridge's gas transmission and midstream pipelines, including TET (Enbridge 2020). On July 17, 2019, Dynamic Risk completed phase one of its review. Dynamic Risk evaluated Enbridge's management system, IM program, and seven threat categories related to corrosion, cracking, dents and geohazards. Enbridge did not include hard spots in the threat categories it prioritized for evaluation. Hard spots were determined to have a low probability of failure.

Dynamic Risk found extensive external corrosion anomalies and possible outliers in the data (Dynamic Risk 2019). Based on these findings, Dynamic Risk recommended Enbridge complete required excavations more quickly to provide feedback on the capability of ILI tools.

Dynamic Risk also found that Enbridge's subject matter experts needed to validate risk instead of using risk results to validate the subject matter experts' judgement. Dynamic Risk recommended that Enbridge deploy stronger reactions to smaller indicators of potential issues to get ahead of emerging integrity vulnerabilities.

[46] These accidents were not investigated by the NTSB.

Dynamic Risk made over 62 recommendations, including:

- Continually evaluate all threats rather than discounting certain threats.
- Formalize a continuous improvement process.
- Conduct an audit of the cathodic protection program to determine effectiveness.
- Consider site-specific rupture consequences for non-HCAs in risk analyses.
- Include the potential for interaction of threats in risk analyses.

1.9 Postaccident Actions

After the 2019 accident, Enbridge acted to identify additional hard spots that may have been missed during the original hard spot ILI runs. Enbridge worked with ILI vendors to develop, test, and evaluate ILI tools capable of detecting, identifying, and characterizing hard spots. Enbridge ran new hard spot tools on several segments of Line 15 and other lines. Over 120 verification digs were completed in response to these new ILI runs; Enbridge used these verification digs to validate the performance specifications of the new ILI hard spot tools. Enbridge modified its procedures on hard spot response and repair criteria.

Enbridge created and implemented the framework and processes needed to execute its 3–5-year plan to transform its approach to IM. Enbridge's goals for this project include changing organization, programs, behaviors, data, and support systems to achieve zero ruptures with confidence. As of May 2022, Enbridge had increased its IM staff from 50 to 124 and added specialists in fields such as reliability and geohazards. It created a new group, focused on clarifying accountabilities and work processes and applying IM program elements, to address Dynamic Risk's recommendations. Before Enbridge remodeled its IM program, different pipelines operated under unique IM programs; now these programs are combined into one consolidated IM program, based on feedback from Dynamic Risk's review. To continue this process, Enbridge intends to perform the following actions:

- Improve data availability and accuracy, including automated data processing and quality control.
- Reinforce shifts in decision making to support conservatism in the absence of certainty.
- Expand the detail of the threat matrix for a more complete risk registry.
- Use meaningful metrics to drive awareness and continuous improvement.

Enbridge also increased the frequency of its integrity-related activities.

From early 2019 to May 8, 2020, Enbridge increased the number of pipeline ILI tool runs from 86 to 371 and subsequently increased the number of anomaly digs from 655 to 980. While data gaps found by Dynamic Risk were being addressed, Enbridge restricted pressure on 101 pipeline segments, which was equivalent to 3,189 miles. Enbridge also restricted pressure on 45 segments with A. O. Smith pipe, corresponding to 2,290 miles. These pressure restrictions affected 28 percent of its total gas transmission and midstream mileage.

After the 2019 accident, Enbridge independently hired an engineering firm to study the area surrounding the rupture to gain information on the roles of the environment, coatings, and cathodic protection in the accident. This firm found the likely source of hydrogen was the applied cathodic protection and the abundance of sulfate present in the environment.[47] However, the report also noted the cathodic protection levels were consistent with normal operating ranges and satisfied the industry and regulatory expectation. The engineering firm found the ground was a type of shale known to expand during heavy rainfall, and the soil contained high concentrations of sulfate-reducing bacteria, which can enhance hydrogen absorption into the steel.

After the accident, Enbridge ran HSMFL ILI tools on 10 segments of Line 15, including the accident segment. These segments represent all of Line 15 between Kosciusko, Mississippi, and Holbrook, Pennsylvania, that contained pipe manufactured by A. O. Smith. These ILI runs were completed as part of the remedial work plan required under a corrective action order from PHMSA.

In response to issues identified during the investigation, Enbridge took a number of actions, including hiring a third party to assess its public awareness and emergency response programs. Enbridge modified the *Stanford Area Emergency Response Plan* and made its safety data sheet for natural gas available on its public website. Enbridge also updated the right-of-way signage for TET, including a telephone number to call for information in the event of an emergency.

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[47] (a) When a pipe is under impressed current cathodic protection, hydrogen generation, also called hydrogen evolution, occurs at exposed steel pipe surfaces such as coating defects or discontinuations. (b) When pipeline steels with sensitive microstructures and higher hardness (such as hard spot locations near coating defects) are exposed to sufficient stress and hydrogen evolution, hydrogen-induced cracking may occur.

2. Analysis

2.1 Introduction

On August 1, 2019, at 1:23 a.m., an Enbridge 30-inch-diameter natural gas transmission pipeline ruptured near Danville, Kentucky, in the Indian Camp Subdivision. A 33.2-foot section of the pipeline was ejected and landed about 481 feet southwest of the rupture. Natural gas that released from the rupture ignited, causing a large natural gas fire, several structure fires, and grass fires in the surrounding area. One person died, and six other people were injured, including a deputy sheriff. The fire destroyed 5 residences and damaged 14 others. As a result of the rupture, about 101.5 million cubic feet of natural gas were released.

This analysis discusses the accident and following safety issues:

- Nonconservative assumptions used to calculate potential impact radius. (See section 2.3.)
- Incomplete evaluation of the risks caused by a change of gas flow direction. (See section 2.4.)
- Limitations in data analysis related to the 2011 in-line inspection. (See section 2.5.)
- Operators' potential for incomplete assessment of threats and threat interactions. (See section 2.6.)
- Missed opportunities in training and requalification practices at Enbridge. (See section 2.7.)

Having completed a comprehensive review of the circumstances that led to the accident, the investigation established that the following factors did not contribute to its cause:

- *Internal corrosion*. No internal corrosion was found between Danville CS and Tompkinsville CS during in-line inspections.
- *Stress corrosion cracking*. NTSB testing concluded there were no branching cracks at the rupture origin, which are indicative of stress corrosion cracking.
- *Mechanical damage*. No significant dents or other deformations were observed within 500 feet of the rupture origin during in-line inspections.
- *Local emergency response*. No deficiencies were found in the review of local emergency response activities, and responders arrived in a timely manner after being alerted to the accident. The natural gas fire and the resulting extreme heat the deceased person was exposed to occurred

before the arrival of emergency responders. The actions of the Lincoln County Sheriff's Office deputy sheriff directly resulted in the rescue of two elderly individuals.

The NTSB concludes that none of the following were factors in the accident: internal corrosion, stress corrosion cracking, or mechanical damage of the pipeline, or local emergency response.

2.2 The Accident

The NTSB investigation found that the fracture of the accident pipeline originated at a hard spot, a flaw in the pipeline created during manufacturing. As a manufacturing defect, hard spots can occur in pipes, particularly those of a certain vintage. Current API 5L standards classify hard spots of more than 2 inches in any direction and with a hardness equal to or more than 327 Brinell as rejectable defects.[48] At 5.85 inches by 3 inches and with continuous hardness values of between 362 and 381 Brinell, the hard spot at the fracture origin on the accident pipeline would be considered a rejectable defect by these standards. However, it was not a rejectable defect at the time of manufacture.

In 2014, Spectra initiated a gas flow reversal project during which they identified increased temperatures on the south side of the Danville CS as a risk that could increase external corrosion of the pipeline. Spectra installed gas coolers as a countermeasure; however, temperatures on the south side of the Danville CS continued to rise. Enbridge's ILI data further showed that external corrosion on the south side of the Danville CS also increased: ILI data from 2010 and 2018 indicated a 166 percent rise in metal loss anomalies, and close interval survey data from 2012 and 2018–2019 showed a 72 percent increase in the length of pipeline on the impacted segment that did not meet PHMSA's cathodic protection effectiveness criteria. (See section 2.4 for additional discussion of the gas flow reversal.)

Enbridge and its predecessors increased cathodic protection voltages on the affected pipeline segment to compensate for the increased external corrosion. Further, after the gas flow reversal, Spectra increased the output voltage at the two rectifiers closest to the rupture origin by 18 percent and 58 percent. However, the increased rectifier outputs did not reduce the corrosion, and the number of external corrosion anomalies still increased.

Although Spectra identified temperature increase as a risk and tried to address it and the resulting external corrosion, Spectra did not address how the temperature

[48] At the time of the pipeline manufacture, the standards then did not specify rejectable criteria for a hard spot, such as hardness and length.

increase would affect other critical aspects of corrosion control, such as coating condition. With increased temperatures, coal tar enamels soften and become more pliable. On pipelines located in rockier areas, including shale, risk of coating damage is compounded, since "the effects of mechanical forces from soil stress increase" with a rise in temperature (Spectra 2014). Adhesion to the pipeline can also be affected, and coating damage can occur. The NTSB was unable to view the condition of the coating in the area closest to the rupture origin because of fire damage, but adjacent sections of pipeline unaffected by fire were examined by the NTSB, and coating damage was observed.

Further, in a pipeline under impressed-current cathodic protection, the formation of hydrogen (commonly known as hydrogen evolution) will occur at external surfaces where the coating is disbonded, cracked, chipped, or otherwise damaged and may allow hydrogen absorption into the pipeline wall. A 2007 report to PHMSA by Kiefner and Associates, Inc., *Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines*, reviewed historical accidents associated with hard spots and found that cathodic protection systems are often the source of hydrogen (Kiefner and Associates, Inc. 2007).[49]

The combination of hydrogen, stress from operating pressure, and a vulnerable microstructure (for example, a rejectable hard spot) can cause hydrogen-induced cracking in locations where there is coating damage. This set of factors, including soil conditions, can also accelerate the growth of existing cracks, disbond coating, and embrittle areas with damaged or disbonded coating. However, if the coating is properly installed, bonded to the pipeline, and intact, hydrogen cannot enter the pipeline wall, and the coating acts as a protective barrier from external corrosion.

The NTSB laboratory evaluation of the accident pipe revealed intergranular fracture features at the rupture origin consistent with hydrogen-induced cracking at a hard spot. Because the pipe was under cathodic protection, areas with coating defects that exposed the pipe metal would have been subjected to hydrogen evolution, allowing hydrogen to be absorbed into the steel surface of the pipe (Kiefner and Associates, Inc. 2007).[50]

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[49] *Atomic hydrogen* is created at a cathode (that is, an exposed pipe surface under cathodic protection), and the more negative the potential with respect to a reference voltage, the more aggressively hydrogen is created (Budinski and Wilde 1987).

[50] Although the coating damage on the accident pipeline may also have been due to original construction defects, impacts from shale ground bedding, or both, evidence for either is unavailable.

The size and hardness of the hard spot at the origin of the fracture—both greater than those permitted by current API 5L standards—made it more susceptible to hydrogen-induced cracking. Therefore, the NTSB concludes that the combination of a pre-existing hard spot (a manufacturing defect), degraded coating, and ineffective cathodic protection applied following a 2014 gas flow reversal project, resulted in hydrogen-induced cracking at the outer surface of Line 15 and the subsequent failure of the pipeline.

2.3 Calculation of the Potential Impact Radius

Federal regulations require operators to mathematically calculate a pipeline's PIR (the area where a pipeline's potential failure could have a significant impact on people or property) when deciding whether the pipeline is located in an HCA. The size of the PIR and the accuracy of its calculation directly impact the number and size of HCAs. Gas transmission pipelines that are in HCAs are subject to additional regulatory requirements, such as integrity management regulations. Although Enbridge did perform some integrity management actions on L15 VS4, the NTSB found deficiencies in its IM program, as discussed in sections 2.4, 2.5 and 2.6.

The PIR at the rupture site calculated under PHMSA regulations was 633 feet. Physical evidence at the accident site and from the Lincoln County Coroner's report showed that the PIR of the accident site was larger than what was calculated. The deceased individual was found 640 feet south of the pipeline failure and natural gas fire, and damage to homes was found up to 1,100 feet from the rupture crater. Past accidents have also demonstrated the insufficiency of the PIR calculation. In 2000, a pipeline rupture in Carlsbad, New Mexico, killed 12 people camped about 675 feet from the rupture crater; the PIR would have been calculated at 598 feet by current federal regulations (NTSB 2003). A pipeline that ruptured in San Bruno, California, in 2010 had a PIR of 414 feet, but homes were damaged up to 600 feet from the rupture origin (NTSB 2011). A rupture in Sissonville, West Virginia, in 2012 displayed evidence of thermal damage up to 610 feet from the rupture origin, but the PIR was calculated as 567 feet (NTSB 2014).

These discrepancies prompted the NTSB to further evaluate the assumptions on which the PIR equation is based. The NTSB found that the equation is based on nonconservative assumptions, including the flow equation and flow coefficient, which are based on restricted gas flow after the rupture. However, the gas flow from this accident pipeline, as well as that of the other gas pipeline accidents discussed above, was unrestricted because a section of pipeline had been ejected. Unrestricted gas flow rates are significantly higher than restricted gas flow rates. The current PIR equation also assumes a gas flow release factor more consistent with the middle-to-end of a release event, not the beginning, which is when the most significant injuries typically occur.[51] Further, the equation assumes a gas temperature of 59°F; however, temperatures were considerably higher on the ruptured pipeline segment in Danville.[52]

Assumptions about the impacted public are also inconsistent with available data. The PIR equation assumes a heat radiation intensity of 5,000 BTU/hr-ft^2.[53] In contrast, API Recommended Practice 521, *Pressure-Relieving and Depressurizing Systems*, recommends only a 1,500 BTU/hr-ft^2 heat intensity in areas where exposures lasting 2–3 minutes may be required by personnel without shielding but with appropriate clothing, and just 500 BTU/hr-ft^2 heat intensity in areas where personnel with appropriate clothing may be continuously exposed.[54] Appropriate clothing includes items such as fire-resistant clothing, which members of the public cannot be expected to have when a rupture occurs. Thus, the PIR equation uses an acceptable heat radiation intensity at least 3.3 to 10 times the actual maximum survivable level of heat radiation, depending on the length of time the public is exposed to the heat intensity before they are able to leave the area. This does not account for the lack of protective clothing likely to be readily available to the public, which further distorts the survivable level in the presence of heat radiation. In the Danville accident, the off-duty sheriff's deputy found the injured couple 480 feet from the rupture crater and reported that the intensity of the heat was more than he could handle. He could not approach the decedent, who was 640 feet from the rupture site, because of the heat's intensity and the duration of his ongoing exposure.

PHMSA's PIR model assumes a 1 percent chance of mortality for a person with 30 seconds of exposure to find shelter. This mortality rate assumes that an individual would take 5 seconds after a fire to analyze the situation, decide to evacuate, run for 25 seconds at 2.5 meters per second, and then successfully find sufficient shelter from the ongoing natural gas fire. Determining the probability of human error is complicated when faced with a circumstance like a gas rupture (Idaho National

[51] Natural gas fires are more intense at the beginning due to the larger amount of gas and higher pressure.

[52] Gas flow rates increase with increased temperatures.

[53] When calculating a potential impact radius, the lower the allowable heat radiation intensity, the more conservative the equation.

[54] API Recommended Practice 521 can be used to calculate permissible levels of heat flux for both acute and chronic exposures based on radiation dose load, temperature limits, exposure time, and pain thresholds, among other factors.

Laboratory 2005).[55] The ability for a member of the public to respond following a gas rupture may be complicated by, for example, sleeping, being in an interior room where one may not be immediately aware of an emergency, or evacuating other household members who cannot self-evacuate. Furthermore, the speed with which the member of the public is assumed to run (2.5 m/s) is not representative of the general population, including the very young, elderly, mobility-impaired, or those with pre-existing medical conditions.[56] The two evacuees rescued by the deputy sheriff were both elderly and mobility-impaired. Further, a study by an engineering firm showed that the assumptions on which the PIR equation is based would likely result in a mortality rate of over 50 percent for individuals aged between 60 and 80 (DEATECH Consulting Company 2008).

PHMSA's PIR equation also assumes that natural gas would have a vertical flame, and damage would occur radially. Aerial evidence of the fire that followed the rupture in Danville demonstrated that the natural gas flame was primarily oriented east with a large horizontal component and that the heat-affected zone was larger in that direction. In summary, the NTSB concludes that PHMSA's equation for determining the PIR of a pipeline rupture is based on assumptions that are inconsistent with findings from recent natural gas ruptures and human response data; thus, high consequence areas determined using the equation do not include the full area at risk. Therefore, the NTSB recommends that PHMSA revise the calculation methodology used in their regulations to determine the PIR of a pipeline rupture based on the accident data and human response data discussed in this report.

2.4 Management of Gas Flow Reversal

As stated previously, because the pipe was under cathodic protection following the gas flow reversal, areas with coating defects had increased hydrogen evolution, which reduced the pipeline integrity. However, after the gas flow reversal in 2014, neither Spectra nor Enbridge evaluated the data available on temperatures, cathodic protection, and external corrosion anomalies in L15 VS4 to determine the impacts of the project on pipeline integrity. These data are difficult to predict in advance, and cathodic protection may not respond to operational changes in a predictable way. Extensive research on the effects of major operational changes has

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[55] In the simplified human reliability analysis method used by the Nuclear Regulatory Commission, success is broken down based on available time, stress, complexity, experience/training, procedures, ergonomics, fitness for duty, and work processes. The nominal error rate is 0.011.

[56] Data collected from 5-kilometer race results in the United States in 2010 found that male race participants aged between 20 and 40 ran 5.9 miles per hour, and females ran 5.0 miles per hour for the same age group. Although 5.6 miles per hour falls within these averages, only a certain percentage of the population is aged 20 to 40 or competes in 5-kilometer races.

not been performed, leaving operators only able to plan for general effects (for example, adding gas coolers to address increased temperatures) and requiring them to perform further study after operational changes to detect more subtle effects (such as unstable or ineffective cathodic protection leading to hydrogen evolution). Because Enbridge and its predecessor did not review critical data, they did not identify the suitability of its corrosion control equipment and infrastructure for reversed flow, recognize indicators of coating damage, or identify the cathodic protection system as a likely source of hydrogen evolution. The NTSB concludes that Enbridge and Spectra did not effectively identify, investigate, or manage the impact of the gas flow reversal project on the level of hydrogen evolution in the pipeline surface, which ultimately contributed to the failure of the pipeline. Therefore, the NTSB recommends that Enbridge evaluate the effectiveness of its corrosion control equipment and infrastructure following any major change in operations, such as a gas flow reversal.

The NTSB further concludes that comprehensive management of the changes resulting from the gas flow reversal project on Line 15 would have identified and addressed risks such as coating damage, ineffective cathodic protection, and suitability of corrosion control equipment and infrastructure that led to hydrogen-induced cracking in the pipeline surface. Therefore, the NTSB recommends that PHMSA advise natural gas transmission pipeline operators on a) the circumstances of this accident; b) the need to evaluate the risks associated with flow reversal projects; and c) the impacts of such projects on hydrogen-induced cracking.

2.5 In-Line Inspection Tool and Data Analyses

The 2011 hard spot in-line inspection data discussed in sections 1.8.4.1 and 1.8.5 were analyzed twice by ILI vendors: the first analysis in 2011 predicted 16 potential hard spots, while the second analysis in 2019 (requested by the NTSB after the rupture) predicted 441 hard spots. Although hard spots occur during manufacturing and would have been present at the time of the 2011 HSMFL ILI run, the closest hard spot reported by NDT Systems & Services in 2011 following their analysis was located about 2.2 miles from the rupture site.

After the 2019 accident, the NTSB performed hardness and microhardness testing in the area of the fracture origin. The NTSB found that two hard spots identified in the 2019 NDT Global analysis near the fracture origin were significantly harder than ILI predictions; in fact, these two hard spots were one hard spot. Further, at an additional location where the 2019 NDT Global analysis predicted a hard spot, the NTSB found that no hard spot was present. Including the four verification digs in 2011 and the NTSB measurements, only seven points were available for comparison between predicted and actual hard spots. A sample size of 7 out of 441 is statistically insignificant, and no trends can be determined from these limited data. Insufficient data are currently available to determine the accuracy of NDT Systems & Services' hard spot tool, NDT Systems & Services' 2011 analysis report, or NDT Global's 2019 analysis report. The NTSB recognizes that the 2019 analysis conducted by NDT Global identified more hard spots than the 2011 analysis. However, the presence of the hard spot found by the NTSB during postaccident testing that exceeded the size and hardness specified by current API 5L standards suggests limitation in either the hard spot tool, the HSMFL ILI inspection method, or of the analysis of the collected data.

NDT Systems & Services' performance specification for its hard spot tool did not clearly state if the probability of detection, location accuracy, and sizing accuracy applied to hard spots, metal loss anomalies, or both. To be consistent with the 2005 edition of API STD 1163, all these specifications should have been included, as well as the limitations of the tool when detecting hard spots. For example, NDT Systems & Services should have listed the upper and lower detection limits for hard spots. At the time of the 2011 HSMFL ILI run, API STD 1163 had been an industry best practice for almost 6 years.

The analysis of ILI data further complicates the issue of tool limitations, as some ILI tools, including hard spot tools, rely heavily on analyst interpretation when processing the raw data. Different software settings selected by the analyst, such as gain, and equipment specifications, including monitor resolution, can result in large differences in findings, which in turn impact ILI predictions. NDT Systems & Services' 2011 analysis did not discuss any specifics on the analysis methods or settings.

In addition to running its HSMFL ILI tool on Line 15 and other TET pipelines, NDT Systems & Services ran its tool on at least 1,320.8 miles of pipelines owned by other operators. As stated above, the tool's performance specifications were incomplete, field verifications consistent with current regulations were insufficient to validate ILI tool performance, and insufficient data were available on the accuracy of the hard spot tool. Even if an operator were to conduct data analyses according to industry standards, because of the deficiencies noted with the tool, the NTSB is concerned that pipelines inspected with NDT Systems & Services' HSMFL ILI tool may have similar unidentified issues. Therefore, the NTSB concludes that the extent of hard spots on other pipelines evaluated using NDT Systems & Services' HSMFL ILI tool is likely unknown because of the limitations of the tool and analysis techniques found during this investigation; thus, operators who have relied on this tool for hard spot detection may be unable to effectively manage pipeline integrity.

The NDT Systems and Services HSMFL ILI tool was not the only tool of this type on the market in 2011. However, starting in 2013, the number of available HSMFL ILI tool vendors diminished, including NDT Systems and Services, which discontinued the use of their tool the year before. Since 2013, new HSMFL ILI tools have been developed, and the availability and maturity of these tools and the analysis of their data has advanced. The advancement in the analysis of the data was demonstrated by the increase of potential hard spots identified in the 2019 analysis conducted by NDT Global; even using data from the old tool, additional hard spots were identified. However, the NTSB also found that the identification did not represent real world findings following the 2019 analysis; thus, a more advanced tool may help improve hard spot identification.

Hard spots are often considered inactive threats, and pipeline operators can consider inactive threats stable. If operating conditions are stable and hard spots are considered an inactive threat, operators would not need to reassess their systems for hard spots. This means that it is possible for a pipeline operator to only run an HSMFL ILI tool on susceptible pipeline segments once over the life of the pipe. Because of the deficiencies noted with the HSMFL ILI tools and analyses used by NDT Systems & Services and potentially others and the fact that improvements have been made since 2013, the NTSB is concerned there are other pipeline operators who performed one-time HSMFL ILI assessments that may not have accurately identified the presence of hard spots. Thus, the NTSB concludes that pipeline operators may not have an accurate understanding about the location, size, hardness, and presence of hard spots on susceptible pipeline segments assessed by HSMFL ILI tools before 2013 or analyzed using this data. Therefore, the NTSB recommends that PHMSA advise natural gas transmission pipeline operators of the possible data limitations associated with HSMFL ILI tools and analyses used in hard spot management programs and reinforce the need to follow industry best practices when conducting ILI data analysis.

2.6 Threat Assessment and Interactions

To support threat deactivation, or the point at which threats can be considered stable, an operator must collect data to identify the potential threats. After excavating four hard spots in 2011, Spectra and later Enbridge considered the threat from hard spots eliminated on L15 VS4, thus deactivated. Although measurements from excavations showed conservative agreement with ILI predictions, the number of sites excavated (which were based on the number and severity of anomalies predicted) was statistically insignificant compared with the mileage inspected. After 2011, no further data on hard spots were collected, and Spectra and Enbridge performed no additional HSMFL ILI runs or analyses on Line 15 until after the 2019 accident, when the data were re-analyzed. In its 2019 audit, Dynamic Risk recommended Enbridge consider all threats possible and continually evaluate them, rather than eliminating certain threats entirely (Dynamic Risk 2019). The NTSB concludes that, although Enbridge had classified the threat of hard spots as inactive at the time of the accident on August 1, 2019, insufficient data were available to support this threat status on the ruptured pipeline segment because of the limitations in the HSMFL ILI tool and Enbridge's analysis.

On February 1, 2020, PHMSA published a guidance document on risk assessments and risk modeling, in part to address NTSB Safety Recommendations

P-15-10, P-15-12, and P-15-13 (PHMSA 2020).[57] This document recommended pipeline operators address all findings within a 2016 study by Kiefner & Associates, Inc. This study found that changes in operating conditions could intensify certain threats, including those posed by hard spots. Examples of operational changes included changes in temperature and cathodic protection loads, as well as reversal of flow direction (Muñoz and Rosenfeld 2016). Degradation of coating, increased rates of external corrosion, and decreased effectiveness of cathodic protection can also result from operational changes. The flow reversal significantly altered operating conditions on L15 VS4; however, Spectra and Enbridge did not assess L15 VS4 for how the change in operating conditions affected the hard spots between the 2014 flow reversal and the 2019 accident, missing an opportunity to identify threats to pipeline integrity, as discussed in section 2.4. The NTSB concludes that, had the status of threats on Line 15 been re-evaluated after the flow reversal project, Spectra or Enbridge would have had the opportunity to determine how the change in operating conditions affected the hard spots.

When considering whether a threat is active or inactive, a pipeline operator must also account for interactions with other threats, according to 49 *CFR* 192.917. At the time of the 2019 accident, Enbridge's IM program manual stated manufacturing threats did not interact with corrosion of any type. However, hard spots interact with external corrosion by destabilizing over time from the introduction of hydrogen by cathodic protection, as well as by interacting with internal corrosion. This has been shown in several industry standards and white papers, including API Recommended Practice 1160, *Managing System Integrity for Hazardous Liquids Pipelines*, and Kiefner & Associates, Inc.'s 2007 report, *Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines* (API 2001; Kiefner & Associates, Inc. 2007).

Enbridge used data from the 2011 HSMFL ILI run to classify the threat of hard spots as inactive on the accident pipeline in the area of the rupture, but later analysis and external audits indicated that these data were not enough to substantiate that classification. Changes in pipeline operation—such as a major flow reversal project—can have significant impacts on threats such as hard spots, so Enbridge should have re-evaluated these threats after the project. Further, federal regulations require pipeline operators to account for interactions among threats in their pipelines, as certain threats can intensify others. The NTSB concludes that Enbridge's processes

[57] In 2015, the NTSB recommended that PHMSA update its guidance for gas transmission pipeline operators and inspectors on the evaluation of interactive threats (NTSB Safety Recommendation P-15-10); evaluate the safety benefits of risk assessment approaches allowed by IM regulations and disseminate the results of the evaluation (NTSB Safety Recommendation P-15-12); and update guidance for gas transmission pipeline operators and inspectors on critical components of risk assessment approaches (NTSB Safety Recommendation P-15-13). All three recommendations are classified "Closed—Acceptable Action."

and procedures were inconsistent with PHMSA guidance and industry knowledge of hard spot threat interactions, leading Enbridge to underestimate the risk posed by hard spots. Therefore, the NTSB recommends that Enbridge revise its integrity management program to include (a) data required to support the active or inactive status of each threat, including hard spots; (b) conditions and situations that require reassessment and re-evaluation of threat status, including flow reversal and other major projects; and (c) the interactions between hard spots and all types of corrosion.

2.7 Training and Requalification Practices

On May 8, 2019, an emergency shutdown occurred at the Danville CS. During this emergency shutdown, the station operator demonstrated a fundamental lack of knowledge of station operations when he failed to use the SCADA graphics to troubleshoot the problem and closed a valve irrelevant to the event. After this incident, the station operator was not disqualified or requalified for any covered tasks nor required to take remedial training.

On August 1, 2019, the same station operator was on duty when the rupture occurred. After viewing the fireball caused by the rupture and receiving a call from the gas control center, the station operator did not refer to the *Stanford Area Emergency Response Plan*, which listed the specific valves that required closure for isolation, and failed to isolate Line 15 at the station until the area supervisor directly instructed him to close valve 15-393. Enbridge employees are required to follow the *Stanford Area Emergency Response Plan* in the event of an emergency. Valve 15-393 took less than 4 minutes to operate, but it was not closed until about 16 minutes after the rupture.

The Danville CS on-duty station operator's lack of knowledge of emergency response procedures resulted in a delay in the closure of valve 15-393. This delay increased the volume of gas released, which increased the duration and intensity of the fire. The NTSB concludes that had Enbridge disqualified, requalified, or provided remedial training to the Danville CS operator after he displayed a fundamental lack of knowledge during the May 8, 2019, emergency shutdown, the operator's closure of valve 15-393 during the August 1, 2019, rupture may not have been delayed, potentially reducing the volume of gas released. Therefore, the NTSB recommends that Enbridge disqualify and require remedial training and requalification of the covered task(s) whenever an employee does not follow procedures when responding to an emergency shutdown, rupture, or other abnormal operation.

3. Conclusions

3.1 Findings

1. None of the following were factors in the accident: internal corrosion, stress corrosion cracking, or mechanical damage of the pipeline, or local emergency response.

2. The combination of a pre-existing hard spot (a manufacturing defect), degraded coating, and ineffective cathodic protection applied following a 2014 gas flow reversal project, resulted in hydrogen-induced cracking at the outer surface of Line 15 and the subsequent failure of the pipeline.

3. The Pipeline and Hazardous Materials Safety Administration's equation for determining the potential impact radius of a pipeline rupture is based on assumptions that are inconsistent with findings from recent natural gas ruptures and human response data; thus, high consequence areas determined using the equation do not include the full area at risk.

4. Enbridge Inc. and Spectra Energy Partners, LP did not effectively identify, investigate, or manage the impact of the gas flow reversal project on the level of hydrogen evolution in the pipeline surface, which ultimately contributed to the failure of the pipeline.

5. Comprehensive management of the changes resulting from the gas flow reversal project on Line 15 would have identified and addressed risks such as coating damage, ineffective cathodic protection, and suitability of corrosion control equipment and infrastructure that led to hydrogen-induced cracking in the pipeline surface.

6. The extent of hard spots on other pipelines evaluated using NDT Systems & Services' hard spot magnetic flux leakage in-line inspection tool is likely unknown because of the limitations of the tool and analysis techniques found during this investigation; thus, operators who have relied on this tool for hard spot detection may be unable to effectively manage pipeline integrity.

7. Pipeline operators may not have an accurate understanding about the location, size, hardness, and presence of hard spots on susceptible pipeline segments assessed by hard spot magnetic flux leakage in-line inspection tools before 2013 or analyzed using this data.

8. Although Enbridge Inc. had classified the threat of hard spots as inactive at the time of the accident on August 1, 2019, insufficient data were available to support this threat status on the ruptured pipeline segment because of the

limitations in the hard spot magnetic flux leakage in-line inspection tool and Enbridge Inc.'s analysis.

9. Had the status of threats on Line 15 been re-evaluated after the flow reversal project, Spectra Energy Partners, LP or Enbridge Inc. would have had the opportunity to determine how the change in operating conditions affected the hard spots.

10. Enbridge Inc.'s processes and procedures were inconsistent with the Pipeline and Hazardous Materials Safety Administration's guidance and industry knowledge of hard spot threat interactions, leading Enbridge Inc. to underestimate the risk posed by hard spots.

11. Had Enbridge Inc. disqualified, requalified, or provided remedial training to the Danville compressor station operator after he displayed a fundamental lack of knowledge during the May 8, 2019, emergency shutdown, the operator's closure of valve 15-393 during the August 1, 2019, rupture may not have been delayed, potentially reducing the volume of gas released.

3.2 Probable Cause

The National Transportation Safety Board determines that the probable cause of the August 1, 2019, rupture of an Enbridge Inc. natural gas transmission pipeline and resulting fire was the combination of a pre-existing hard spot (a manufacturing defect), degraded coating, and ineffective cathodic protection applied following a 2014 gas flow reversal project, which resulted in hydrogen-induced cracking at the outer surface of Line 15 and the subsequent failure of the pipeline. Contributing to the accident was the 2014 gas flow reversal project that increased external corrosion and hydrogen evolution. Also contributing to this accident was Enbridge's integrity management program, which did not accurately assess the integrity of the pipeline or estimate the risk from interacting threats.

4. Recommendations

4.1 New Recommendations

As a result of this investigation, the National Transportation Safety Board makes the following new safety recommendations:

To the Pipeline and Hazardous Materials Safety Administration:

1. Revise the calculation methodology used in your regulations to determine the potential impact radius of a pipeline rupture based on the accident data and human response data discussed in this report. (P-22-1)

2. Advise natural gas transmission pipeline operators on a) the circumstances of this accident; b) the need to evaluate the risks associated with flow reversal projects; and c) the impacts of such projects on hydrogen-induced cracking. (P-22-2)

3. Advise natural gas transmission pipeline operators of the possible data limitations associated with hard spot magnetic flux leakage in-line inspection tools and analyses used in hard spot management programs and reinforce the need to follow industry best practices when conducting in-line inspection data analysis. (P-22-3)

To Enbridge Inc.:

4. Evaluate the effectiveness of your corrosion control equipment and infrastructure following any major change in operations, such as a gas flow reversal. (P-22-4)

5. Revise your integrity management program to include (a) data required to support the active or inactive status of each threat, including hard spots; (b) conditions and situations that require reassessment and re-evaluation of threat status, including flow reversal and other major projects; and (c) the interactions between hard spots and all types of corrosion. (P-22-5)

6. Disqualify and require remedial training and requalification of the covered task(s) whenever an employee does not follow procedures when responding to an emergency shutdown, rupture, or other abnormal operation. (P-22-6)

BY THE NATIONAL TRANSPORTATION SAFETY BOARD

JENNIFER HOMENDY
Chair

MICHAEL GRAHAM
Member

BRUCE LANDSBERG
Vice Chairman

THOMAS CHAPMAN
Member

Report Date: August 15, 2022

Appendix A: Investigation

The National Transportation Safety Board (NTSB) was notified on August 1, 2019, of the accident that occurred in Danville, Kentucky. A 30-inch natural gas transmission pipeline ruptured, which caused a large natural gas release and fire.

The NTSB launched an investigator-in-charge, a senior metallurgist from the NTSB Materials Laboratory, and a survival factors and emergency response investigator.

The parties to the investigation are the Pipeline and Hazardous Materials Safety Administration, Lincoln County Emergency Management, Lincoln County Fire Protection District, Enbridge Inc., and NDT Global LLC.

Appendix B: Consolidated Recommendation Information

Title 49 *United States Code* (USC) 1117(b) requires the following information on the recommendations in this report.

For each recommendation–

(1) a brief summary of the NTSB's collection and analysis of the specific accident investigation information most relevant to the recommendation;

(2) a description of the NTSB's use of external information, including studies, reports, and experts, other than the findings of a specific accident investigation, if any were used to inform or support the recommendation, including a brief summary of the specific safety benefits and other effects identified by each study, report, or expert; and

(3) a brief summary of any examples of actions taken by regulated entities before the publication of the safety recommendation, to the extent such actions are known to the Board, that were consistent with the recommendation.

To the Pipeline and Hazardous Materials Safety Administration

P-22-1

Revise the calculation methodology used in your regulations to determine the potential impact radius of a pipeline rupture based on the accident data and human response data discussed in this report.

Information that addresses the requirements of 49 *U.S.C.* 1117(b)(1), as applicable, can be found in section 2.3 Calculation of the Potential Impact Radius; (b)(2) is not applicable; and (b)(3) is not applicable.

P-22-2

Advise natural gas transmission pipeline operators on a) the circumstances of this accident; b) the need to evaluate the risks associated with flow reversal projects; and c) the impacts of such projects on hydrogen-induced cracking.

Information that addresses the requirements of 49 *U.S.C.* 1117(b)(1), as applicable, can be found in section 2.4 Management of Gas Flow Reversal; (b)(2) can be found in 1.8.2 Threat Identification and Interaction; and (b)(3) is not applicable.

P-22-3

Advise natural gas transmission pipeline operators of the possible data limitations associated with hard spot magnetic flux leakage in-line inspection tools and analyses used in hard spot management programs and reinforce the need to follow industry best practices when conducting in-line inspection data analysis.

Information that addresses the requirements of 49 *U.S.C.* 1117(b)(1), as applicable, can be found in section 2.5 In-Line Inspection Tool and Data Analyses; (b)(2) is not applicable; and (b)(3) can be found in 1.9 Postaccident Actions.

To Enbridge Inc.

P-22-4

Evaluate the effectiveness of your corrosion control equipment and infrastructure following any major change in operations, such as a gas flow reversal.

Information that addresses the requirements of 49 *U.S.C.* 1117(b)(1), as applicable, can be found in section 2.4 Management of Gas Flow Reversal; (b)(2) is not applicable; and information supporting (b)(3) can be found in section 1.9 Postaccident Actions.

P-22-5

Revise your integrity management program to include (a) data required to support the active or inactive status of each threat, including hard spots; (b) conditions and situations that require reassessment and re-evaluation of threat status, including flow reversal and other major projects; and (c) the interactions between hard spots and all types of corrosion.

Information that addresses the requirements of 49 *U.S.C.* 1117(b)(1), as applicable, can be found in section 2.6 Threat Assessment and Interactions; (b)(2) is not applicable; and information supporting (b)(3) can be found in section 1.9 Postaccident Actions.

P-22-6

> Disqualify and require remedial training and requalification of the covered task(s) whenever an employee does not follow procedures when responding to an emergency shutdown, rupture, or other abnormal operation.

Information that addresses the requirements of 49 *U.S.C.* 1117(b)(1), as applicable, can be found in section 2.7 Training and Requalification Practices; (b)(2) is not applicable; and information supporting (b)(3) is not applicable.

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The National Transportation Safety Board (NTSB) is an independent federal agency dedicated to promoting aviation, railroad, highway, marine, and pipeline safety. Established in 1967, the agency is mandated by Congress through the Independent Safety Board Act of 1974, to investigate transportation accidents, determine the probable causes of the accidents, issue safety recommendations, study transportation safety issues, and evaluate the safety effectiveness of government agencies involved in transportation. The NTSB makes public its actions and decisions through accident reports, safety studies, special investigation reports, safety recommendations, and statistical reviews.

The NTSB does not assign fault or blame for an accident or incident; rather, as specified by NTSB regulation, "accident/incident investigations are fact-finding proceedings with no formal issues and no adverse parties … and are not conducted for the purpose of determining the rights or liabilities of any person" (Title 49 *Code of Federal Regulations* section 831.4). Assignment of fault or legal liability is not relevant to the NTSB's statutory mission to improve transportation safety by investigating accidents and incidents and issuing safety recommendations. In addition, statutory language prohibits the admission into evidence or use of any part of an NTSB report related to an accident in a civil action for damages resulting from a matter mentioned in the report (Title 49 *United States Code* section 1154(b)).

For more detailed background information on this report, visit the NTSB investigations website and search for NTSB accident ID PLD19FR002. Recent publications are available in their entirety on the NTSB website. Other information about available publications also may be obtained from the website or by contacting–

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NTIS website

August 2, 2024

Southern California Gas Company
555 West Fifth Street
Los Angeles, CA 90013

Submitted via email to ALP1_Study_PAG_Feedback@insigniaenv.com

Feedback for Southern California Gas Company on the Workforce Planning & Training Evaluation Draft Report

Communities for a Better Environment (CBE) submits this letter of feedback to Southern California Gas Company (SoCalGas) on the Workforce Planning & Training Evaluation Draft Report (the "Report") provided on July 5, 2024. This report still lacks fair discussion of several important issues surrounding workforce planning, largely because it relies on the Plan for Applicable Safety Requirements ("Safety Study"). As we explained in our feedback letter regarding the Safety Study (from July 19, 2024), that safety draft report has major flaws and omissions. Thus, SoCalGas's reliance on the Safety Study in this workforce report is misplaced. California Public Utilities Commission (CPUC) Decision 22-12-055 emphasizes the importance of stakeholder engagement. Meaningful engagement is impeded where key information is either omitted or presented in a misleading manner. Particularly, the Report:

I. Does Not Adequately Addresses Prior Concerns Raised by CBE about Worker Safety Because It Relies on the Flawed Safety Study
II. Fails to Go Far Enough in Committing to More Local Hiring and Greater Numbers of Union Represented Employees
III. Has Shortcomings in its Discussion of Gas Control and Emergency Response Personnel for Hydrogen and Natural Gas Systems
IV. Glosses Over Key Differences Between Hydrogen and Natural Gas

I. The Report Does Not Adequately Addresses Prior Concerns Raised by CBE About Worker Safety Because It Relies on the Flawed Safety Study

In the Report's Stakeholder Comments section, SoCalGas states it has addressed concerns voiced by CBE to expand on worker safety concerns related to pipeline transportation of 100% hydrogen.[1] The Report claims: "Employee safety is addressed throughout the study and is specifically evaluated in the *Plan for Applicable Safety Requirements* Study (Safety Study)."[2]

[1] Report at 34.
[2] *Id.* at 34.

However, the Safety Study lacked meaningful details on numerous important topics. For example, in the Safety Study, SoCalGas made multiple references to the roughly 1,600 miles of hydrogen pipelines that already exist and operate in the United States. As we pointed out in our feedback letter for the Safety Study, SoCalGas failed to examine the supposed safety standards of the existing 1,600 miles of hydrogen pipelines because it did not discuss any specific hydrogen pipeline nationwide.[3] In addition, the Safety Study failed to examine international hydrogen safety standards beyond merely naming organizations like HySafe, providing brief general descriptions of the organizations, and providing URLs for them.[4] The Safety Study also minimized the risks of serious bodily injury and death that can result from hydrogen leaks and explosions because it cherry-picked relatively less serious hydrogen accidents and excluded key details in some of the incidents SoCalGas described.[5] This Report repeatedly refers to the Safety Study[6] as if the safety report sufficiently resolved CBE's safety concerns. As CBE has raised, the Safety Study was flawed in several ways. SoCalGas's reliance on it in this Report is misplaced, and the comments made around worker safety at the Preliminary Data and Findings stage have still not been adequately addressed.

II. The Report Fails to Go Far Enough in Committing to More Local Hiring and Greater Numbers of Union Represented Employees

The report does not adequately discuss steps to providing stable, well-paying jobs to union workers and investing in new members of the workforce. A project's safety and integrity are only as good as the workers that construct and operate it. It is critical that any pipeline that is in fact constructed builds up the opportunities and skilled workforce of the community it is located in. Projects should work in concert with California's professional trade unions to provide well-paid, stable jobs to existing workers and invest resources in recruiting and training the next generation of workers from the project community.

The Report's Employment Impact Analysis appendix includes discussion of projected economic benefits for Diverse Business Enterprises (DBEs) during the construction phase of Angeles Link.[7] This section also includes an estimate of more than 23,000 direct DBE jobs during the project construction period.[8] However, these DBE projections only refer to SoCalGas contracts for "goods and services from diverse suppliers[.]"[9] Neither the Report nor its appendix say more statements like "workforce planning includes managing the recruitment and selection

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[3] CBE Feedback for Southern California Gas Company on the Plan for Applicable Safety Requirements Draft Report (July 19, 2024), at 3.
[4] *Id.* at 2.
[5] *Id.* at 4-5.
[6] Report at 11, 12, 22, 34.
[7] Appendix A at 14.
[8] *Id.*
[9] *Id.* at 14.

of a qualified and diverse workforce, while complying with legal requirements throughout the staffing process."[10] Further, "[a]pproximately one-half of the SoCalGas workforce is union represented[.]"[11]The Report should aim to boost the percentage share of full-time, union represented employees (not just independent contractors that usually lack the benefits afforded to full-time, union represented employees) and explore in greater detail what investments and training must be made to mobilize local workforces and bring adequate hydrogen specific training to union workers.

III. The Report Has Shortcomings in its Discussion of Gas Control and Emergency Response Personnel for Hydrogen and Natural Gas Systems

After reviewing the Report's discussion of workforce personnel for SoCalGas's existing natural gas network and proposed Angeles Link hydrogen pipeline, CBE believes that SoCalGas needs to strike a better balance between proposing cross-training[12] for both systems while maintaining distinct gas control and emergency response personnel. Such balance is essential to promote safety for natural gas and hydrogen systems. The Report repeatedly hedges about separate teams for the natural gas and hydrogen systems: "may have designated responsibilities for the control of both natural gas and hydrogen systems;"[13] operator qualifications "may be different due to the physical and chemical properties of hydrogen;"[14] "[s]eparate control room management plans may be implemented for natural gas and hydrogen."[15] This hedging is also present when discussing field personnel, not just control room staff: "SoCalGas will determine if field personnel can carry OQs [Operator Qualifications] for both natural gas pipeline O&M [Operations & Maintenance] and Angeles Link hydrogen pipeline O&M, or if they must be carried by separate personnel."[16] SoCalGas should make these determinations and issue associated explanations for them as soon as feasible so that parties can review their decisions. Given the differing chemical properties of hydrogen and natural gas and the novelty of this projects proposed scale, it is vital that adequate safety teams are trained and on call at all times.

IV. The Report Again Glosses Over Key Differences Between Hydrogen and Natural Gas

The Report continues the error made in the Safety Study concerning the lack of differentiation in federal safety regulations for natural gas pipelines and hydrogen pipelines. As

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[10] Report at 32.
[11] *Id.* at 32.
[12] *Id.* at 23 ("An alternate approach to consider for staffing gas control and emergency response functions would be to rotate gas control personnel and emergency response personnel between natural gas and hydrogen infrastructure, thereby providing cross-training of personnel.")
[13] *Id.*
[14] *Id.*
[15] *Id.*
[16] *Id.* at 18.

we explained in our feedback to the Safety Study,[17] CBE's communities have not been sufficiently protected by industry best practices, even when federal and state laws and regulations directly apply these practices. Chemical leaks, flaring, explosions, and spills are commonplace in communities like Wilmington despite safety regulations. These exposures impact workers, first responders, community members' health and well-being. Unnecessary risks which can be eliminated by new training, research, and updated operating practices must be to priority. Because hydrogen-specific standards are not directly incorporated into federal and state laws or regulations in all circumstances, only industry best practices provide for some, albeit insufficient, level of protection.

In the Report, SoCalGas states: "Angeles Link and the natural gas infrastructure would both be governed by 49 CFR Part 192 with the same regulatory requirements." But the Report fails to mention the lack of differentiation in federal safety regulations for natural gas pipelines and hydrogen pipelines. SoCalGas then presents Table 5 (Pipeline and Compressor Station Requirements) to show that many subsections of 49 Code of Federal Regulations (CFR) 192 apply to both natural gas and hydrogen infrastructure.[18] The table has 19 rows of CFR sections, and they all say "Yes" for applicability for natural gas and for hydrogen. Accordingly, the Report asserts that corrosion control, operating, and maintenance requirements for "natural gas infrastructure and Angeles Link may be similar."[19] Even though the sentence before Table 5 is presented includes the caveat that "this is not an exhaustive list)," this table masks the potential need for differing regulatory standards for hydrogen versus natural gas because it draws support from existing federal standards that also fail to distinguish between the risks associated with hydrogen and natural gas. Thus, Table 5 presents information in a misleading manner.

A fairer version of Table 5 would include at least one, and preferably more, differences between hydrogen and natural gas. And if there truly are no applicability differences because current federal regulations do not specify differences between natural gas, hydrogen, or other gases, then SoCalGas should identify updated requirements which would more effectively protect the ALP workforce and the communities bearing impacts from the project.

V. Conclusion

CBE appreciates the opportunity to provide feedback and urges SoCalGas to incorporate, in greater depth, workforce development and training needs, opportunities to partner more closely with unionize workers, and investigate worker and community safety response plans more expansively. The Report's conclusion section asserts: "SoCalGas is uniquely well-positioned to operate and maintain a clean renewable hydrogen pipeline system due to its vast

[17] CBE Feedback for Southern California Gas Company on the Plan for Applicable Safety Requirements Draft Report (July 19, 2024), at 3.
[18] Report at 28.
[19] *Id.*

experience operating and maintaining a highly developed gas transmission and distribution system, existing highly trained and qualified workforce, and comprehensive programs and procedures."[20] CBE reiterates that the company has many long strides to make with respect to safety and basic hydrogen learning before making such claims in its report.

CBE emphasizes, and echoes comments made in prior letters as well as in person at CBOSG and PAG meetings that the volume and speed at which report feedback is requested is vastly inappropriate for meaningful engagement and feedback on Phase 1 reports as is repeatedly emphasized in CPUC Decision 22-02-007.

Sincerely,

Jay Parepally
Theo Caretto
Communities for a Better Environment

CC:
Emily Grant, SoCalGas
Chester Britt, Arellano Associates
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[20] *Id.* at 35.

August 2, 2024

VIA EMAIL TO
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Re: Angeles Link Planning Advisory Group (PAG) Feedback of Air Products and Chemicals Inc. on Water Resources Evaluation (July 2024 Draft)

Air Products and Chemicals, Inc. ("Air Products") submits the following feedback concerning the July 2024 draft Water Resources Evaluation ("Draft Water Evaluation").

Air Products expects that the below feedback will be addressed in the final Studies and in Southern California Gas Company's ("SoCalGas") quarterly reporting. Air Products also welcomes any response that SoCalGas may wish to provide to the comments below.

The Water Evaluation Fails to Focus on Relevant Production Areas

SoCalGas has identified the specific areas where it believes hydrogen production is likely to take place—primarily inland locations that are favorable for renewable energy, including Blythe, Lancaster and the San Joaquin Valley.[1] Yet the Draft Water Evaluation minimizes—indeed, effectively ignores—the challenges associated with water availability by focusing on water availability across the state, without any detailed evaluation of whether that water can economically be delivered to the production locations that it identified. The Draft Water Evaluation notes that the potential water sources identified are located far from the location of presumed production, including in coastal or urban areas throughout California.[2] And the Draft Water Evaluation acknowledges that "[l]ong pipelines may be needed to convey water from the coastal and urban areas to the production areas." There are a litany of challenges associated with construction of such pipelines, as the Draft Water Evaluation also acknowledges. The pipelines will be costly, will need to be permitted and sited through high population urban areas, and may have significant environmental impacts, including energy demand that may have impacts on greenhouse gas emissions, and energy costs that will further exacerbate the expense associated with delivering water to the production areas. Simply put, these challenges are likely to make access to a significant portion of the identified water sources uneconomic, unacceptable from an

[1] Production and Planning Assessment Study at ____; Water Evaluation at 4-12.
[2] Water Evaluation at 4-12.

environmental impact perspective, or simply logistically infeasible. Yet the Draft Water Evaluation fails to comprehensively evaluate these challenges or make any determination as to whether identified water sources are actually viable water sources for hydrogen production, based on these factors.

The Draft Water Evaluation is therefore useless for determining whether water is actually economically available for hydrogen production in the areas where SoCalGas assumes hydrogen production would occur. The Draft Water Evaluation effectively acknowledges this issue when it states that "[p]rioritizing sources close the hydrogen production areas would mitigate construction and cost challenges associated with long conveyance requirements."[3] However, aside from the offhand comment, the Draft Water Evaluation fails to do exactly that—prioritize and analyze sources that can logistically and cost-effectively be transported to production areas.

The Draft Water Evaluation provides one other potential solution—stating that "[a]cquiring surface water through an exchange provides another opportunity to mitigate challenges associated with conveyance."[4] Yet, as with other conveyance approaches, the Draft Water Evaluation fails to provide any actual analysis of surface water exchange options that might be available. Factors impacting the availability of transfers and exchanges include the duration of the transfer or exchange, the type of water at issue, potential injury to other water rights holders, the anticipated environmental impacts, and whether State or Federal facilities are involved.

Finally, the Draft Water Evaluation identifies water supply challenges, including concentrate management, treatment issues, and supply reliability.[5] However, because the Draft Water Evaluation does not evaluate water availability as it relates to specific production areas, it is impossible to determine how and to what extent these water supply challenges will impact specific production areas. Again, a focus on production areas—rather than water supply statewide—is the appropriate approach. The Draft Water Evaluation's blithe assertion that the "[w]ater required for the portion of clean renewable hydrogen production that Angeles Link could transport is a small percentage… of California's total water usage each year"[6] misses the point. The issue is not what is used, or what might be available statewide. What the Draft Water Evaluation should actually evaluate is the extent to which sufficient water supply would be available for hydrogen production in SoCalGas's identified production areas.

The Draft Water Evaluation notes that "project-level analysis for specific proposed clean renewable hydrogen production projects would be speculative…, given the unknown variables associated with project-level analysis…"[7] However, that concern about the speculative nature of individual project should not preclude a more granular analysis of the specific production areas that SoCalGas has already identified. The Draft Water Evaluation's statewide approach, in

[3] *Id.*
[4] *Id.*
[5] *Id.* at 4-6.
[6] *Id.* at INTRO-i.
[7] *Id.* at 4-6.

contrast, makes it virtually useless for determining whether there is sufficient water to supply likely hydrogen production areas which the Angeles Link project proposes to serve.

Additional Data Issues with Draft Water Evaluation

Beyond its broad concern about the lack of granularity in the Draft Water Evaluation, Air Products has identified a number of concerns about the data provided in the Draft Water Evaluation, as explained in detail below.

Water Demand Figures

Air Products appreciates that that the Draft Water Evaluation, in response to Air Products' previous comments, attempts to distinguish between raw water demands and stoichiometric ultra pure water (UPW) needs.[8] However, there are still numerous instances throughout the Draft Water Evaluation where it is unclear whether water needs refer to UPW needs or raw water needs. Air Products suggests that the Draft Water Evaluation be revised to always default to raw water demand, where possible.

In Table 1.ES-1 at p. 1-2, the referenced annual water needs appear to be raw water demand. It appears that the Draft Water Evaluation is assuming approximately 65% recovery through water treatment systems to calculate raw water demand, but the assumption on recovery percentage through water treatment systems is not specified anywhere in the Draft Water Evaluation. Also, the annual water demand does not seem to account for cooling water needs for the electrolyzer and the hydrogen production facility. Air Products would expect cooling water needs to be roughly twice the UPW stochiometric flow demand.

Electrolyzer Feed Water Requirements

Table 3-4 purports to list the "Water Quality Requirements for Electrolyzer Supplier's Polishing Treatment System." It is unclear whether these are suggested requirements for RO or EDI. RO membrane manufacturers typically do not specify limits for TDS or total silica, and the listed figures appear low for RO membranes. However, the listed requirements appear higher than typical feedwater limits for an EDI system.

Table 3-4 is also inconsistent with the feedwater requirements cited in Chapter 2 at p. 2-2 (water conductivity of <0.2 μS/cm and <5 μS/cm for PEM and alkaline electrolyzers, respectively).

Chapter 3 also refers to RO and EDI treatment as polishing steps, while Chapter 2 (p. 2-3) refers to the polishing step as post-RO treatment. Feed water requirements at the post-RO stage are significantly tighter than the figures specified in Table 3-4.

Also, at p. 3-11, the Draft Water Evaluation states that "anticipated TDS and TOC concentrations for all potential supply types identified in Chapter 1: Water Availability Study

[8] *Id.* at INTRO-iii.

(Rincon 2024) exceed these limits [in Table 3-4], with the exception of surface water sources and urban stormwater capture and reuse (refer to Table 3-3). Consequently, pretreatment by RO will be required for those remaining eight supply sources." However, as referenced in note [a] to Table 3-3, surface water sources other than SWP Water-Lake Perris Outlet may have TDS levels higher than 350 mg/l, and therefore also require pretreatment by RO.

The Draft Water Evaluation also estimates a water recovery of 98% is achievable for treatment of SWP.[9] This seems unrealistic in Air Products' experience. The Draft Water Evaluation also claims that the water recovery rate for the UF would 98%, assuming that the clarified backwash water return will be transferred back to the UF feed.[10] It is Air Products' understanding that this is not possible given the high levels of coagulant and polymer in these waste streams. Please provide a further explanation as to why SoCalGas believes these water recovery rates are realistic.

Wastewater Treatment

Section 6 presents planning-level cost estimates for two options for concentrate management to provide a range of potential costs for potential third-party production projects. The two options presented are discharge to existing brine disposal facilities, or the construction of onsite evaporation ponds.[11] Regardless of feed water resource type, all treatment facilities are expected to produce continuous wastewater discharge. This section fails to provide a detailed analysis on approaches to comply with wastewater discharge limits and challenges associated with obtaining discharge permits in the regions where production is anticipated to occur. It will be critical for production to identify a workable wastewater discharge strategy.

Conclusion

Air Products appreciates the opportunity to provide this feedback concerning the July 2024 Draft Water Evaluation.

[9] *Id.* at Section 5.1.1 at p. 3-13.
[10] *Id.* at Section 5.2.1 at p. 3-14.
[11] *Id.* at Section 6 at p. 3-24.

Respectfully,

Miles Heller Director, Global Greenhouse Gas,
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COMMUNITIES FOR A BETTER ENVIRONMENT
established 1978

August 2, 2024

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Submitted via email to ALP1_Study_PAG_Feedback@insigniaenv.com.

Feedback for Southern California Gas Company on Water Resources Evaluation Draft Report

Communities for a Better Environment (CBE) submits this letter of feedback to Southern California Gas Company (SoCalGas) on the Water Resource Evaluation Draft Report (Water Report) provided on July 5, 2024. This letter raises concerns regarding the scope of the water report and significant omissions that the final report must remedy. The following sections, addressed at length below, outline CBE's concerns across the five chapters of the Water Report:

I. Water Source Feasibility Concerns
II. Geographic Scope, Acquisition, and Treatment Feasibility Concerns
III. Failure to Include Community Concerns in Feasibility Analysis
IV. Inadequate Greenhouse Gas Emissions Analysis

Echoing the Equity Principles for Hydrogen,[1] CBE emphasizes the importance of environmental justice protections related to water use and treatment to mitigate the negative impacts of hydrogen projects on California's already stretched water supply. Foundational environmental justice protections include requirements that water sources are surplus and not diverted from sources which serve jurisdictions that are struggling or failing to meet clean drinking water needs, nor can the water source be potable water when drinking water needs are not met.

I. Water Source Feasibility Concerns

Water Report chapter one on availability identifies ten sources of water as feasible for hydrogen production in service of the Angeles Link Project based on a flawed set of criteria that fail to account for water treatment, and acquisition. While treatment and acquisition are separately addressed in Chapters two and three respectively, their assessment does not affect the Report's presumption of feasibility based on availability alone. For example, some sources, such as imported surface water have been fully allocated and are only accessible via exchange agreements. Whereas other sources such as dry weather flows, urban stormwater capture and reuse, and oil and gas industry water are ephemeral, inconsistent sources that exist dependent on

[1] CBE et al., Environmental Justice Position on Green Hydrogen in California, Equity Principles for Hydrogen (2023).

specific weather or market conditions. Finally, sources such as agricultural industry water, brine line flows, advanced water treatment concentrate, and oil and gas industry water will require significant, costly treatment to reach the level of purity required to be used in electrolysis. While these topics are addressed elsewhere in the report, they are not adequately expressed in terms of feasibility.

Exploring this further, CBE raises the following concerns regarding the feasibility of the most alarming water sources:

- **Imported surface water is already allocated.** CBE is concerned with the lack of analysis regarding the feasibility of acquiring land rights to acquire water rights as well as the feasibility of coming to exchange agreements on already fully allocated State Water Project, Colorado River, and Central Valley Project.
- **There are significant groundwater management concerns across Southern California**. While the Water Report assumes that over drafted groundwater was unavailable, it fails to provide sufficient analysis on the extent of water management impacts on groundwater availability. For example, the State Water Resources Control Board is holding hearings regarding major concerns with local groundwater management plans and critical overdraft in Kern County of the San Joaquin Valley, where a potential production site is to be located.[2]
- **Oil and Gas Industry Water is not a viable source of water.** As the Water Report itself states, the oil and gas industry is expected to decline in coming years. However, this fact is not adequately addressed in the feasibility consideration of oil and gas industry water for hydrogen production. A concerning result of this relationship would be hydrogen producers scrambling to find higher cost, less conflict vetted water sources when oil refineries go offline and are no longer able to fulfill hydrogen producers' contracts for water supply.

II. Geographic Scope, Acquisition, and Treatment Feasibility Concerns

All the Water Report's chapters use a wide geographic boundary inspired by SoCalGas's service territory covering almost the entirety of Southern California. This far-reaching scope completely fails to contextualize availability, acquisition, and treatment of water sources in the areas SoCalGas has identified as potential production sites, the San Joaquin Valley, Lancaster, and Blythe – all notably water strapped communities. While Chapter four titled "Challenges and Opportunities" identifies geographic location and distance to hydrogen production as key topics of assessment, these concerns are not addressed in terms of feasibility. Concerningly, Chapter 3 cost calculations even assume that water will be transported only 25 miles on average to treatment facilities. The Report thereby fails to provide any analysis realistically rooted in how identified water sources from this entire region will arrive and be treated in the San Joaquin Valley, Lancaster, and Blythe. These challenges are generically described and should be better defined in relation to the three identified production facilities and included in feasibility analyses.

[2] State Water Resources Control Board, Kern County Subbasin Probationary Hearing Draft Staff Report (2024).

Chapters two and three of the Water Report provide insight into the specific demands of the ALP. SoCalGas' "moderate" demand scenario, places ALP hydrogen demand at 1 million metric tons of hydrogen per year, or 1 billion kilograms requiring 11,000 acre-feet of water per year[3] or 13,568,300,000 (13.57 billion) liters per year. In other words, the Report estimates a water consumption rate of 13.6 kg of water per kg of hydrogen. To purify this water, the report estimates an average cost of $8,124 per million gallons or between $436 million and $1.3 billion (including facilities over 30 years). This average estimate, while useful, leaves significant margins if any assumptions prove underestimates. Studies show that electrolysis can consume between 9 (the stoichiometric water demand) and 30kg of water per kg of hydrogen. In addition, the Report's cost estimates exclude permitting, engineering, water transportation costs beyond 25 miles, and land costs; and explain that water purification cost is *heavily* dependent on purification demands leaving significant (billion-dollar) wiggle room in the presented estimates.

CBE is also concerned about unanswered questions around wastewater concentrate. The Report outlines that electrolysis will produce approximately half a billion of gallons of concentrated wastewater each year that must be either treated at new or existing wastewater treatment facilities or disposed of via evaporation ponds that would be collocated, or near treatment and electrolysis facilities. Long-term storage of wastewater concentrate in evaporation ponds will introduce an additional source of pollution risk into any communities, or groundwater supplies located near the water treatment facility. While treatment at capable treatment facilities is both cheaper than evaporation and could potentially reduce the risk of groundwater contamination, the report does not delve into this solution or fully discuss water treatment facility options.

III. Community Needs and Concerns Were not Included in Feasibility Analysis

The Water Report' stated feasibility criteria imply that the authors determined whether the use of a specific water source "would conflict with existing or anticipated water needs." However, the details of this analysis are not provided. Information regarding conflicts with existing and anticipated water needs is essential for drought stricken and water strapped communities to be fully informed of the impact of hydrogen production. The volumes of water, and scale of new-built water infrastructure contemplated by the report would significantly alter the landscape of each proposed production community. However, they are not consistently provided in the report. Without this information affected communities cannot provide informed consent or meaningful feedback. To remedy this, the Water Report should be amended to include a comprehensive chart that delineates, for each source, the amount of untreated water available, the estimated throughput of water from treatment, and resulting amount of treated water available for electrolysis.

IV. Inadequate Greenhouse Gas Emissions Analysis

[3] A significant increase over current consumption in communities SoCalGas taps for possible production facilities. City of Blythe, General Plan Water Supply Assessment, at 3 August 31, 2006 https://www.cityofblythe.ca.gov/DocumentCenter/View/279/Water-Supply-Assessment---General-Plan-20061011?bidId=; City of Lancaster, General Plan 2030 Master Environmental Assessment, at10.1-11, April 2009, https://www.cityoflancasterca.org/home/showpublisheddocument/11352/635775792210230000.

CBE stresses the importance of gathering high quality greenhouse gas (GHG) emissions data as soon as possible. The Report states that a "detailed, quantified analysis of potential GHG emissions associated with water conveyance and treatment is outside the scope of the WRE."[4] While we recognize Phase One feasibility studies are preliminary in nature, detailed analysis is essential to determining whether Angeles Link will indeed transport the "clean renewable hydrogen" SoCalGas has repeatedly promised to support throughout this process. Regarding third-party hydrogen production, this chapter of the Report notes:

> SoCalGas anticipates clean renewable production projects would undergo a thorough environmental review under the California Environmental Quality Act (CEQA) and/or the National Environmental Policy Act (NEPA), as applicable . . . That environmental review would likely include an analysis of potential GHG emissions associated with development of those projects.[5]

SoCalGas must carefully examine all environmental impacts of the ALP. The ALP has made many broad claims as to air quality and general environmental impacts of the project. Without a clear study of these impacts, it will not be possible to determine critical opportunities for mitigation, assess project alternatives, or analyze how the ALP will really impact environmental justice communities. In the absence of such analysis, SoCalGas statements about green hydrogen or "clean renewable hydrogen" are, at best, wishful thinking.

Finally, in addition to examining GHG emissions, SoCalGas should also evaluate other criteria pollutants associated with water treatment and conveyance.

V. Conclusion

CBE appreciates the opportunity to provide feedback. However, SoCalGas has chosen not to pursue representation of the communities along the ALP route and in areas they view as potential hydrogen production zones in Phase 1. To the extent that the Water Report speaks to environmental impacts in those communities, the voices of community members not represented in the ALP process at this time cannot be ignored. This feasibility study alone illustrates the significant challenges that water availability adds to the development of such extensive hydrogen infrastructure in Southern California. When looked at in the context of the released and forthcoming feasibility studies, it is essential that the significant challenges to hydrogen, and strategies to address these challenges need to be elucidated so that the communities this infrastructure will most impact can position themselves to be a meaningful part of the conversation. Both the report itself, and the ALP Phase 1 process fall short in this regard.

CBE emphasizes, and echoes comments made in prior letters as well as in person at CBOSG and PAG meetings that the volume and speed at which report feedback is requested is vastly inappropriate for meaningful engagement and feedback on Phase 1 reports as is repeatedly emphasized in CPUC Decision 22-02-007.

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[4] Water Report at 5-1.
[5] Id.

Respectfully Submitted.

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August 7, 2024

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<u>Subject:</u> Environmental Defense Fund (EDF) Comments of Greenhouse Gas (GHG) Emissions Evaluation Draft Report

As a follow-up to the draft reports on greenhouse gas (GHG) emissions evaluation draft report shared July 2024, EDF submits the following comments.

Overall, EDF believes that the issue of GHG emissions reduction benefits expected from a potential dedicated Angeles Link hydrogen pipeline project **<u>must be evaluated as a question of optimization and relative efficiencies</u>**. Any emissions reductions expected from the Angeles Link project have to be examined relative to reductions expected from other decarbonization pathways available for the end-uses targeted for hydrogen adoption and serviced by the potential project. In turn, this evaluation must be conducted comprehensively, taking into account the GHG emissions impact of the entire value chain which ranges from the electricity used for hydrogen production to leakage expected from hydrogen transport and use.

For example, how do the expected GHG emissions benefits of a large pipeline project—in particular given the leakage concerns previously highlighted by EDF—compare to the analogous expected benefits of transmitting renewable electricity closer to end-users, either for direct electrification or on-site hydrogen production—that may experience line loss but avoid minimize hydrogen pipeline leakage? It is necessary to show not just the expected emissions benefits of the potential Angeles Link project, as the draft report focuses on; but the existence of a relative cost- and climate-efficiency benefit of building the pipeline over other decarbonization options. The draft report fails to provide such analysis.

Based on the above overall comments, EDF makes two specific points on the draft report. First, the GHG reductions benefits expected from a potential Angeles Link Pipeline must be **compared to other decarbonization pathways**; and **provide justification for the pipeline project specifically**. The draft report currently focuses exclusively on the expected benefits of hydrogen adoption—much of which does not depend on the Angeles Link Pipeline project but is instead already required by existing regulatory and policy decisions. For instance, the demand study draft report cited various policy and legislative initiatives for a zero-emissions mobility sector that target diesel use for heavy duty vehicle specifically as a driving force for hydrogen adoption in California.[1] The results of the demand study, in turn, inform the results of the GHG emissions evaluation draft report.[2] In order to justify the need for the Angeles Link Pipeline project based on these regulatory initiatives, SoCalGas needs to show clearly that hydrogen adoption in the targeted end-uses are either required and necessary (*i.e.*, it offers the only decarbonization pathway); or at the very least preferable to other pathways (*i.e.,* it offers the best pathway). The GHG emissions evaluation report, however, fails to provide such detailed comparative analysis.

Second, while the GHG emissions evaluation draft report incorporates the GHG impacts of hydrogen leakage, its **scope and evaluation are incomplete, as the draft report acknowledges**. EDF welcomes SoCalGas' efforts to calculate the direct GHG emissions impact of hydrogen leakage from a potential Angeles Link pipeline project; and the acknowledgement of hydrogen as an indirect GHG.[3] EDF also notes that SoCalGas acknowledges but does not quantify the potential for leakage for various end users throughout the draft report.[4] The draft report argues that "[e]stimating the potential for leakage associated with end users of Angeles Link was not feasible given the limited amount of information available", such as specific equipment and facility data.[5] However, the expected GHG emissions reduction benefits highlighted in the draft report depends on the amount of fossil fuel use displaced by potential hydrogen adoption for the different end-uses. Then, by extension, a complete picture of the GHG emissions reduction impacts must also include the potential downside of hydrogen adoption, as represented by leakage impacts. SoCalGas'

[1] Demand Study Draft Report at 24.
[2] GHG Emissions Evaluation Draft Report at 9.
[3] GHG Emissions Evaluation Draft Report at 79.
[4] GHG Emissions Evaluation Draft Report at 49.
[5] GHG Emissions Evaluation Draft Report at 28.

decision to avoid quantifying the end-use leakage impacts, therefore, paints an incomplete picture for the overall GHG emissions evaluation of the Angeles Link project.

Respectfully,

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Re: Angeles Link Planning Advisory Group (PAG) Feedback of Air Products and Chemicals Inc. on Greenhouse Gas (GHG) Emissions Evaluation (July 2024 Draft)

Air Products and Chemicals, Inc. ("Air Products") submits the following feedback concerning the July 2024 draft GHG Emissions Evaluation.

Air Products expects that the below feedback will be addressed in the final Studies and in Southern California Gas Company's ("SoCalGas") quarterly reporting. Air Products also welcomes any response that SoCalGas may wish to provide to the comments below.

The GHG Emissions Evaluation Suffers From Flawed Assumptions

The GHG Emissions Evaluation rests on a number of flawed assumptions, including assumptions that are inconsistent with assumptions and timing adopted by regulatory agencies such as the California Air Resources Board ("CARB") or the California Public Utilities Commission ("CPUC"), and claims credit for reductions not directly tied to Angeles Link, while failing to include other relevant emissions. Those flaws are set forth in more detail below.

Refinery Emissions

The GHG Emissions Evaluation asserts that the majority of greenhouse gas reductions in the Hard to Electrify Industrial sectors would come from refineries, which would account for 65.5% of the reductions in 2030, with the percentages remaining consistent from 2030 to 2045, in the high throughput scenario.[1] This assertion is flawed for a number of reasons. First and foremost, CARB's 2022 Scoping Plan for Achieving Carbon Neutrality (2022 Scoping Plan) modeled a 94% reduction in refinery production in 2045.[2] This significant drop in production will drastically reduce the opportunities to reduce emissions by replacing natural gas usage at petroleum refineries.

[1] GHG Emissions Evaluation at 12.
[2] 2022 Scoping Plan at 2

Hard To Electrify Industrial Sectors Transition to Hydrogen

In order to accelerate the transition to hydrogen, the GHG Emissions Evaluation assumes that the hard to Electrify Industrial sectors would "begin with hydrogen/natural gas blends in 2030 by the end users, behind the meter, and eventually transition to 100% hydrogen fuels by 2050." It is at best unclear at this point whether and when hydrogen blending will be permitted in natural gas pipelines, which would be required for end users to begin that transition. The CPUC declined to adopt any hydrogen blending standard in D.22-12-057, and instead directed the utilities, including SoCalGas, to propose pilot programs to determine the propriety of permitting hydrogen blending in existing natural gas pipelines. The joint amended application proposing those pilots was filed on March 1, 2024. The schedule proposed by applicants contemplates a final decision in March 2025—given the pendency of a motion to dismiss the amended application, a final decision will likely be delayed beyond that date. SoCalGas's projected schedule for its blending pilots extends for four years.[3] It is therefore unlikely that the Commission would render any decision on the propriety of blending hydrogen into existing natural gas lines until sometime well after 2030. The assumption that end users will begin using blended hydrogen from utility natural gas pipelines by 2030 therefore appears to be overly optimistic.

Mobility Reductions

The GHG Emissions Evaluation projects up to nearly 17 (low demand scenario) and 36 million metric tons (high demand scenario) of CO2e per year removed from SoCalGas geographic service territory by end users by 2045, with 72.5% (low demand scenario) and 50.3% (high demand scenario) of overall GHG reductions attributed to the mobility sector.[4] However, Angeles Link will not directly serve refueling stations. Nor does the GHG Emissions Evaluation provide any analysis of refueling station locations, or if or how Angeles Link routing might be consistent with the locations, or how these fueling stations might actually connect to Angles Link through a pipeline distribution system. Absent any analysis showing how and to what extent Angeles Link will be involved in providing hydrogen to these fueling stations, any GHG reductions associated with those fueling stations cannot be credited to Angeles Link.

Biomass Gasification

In sharp contrast to claiming credit for hydrogen fueling reductions, the GHG Emissions Evaluation states that GHG emission associated with the transport of feedstock, including for biomass gasification, are "out of scope."[5] While Air Products appreciates that the Evaluation does include in Appendix B a summary of estimated carbon intensity values for cradle to gate summarized from literature, that data can and should be used to estimate GHG emissions associated with feedstock transportation and feedstock preparation. Crediting GHG emissions

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[3] Prepared Direct Testimony of Kevin Woo on behalf of Southern California Gas Company, Figure 4 at p. 11.
[4] GHG Emissions Evaluation at 10.
[5] *Id.* at 23.

reductions associated with hydrogen transportation on one hand, while failing to acknowledge transportation emissions associated with the production of that hydrogen, skews the analysis and fails to provide a complete picture of the GHG emissions impacts of Angeles Link.

Hydrogen Production Generally

The GHG Emissions Evaluation further minimizes GHG emissions associated with all production types by assuming that all electricity consumed as feedstock to electrolyzers or as process energy to production and transportation (compression) will have zero GHG emissions associated with it. It is extremely unlikely that all such electricity will be sourced from new renewable generation based on the need for grid connection and use over 24 hours at each location of demand. Even if sourced from existing renewable generation, resource shuffling associated with procurement of that electricity will result in GHG emissions. It is simply unrealistic to assume that there will be zero GHG emissions associated with the electricity needed for hydrogen production, and the GHG Emissions Evaluation should be revised to provide a more realistic estimate of production-related GHG emissions.

Conclusion

Air Products appreciates the opportunity to provide this feedback concerning the July 2024 Draft GHG Emissions Evaluation.

Respectfully,

Miles Heller Director, Global Greenhouse Gas,
Hydrogen, and Utility Regulatory Policy

August 13th, 2024

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Subject: Natural Resources Defense Council Comments on the Greenhouse Gas Emissions (GHG) Evaluation Draft Report

As a follow-up to the GHG Emissions Evaluation draft report shared on July 10th, the Natural Resources Defense Council (NRDC) provides the following comments and feedback.

1. **Electricity emissions**

First, the report inadequately covers emissions from electricity used in the production of hydrogen. The report assumes that all electricity inputs, to electrolysis or any other production pathways, will have zero associated GHG emissions. This is directly at odds with SoCalGas and Angeles Link's lack of commitment to require the three pillars of incrementality, hourly matching, and geographic deliverability for electrolytic production, as proposed by the Biden administration's proposed rule for the 45V tax credit in December 2023[1]. Without requiring the three pillars, or some other mechanism, there is no reason to assume that the electricity used for hydrogen production to serve the pipeline does not increase GHG emissions on the grid.

While SoCalGas has not to our knowledge taken a public position against the three pillars, SoCalGas is a partner of the ARCHES hydrogen hub, with the Angeles Link pipeline a constituent project of ARCHES. The ARCHES hub has been publicly opposed to the three pillars[2], despite strong evidence that they are required in California to meet the emissions

[1] Proposed Rule by the Internal Revenue Service and Treasury on the Section 45V Credit for Production of Clean Hydrogen, December 2023 https://www.federalregister.gov/documents/2023/12/26/2023-28359/section-45v-credit-for-production-of-clean-hydrogen-section-48a15-election-to-treat-clean-hydrogen

[2] February 27th 2024 comment from Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES) to the Treasury on the proposed 45V rule of December 2023, https://www.regulations.gov/comment/IRS-2023-0066-29465

thresholds required by the statute of the Inflation Reduction Act to qualify for the 45V tax credit. Therefore, rather than assuming that electrolytic hydrogen that is delivered by Angeles Link will be zero emissions, the GHG Emissions Evaluation Report must model the range of possible grid impacts.

We offer two studies as examples of the potential scale of GHG impacts from electrolytic production. Energy Innovation found that without requiring incrementality (also known as additionality), electrolytic hydrogen produced in California will have a GHG intensity of over 20 kgCO2e per kg of hydrogen[3]. Taking the medium demand scenario from the draft report, where 1 MMT of hydrogen delivered through Angeles Link results in an emissions reduction of 7.8 MMT CO2e due to displaced use of fossil fuels, the emissions associated with production would be over 20 MMT CO2e. The emissions from production are more than double the savings from using hydrogen, eliminating the climate benefit of Angeles Link and resulting in a a net increase in emissions. Further, Princeton University studied the long-run emissions impact of various hydrogen tax credit requirements, and similarly found that in California, consequential emissions from hydrogen production without the three pillars are approximately 20 kg CO2 per kg of hydrogen.[4] The authors of this paper have also explained in a follow up paper[5] why their results are different, and more accurately represent the real world, than the short-run modelling relied upon by ARCHES and other groups attempting to weaken the three pillars. There is strong consensus among long-run models of the need for the three pillars to ensure emissions do not increase due to hydrogen production.

2. **Emissions savings that are forfeited by diverting clean energy to hydrogen production**

Second, the draft report does not consider the GHG emissions consequences of diverting clean energy from other more productive uses. In a world with constrained renewable build out, this is a crucial consideration. For a direct example, battery electric trucks can travel three times farther than hydrogen fuel cell trucks for the same amount of renewable energy, therefore displacing three times more diesel emissions per unit of renewable energy.[6] While certain specific heavy duty trucking needs may be well served by hydrogen fuel cell trucks, battery

[3] Energy Innovation. (n.d.). *Smart Design Of 45V Hydrogen Production Tax Credit Will Reduce Emissions And Grow the Industry—Energy Innovation: Policy and Technology*. Retrieved August 15, 2023, from https://energyinnovation.org/publication/smart-design-of-45v-hydrogen-production-tax-credit-will-reduce-emissions-and-grow-the-industry/
[4] Ricks, W., Xu, Q., & Jenkins, J. D. (2023). Minimizing emissions from grid-based hydrogen production in the United States. *Environmental Research Letters*, *18*(1), 014025. https://doi.org/10.1088/1748-9326/acacb5
[5] Ricks, W., Gagnon, P., & Jenkins, J. D. (2024). Short-run marginal emission factors neglect impactful phenomena and are unsuitable for assessing the power sector emissions impacts of hydrogen electrolysis. *Energy Policy*, *189*, 114119. https://doi.org/10.1016/j.enpol.2024.114119
[6] Wilson, S. (2023). *Hydrogen-Powered Heavy-Duty Trucks: A review of the environmental and economic implications of hydrogen fuel for on-road freight*. Union of Concerned Scientists. https://doi.org/10.47923/2023.15274

electric trucks will always have this significant efficiency advantage and therefore likely serve the majority of the heavy duty market as well as all of the light and medium duty market.

For power generation, using hydrogen as energy storage only has a round trip efficiency of approximately in the range of 18-46%[7], and therefore can only be justified for long duration storage beyond the capabilities of batteries or other storage mediums with more favorable efficiencies. Given that some of the hydrogen delivered by Angeles Link is proposed to be combusted to generate power, and the fact that the hydrogen may not even be produced from all renewable energy (due to not requiring the three pillars), let alone entirely from avoided curtailment of renewables that could not be stored in batteries, there are significant GHG emissions consequences not captured in this draft report.

Even for hydrogen use cases that cannot be served by direct electrification, there is still an opportunity cost to using renewable energy for the production of hydrogen if it would otherwise have been used to displace fossil fuels on the grid, for example in a battery electric vehicle or a heat pump. This opportunity cost has GHG emissions impacts that are not captured by this draft report. One way to minimize, although not always eliminate, this impact is to require the three pillars, including incrementality, for hydrogen production.

3. **Emissions from biomass and RNG production pathways**

Third, the report assumes that the carbon content of biomass and biomethane (also known as renewable natural gas or RNG) used for gasification or steam methane reformation is net zero. However, this assumption will not hold true unless these are unavoidable waste feedstocks. Without adequate guardrails, in particular around the use of credits or a book and claim system for biomethane, considerable GHG emissions could be underreported for these pathways. The greenhouse gas impacts from leakage of biomethane have also not been considered. SoCalGas should examine the full range of GHG impacts from these feedstocks and detail any requirements that will be made of their biomass and biomethane hydrogen production pathways to minimize these.

Similarly to electricity, the report should also consider if these biogenic feedstocks could be better utilized directly. Transforming biomethane to hydrogen involves energy losses that could be avoided if the biomethane can be used directly. The report should examine if more emissions could be displaced by direct use of biomethane compared to using it for hydrogen.

4. **Warming impact of hydrogen emissions**

NRDC acknowledges the progress made on the issue of the warming impact of hydrogen with its inclusion in this report. However, the current estimates in the report are likely to be a significant underestimate of the full indirect warming impact from hydrogen leakage. The

[7] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/hydrogen-technology-faces-efficiency-disadvantage-in-power-storage-race-65162028

warming impacts estimated in the draft report rely on the levels of leakage from the leakage report, which fails to take into account any hydrogen leakage during production or end use, and only includes hydrogen leakage from the pipeline itself. This is inconsistent with the GHG accounting framework for other warming gases, where the impacts of using hydrogen on emission from fossil fuels at the end use stage, and the impacts of combusting feedstocks at the production stage, are clearly within scope. Therefore both this report and the leakage report should be updated to include leakage estimates for the entire hydrogen value chain associated with the proposed pipeline. Also, the estimated warming impact needs to be factored into the headline GHG impacts, not reported separately.

5. **Links to demand study**

Finally, as detailed in our joint comments with the Environmental Defense Fund on the demand study draft report on February 23rd 2024, we find significant shortcomings in the demand study and potential overestimations of hydrogen demand to be served by Angeles Link. The results are much higher than, for example, the California Air Resources Board's Scoping Plan. The calculations of GHG emissions reductions in this report, which rely on the demand scenarios that result from the demand study, are predicated on the same extremely high levels of demand for hydrogen. SoCalGas should incorporate the feedback from EDF, NRDC and the rest of the Pipeline Advisory Group to the demand study and apply the updated results to the GHG evaluation.

Respectfully,

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August 14, 2024

COMMUNITIES FOR A BETTER ENVIRONMENT
40 years | established 1978

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Submitted via email to ALP1_Study_PAG_Feedback@insigniaenv.com

Feedback to Southern California Gas Company on Greenhouse Gas Emissions Evaluation Draft Report

Communities for a Better Environment (CBE) submits this letter of feedback to Southern California Gas Company (SoCalGas) on the Greenhouse Gas Emissions Evaluation Draft Report (Draft Report) provided on July 10, 2024. First and foremost, a greenhouse gas (GHG) emissions study should identify emissions sources for a proposed project. Once emissions sources have been identified, the study can investigate each source's GHG emissions volume, characteristics, and impacts. The emissions from each source must be identified and quantified to develop a picture of the whole project's estimated emissions. The foundation of the project's estimated emissions must be the basis for the study to proceed to analyze project emissions reductions. The Draft Report does not identify all GHG emissions sources for the Angeles Link Project (ALP). Rather, it analyzes fragments of the emissions from "third-party production, third-party storage, and transmission of hydrogen" before turning to make sweeping assumptions about emissions reductions based on limited data. The result is a report which does not accurately estimate the ALP's GHG emissions or the emissions reduction that the project will facilitate.

Several of the most significant omissions or flawed assumptions are raised by Communities for a Better Environment here. As an initial matter, the Draft Report does not correct several significant errors raised by CBE's March 29, 2024 feedback on SoCalGas's "Greenhouse Gas Emissions Preliminary Data and Findings" In that feedback, CBE noted that the preliminary findings:

- Relied on flawed demand data in calculating greenhouse gas emissions and emissions reductions.
- Severely underestimated emissions from hydrogen production.
- Ignored lifetime emissions from hydrogen infrastructure.

As this letter explores, the Draft Report builds on these errors, by failing to analyze emissions from project construction, water treatment, water procurement, and methane leakage. These omissions and the compounding effect of overreliance on the flawed demand report result in emissions calculation failures.

I. *The Draft Report fails to examine significant sources of climate pollution that must be explored to establish an accurate depiction of the ALP's greenhouse gas impacts*

The Draft Report assumes that zero climate warming emissions will be generated to electrolyze, gasify, or steam reform the hydrogen transported by the ALP between 2030-2045. Each of these production methods can produce GHG emissions. Both biomass gasification and steam methane reformation (SMR) are chemical reactions that necessarily produce GHG emissions.[1] Electrolysis produces GHG emission unless all energy needs (including water conveyance and intensive purification) are supplied by dedicated zero emission resources like wind or solar. The Draft Report's assumption that hydrogen production will produce zero-emissions by 2030 is not realistic.

While CBE strongly advocates for hydrogen to be produced exclusively through electrolysis powered by wind and solar, there are no laws or regulations which mandate this. The California Air Resources Board's 2022 Scoping Plan assumes that two-thirds of the Statewide Hydrogen demand (1.9 million metric tons (MMT) per year, which is significantly lower than the ALP Demand Study estimates) will be produced by electrolysis by 2045. Supplying just this portion via electrolysis would require approximately 25 gigawatts of new, dedicated "off-grid"[2] solar capacity.[3] CARB ambitiously assumes that this capacity will be available by 2045; the Draft Report assumes without support that this capacity will be available by 2030. The 2030 timeline would require over 5 gigawatts of new solar every year built solely for hydrogen production on top of California's existing solar build rate. Concerningly, the Draft Report does not provide support for a 2030 timeline for development of off-grid resources that could result in a zero-emission scenario.

The Draft Report's GHG emissions assumptions for biomass gasification and steam methane reformation must be rectified. The GHG study assumes that biomass gasification will not produce GHG emissions.[4] The process of biomass gasification creates CO_2 emissions.[5] Strangely, while the Draft Report notes that "[t]he carbon intensity of biomass gasification can vary based on a variety of… inputs" the report nonetheless assumes zero-emissions for the process.[6] The process of SMR creates CO_2 emissions.[7] Without carbon capture systems, which

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[1] PSE Healthy Energy, Green Hydrogen Proposals Across California, at 20-21, May 21, 2024, (available online at https://www.psehealthyenergy.org/wp-content/uploads/2024/05/Green-Hydrogen-Proposals-Across-California.pdf).
[2] Dedicated, off grid renewables are necessary for zero-emissions hydrogen. Simply adding zero-emission generation capacity to the grid does achieve zero-emissions.
[3] Green Hydrogen Proposals Across California at 55.
[4] The Draft Report assumes that SMR will produce nominal GHG emissions from N_2O but does not discuss CO_2 emissions.
[5] US DOE, Hydrogen Production: Biomass Gasification, (https://www.energy.gov/eere/fuelcells/hydrogen-production-biomass-gasification); Draft Report at 122.
[6] Draft Report at 123.
[7] US DOE, Hydrogen Production: Natural Gas Reforming, (https://www.energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming); Draft Report at 122.

increase energy intensity, SMR generates 8.47 kilograms of CO_2 per kilogram of hydrogen. In other words, without a clear discussion of where the ALP's hydrogen sources avoid these emissions, one can assume 12.7 MMT of CO_2 equivalent for the ALP's 1.5 MMT throughput of hydrogen.[8] The Draft Report does not explain why these per unit emissions for gasification or SMR are not calculated, let alone final emissions value. The Report's assumptions are further complicated by its conclusion that various forms of combustion equipment are fueled by zero-emissions hydrogen without substantiation. Without proper analysis of such potentially significant sources of GHG emissions, the Draft Report provides a misleading picture of potential ALP related GHG emissions.

II. The Draft Report is in large part premised on the draft Demand Report, which is both flawed and does not represent the carrying capacity of the ALP

The Draft Report bases a large portion of the discussion and conclusion on theoretical emissions and emissions reductions based on hydrogen usage estimated in SoCalGas' Demand Study. The Demand Study does not accurately forecast hydrogen demand which skews the Draft Report's stated emissions figures. This error is compounded because neither the Demand Study nor the Draft Report closely consider the impact of hydrogen alternatives (and whether the claimed emissions reductions benefits will be achieved by hydrogen or by electrification). Parties have already raised that Demand Study does not appropriately account for the cost of hydrogen, the volume supplied by the ALP, or the timing of hydrogen project readiness.[9] These errors result in a substantially inflated demand. In fact, the Demand Study estimates hydrogen demand three-times greater than CARB's 2022 Scoping Plan[10] and four times greater than the ALP's maximum estimated throughput.[11] In applying the overly broad projections of the Demand Study, the Draft Report fails to clearly explain how the inflated Sothern California demand estimates reflect or relate to emissions or emissions reductions specifically from the ALP.

III. The Draft Report ignores lifetime emissions from hydrogen infrastructure

The Draft Report repeats the error of the initial GHG Study by using a brief, 15-year window to examine ALP GHG emissions and emissions reductions. Not only does the Draft

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[8] Or 50 MMT of CO_2 equivalent emissions for the entire high demand scenario. Mary Katebah, et al., Analysis of hydrogen production costs in Steam-Methane Reforming considering integration with electrolysis or CO_2 capture, at 4, Cleaner Engineering and Technology 10 (2022) (https://doi.org/10.1016/j.clet.2022.100552).

[9] Utility Consumers' Action Network, Feedback for SoCalGas Regarding Demand Study Technical Approach/Data & Preliminary Findings, Sept. 25, 2023; Environmental Defense Fund & Natural Resources Defense Council, Environmental Defense Fund and Natural Resources Defense Council Comments on the Demand Study Draft Report, Feb. 23, 2024; UCAN, Feedback for SoCalGas Regarding Angeles Link Demand Report Draft, Feb. 26, 2024.

[10] The Scoping Plan estimates a hydrogen demand of approximately 1.9 MMT per year *statewide in 2045*. Green Hydrogen Proposals Across California at 17, fn. 16.

[11] Draft Report at 9.

Report acknowledge that federal hydrogen production standards look at lifecycle emissions, Appendix B discusses available data on lifecycle emissions (referred to as "well-to-gate").[12] Despite this, the data discussed in Appendix B is not incorporated into the Draft Report, which without explanation assumes zero or nominal emissions for all hydrogen production scenarios.

The Draft Report's limited 2030-2045 window also excludes crucial future impacts such as extended reliance on and intensification production of methane to produce hydrogen, and continued acceleration of direct electrification eliminating emissions ahead of hydrogen. Direct electrification is significantly more efficient and less expensive than hydrogen for many applications SoCalGas claims the ALP will serve.[13] The Draft Report does not analyze GHG emissions from hydrogen feedstocks or hydrogen alternatives. As CBE previously raised, without this analysis, the ALP's emissions and emissions reductions claims are not credible.

IV. The Draft Report ignores known sources of climate emissions

The Draft Report does not analyze emissions from project construction, water treatment, water procurement, and methane leakage, despite available data. First and foremost, a GHG emissions report should identify emissions sources for a proposed project. Once those sources have been identified for study (and for the awareness of parties involved in the ALP process) the report can and should discuss each of the source emissions (and emissions reductions, as the Draft Report does so extensively).

The Draft Report fails to take this initial step, missing several emissions sources entirely and burying mention of others, sans analysis, deep in appendices. The following examples illustrate SoCalGas's procedural failures in analysis despite topic-specific prompting:

- *Water Feedstock Emissions*: Several parties, in comments and meetings, have raised the issue of emissions stemming from water procurement and processing. The Draft Report, in Appendix B mentions that water "may" require treatment, increasing energy demand, but neither analyzes this issue nor integrates it into the Draft Report. Without understanding the energy intensity of water treatment (all water sources analyzed in the ALP Water Study required treatment), the Draft Report is not complete.
- *Project Construction*: The ALP, if constructed, will generate GHG emissions from construction, as acknowledged in SoCalGas's Environmental Social Justice Draft Screening Report and the Environmental Analysis Draft Report.[14] Though the Draft

[12] Draft Report at 99, 121-23 (appx. B).
[13] *See, e.g.* Green Hydrogen Proposals Across California at 29-42, figs. 3.1-3.4; Draft Report at 12.
[14] SoCalGas, Environmental Social Justice Draft Screening, July 2024, at 11 (acknowledged as Ozone). SoCalGas, Environmental Analysis Draft Report, July 2024, at 6. "Pipeline construction, operation, and maintenance could result in potential impacts associated with air quality and GHG emissions."

Report covers the period "from construction"[15] through 2045, it does not consider construction emissions.

- *Methane Leakage*: Methane is a powerful greenhouse gas. "Upstream emissions have a substantial impact on overall [hydrogen production] plant emissions and the dominant aspect is the methane leak rate."[16] Despite citing studies which analyze methane leakage in the hydrogen industry, the GHG report does not discuss the issue.

These are just three examples of what could be numerous omissions from the Draft Report's emissions analysis. These examples raise significant concerns regarding the scope and reliability of the Draft Report's GHG emissions analysis.

V. Conclusion

Communities for a Better Environment appreciates the opportunity to provide feedback on the Draft Report. Due to the omissions and flawed assumptions discussed above, the Draft Report does not provide meaningful GHG emissions data for the ALP. The focus on emissions reductions, while several emissions sources and emissions values are either ignored or unreasonably reduced, indicates that the Draft Report severely underestimates the ALP's GHG impacts. CBE recommends SoCalGas rectify all issues raised in this letter before issuing a final GHG report to provide serviceable data by which the ALP can be assessed.

Respectfully Submitted,

Theo Caretto
Communities for a Better Environment

CC:
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[15] Draft Report at 20.
[16] Mary Katebah, et al. at 11.

COMMUNITIES FOR A BETTER ENVIRONMENT
40 years | established 1978

August 14, 2024

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Submitted via email to ALP1_Study_PAG_Feedback@insigniaenv.com

Feedback for Southern California Gas Company on the Nitrogen Oxides (NOx) and Other Air Emissions Assessment Draft Report

Communities for a Better Environment (CBE) submits this letter of feedback to Southern California Gas Company (SoCalGas) on the Nitrogen Oxides (NOx) and other Air Emissions Assessment Draft Report (the "Report" or "Study") provided on July 17, 2024. This letter discusses serious errors that the final report must remedy. The Report fails to discuss NOx emissions or other air emissions focused on construction and operations of Angeles Link and the emissions impact on communities. Instead, it repeatedly emphasizes that there will be widespread market adoption of hydrogen in California and that the Angeles Link Project (ALP) will help satisfy this high demand for clean renewable hydrogen. It contends that third-party production will generate relatively little NOx and claims that end-uses of transported hydrogen will result in massive emissions reductions. California Public Utilities Commission (CPUC) Decision 22-12-055 emphasizes the importance of stakeholder engagement. Meaningful engagement is impeded where key information is either omitted or presented in a misleading manner. Particularly, the Report:

- Cherry Picks What is Within Scope and Out of Scope for the Study, Claims and Overemphasizes Emissions Reductions to Make ALP Seem Beneficial, and Minimizes or Excludes Facts that are Unfavorable to Perception of ALP
- Features Faulty, Unreasonable Assumptions about NOx Emissions, Especially Related to Biomass Gasification
- Draws a Major False Equivalency between Electrolysis and Biomass Gasification
- Contains Internal Contradictions about Third-Party Hydrogen Production Methods and Renewable Electricity
- Lacks Comparisons to NOx Emission Reductions from Battery Electric Vehicles Displacing Fossil Fuels in the Mobility Sector
- Relies on Proxy Emission Factors and Concedes Many Unknowns about 100% Hydrogen, Thereby Undermining the Supposed Feasibility of ALP

I. The Report Cherry Picks What is Within Scope and Out of Scope for the Study, Claims and Overemphasizes Emissions Reductions to Make ALP Seem Beneficial, and Minimizes or Excludes Facts that are Unfavorable to Perception of ALP

The Report selectively includes favorable aspects of Angeles Link and the lifecycle of hydrogen as being within the scope of a Phase 1 feasibility study and excludes the unfavorable aspects as being out of scope. Critically, the Report does not include air pollution emissions from hydrogen combustion in the commercial sector. The Study also buries this caveat deep in the report. For example, we are not told until the section containing SoCalGas's responses to stakeholder comments more than two-thirds of the way into the report that "[t]he Study does not evaluate hydrogen combustion for commercial…end users."[1] The major problem here is that although SoCalGas takes credit for NOx and other emissions reductions from third-party end users,[2] SoCalGas distances itself from environmentally harmful emissions added to the atmosphere by end users, such as those associated with hydrogen combustion.

The Study excludes more than the hydrogen combustion of commercial end users. It also chooses not to "evaluate the NOx associated with water conveyance or the transportation of other materials such as biomass to the production site or biomass feed preparation as those details are beyond the scope of this feasibility study."[3] The Report's omission of biomass transportation emissions is particularly troubling because the Report repeatedly claims that the biomass gasification scenario of third-party hydrogen production involves "zero NOx."[4] The Report explains that since biomass gasification "does not use combustion, there is no potential for NOx emissions associated with biomass gasification."[5] As explained in the next section of this letter, this is a faulty and unreasonable assumption.

II. The Report Features Faulty, Unreasonable Assumptions about NOx Emissions, Especially Related to Biomass Gasification

The Report/Study applies assumptions skewed in favor of the Angeles Link project when presented with unfavorable data regarding NOx emissions. For example, in relation to biomass gasification, the Report notes one study that found that "there is potential for nitrogen contamination in the outlet of the biomass gasification system if fuel nitrogen is present."[6] This means that if nitrogen is present in biomass feedstock, biomass gasification is not entirely clean, and the inference can be made that nitrogen in biomass feedstock can lead to NOx emissions. Yet

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1 Report at 12.4.
2 Report at 2.1 ("The study…estimates NOx emission reductions from end users of hydrogen in the mobility, power generation, and hard to electrify industrial sectors, to determine anticipated overall NOx reductions.").
3 Report at 12.4.
4 Report at 3.8, 3.9, 7.4, 8.20, 12.4.
5 Report at 3.2.
6 Report at 3.9-3.10.

the Report contradictorily assumes "no nitrogen is contained in the biomass or any other fuel source for use in hydrogen production."[7] This is a nonsensical assumption because the Report itself acknowledges that biomass in the form of animal waste is "high in protein;"[8] proteins are made up of amino acids, which in turn are made up of elements like nitrogen. SoCalGas does not explain the unique set of conditions in which the biomass feedstock used to produce hydrogen could somehow entirely lack nitrogen; instead SoCalGas improperly chooses to assume "there are no NOx emissions from biomass gasification."[9]

Another unreasonable assumption the Report makes about biomass gasification deals with the moisture content of biomass feedstock. The Report notes that biomass gasification "requires dry biomass" and admits the possibility that biomass at a gasification facility site might contain moisture "that would require drying on-site."[10] Therefore, it can be inferred that industrial processes to dry out biomass would generate various types of air emissions, potentially even NOx emissions. Purportedly, "[d]ue to the level of uncertainty around whether on-site drying would be required for each specific biomass gasification facility," the Report makes another biased assumption that "biomass would be procured ready to utilize and would not require moisture removal on-site."[11] Uncertainty should tip the scales in favor of assuming the potential for *more* air emissions, not reduced emissions or no emissions. But likely because the added air emissions of drying out biomass would contradict SoCalGas's depiction of biomass gasification as a "zero NOx" production method of hydrogen, the study elects the dry biomass assumption, despite the unreasonableness of that assumption.

A recent report on green hydrogen proposals in California[12] further demonstrates that biomass gasification involves several polluting steps that the Report either ignores or makes faulty assumptions about. As noted above, SoCalGas decides in the Report that biomass transportation to hydrogen production sites is outside the scope of this study.[13] Yet transportation emissions, including NOx emissions, can only be plausibly excluded if the biomass gasification facilities are "located only where the appropriate biomass feedstocks are abundant[.]"[14] In contrast to SoCalGas's chosen assumption that biomass transportation is beyond the scope of this study, it is far more likely that at least some transportation will be required to any third-party production sites. This transportation "will result in increased pollution along common trucking corridors and potentially in the communities surrounding the gasification plants unless biomass

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[7] Report at 3.10.
[8] Report at 3.9.
[9] Report at 3.10.
[10] Report at 3.10.
[11] Report at 3.10.
[12] PSE Healthy Energy, Green Hydrogen Proposals Across California: An Assessment of opportunities and challenges of using hydrogen to meet state climate goals, (May 21, 2024), https://www.psehealthyenergy.org/wp-content/uploads/2024/05/Green-Hydrogen-Proposals-Across-California.pdf.
[13] Report at 12.4.
[14] Green Hydrogen Proposals Across California at 60.

feedstocks are transported using zero-emission vehicles."[15] SoCalGas's flawed and misleading assumptions about zero NOx for biomass gasification must be corrected in the final version of the Report.

III. *The Report Draws a Major False Equivalency between Electrolysis and Biomass Gasification*

The Report repeatedly draws a false equivalency between electrolysis and biomass gasification by claiming there are zero NOx emissions when producing hydrogen by 100% electrolysis or biomass gasification.[16] Hydrogen production from electrolysis is only truly green if the three pillars of incrementality, temporality, and deliverability are met.[17] If electrolysis relies on combustion of gas for power generation, then NOx emissions result. Further, research indicates that: "Dust, soot, tar, and particulate matter are all components of the gas created during [biomass] gasification, and the exhaust gas contains carbon monoxide, harmful organic compounds such as benzene, NOx, and particulate matter."[18] Clearly then, biomass gasification involves NOx emissions and other harmful air pollutants like particulate matter. In contrast, green electrolysis using renewable, non-combustion resources does not result in such NOx emissions. SoCalGas's false equivalency about electrolysis and biomass gasification is compounded by the fact that electrolytic hydrogen is generally significantly more energy efficient than biomass gasification.[19] Therefore, biomass gasification categorically cannot be classified as having zero NOx emissions and should not be lumped together with electrolysis powered by additional renewable energy from wind and solar.

IV. *The Report Contains Internal Contradictions about Third-Party Hydrogen Production Methods and Renewable Electricity*

The Report also describes some assumptions that contain internal contradictions and inaccuracies. Specifically, the Report states: "The draft NOx study report assumes that production of hydrogen will use renewable electricity with zero NOx emissions regardless of production method – electrolysis, biomass gasification, or steam methane reforming, although electricity is only assumed to be used for electrolysis." First, regarding zero NOx emissions, the rest of the Report admits that steam methane reformation (SMR) "has NOx emissions and those potential emissions were evaluated" or describes SMR fueled by renewable natural gas (RNG) feedstock so there is "the potential for NOx formation."[20] So, the stated assumption in Chapter

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[15] Green Hydrogen Proposals Across California at 85.
[16] Report at 3.9, 7.4, 7.5, 8.20, 8.21
[17] Morgan Rote, Why a strong '3 pillar' framework makes sense for pivotal hydrogen tax credit, Environmental Defense Fund (Feb. 8, 2024), https://blogs.edf.org/energyexchange/2024/02/08/why-a-strong-3-pillar-framework-makes-sense-for-pivotal-hydrogen-tax-credit/.
[18] Green Hydrogen Proposals Across California at 85.
[19] Green Hydrogen Proposals Across California at 31, 93.
[20] Report at 3.10.

12 is inaccurate with respect to the claim of zero NOx emissions related to steam methane reforming. Second, although CBE would like SoCalGas to commit to utilizing third-party hydrogen only produced by green electrolysis for Angeles Link, SoCalGas has not committed to that throughout the Phase 1 process, as it continues to call for hydrogen produced by biomass gasification and steam methane reformation. Therefore, the assumption about hydrogen production using "renewable electricity with zero NOx emissions regardless of production method" is not only contradictory to SoCalGas's position but also unsubstantiated.[21]

V. The Report Lacks Comparisons to NOx Emission Reductions from Battery Electric Vehicles Displacing Fossil Fuels in the Mobility Sector

CBE is concerned that this study and the Demand Study underpinning it both fail to accurately address NOx emissions reductions associated with the displacement of fossil fuel powered vehicles by battery electric vehicles (BEVs) between 2030-2045. The Report states: "The Demand Study projected the anticipated fossil fuel displacement associated with FCEVs [fuel cell electric vehicles] only. The associated NOx reductions were estimated only for conversion to FCEVs; this study does not project emission reductions related to fossil fuel displacement that will be associated with BEVs."[22] For this NOx and other air emissions study to be credible, the final Report must include side-by-side comparisons of added NOx emission additions and reductions between hydrogen powered FCEVs and renewable electricity powered BEVs. Even if direct electrification and BEVs are discussed in the separate Project Options and Alternatives Draft Report, that is insufficient because SoCalGas released the Project Options and Alternatives report more than a week after this NOx report and it has a separate, later feedback deadline. It is unfair to put the burden on stakeholders already juggling multiple overlapping studies and feedback deadlines to dig for alternatives comparisons when commenting on this entirely pro-hydrogen NOx report.

VI. The Report Relies on Proxy Emission Factors and Concedes Many Unknowns about 100% Hydrogen, Thereby Undermining the Supposed Feasibility of ALP

With respect to NOx emissions factor, CBE is alarmed by the Report's characterization of the many unknowns regarding constructing and operating a massive pipeline to transport 100% hydrogen. The Report notes the following about hydrogen combustion: "research completed for this study did not reveal any published hydrogen-specific combustion emission factors;" "direct measurements of NOx emissions from practical combustion systems using pure hydrogen are scarce at the present time;" "very little test data is available, as few types of combustion units can effectively operate on pure 100% fuel at this time."[23] The Report even admits that it could

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[21] See CBE Feedback to Southern California Gas Company on Greenhouse Gas Emissions Evaluation Draft Report, at 2-3, Aug. 14, 2024.
[22] Report at 7.7.
[23] Report at 3.5.

not utilize direct measurements of NOx emissions from combustion units "representative of hydrogen combustion technology to quantify NOx emissions within this study"[24] because such test data does not yet exist. Since published and reputable hydrogen emission factors are not yet available, the Report relies on proxy emission factors to quantify NOx emissions from hydrogen combustion.[25] Yet, without citing to any source about the validity of proxy emission factors for this type of emissions study, the Report confidently claims: "Proxy emissions factors are compatible with the Demand Study, were sufficient to estimate end-user emissions, available for combustion units, and applicable across the entire project geography." Setting aside the overinflated hydrogen projections in the Demand Study, the numerous flaws in this Report we have discussed, as well as the many unknowns about hydrogen, indicate that this NOx emissions feasibility study cannot reasonably be relied upon as a fair evaluation of the air quality impacts of Angeles Link.

VII. Conclusion

Communities for a Better Environment appreciates the opportunity to provide feedback on the Report. Due to the Report's omissions and misleading discussion outlined above, CBE strongly objects to the characterization of emissions represented in this report. Accurate emissions estimates must be provided for communities to engage in meaningful dialogue with SoCalGas regarding the ALP. CBE recommends SoCalGas rectify all issues raised in this letter before issuing a final NOx and Other Air Emissions report to provide serviceable data by which the ALP can be assessed.

Sincerely,

Jay Parepally
Communities for a Better Environment

CC:
Emily Grant, SoCalGas
Chester Britt, Arellano Associates
Alma Marquez, Lee Andrews Group
Angeles Link service list

[24] Report at 3.5.
[25] Report at 3.6.

August 16, 2024

Informal Comments of the Public Advocates Office on Southern California Gas Company's July 2024 Production Planning & Assessment Draft Report for the Angeles Link Hydrogen Project

The Public Advocates Office (Cal Advocates) at the California Public Utilities Commission (Commission) provides these comments on Southern California Gas Company's (SoCalGas) *Angeles Link Preliminary Production Planning & Assessment Draft Report* (Production Planning report) issued on July 19, 2024. The Production Planning report discusses the potential sources of clean renewable hydrogen, the requisite land and infrastructure inputs, and estimated production costs, as required by the Commission's Decision for the Angeles Link Phase 1 feasibility studies.[1] The desktop-only Production Planning report does not utilize all publicly-available data for its analysis, particularly in the Production Land Assessment section, and thus makes inaccurate estimates based on the data which SoCalGas limits itself to. Cal Advocates provides comments and makes recommendations on the following three issues:

1. SoCalGas should consult with permitting agencies in potential production areas and revise its land use estimates based on publicly available data and information.
2. SoCalGas should expand the analysis of potential production areas beyond its service territory.
3. SoCalGas should explore alternative renewable energy production technologies other than solar.

1. SoCalGas should consult with permitting agencies in potential production areas and revise its land use estimates based on publicly available data and information

The Production Planning report assumes 240,000 acres for 39 GW of solar capacity will be necessary to produce 1.5 million tons per year (MMTPY) of clean renewable hydrogen.[2] SoCalGas states that 1.932 million total acres are available in its service territory and, therefore, the area required for solar represents only 12 percent of this available area.[3] SoCalGas considered various desktop screening criteria to arrive at this estimate, including avoiding urban/suburban development, environmental regions such as parks and preserves,

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[1] Southern California Gas Company's *Angeles Link Preliminary Production Planning & Assessment Draft Report* at 3-4. Commission Decision (D).22-12-055 approving Angeles Link Memorandum Account to record Phase One Costs at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M500/K167/500167327.PDF. Date accessed: August 12, 2024.

[2] *Production Planning & Assessment Draft Report* at 47.

[3] *Production Planning & Assessment Draft Report* at 47. The total 1.932 million acres are found in San Joaquin Valley (535,000 acres), Lancaster (1,124,000 acres), and Blythe (273,000 acres).

bodies of water, and topography greater than 15 percent slope.[4] This list of constraints is insufficient, however, as SoCalGas explicitly does not consider state and local zoning and land use ordinances.[5] This oversight means SoCalGas considers land as available that is reserved for existing or developing solar projects, or excluded from future solar development (see the list below for publicly accessible data from the California Energy Commission (CEC)).[6]

Consequently, the draft report's conclusion about the amount of available land for hydrogen production in SoCalGas service territory is grossly optimistic. Calculations using Figure 10.2 in the Production Planning report – which maps potential production areas identified by SoCalGas – overlaid with CEC exclusions data suggest that SoCalGas overestimated the available production area by 25 to 30 percent in San Joaquin Valley, by 40 to 50 percent in Lancaster, and by 60 to 80 percent in Blythe (see Figure 1). Land use management plans, as well as the location of existing solar facilities are therefore important determinants of land availability. Cal Advocates recommends that SoCalGas review the publicly available data identified in Appendix A and revise its estimate of the available acreage.

Permitting authorities include not only State agencies such as the CEC, but also the County and City governments. Assembly Bill 205 (2022) granted CEC the authority to permit powerplant construction as an alternative to permitting through Counties, but local governments should not be ignored.[7] For example, the City of Lancaster has been promoting itself as "Hydrogen City" and its encouragement of renewable energy development within its territory could create competition for land.[8] Similarly, the Bureau of Land Management (BLM) sets restrictions on solar development on Federally managed land in the Blythe region.[9] Ultimately, the production study must identify any legal or land use policy limitations that would impact production, and in turn, inform transmission pipeline size and location. SoCalGas must consult the proper permitting authorities in potential production areas to ascertain actual land availability (as set in land use management plans and local tolerance for solar development).

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[4] *Production Planning & Assessment Draft Report* at 45 and 46.

[5] *Production Planning & Assessment Draft Report* at 48. SoCalGas submitted a separate *High Level Feasibility Assessment & Permitting Analysis Draft Report*, which analyzes permitting issues only for pipelines.

[6] For existing solar development, see CEC Solar Footprints in California. https://cecgis-caenergy.opendata.arcgis.com/datasets/CAEnergy::solar-footprints-in-california/about. For land prohibited from solar use for protection, technological, or economic reasons, see CEC Base Exclusions (Solar). https://cecgis-caenergy.opendata.arcgis.com/datasets/CAEnergy::base-exclusions-solar-1/about. Date accessed: August 12, 2024.

[7] See Public Resources Code 25545 at https://leginfo.legislature.ca.gov/faces/codes_displayText.xhtml?lawCode=PRC&division=15.&title=&part=&chapter=6.2.&article=. Date accessed: August 12, 2024.

[8] Lancaster "Hydrogen City" at https://www.cityoflancasterca.org/our-city/about-us/sustainability/green-practices/hydrogen. Date accessed: August 12, 2024.

[9] Desert Renewable Conservation Plan Land Use Plan Amendment (LUPA) at https://eplanning.blm.gov/public_projects/lup/66459/133474/163144/DRECP_BLM_LUPA.pdf. See also https://eplanning.blm.gov/public_projects/lup/66459/20012404/250016892/II.3_Preferred_Alternative.pdf. Date accessed: August 12, 2024.

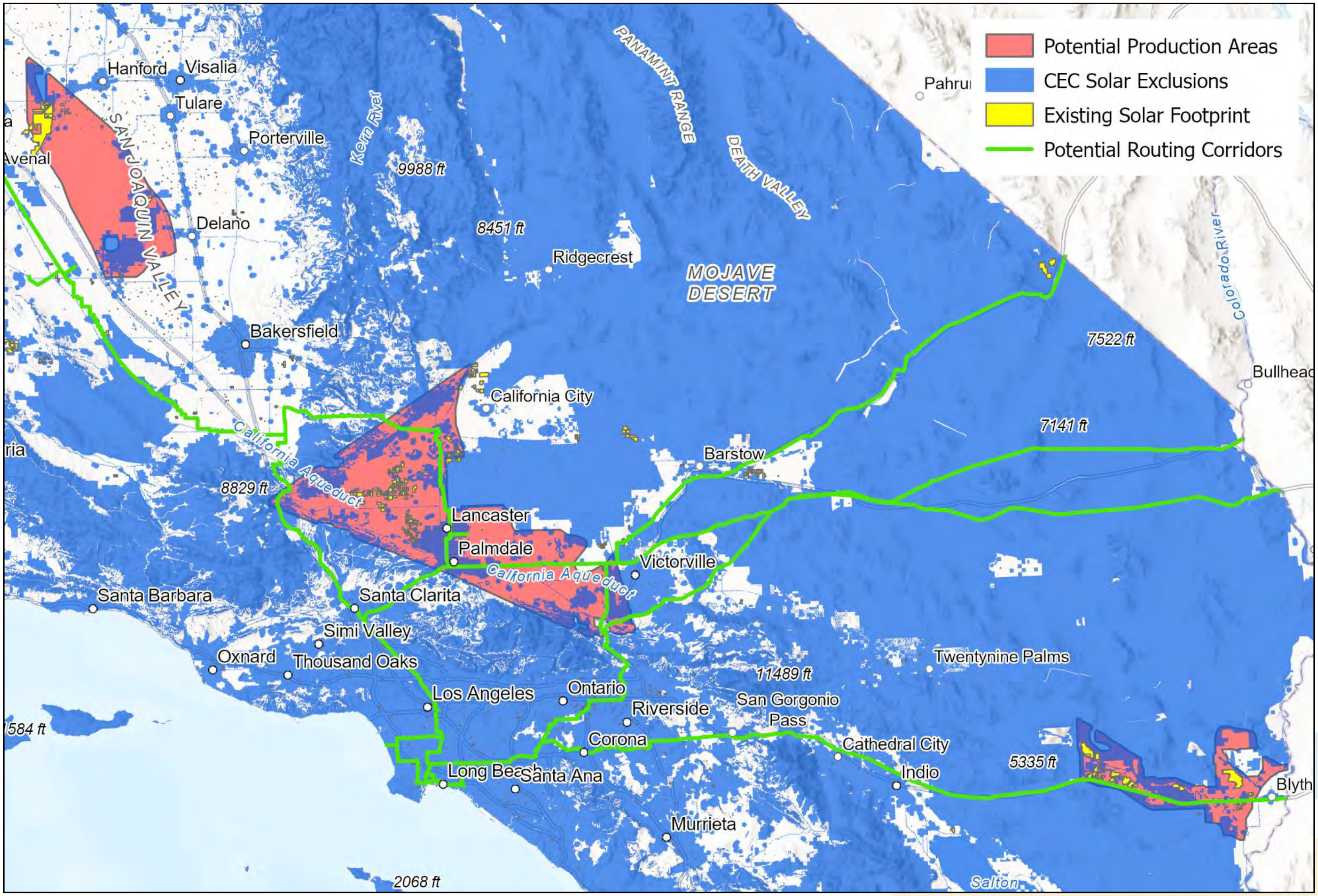

Figure 1: Overlap between SoCalGas-reported potential hydrogen production areas and CEC-determined solar exclusions

SoCalGas's Angeles Link Preliminary Routing/Configuration Analysis Draft Report identifies the most feasible Angeles Link hydrogen pipeline to be one that would serve the San Joaquin and Lancaster regions.[10] To fulfill the proposed 1.5 MMTPY scenario, Cal Advocates estimates that such a pipeline would require that 20% (240,000 acres/1.182 million acres) of suitable land be dedicated to solar for hydrogen production. This is a historic degree of land conversion, and SoCalGas has provided no assessment of local, state, or federal agencies agreement with, or awareness of these studies. So that the Commission can make a fully informed appraisal of the feasible size of a pipeline, it is essential that SoCalGas both review and integrate the sources of information presented in Appendix A and consult with land management and permitting agencies. Without these actions, the scenario is likely to draw inaccurate conclusions about the availability of the type and scale of renewable energy resources that could be used to create hydrogen.

2. SoCalGas should expand the analysis of potential production areas beyond their service territory

The Production Planning report restricts its analysis of the available land for solar production to areas within the SoCalGas service territory. This is an arbitrary restriction on the scope of the study. SoCalGas should expand its analysis of potential production areas into the service territories of other utilities. For example, SoCalGas is already considering a hydrogen pipeline routing corridor from PG&E's service territory in northern San Joaquin Valley.[11] Given the solar exclusions in southern California, the greater San Joaquin Valley region shows greater promise for solar development. SoCalGas should identify potential production areas in PG&E service territory that could feed a northern San Joaquin Valley corridor. Thus, the Production Planning report likely underestimates the total available land for hydrogen production in the state as a whole.

3. SoCalGas should explore alternative renewable energy production technologies other than solar

The Production Planning report also assumes the use of only solar energy for hydrogen production. SoCalGas should consider other renewable energy technologies, especially geothermal generation in the Salton Sea area near Blythe. The Production Planning report dismisses geothermal technologies because of feasibility issues such as project discovery and siting difficulty, uncertain access to adequate fluid temperatures and flows, uncertainty about proximity to energy demand, and uncertainty around technology and project costs.[12] However, the Salton Sea is a Known Geothermal Resource Area (KGRA) that resolves much of the uncertainties that

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[10] Southern California Gas Company's *Angeles Link Preliminary Routing/Configuration Analysis Draft Report* at 42-44.

[11] In Figures 10.1 and 10.2 of the Production Planning study, SoCalGas shows a conceptual routing option to the northwest of its service territory within PG&E's domain.

[12] Production Planning report at 57.

SoCalGas raises.[13] The Imperial Valley Geothermal Project already operates 11 geothermal power stations in the Salton Sea Geothermal Field, and experts estimate that the Salton Sea KGRA could support further development of 2 GW of additional power plant capacity.[14] Financial incentives – such as the CEC's Geothermal Grant and Loan Program or lithium extraction (with the colocation of lithium recovery facilities with geothermal power plants) – for developing geothermal power at the Salton Sea could also prove attractive.[15]

Conclusion

In summary, SoCalGas should review its assumptions in its Production Planning report. To demonstrate more accurately where 240,000 acres of solar can feasibly be permitted, SoCalGas must consult with the primary land use permitting authorities to understand what development is occurring and the limits in existing land use plans. SoCalGas should also expand the scope of its study to include regions outside its service territory and consider renewable energy production beyond solar.

[13] CEC Geothermal Energy at https://www.energy.ca.gov/data-reports/california-power-generation-and-power-sources/geothermal-energy. Date accessed: August 12, 2024.

[14] Lithium Valley Commission Report at 30. https://www.energy.ca.gov/data-reports/california-power-generation-and-power-sources/geothermal-energy/lithium-valley. Date accessed: August 12, 2024.

[15] CEC Geothermal Grant and Loan Program. https://www.energy.ca.gov/programs-and-topics/programs/geothermal-grant-and-loan-program. Date accessed: August 12, 2024.

Appendix A - Public Data for Solar Energy Siting Considerations in Angeles Link

Cal Advocates provides this list of publicly available data which can help inform SoCalGas's considerations on available solar energy siting in its production analysis for the proposed Angeles Link Hydrogen Project.

- California Energy Commission
  - Solar Footprints in California. https://cecgis-caenergy.opendata.arcgis.com/datasets/CAEnergy::solar-footprints-in-california/about
  - Base Exclusions (Solar). https://cecgis-caenergy.opendata.arcgis.com/datasets/CAEnergy::base-exclusions-solar-1/about
  - Geothermal Energy. https://www.energy.ca.gov/data-reports/california-power-generation-and-power-sources/geothermal-energy
- Bureau of Land Management
  - BLM California Renewable Energy Projects. https://gbp-blm-egis.hub.arcgis.com/maps/9b663af4613847d7a3ec1c1a81a02c85/about
  - BLM Land Use Plan Amendment (LUPA) Renewable Energy Designations.
    - LUPA Document. https://eplanning.blm.gov/public_projects/lup/66459/133474/163144/DRECP_BLM_LUPA.pdf
    - LUPA Map. https://gis.data.ca.gov/datasets/CAEnergy::blm-lupa-renewable-energy-designations/about
- County General Plans and Land Use
  - Fresno County. https://www.fresnocountyca.gov/Departments/Public-Works-and-Planning/divisions-of-public-works-and-planning/development-services-division/planning-and-land-use
  - Kern County. https://kernplanning.com/planning/planning-documents/general-plans-elements/
  - Kings County. https://www.countyofkingsca.gov/departments/community-development-agency
  - Los Angeles County. https://planning.lacounty.gov/long-range-planning/
    - Renewable Energy. https://case.planning.lacounty.gov/energy/
  - Riverside County. https://planning.rctlma.org/
    - Energy Division. https://www.rivcoenergy.com/
  - Tulare County. https://tularecounty.ca.gov/rma/planning-building/
- City of Lancaster
  - Sustainability. https://www.cityoflancasterca.org/our-city/about-us/sustainability
  - General and Master Plans. https://www.cityoflancasterca.org/our-city/departments-services/development-services/planning
- City of Blythe
  - General Plan and Zoning Maps. https://cityofblythe.ca.gov/27/Planning-Zoning

Notes and comments on ESJ Draft Engagement Plant and ESJ Screening

- Curious why "non-discriminatory" is emphasized. What is, or has been, normal with pipeline systems? Who is the intended audience?
- Under Background section, perhaps end in an end note or hyperlink which lists all the orgs that have been involved in the PAG and CBOSG.
- Good job in explicitly stating the stakeholder input and SCG's direct output
- Under goals of the plan, goal bullet point 2, providing information seems passive. Maybe frame it a but more collaboratively? (workshops, informal interviews, etc)
- What will the processes be for monitoring and assuring quality/efficacity for the community benefits plan?
- Can you elaborate on the direct and indirect benefits for stakeholders/communities
- I would caution on an over-reliance on elected officials for DAC perspectives/needs/wants. There is often a level of mistrust between DAC and government.
- When you get around to it, more clarity on the *how often* and *how* the engagement strategies will take place
- For Phase 2 engagement meeting approach: as part of EJ, please make sure to value stakeholders time, through either incentives (food, beverage, gift cards) or compensation (stipends, honorariums)

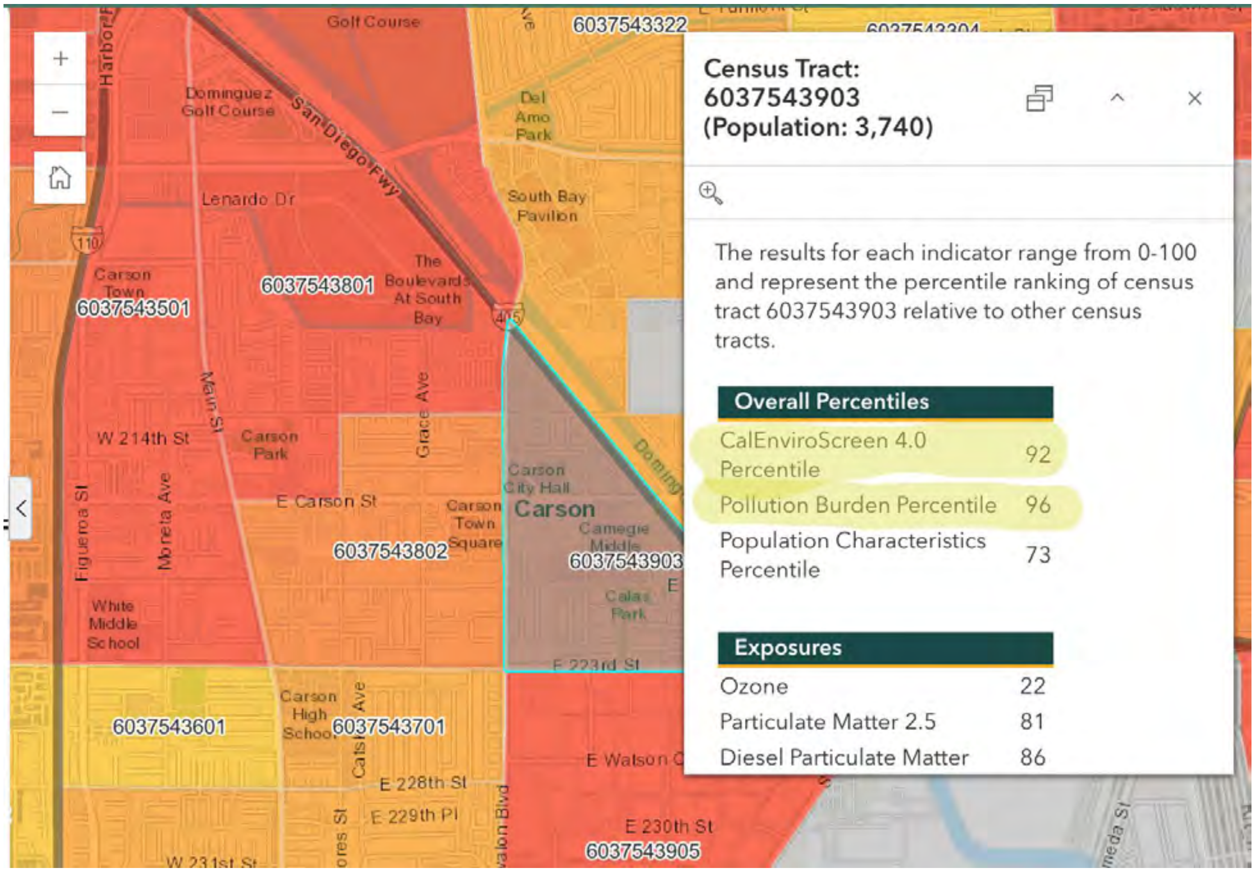
Notes and comments on ESJ Draft Social Justice Screening

- I appreciate the linkage with the appropriate macro-level EJ initiatives
- I would appreciate also in the tables for census tracts, the addition of two more metrics: EnviroScreen overall percentile, and the pollution burden percent. (please see the end for an example)[1]. It allows me to quickly and more meaningfully analyze the tract (beyond classification of DAC).
- Section 2.3. As a part of EJ, a general environmental description would also be helpful (type of environment, historical environmental concerns). While this may exist in other reports (environmental impact report), it should also be a part of the EJ assessment.
- I would love to see what the EJ benefits could be. I know it's all conceptual at this stage, but SCG should know what they are capable of providing and letting stakeholders know a starting off point would be helpful.
- In the document, my side notes that show EJ+ means a short hand for me saying these communities could use a lot of love and attention. It would be powerful for SCG to treat these communities with an overabundance of

benefits. One idea I have is that since you have the data, you can determine if a community is in need of, jobs, education, green space, etc. Obviously waiting for feedback from the communities for what is desired on-the-ground and the best means of acquiring/distributing the benefits

- Also, for the sake of the reader, having a (small) map of the proposed line would help me situate/contextualize the route segments
- Knowing the criteria of assessment would also be helpful for sake of transparency. For grants, a lot of grantors have scoring systems of how they will assess

1



August 20, 2024

Southern California Gas Company
555 West Fifth Street
Los Angeles, CA 90013

Submitted via email to: **ALP1_Study_PAG_Feedback@insigniaenv.com**

RE: Feedback for Southern California Gas Company on

1. Production Planning and Assessment Draft Report (Dated July 2024)
2. Preliminary Routing /Configuration Analysis (Draft)

The Green Hydrogen Coalition ('GHC') is appreciative of SoCalGas' effort to implement Angeles Link, the nation's first dedicated common carrier renewable hydrogen pipeline, as it is an essential component of California's goal of economy wide decarbonization and our transition away from fossil fuels. The GHC is a California educational 501(c)(3) non-profit organization that was formed in 2019 to recognize the game-changing potential of "green hydrogen" to accelerate multi-sector decarbonization and combat climate change. The GHC's mission is to facilitate policies and practices that advance green hydrogen production and use across all sectors of the economy to accelerate a carbon-free energy future and a just energy transition.

Background/Basis for GHC's Comments

From 2020-2023 the GHC launched and completed HyBuild Los Angeles, a multi stakeholder independent system planning effort to determine if it is commercially and technically possible to create a mass-scale green hydrogen ecosystem to displace fossil fuels across multiple sectors. This effort was geared toward first identifying potential multi-sectoral buyers/demand for the renewable hydrogen and then architecting the needed scaled production and transport infrastructure to serve that demand. Findings from this effort were highly encouraging. The GHC found that achieving a mass-scale green hydrogen economy to rapidly displace fossil fuels in several hard to abate sectors is indeed technically and commercially possible. It will require shared, scaled infrastructure; namely green hydrogen pipeline transport connected to underground geologic storage of hydrogen. This infrastructure combination affords the lowest cost pathway to achieving mass-scale supply assurance and low delivered cost to enable widespread adoption of GH2. The successful implementation of Angeles Link is thus a gating factor for Southern California's realization of a green hydrogen economy and a faster transition away from fossil fuels economywide. The GHC is pleased to see that many of the assumptions and findings in the Socalgas draft reports are consistent with the HyBuild LA findings.

Green Hydrogen Coalition

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GREEN HYDROGEN COALITION

GHC Comments: Production Planning and Assessment Draft Report

1. HyBuild LA demand assessment findings are consistent with the preliminary findings from the Angeles Link work to date, namely the forecasted demand scenarios for the pipeline sizing (0.5, 1.0 and 1.5 million metric tons per year). The GHC's findings were based on direct interviews with potential scalable multi sectoral off takers in the LA basin, to ascertain and qualify potential demand for green hydrogen.
2. The GHC found that there was significant renewable resource in the locations identified by Socalgas for third party clean renewable hydrogen production, including locations in the San Joaquin Valley, and near Lancaster CA. GHC also applauds SoCalGas' thorough evaluation of potential geologic storage options for green hydrogen, including not only commercially available salt dome storage but also the potential for hydrogen storage in depleted oil and gas fields.
3. The GHC also found that utility-scale solar is the lowest cost and most scalable source of renewable electricity for electrolytically produced hydrogen (as compared to onshore and offshore wind and rooftop solar)
4. While GHC did not study waste to hydrogen pathways as part of HyBuild LA due to budget constraints, GHC strongly supports and applauds Socalgas' exploration of various biomass to hydrogen technologies. The GHC strongly supports the use of non-recyclable and non-compostable waste, especially municipal waste, as a valuable feedstock for the production of Clean Hydrogen.
5. The attached Biofuels article jointly authored by the Professors from University of California Berkeley, University of California Agriculture and Natural Resources and Stanford University found that hydrogen projects from all three sources of waste deliver positive internal rates of return, with municipal solid waste being the highest at 37%, suggesting that "hydrogen production from these waste streams would be a financially worthwhile enterprise at scale in CA"[1].
6. GHC encourages Socalgas to continue to explore these pathways, particularly given the high taxpayer burden of dealing with this waste today. For example, LA is burdened with a significant and expensive waste removal problem that costs taxpayers $700 million per year,

[1] Page 6: 2023 Society of Industrial Chemistry and John Wiley & Sons Ltd – Biofuels, Bioprod, Bioref.. (2023) DOI: 10.1002/bbb/2492 Authors: Haris Gilani, Dept of Environmental Science, University of CA Berkeley; Karim Ibrik, Stanford University, Daniel Sanchez, University of California Agriculture and Natural Resources

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and more than $2 billion per year if wastewater treatment is included.[2] The portion of waste that cannot be recycled or composted produces methane emissions and its removal via diesel powered trucks to landfills contributes to toxic air pollution and road congestion. **The fraction of LA's solid waste that cannot be recycled or composted and is destined for landfills should be explored for conversion to clean hydrogen. GHC recommends that further work be undertaken in the next phase to evaluate specific in-basin opportunities for waste to hydrogen production, perhaps co located with existing waste sorting/collection locations**.

GHC Comments: Preliminary Routing /Configuration Analysis (Draft)

The GHC appreciates Socalgas' thoughtfulness in creating multiple pipeline routing options that take into consideration both system evaluation and route evaluation, following transit corridors. Establishing transport infrastructure that can connect multiple scaled producers with multiple scalable off takers is the key to realizing a cost competitive clean hydrogen economy and achieving deep economy wide decarbonization.

The GHC also appreciates the attention given to prioritizing needed pipeline infrastructure to support ARCHES, which will drive the first scaled green hydrogen production and off take projects statewide.

Finally, the GHC appreciates Socalgas' development of an Environmental Justice and Social Justice Community Engagement Plan which includes potential alternative route Variation 1 that minimizes main pipeline route mileage traversing DACs in the LA Basin. While it is critically important to avoid impacts to such communities during the construction phase of Angeles Link, it is important to also factor in the broader costs and benefits to DACs. For example, Route Variation 1 may minimize construction impacts by avoiding traversing DACs, but in so doing could potentially minimize the beneficial impacts for disadvantaged communities either by

1. delaying or increasing the delivered hydrogen cost for clean renewable hydrogen in heavily trafficked transit corridors and

[2] City of LA 2023-2024 Adopted Budget; solid waste collection and disposal cost is budgeted at $669,819,775 for 2023-2024; an additional $1,328,074,031 is budgeted for wastewater collection and treatment page 6: 2023-24 Budget Summary_FINALrev.pdf (lacity.gov)

2. delaying and increasing the delivered cost for clean renewable hydrogen to municipalities including local electric generation facilities that must remain online to ensure grid reliability. For these latter generation plants, access to clean renewable hydrogen will be key to enabling their transition away from natural gas usage, the current default fuel. In other words, sitting Angeles Link too far away from these large municipal loads (and their vehicle/truck fleets) may in advertently slow their adoption of clean hydrogen and unnecessarily prolong the continued use of fossil fuels in/around DACs.

Notably, the GHC's work on HyBuild LA identified significant air quality, public health and economic development opportunities that will result from a scaled green hydrogen economy for Southern California, largely due its ability to displace the combustion of diesel fuel. The impact of reduced emissions is significant - for a single winter month in 2045 the value of public health benefits exceeded $350 million for the LA Basin, representing 27 fewer premature deaths, 964 fewer hospitalizations for respiratory and cardiovascular illness and 7,500 fewer work loss days. These benefits will only be achievable by establishing a cost competitive alternative fuel to gasoline and diesel fuel, and to achieve that goal pipeline transport is essential.

The GHC looks forward to participating in the final October PAG meeting and to the opportunity to further comments as additional analyses are completed.

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Biofpr Biofuels Bioproducts & Biorefining

Techno-economic and policy analysis of hydrogen and gasoline production from forest biomass, agricultural residues and municipal solid waste in California

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Karim Ibrik, Stanford University, Stanford, CA, USA
Daniel L. Sanchez, University of California, Agriculture & Natural Resources, Davis, CA, USA

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View online at Wiley Online Library (wileyonlinelibrary.com);
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Abstract: Techno-economic and policy analyses were performed of hydrogen and gasoline production from forest biomass (FB). They were compared with fuels produced using agricultural residues and municipal solid waste in California. Twelve process designs were analyzed, with and without carbon capture and storage, and life-cycle analysis was performed, using California's Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) 3.0 model, to calculate the average life-cycle carbon intensity of different process designs for hydrogen and gasoline. Discounted cash flow models were developed to assess profitability in terms of the net present value and internal rate of return (IRR). The results showed that forest-to-fuel pathways (positive IRR between 2%–16%) were the least competitive biomass-based pathway option. Sensitivity analysis was performed on economic parameters including feedstock price and renewable identification number (RIN) credit price. In the case of RIN credits, profitability declined significantly as the proportion of FB from federal lands increased given existing statutory limitations. Given the importance of increasing forest management to reduce wildfire risks, the necessary additional policy incentives were quantified to equalize the cost of forest-to-fuels pathways with the other biofuels pathways. To ensure FB-to-fuels pathways are cost competitive with agricultural residues, policymakers could increase the low carbon fuel standard (LCFS) credit price for forest fuels (additional credit price support of \$41–75 t/CO_2e), give additional credit to lifecycle emissions reductions from forest fuels (additional carbon intensity decrease of 19–76 gCO2e MJ^{-1}), provide concessionary debt or equity with a target weighted average cost of capital (WACC) = 3–4%, subsidize

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capital costs (12–22% of costs), or subsidize FB delivery ($35–66 per dry ton delivered).

Supporting information may be found in the online version of this article.

Key words: Biomass and biofuels; Hydrogen; Climate and Energy Policy; California Low Carbon Fuels Standard; Bioenergy

Introduction

The transportation sector is one of the largest contributors to greenhouse gas (GHG) emissions, accounting for approximately 23% of total energy-related GHG emissions globally and 39.6% of total GHG emissions – more than any other single sector – in the state of California (CA).[1,2] Production and refining of petroleum fuels accounts for an additional 10–12% of total GHG emissions, making the life cycle impact of transportation in CA over 50% of total GHG emissions.[3] Reducing the carbon intensity of transportation fuels will play an important role in decarbonizing the transportation sector and will require aggressive policy action.[4] To spur emissions reductions from transportation fuels, CA developed the low carbon fuel standard (LCFS) in 2009 and began implementation in 2011. California's LCFS is a market-based policy instrument that specifies declining standards for the average life cycle fuel carbon intensity (CI) of transportation fuels sold in the state.

The primary goals of LCFS are to: (i) reduce the average carbon intensity for all transportation fuels used in CA, as measured on a life cycle basis; (ii) incentivize innovation, technological development, and deployment of low-carbon and carbon-negative fuels; and (iii) provide a framework for regulating transportation sector GHG emissions within a broader portfolio of climate policies.[4,5] Under the LCFS, fuel providers are required to track the life cycle CI of their fuels, measured on a per-unit-energy basis, and reduce this value over time. The LCFS covers nearly all fuels consumed for on-road transportation in CA, so any given fuel producer could choose to buy credits, engage in GHG-reducing projects like carbon capture and storage (CCS) or Zero-Emission Vehicle (ZEV) infrastructure development, or reduce the CI of their fuels. The CI is measured in terms of grams of carbon dioxide equivalent per megajoule ($gCO_2e\ MJ^{-1}$) and it is calculated by adjusting the $gCO_2e\ MJ^{-1}$ of fuel entering the vehicle accounting for inherent differences in the in-use energy efficiency of different fuels – for example, diesel, electricity, and hydrogen.[5]

The LCFS program provides an economic incentive for the development of low carbon fuels, which could promote the development and deployment of forest-to-fuel pathways. California's Forest Carbon Plan (FCP) calls for a significant increase in the level of forest treatments as well, implementing a new strategy for forest residues management. The state has set an ambitious goal of treating 1 million acres of forest per year to reduce wildfire risk and improve forest health.[6]

Estimates of the level of current forest health activities being undertaken across the state vary, particularly because a large proportion of forests are owned and managed by private entities. Between 2017 and 2020, the California Department of Forestry and Fire Protection (CAL FIRE) and the US Forest Service completed or assisted with prescribed fire activities on approximately 80 000 acres annually.[7] Forest health-oriented thinning has decreased since it reached a peak in 2008. At most, 300 000 acres were completed each year, 30% of the statewide million-acre goal.[8] The business-as-usual uses of this biomass include pile burning, decomposition on-site, or combustion in a biomass power plant.

Recent research by the Joint Institute for Wood Products Innovation (JIWPI) suggested that CA's small-diameter trees and unutilized forest biomass (FB) waste from current forestry practices can play an important role in achieving carbon neutrality by 2045 by pursuing innovative wood-based products such as forest biofuels.[9] The Joint Institute found that converting FB into liquid and gaseous transportation fuels, such as renewable hydrogen, natural gas, and sustainable jet fuel (collectively: biofuels), was one of the most commercially and technologically viable wood product innovation options in the state.

Lignocellulosic biomass-based fuels have received considerable attention in recent decades, as these biofuels can have low- or net-negative life cycle CO_2 emissions. A variety of different biofuels, including hydrogen and gasoline, can be produced from biomass using thermochemical conversion processes that incorporate carbon capture and storage (CCS). Biofuels can be produced by processing FB using gasification and pyrolysis technologies. Gasification of coal to produce electricity is a mature technology pathway but gasification of biomass to produce hydrogen and other products is a nascent technology that uses a controlled process involving heat, steam, and oxygen, without combustion. Pyrolysis is the heating of biomass, in the absence of oxygen to convert the cellulosic compounds that make up that material thermally decompose into combustible gases and charcoal. Most of these combustible gases can be condensed into a combustible liquid, called bio-oil, which can subsequently be converted into higher value products including hydrogen during a catalytic reaction. Gasification and pyrolysis are emerging, low-carbon options compared to existing biomass electricity plants in CA. Advanced biofuels production is in its infancy, as it has not yet reached commercial-scale production.

There are a wide variety of pathways available for producing biofuels using biomass. For example, biomass to liquid (BTL) diesel can be produced from any hydrocarbon material including biomass using the well established Fischer–Tropsch (FT) process.[10] This renewable diesel is a high-quality diesel-blending component, similar in quality to hydrogenated vegetable oil diesel, having very high cetane, zero sulfur content, and clean burning characteristics. Another pathway to produce liquid fuels is through biomass pyrolysis through thermal degradation of biomass by heat in the absence of oxygen, which results in the production of charcoal (solid), bio-oil (liquid), and fuel gas products. This oil can potentially be upgraded to produce synthetic diesel and gasoline fuels.[11] Although pyrolysis technologies are commercially available, further R&D is required before the upgrading technologies are commercially available. While some renewable fuels are already being deployed in CA, others are ready for production and deployment in the near-term. Here, we focus on two fuels – namely hydrogen and gasoline – which could be deployed in CA in the near term and are compatible with existing infrastructure or engines.

As shown in Fig. 1, two commercially relevant transportation fuels, hydrogen and gasoline, can be produced by converting biomass through gasification.[12,13] For hydrogen production, the clean syngas leaving the gasifier is subjected to a water gas shift ($CO + H_2O <=> H_2 + CO_2$), after which CO_2 is removed and hydrogen in the remaining gas is purified using a pressure swing adsorption system.[14] The gasoline production process involves the first step of conventional methanol production from syngas, followed by partial conversion of methanol to dimethyl ether (DME)

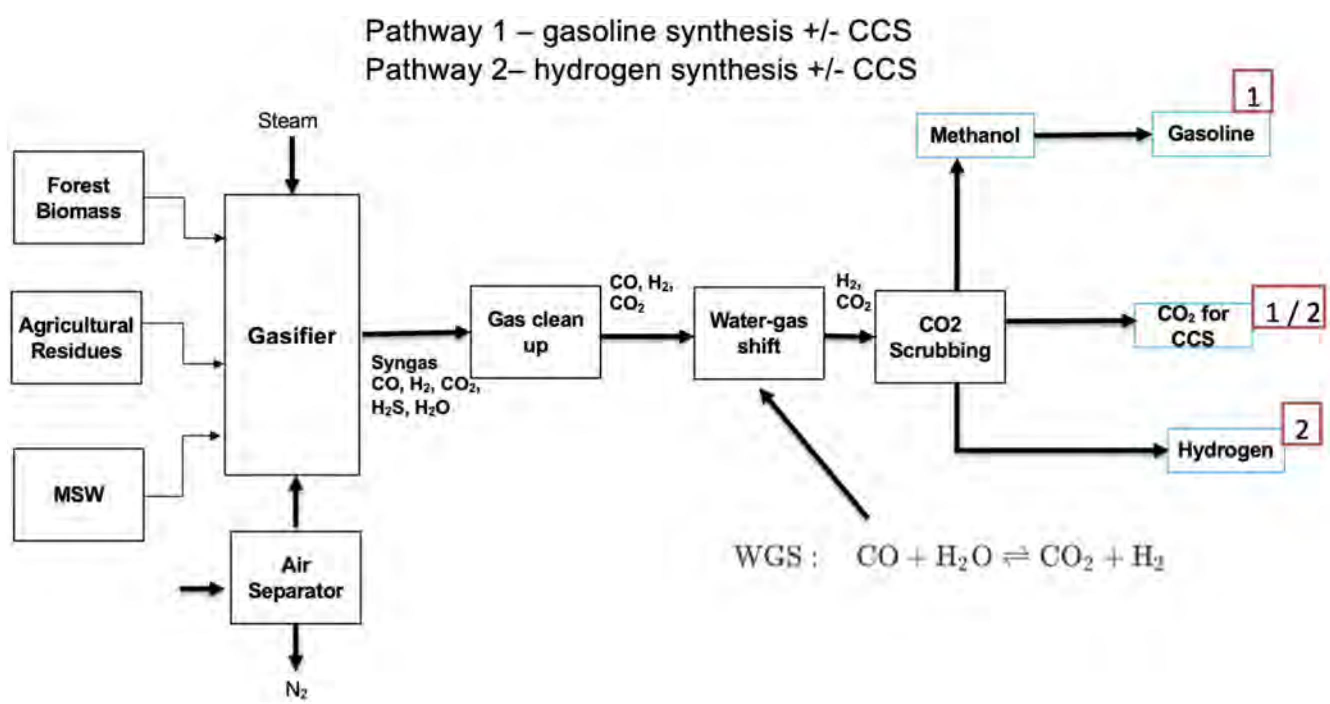

Figure 1. Biomass-to-fuels pathways considered in this paper. Biomass gasification of different feedstocks including forest biomass, agricultural residues, and municipal solid waste is used to produce syngas. Hydrogen synthesis is a pathway with carbon-negative potential that uses a controlled process involving heat, steam, and oxygen to convert biomass to hydrogen and carbon dioxide without combustion. Carbon dioxide can be captured, compressed, and sequestered in geologic formations, resulting in negative emissions of hydrogen. In gasoline synthesis, syngas is converted into drop-in fuel, gasoline, through the synthesis of methanol from clean syngas using a catalytic process, and methanol is subsequently converted to gasoline using the methanol-to-gasoline (MTG) pathway.

in a separate reactor, followed by conversion of the DME/methanol mixture into gasoline in a third, fixed-bed reactor.[12] A number of techno-economic assessments using process design and simulation models have been conducted for biomass gasification to fuels such as Fischer–Tropsch fuels,[15] hydrogen,[16–19] and MTG,[12,20] but limited research and analysis work has been conducted to evaluate the economic feasibility of biomass conversion to hydrogen and gasoline using different biomass feedstocks including FB, agricultural residues (ARs), and municipal solid waste (MSW).[21] Our study also includes detailed representation of state and federal low-carbon and renewable fuel policies. This allows us to quantify robustly the range of policy interventions necessary to make FB competitive with ARs and MSW.

Biofuels present a promising forest product for three key reasons. The first is that they are a high-value product. Between incentives available through the state's LCFS and the federal government's renewable fuel standard programs, as well as the inherent value of a product like hydrogen, biofuels command a much higher value 'per ton' of FB than current wood product options. This can create a reliable income stream to support forest health treatments and a pathway to the state's overall forest treatment goal. Second, biofuels are a scalable product. California's liquid fuels end market is extremely large and established. Renewable liquid and gaseous fuels can meet existing demand by displacing fossil fuels in a diversity of hard-to-electrify applications in the coming decades.[22] Finally, biofuels can provide substantial GHG benefits. In a recent study, Lawrence Livermore National Laboratory (LLNL) estimated that converting CA's FB into biofuels coupled with CCS could achieve about 70 million tonnes of GHG mitigation, which is equal to over 15% of the state's entire GHG inventory.[23] Adding CCS can also qualify biofuels pathways for added incentives under the LCFS and the federal government's 45Q tax credit. Carbon capture and storage has been identified by the Intergovernmental Panel on Climate Change as a necessary GHG mitigation option for achieving the Paris Agreement climate goal of limiting global warming to less than 2 °C.[24] Overall, mobilizing FB into biofuels with CCS could be a highly promising strategy to help CA achieve its ambitious forest treatment and climate goals.

The research reported here investigated the economics of producing low-carbon and carbon-negative fuels from biomass in CA. First, techno-economic assessment developed a deeper understanding of costs associated with producing hydrogen and gasoline from FB, agriculture residues and MSW, without and with capture and storage of by product CO_2. Second, factors were identified and policy interventions are described through which forest-to-biofuels could achieve similar economic returns to ARs and the MSW in CA.

Methodology

Hydrogen and gasoline can be produced within CA using a variety of lignocellulosic feedstocks. In this study, 12 process configurations for producing hydrogen and gasoline from FB, agriculture residues and MSW were evaluated. These 12 process configurations are shown in Table 1. This research was carried out in several steps: First, a technology and process design assessment on gasification, hydrogen and gasoline conversion using different feedstock was conducted using information from the literature and in consultation with technology developers, researchers and investment firms who had been involved in similar biomass-to-biofuel projects. Second, life cycle analysis was performed, using CA's Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) 3.0 model, to calculate average life cycle carbon intensity of different production processes for hydrogen and gasoline from FB, ARs and MSW. The GREET model was used for upstream emission factors, but the authors substituted their own model for conversion processes that GREET does not adequately cover. Third, discounted cash flow analysis was performed to estimate the net present value and the internal rate of return for each process configuration.

To estimate total plant costs, we drew on extensive discussions with industry experts and on sources in the literature.[25–27] Adjustments were made to ensure that assumptions regarding engineering, procurement and construction (EPC) charge and contingency costs were applied consistently and realistically across all plant designs. Input data and modeling parameters were developed in consultation with industry experts and the California Air Resources Board (CARB) staff, and also relied on previous techno-economic studies by various researchers.[12,14,17,18] The modeling parameters for each process configuration and the discounted cashflow analysis results are provided in Data S1 and S2. Capital costs include gasification, gas cleanup, char/ash handling, conversion of syngas to products including hydrogen and gasoline while operating costs consist of electricity, labor, maintenance, other operating cost, water, land rent, and natural gas.[28] Each integrated conversion and refining system is designed to process 200 tonnes of feedstock per day. This study assumed a moisture content of 23%, 12%, and 41% for FB, ARs, and MSW, respectively. The daily feedstock processed in bone dry tonns is shown in Table 2. These are small-scale facilities. For revenues, we include the income for each process configuration based on

Table 1. Process configuration for producing hydrogen and gasoline from forest biomass, agricultural residues and MSW.

Feedstock	Forest biomass				Agriculture residues				Municipal solid waste			
Fuel	Hydrogen		Gasoline		Hydrogen		Gasoline		Hydrogen		Gasoline	
CO_2 sequestered/ emitted	CCS	w/o CCS	CCS	w/o CCS	CCS	w/o CCS	CCS	w/o CCS	CCS	w/o CCS	CCS	w/o CCS
Process configuration	FB hydrogen CCS	FB hydrogen	FB MTG CCS	FB MTG	AR hydrogen CCS	AR hydrogen	AR MTG CCS	AR MTG	MSW hydrogen CCS	MSW hydrogen	MSW MTG CCS	MSW MTG
Feedstock Price/ BDT	$50				$30				$(50)			

NCCS = Carbon capture and storage; FB = Forest biomass; AR = Agricuutrual residues; MSW = Municipal solid waste; MTG = Methanol-to-gasoline.

respective production and fuels price ($1.10/kg for hydrogen and $2.42/gge for gasoline). Different studies have estimated harvesting, chipping, and hauling FB costs. This study used a FB feedstock price of $50 per bone dry ton (BDT).[29–31] It estimated $35 per BDT for ARs[29] and $50 per BDT for MSW as tipping fees.[32]

Revenues also include policy support, which is substantial for low-carbon fuels consumed in CA. This study estimated LCFS credit value based on expected tonnes abated per year, at a LCFS credit price of $125/t$CO_2$e abated. The expected tonnes of carbon dioxide abated per year for each process configuration were calculated based on the annual plant capacity at 80%, accounting for the energy content of hydrogen (119 MJ per kg) and gasoline (130 MJ per gallon) and subtracting carbon intensities of each fuel produced from the benchmark carbon intensities for fossil-based hydrogen and gasoline. For CCS cases, we include 45Q sequestration tax credits for the first 12 years of the plant life at $50/ton for the amount of CO_2 sequestered. Finally, renewable identification number (RIN) credit value is a potential source of revenue for all process configurations. A RIN is a credit under the renewable fuels standard that is generated each time a gallon of renewable fuel is produced. This study used the D3 category of cellulosic biofuels for gasoline produced from qualified FB and ARs at the price of $3.5/gge and the D5 category of advanced biofuels for separated MSW at the price of $2/gge for gasoline (EPA).[33] The U.S. Environmetal Protection Agency (EPA) has not certified RIN pathways for hydrogen. Hence no RIN credits were allocated to hydrogen pathways in our calculations. These RIN classifications are representative of low-carbon fuels produced from FB from private landowners, rather than the US Forest Service, as discussed later in this article. Table 2 shows cost and revenue assumptions for hydrogen and gasoline production.

The analysis described in this paper is based on the discounted cash flow (DCF) methodology,[34] to arrive at a net present value and internal rate of return (IRR) for hydrogen and gasoline produced from different feedstocks, with and without carbon capture and storage. In this analysis we used a 20-year time period to develop our discounted cash flow analysis using a weighted average cost of capital (WACC) of 10%. A data intensive DCF spreadsheet model of each process configuration was developed to ascertain the hydrogen and gasoline production cost for each scenario considered in this study. The DCF was calculated for each year of the analysis to generate a table of annual cash flow to assess plant profitability. The results of the DCF are presented in terms of the IRR of each process configuration. Finally, sensitivity analysis was performed on the parameters of interest including feedstock price and RIN credit price to evaluate the effect on IRR.

Table 2. Economic assumptions.

Process configuration	Biomass processed BDT	Capital cost M $	Operating cost* M $	Plant capacity kg H_2/day gge gas/day	Fuel production kg H_2/year gge gas/year (M)
FB hydrogen CCS	167	152	7.9	12612	4.56
AR hydrogen CCS	174	161	8.5	14674	5.30
MSW hydrogen CCS	161	161	7.8	12531	4.53
FB hydrogen	167	130	6.7	12612	4.56
AR hydrogen	174	134	7.1	14674	5.30
MSW hydrogen	161	141	6.7	12531	4.53
FB gasoline CCS	167	185	6.4	8082	2.95
AR gasoline CCS	174	201	6.8	9342	3.40
MSW gasoline CCS	161	188	6.2	7973	2.90
FB gasoline	167	173	5.6	8082	2.95
AR gasoline	174	188	5.8	9342	3.40
MSW gasoline	161	178	5.6	7973	2.90

*Excludes feedstock cost.

Average life cycle carbon intensity

The life cycle accounting of hydrogen and gasoline from FB, ARs and MSW, including harvest and transport, production emissions, product substitution, and end of life, was estimated. Values were aggregated from several published life cycle assessments (LCAs) and they were adjusted where necessary to achieve consistency. For hydrogen production, the LCA of hydrogen gas produced from wood waste conducted by Antonini *et al.* was used.[17] Their entrained flow gasifier with CO_2 capture and storage was modeled; this has a CI of −130 gCO_2 MJ^{-1}. This process was chosen because it has the highest rate of carbon capture among all modeled hydrogen production processes. This CI was adjusted to −126.89 by accounting for the upstream emissions using values using the GREET model. For gasoline production, with and without carbon capture and storage (CCS) from FB, ARs, and MSW, this study relied on modeling done by Liu *et al.*[12] The range of the CI score was −126.89 to −323 gCO_2e MJ^{-1} for hydrogen with CCS and 3.1 to −193 gCO_2e MJ^{-1} without CCS. Gasoline CI score range from −38.4 to −253.2 gCO_2e MJ^{-1} with CCS and 4.49 to −204.6 gCO_2e MJ^{-1} without CCS. This result corroborates the work of Antonini *et al.* who found that entrained flow gasification was the most climate friendly among three gasification technologies for H_2 production analyzed in the research.[17] The final carbon intensity values for all process configurations are shown in Table 3 and the capital costs of each process configuration with corresponding CO_2 abated/year are shown in Fig. 2.

To estimate the life cycle carbon intensity for fuels from MSW, this study used the avoided emissions factor of landfill diversion which is based on CARB's pathway on compressed natural gas (CNG) from food scraps and urban landscaping waste, and it included an avoided direct emissions credit of −219 gCO_2e MJ^{-1}.[35,36] This method accounts for all of the carbon in the feedstock, which, in the absence of biofuel production, would be converted to CO_2, CH_4, or remain in the landfill. We assumed that MSW had 80% biogenic and 20% fossil components, resulting in a final carbon intensity value of −204 gCO_2e MJ^{-1} for hydrogen without CCS and −253 gCO_2e MJ^{-1} for hydrogen with CCS.

Results

A comparison based on the IRR shows that FB was the least profitable feedstock option for both hydrogen and gasoline production. Under existing policy, MSW was the most profitable route, followed by ARs. The projects can achieve additional returns with the integration of carbon capture and storage. Figure 3 shows the profitability for each pathway.

Hydrogen

Under the economic assumptions made in this study, all three feedstocks generated a highly positive IRR across technology configurations for hydrogen (Fig. 3). This suggests that hydrogen production would be a financially worthwhile enterprise at scale in CA. The IRR for hydrogen from MSW was higher (37%) than those of ARs (17%) and FB (14%) with carbon capture and storage. This favorable result for MSW was due to its lower life-cycle carbon intensity. Municipal solid waste feedstock can produce extremely low-carbon and carbon-negative fuels, primarily from avoided methane

Table 3. Carbon intensity.

Process configuration	Volume of CO_2 emitted/sequestered tCO_2e/year	CO_2 storage and transport tCO_2e/year	Tonnes abated/year	Carbon intensity $gCO_2e\ MJ^{-1}$
FB hydrogen CCS	–66 300	71 261	108 249	–126.89
AR hydrogen CCS	–78 400	82 820	125 941	–122.57
MSW hydrogen CCS	–93 900	221 876	228 511	–323
FB hydrogen	+12 200	-	42 423	3.1
AR hydrogen	+12 500	-	49 357	7.42
MSW hydrogen	–24 400	-	163 110	–193
FB gasoline CCS	–40 500	13 639	42 473	–38.44
AR gasoline CCS	–48 600	13 219	46 933	–32.34
MSW gasoline CCS	–81.300	110 029	125 820	–253.27
FB gasoline	+10 300	-	29 333	4.39
AR gasoline	+10 300	-	31 740	10.5
MSW gasoline	–39.200		111 096	–204.62

emissions associated with landfilling of waste. This leads to a higher number of tonnes of CO_2 abated per year under the LCFS. Municipal solid waste generated 60% more LCFS credits than FB. Forest biomass also had the highest feedstock cost of $50/BDT compared with $30/BDT for ARs and $-50/BDT tipping fee for MSW, which contributed to high operating costs for FB hydrogen CCS at $10.95 million/year, compared with $10.4 million/year for AR hydrogen CCS and $3.26 million/year for MSW hydrogen CCS.

The amount of CO_2 for transport and storage is the highest in the case of MSW hydrogen CCS; the associated cost for CO_2 transport and storage is more than double for MSW hydrogen CCS ($1.65 million/year) in comparison with AR hydrogen CCS and FB hydrogen CCS at $0.78/year million and 0.7/year million respectively. The fuel income for all three process configurations was roughly the same; however, other sources of revenue including 45Q tax credit for the first 12 years of the plant operations showed that MSW hydrogen CCS had slightly higher 45Q tax credit ($4.7 million/year) than AR hydrogen ($3.92 million/year) and FB hydrogen ChS ($3.32 million/year). The RFS currently does not have RIN pathways for hydrogen; only gasoline production earned additional revenues through RIN credits. Figure 4 shows a breakdown of average annual revenues by category for hydrogen and gasoline produced from FB, with and without carbon capture and storage.

Without CCS, IRR for hydrogen declined significantly although it still remained positive. Without CCS, the internal rate of return for hydrogen from MSW was 25%, compared with ARs (2%) and FB (–1%). Although the capital cost of MSW hydrogen was slightly higher than those of AR hydrogen and FB hydrogen, the operating cost for MSW hydrogen was the lowest ($3.7 m) as MSW hydrogen benefits markedly from the landfill tipping fee of $50/ton. The operating cost for FB hydrogen and AR hydrogen were significantly higher at $9.75 million/year and $9 million/year respectively. Due to the lower life cycle intensity of MSW, MSW hydrogen generated more LCFS credits than AR hydrogen and FB hydrogen.

Gasoline

For gasoline production with carbon capture and storage, the comparison showed that MSW yielded the highest IRR of 10%. This was followed by ARs with 4% IRR and FB with 2%. The capital costs of producing gasoline from the three feedstocks are significantly higher than those of hydrogen production. With CCS, the capital costs for gasoline production ranged between $185 million to $201 million, with AR gasoline CCS being the most capital intensive. As in the case of hydrogen, MSW gasoline CCS benefitted from landfill tipping fee of $50/ton, which helped brings the operating cost down to $3.26 million/year, in comparison with $8.7 million/year for AR Gasoline CCS and 9.4 million/year for FB Gasoline CCS. The cost for CO_2 transport and storage was approximately the same for FB gasoline CCS (0.14 million/year) and AR gasoline CCS ($0.13 million/year); however, MSW gasoline CCS had a slightly higher CO_2 transport and storage cost of $1.1 million/year. For the first 12 years of plant life, MSW gasoline CCS earned twice as much 45Q tax credits ($4.07 m/year) as AR gasoline CCS and FB gasoline CCS. The most significant factor that impacted profitability for MSW gasoline CCS was the LCFS credits of $25.16 million/year. Forest biomass gasoline CCS earned 6.37 million/year in LCFS credits and AR gasoline CCS earned $9.39

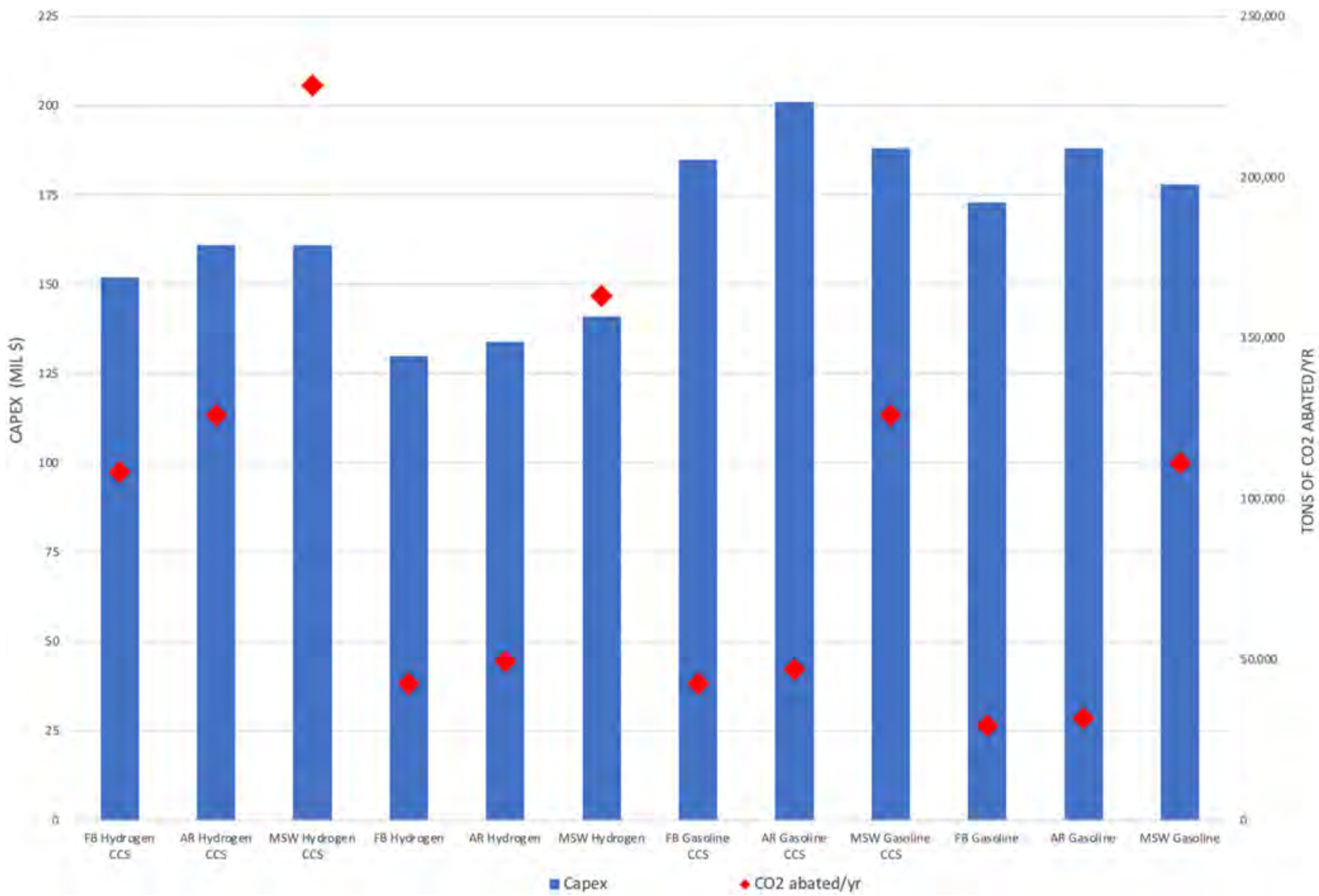

Figure 2. Capex of each process configuration with corresponding CO_2 abated/year.

million/year. On the other hand, MSW earned the lowest RIN credits ($4.65 million/year), in comparison with AR ($11.92 million/year) and FB ($10.35 million/year) (Fig. 4).

When CCS was not integrated, the IRR for the three cases dropped, although it still remained positive. The IRRs for gasoline without carbon capture and storage for forest residues, ARs, and MSW are 1%, 3%, and 9% respectively. These results indicate that the financial benefit of carbon capture and storage from gasoline production was less pronounced than for hydrogen. Gasoline production yielded positive returns across feedstocks but it is not profitable to produce gasoline from FB and ARs in the current policy environment as the IRRs for these two feedstocks did not exceed the discount rate of 10%.

Sensitivity analysis: feedstock and RIN price

A sensitivity analysis was performed on feedstock price of FB and RIN credits. We also ran a sensitivity analysis allowing hydrogen pathways to qualify for RIN credits. With a constant price of hydrogen and gasoline, changing the FB feedstock price from $50/BDT to $80 BDT resulted in decreased IRR for both hydrogen and gasoline. For instance, the IRR for hydrogen dropped from 14% to 11% with CCS. Similarly, the IRR for gasoline dropped from 2% to −1% with CCS. A further increase in the price of FB to $100/BDT led to reduced IRR, yielding negative IRRs for gasoline (Fig. 5). Thus, fuel production from FB was relatively insensitive to feedstock price.

Forest biomass originating from federal lands is currently not eligible for RIN credits, whereas FB originating from private lands can likely qualify for RINs. This is a large issue in CA, as roughly 60% of forests in CA are under federal jurisdiction. Federal lands are also most in need of restoration to reduce fire risk.[37] A sensitivity analysis was conducted on the proportion of FB from private land versus federal land. Five scenarios were evaluated: (1) 100% FB from private lands or 0% from the federal lands; (2) 75% FB from private lands and 25% from federal lands; (3) 50% each from private and federal lands; (4) 25% from private lands and 75% from federal lands; (5) 0% from the private lands or 100% from federal lands (Fig. 6).

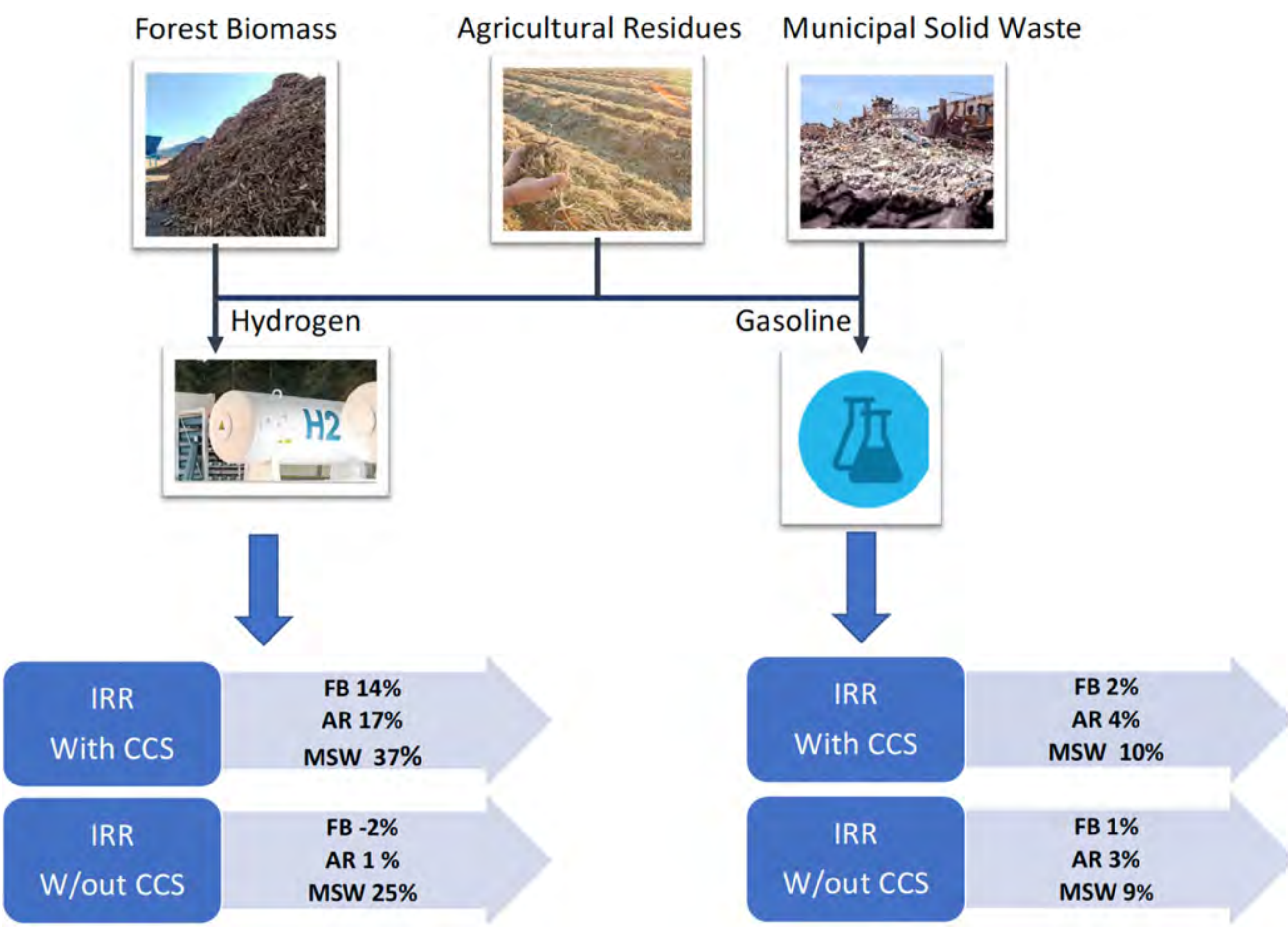

Figure 3. Internal rate of returns for 12 process scenarios.

The IRR dropped precipitously as the proportion of FB from the federal forests increased. However, the IRR remained positive until approximately a 25/75 proportion from federal and private lands is reached. As the proportion of FB from the federal lands increased above 25%, the IRR dropped below zero for all cases except for hydrogen with CCS, indicating a negative return on investment. The IRR for hydrogen with CCS from FB remained above 10% with 75% of the feedstock originating from the private lands. This result points to the need to change the Energy Independence and Security Act's (EISA) definition of 'renewable biomass'. The current biomass definition that qualifies for RIN credits is woody debris that originates '… from non-federal forestland including forestland belonging to an Indian tribe or an Indian individual …'[38] This definition excludes the more than 19 million acres of federal forests in CA that could provide additional FB to produce low-carbon and carbon-negative fuels. A revised biomass definition can allow production RIN credits to low-carbon and carbon-negative fuels derived from both private and federal lands. This would expand the amount of FB that qualifies for RIN credits, thereby offering a pathway to decarbonization and promoting the commercialization of forest-to-fuels pathways.

Discussion

In this study a techno-economic assessment of hydrogen and gasoline from FB, AR, and MSW was conducted. A wide range of factors impacted the overall cost of producing hydrogen and gasoline from biomass. These factors included delivered feedstock cost, capital costs, operation and maintenance costs, and costs associated with integration of carbon capture and storage. These costs varied with the feedstock type and whether or not CCS was integrated. We did not include uncertainty in the systems we were dealing with in this study with respect to costs and yields, which may vary widely, as point estimates generally exist in the literature.

This analysis indicated that forests-to-fuels pathways were the least competitive but changes to supportive policies could allow similar returns between FBs and biofuels derived from ARs or MSW. Five potential policy interventions to support

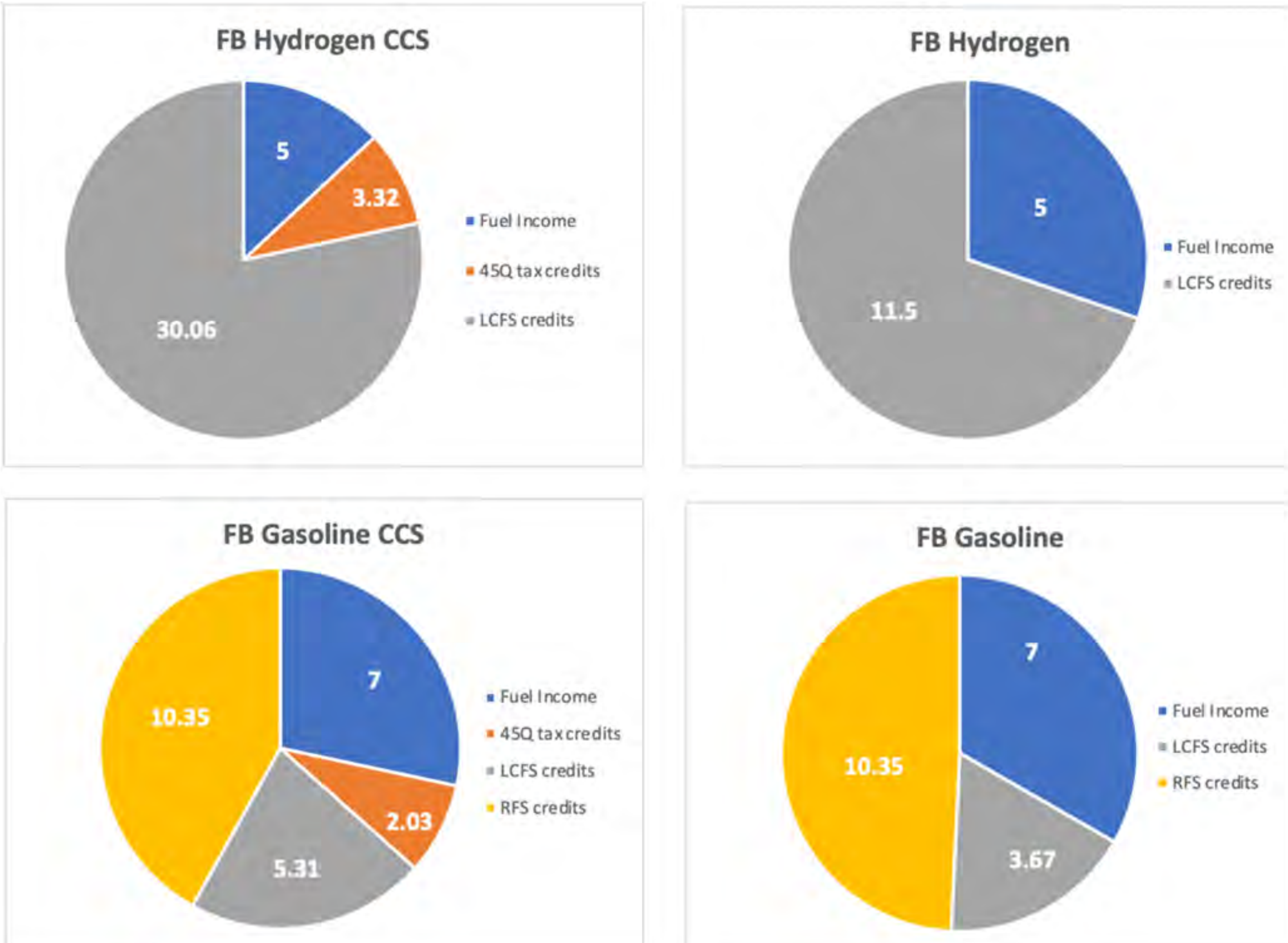

Figure 4. Average annual revenues for hydrogen and gasoline from forest biomass (million $).

forest residue conversion to fuels in CA have been discussed. These interventions include: (i) adjustments to the LCFS credit price for forest fuels; (ii) adjustments to the carbon intensity (CI) of forest fuels; (iii) concessionary finance from the state; (iv) a subsidy for capital costs, and (v) a subsidy for feedstock delivery. Table 4 shows the range of policy interventions necessary for each of these five options to make FB competitive with ARs. C could also implement a mixture of these policies to achieve the same goal.

Low carbon fuel standard credits credit price

Low carbon fuel standard credits played a vital role in the profitability of biofuels pathways in CA. At the assumed price of $125 per ton abated, FB remained a financially weaker option than ARs or MSW. This was particularly true because of avoided methane emissions for MSW. Adjusting LCFS credit price for forest-biofuels could increase their profitability. This study's analysis for hydrogen shows that at LCFS credit price of $166.5/t$CO_2$e, FB would become competitive with ARs with CCS, and $180/t$CO_2$e it would be competitive without CCS. For gasoline, an LCFS credit price of $186/t$CO_2$e would make FB competitive with AR with CCS, and $200/t$CO_2$e without carbon capture and storage. When considering a LCFS credit value of $125/t$CO_2$e, additional LCFS credit price support ranges from $41–75 t/$CO_2$e. It is important to note that, at present, there is no mechanism for CARB to adjust LCFS prices intentionally for a given fuel.

Carbon intensity score

The CI score of MSW benefits from avoided direct emissions when calculating the CI. A similar full life cycle assessment to properly account for the GHG benefits provided by fuels derived from forest resides, as discussed in Sanchez *et al.*, could improve the carbon intensity of these fuels.[39] In this study, the avoided methane credit

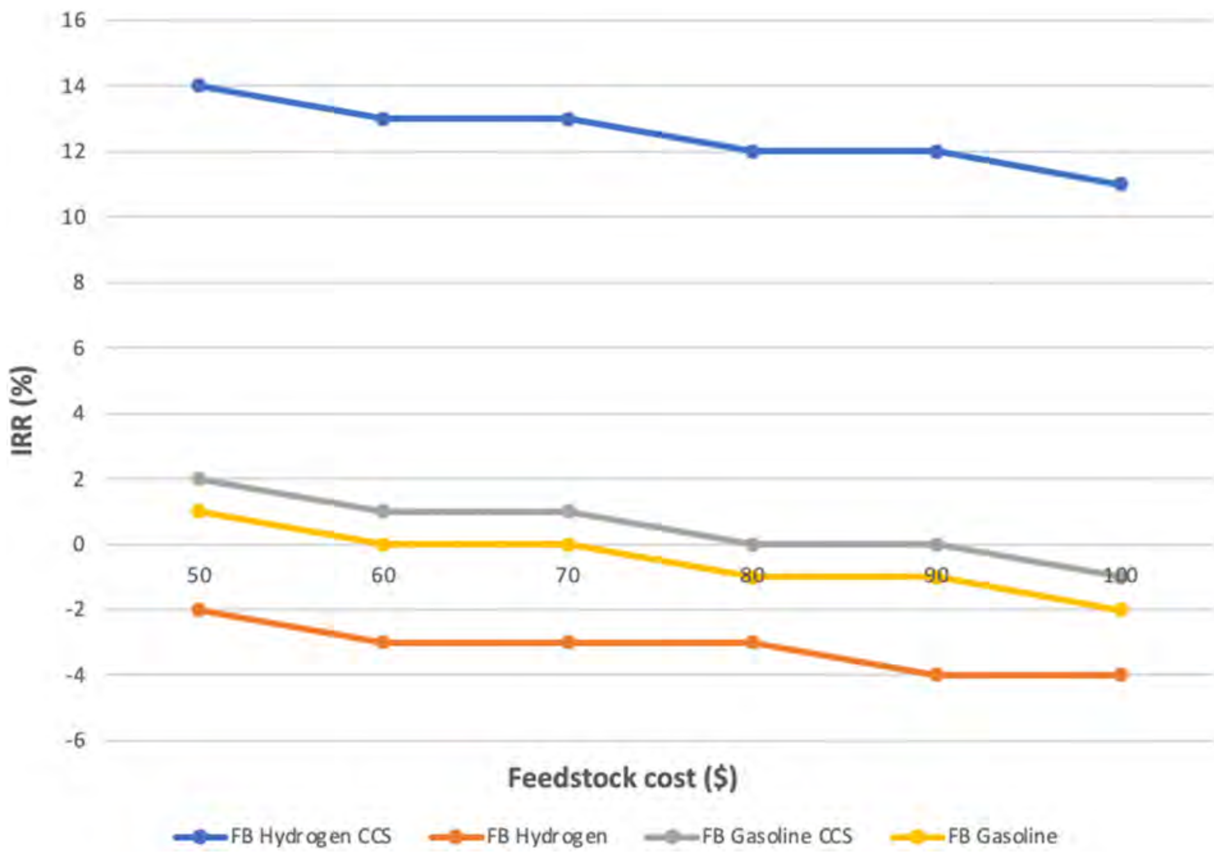

Figure 5. Sensitivity analysis: internal rate of return versus feedstock cost.

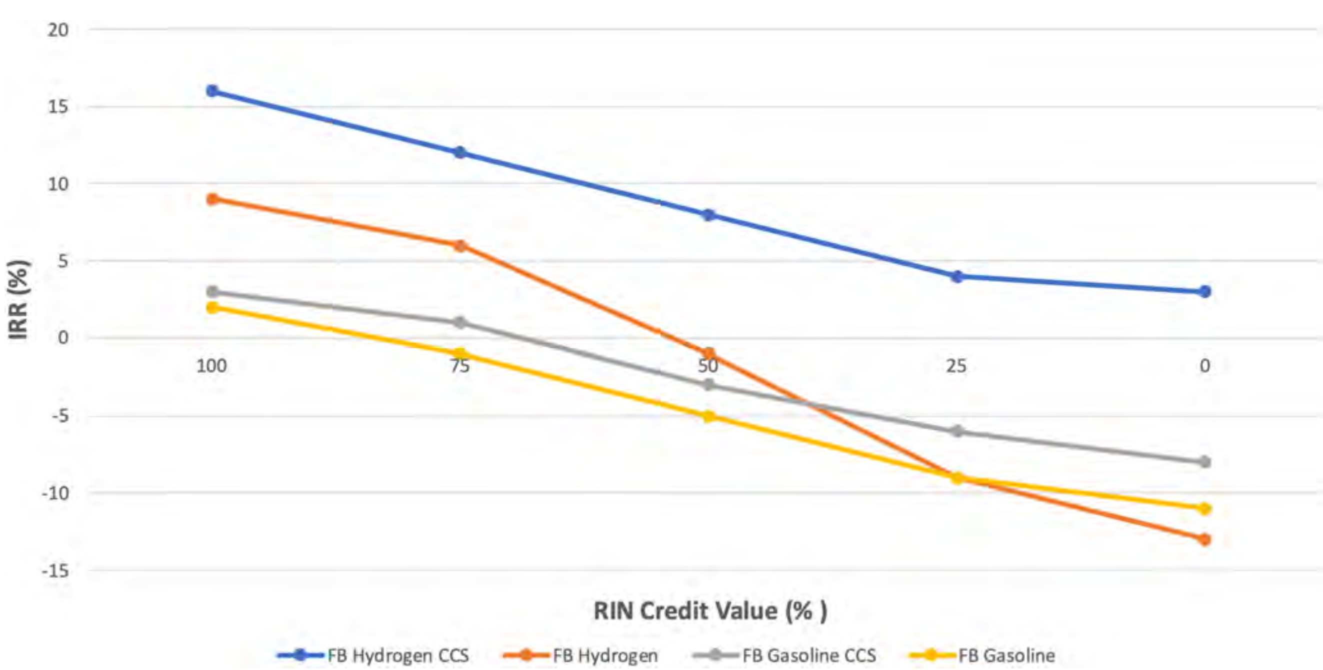

Figure 6. Sensitivity analysis internal rate of return versus renewable identification number price.

Table 4. Range of policy interventions to support forest biomass conversion to fuels.

Policy area	FB hydrogen CCS (initial values)	FB hydrogen w/o CCS (initial values)	FB gasoline CCS (initial values)	FB gasoline w/o CCS (initial values)	Range of policy intervention
LCFS credit ($/t$CO_2$e)	166.5 (125)	180 (125)	186 (125)	200 (125)	41 to 75
CI score (gCO_2e MJ^{-1})	−155.4 (−127)	−16.2 (3.1)	−114 (−38)	−51.4 (4.4)	−19 to −76
Concessionary finance (WACC%)	7 (10)	6 (10)	6 (10)	7 (10)	3 to 4
Capex subsidy (million $)	135 (152)	102 (130)	152 (185)	150 (173)	17 to 33
Feedstock subsidy ($/BDT)	−16 (50)	3 (50)	7 (50)	15 (50)	35 to 66

played a major role in delivering the low CI scores that provided a significant share of revenue for MSW pathways under the LCFS. Avoided methane credits depend on the elimination of fugitive methane being additional to the status quo. The LCFS bases its treatment of additionality on CA state law or policy, even when fuels are produced outside of CA. Only the GHG emissions reductions that exceed any GHG emissions reductions required by the regulation would be eligible for either compliance offset credits or a CI that reflects avoided methane emissions for the purpose of generating LCFS credits. Hence, where state policy such as the Short-Lived Climate Pollution Reduction Strategy (SLCP Strategy) requires organic waste diversion or alternative management of AR, those avoided methane credits may no longer be available and the CI score would increase exponentially, resulting in reduced IRR for MSW.

The analysis for hydrogen shows that, with a CI score of −155.4 gCO_2e MJ^{-1} (initial = −127 gCO_2e MJ^{-1}), FB would become competitive with ARs with CCS, and −16.2 gCO_2e MJ^{-1} without CCS (initial = 3.1). For gasoline, a CI score of −114 gCO_2e MJ^{-1} (initial = −38) would make FB competitive with ARs with CCS, and −51.4 gCO_2e MJ^{-1} (initial = 4.4) without carbon capture and storage. When considering the initial CI scores of forest-to-fuel pathways, the range of necessary additional CI decrease is 19–76 gCO_2e MJ^{-1}.

Concessionary finance

California can play an important role by providing concessionary finance in the early stages of deployment, leveraging private capital to achieve scale. This support can take the form of loans, equity investments, or other credit subsidies. We found that, for hydrogen production, FB became competitive with ARs at 7% and 6% (WACC) with and without carbon capture and storage, respectively. For gasoline production, there was a 6% WACC with CSS, and a 7% WACC without CCS. When considering the initial WACC of 10%, the range of concessionary debt or equity was 3–4%. In the discounted cash flow analysis, this study assumed a mix of 50% debt and 50% equity. However, the additional debt will impact both the equity and debt investors because additional leverage make its riskier for equity investors. In other words, as the total debt percentage increases, the interest rate on the debt also increases as the lenders will demand higher rate of interest because of higher risk. As a result, the cost of debt and the cost of equity both increased due to changes in the capital structure and therefore the WACC also increased.

Capital cost subsidy

To improve financial outcomes for forest fuel production systems, the state could provide grants for systems located in CA. The analysis shows that, for hydrogen production, a capital cost of $135 million (initially $152 million) allowed FB to deliver the same IRR as ARs with carbon capture, and $102 million (initial = $130 million) without CCS. For gasoline, a capital cost of $152 million (initial = $185 million) made FB competitive with carbon capture, and $150 million (initial = $173) without carbon capture. As a percentage of base capital costs, necessary capital cost subsidies ranged between 12–22%.

Feedstock subsidy

Forest biomass faces direct competition from other biogenic feedstock, notably from ARs, for biofuel production. Competition may be increased through the introduction of new regulations that restrict or completely phase out agricultural burning. In addition, due to their proximity to urban centers, ARs are relatively easier to mobilize than forest residues, which are heterogeneous and need to be transported to a centralized infrastructure for conversion. Production costs of biofuels depend on

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the feedstock cost. Forest biomass was roughly 60% more expensive than AR in the base case. This reduced the profitability of forest-to-fuel pathways. One potential policy intervention is a feedstock subsidy. The analysis shows that for hydrogen production, a feedstock price of $-16 per dry ton allowed FB to deliver the same IRR as ARs with CCS, and a price of $3 allowed this without CCS. For gasoline, a feedstock price of $7 per dry ton made FB competitive with ARs with CCS, and $15 without CCS. When including the assumed cost of biomass of $50 per dry tonne, subsidies from the state would need to range from $35–66 per dry tonne.

Conclusion

The development of low-carbon or carbon negative fuels can play a vital role in realizing CA's climate change mitigation goals. The hydrogen and gasoline required to meet the LCFS can be produced within CA using a variety of feedstocks. In this study, 12 process configurations for producing hydrogen and gasoline from FB, agriculture residues and MSW were evaluated. The study found that MSW had the highest IRR for hydrogen and gasoline production, followed by ARs and FB. The integration of CCS yields additional benefits for all feedstock types. Possible interventions to support forest fuels include modifications to the LCFS, providing concessionary debt or equity, subsidizing capital costs, or subsidizing FB delivery. The CI scores that form the basis for this analysis were significantly different from the most analogous CI pathways from the LCFS, particularly for MSW, due to avoided methane credits. Previous research estimated GHG emissions of most of the scenarios at approximately 45–60 g carbon dioxide equivalent per MJ of delivered fuel (g CO_2e MJ^{-1}) without credit for coproducts, and 20–30 g CO_2e MJ^{-1} when co-products are considered.[40] In the absence of avoided methane credit, the profitability of producing these fuels will change significantly as higher CI scores will result in decreased IRRs.

To ensure FB to fuel pathways are cost competitive with ARs, CA could increase the LCFS credit price for forest fuels (an additional credit price support of \$41–75 t/CO_2e), give additional credit to the reduction of life cycle emissions from forest fuels (an additional CI decrease of 19–76 gCO_2e MJ^{-1}), provide concessionary debt or equity (target WACC = 3–4%), subsidize capital costs (12–22% of costs), or subsidize FB delivery (\$35–66 per dry ton delivered).

Increasing the price of FB would reduce the profitability, although the IRR remained positive at \$80/BDT as well as \$100/BDT for hydrogen with CCS. For all other scenarios, the IRR for FB became negative, reflecting the need for further policy interventions. There are a number of uncertainties, such as the ability to obtain long-term feedstock supply that must be addressed for further market development of forest biofuels in the state. This is a risk from the perspective of project developers, so a strong IRR is necessary, especially for first-of-a-kind facilities. In the case of RIN credits, as the proportion of FB from federal lands increases, profitability declines significantly. At a maximum, a 50/50 ratio of public to private lands for FB can maintain profitability. Based on this finding, CA may need to seek changes to federal law as it scales up a FB-to-fuels industry.

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SOUTHERN CALIFORNIA GENERATION COALITION
COMMENT ON ANGELES LINK PHASE I
DRAFT PRODUCTION PLANNING & ASSESSMENT

August 21, 2024

Submitted via Email to:
ALP1_STUDY_PAG_FEEDBACK@INSIGNIAENV.COM

The Southern California Generation Coalition ("SCGC") respectfully comments on the draft Angeles Link Phase 1 Production & Planning Assessment ("Draft Production Assessment") posted by the Southern California Gas Company ("SoCalGas") in the Angeles Link Living Library on July 19, 2024.

I. INTRODUCTION AND SUMMARY

The Draft Production Assessment provides the most comprehensive assessment so far of the potential for storing hydrogen in what SoCalGas calls the Area of Interest ("AOI") for Angeles Link. The AOI is an area encompassing the SoCalGas and SDG&E service territories in California plus the states of Nevada, Utah, and Arizona.[1] SoCalGas projects a significant level of power sector demand for hydrogen transported through Angeles Link, but storage would be essential for the power plants. However, storage is not included in planning for Angeles Link currently.

The Draft Production Assessment indicates that the best option for storage for the power sector would be underground hydrogen storage ("UHS") near power sector demand. For the reasons discussed below, UHS to serve Angeles Link power sector demand should be included in Angeles Link studies.

[1] Draft Production Study, p. 87.

II. POWER SECTOR DEMAND.

SoCalGas projects significant power sector demand for hydrogen transported through Angeles Link. In the Draft Production Assessment, SoCalGas says that in 2045 the power sector is expected to make up 45 percent of demand in the ambitious case for Angeles Link throughput, 51 percent of demand in the moderate case, and 38 percent in the conservative case.[2] However, SoCalGas projects that the power sector demand will have only a 15 percent capacity factor.[3] SoCalGas also observes that hydrogen supply to the power sector will need to ramp quickly to make up for power loss as wind and solar resources go offline.[4]

Storage will be essential to provide for the projected power sector ramp requirements. Storage will also be essential to enable utilization of upstream Angeles Link capacity at a high enough load factor to make the capacity economic. Nevertheless, SoCalGas says that hydrogen storage is not currently part of Angeles Link.[5]

III. THE DRAFT PRODUCTION ASSESSMENT INDICATES THAT UHS NEAR POWER SECTOR DEMAND IS THE BEST STORAGE OPTION.

The Draft Production Assessment says that storage could be provided in various ways, including line pack, construction of a parallel pipeline on portions of the pipeline system, on-site storage by upstream hydrogen producers or downstream hydrogen end users, and dedicated aboveground or underground storage.[6] However, the Draft Production Assessment states that while aboveground hydrogen storage is technically viable, storing hydrogen above ground comes with significant costs at limited capacities which makes it "challenging to use as a means of steadying the energy production from renewable sources at large volumes in a centralized

[2] *Ibid*, p. 37.

[3] *Ibid*, p. 35.

[4] *Ibid.*

[5] *Ibid*, p. 36.

[6] *Ibid*, p. 36.

location."[7] Thus, the Draft Production Assessment indicates that the preferable option for the power sector is UHS which is as proximate as possible to downstream power sector demand.

IV. THE DRAFT PRODUCTION ASSESSMENT INDICATES THAT UHS COULD SERVE THE POWER SECTOR.

The Draft Production Assessment says that a total of 297 oil and gas fields and six salt basins were evaluated within the four-state AOI.[8] The Draft Production Assessment also says that depleted reservoirs in oil and gas fields offer the most economical options.[9] At least two currently undeveloped fields that have a geologic confidence of adequacy greater than fifty percent are located in the Los Angeles Basin.[10]

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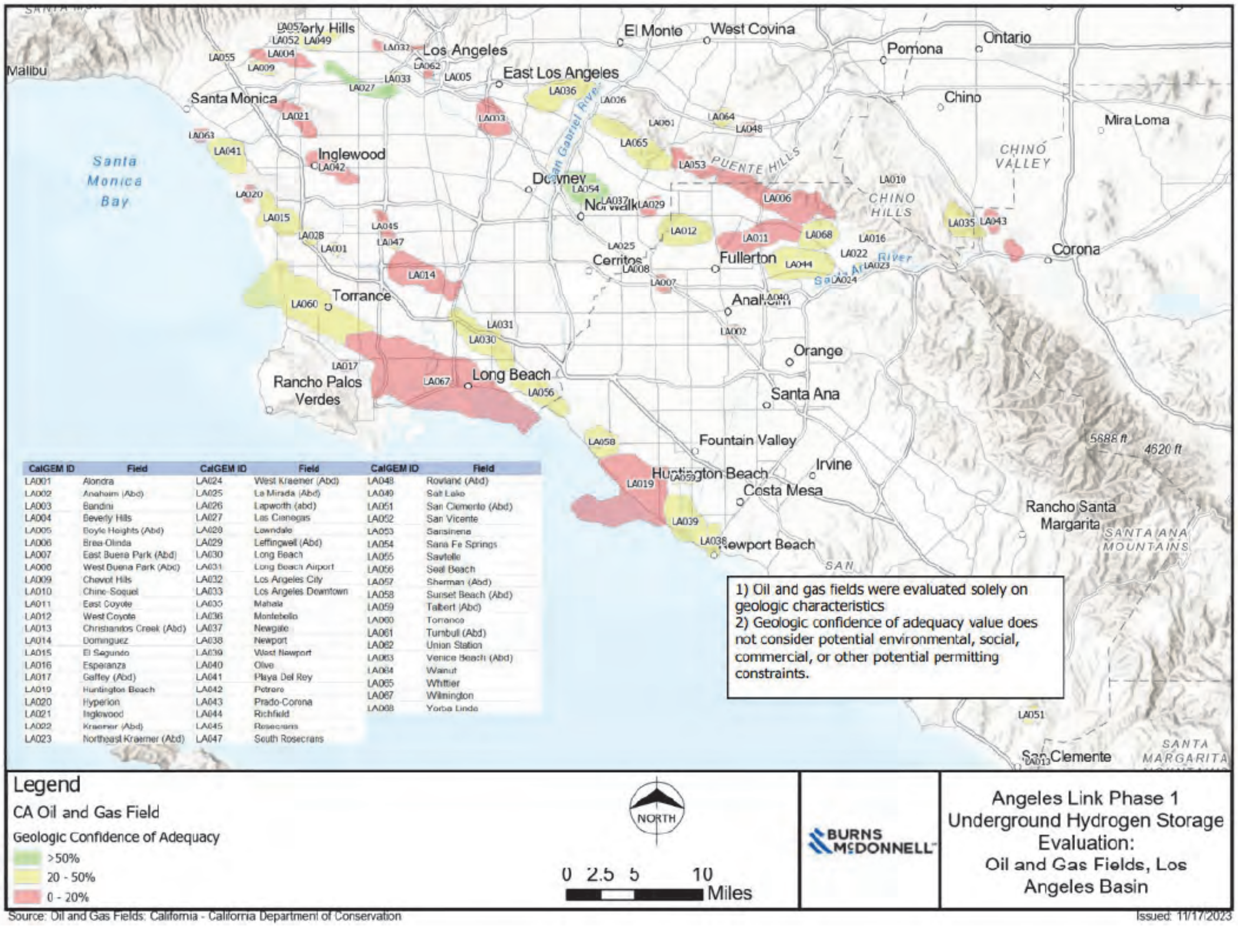
[7] *Ibid*, p. 40.

[8] *Ibid*, p. 73.

[9] *Ibid*, p. 74.

[10] *Ibid*, p. 98.



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Another field that should be considered is Honor Rancho. It is located adjacent to the route of Angeles Link from the San Joaquin Valley to Santa Clarita. Although SoCalGas currently operates a natural gas storage facility at Honor Rancho, there may be unutilized strata which are not connected to natural gas storage strata but which are sufficiently porous and permeable to be used to store hydrogen.

SoCalGas says without explanation, "While existing SoCalGas facilities were evaluated for geologic adequacy because they are located within the study area, they are not currently

[11] *Ibid.*.

being considered as storage options for Angeles Link."[12] Honor Rancho should be considered if it is geologically adequate.

The California Energy Commission ("CEC") is funding a study to evaluate the feasibility of using existing underground storage facilities to store clean renewable hydrogen in California.[13] At the CEC's April 17, 2024 Pre-Application Workshop, the CEC summarized the purpose of it solicitation as follows: "Fund a project that will evaluate the technical and economic feasibility of using existing underground gas storage to store clean renewable hydrogen in California."[14] The CEC study should include Honor Rancho.

SoCalGas observes that even though there are no currently permitted examples of UHS in depleted oil and gas reservoirs,[15] "these structures have held an accumulation of hydrocarbons under significant pressure for millions of years, suggesting that they may likely be capable of containing other gases such as hydrogen…."[16]

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[12] *Ibid*, p. 40, footnote 44.

[13] *Ibid*, p. 40.

[14] GFO-23-503, Feasibility of Underground Hydrogen Storage in California, Pre-Application Workshop, p. 11 (April 17, 2024)

[15] *Ibid*, p. 77

[16] Draft Production Assessment, p. 84.

V. CONCLUSION

UHS which would make Angeles Link operationally and economically viable to serve low load factor power sector demand should be included in the Angeles Link hydrogen transportation studies so that Angeles Link will have the potential to be useful for the power sector.

Respectively submitted,

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Dated: August 21, 2024

SOUTHERN CALIFORNIA GENERATION COALITION
COMMENT ON ANGELES LINK PHASE I
DRAFT PRELIMINARY ROUTING/CONFIGURATION ANALYSIS

August 21, 2024

Submitted via Email to:
ALP1_STUDY_PAG_FEEDBACK@INSIGNIAENV.COM

The Southern California Generation Coalition ("SCGC") respectfully comments on the draft Angeles Link Phase 1 Preliminary Routing/Configuration Analysis ("Draft Routing Analysis") posted by the Southern California Gas Company ("SoCalGas") in the Angeles Link Living Library on July 19, 2024.

I. Introduction and Summary.

SoCalGas says that the Draft Routing Analysis is "Preliminary" and "was conducted at a high level" to identify "broad directional pathways with the highest potential for achieving the purpose of the Angeles Link Pipeline System."[1] The selection of a single preferred route would be left to Application ("A.") 22-02-007 Phase 2 in which SoCalGas will prepare a Front End Engineering and Design ("FEED") for the Angeles Link Pipeline.[2] Thus, the Phase 1 Draft Routing Analysis posted on July 19, 2024, presents the options that are to be narrowed to one preferred route in Phase 2.

The Draft Routing Analysis presents Preferred Routes A, B, C, and D leading from production areas in the San Joaquin Valley and near Lancaster to demand in what SoCalGas calls the "Central Zone" in Los Angeles County, the region shaded in yellow on the maps below that generally lies south of Century Boulevard and west of I-605:

[1] Draft Routing Analysis, p. 5.

[2] *Ibid.*

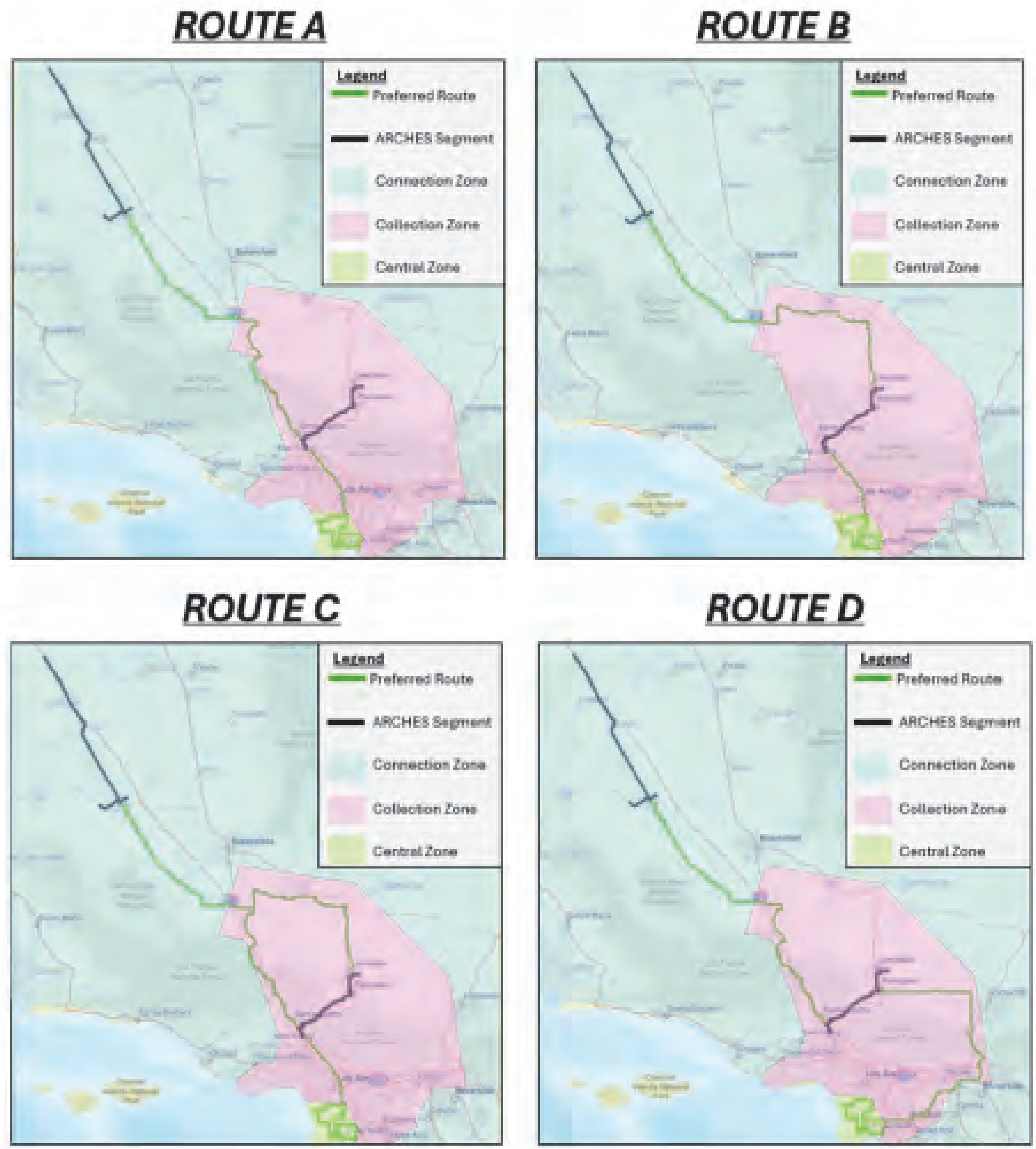

Figure 23. Preferred Route Configurations with Zones

[3]

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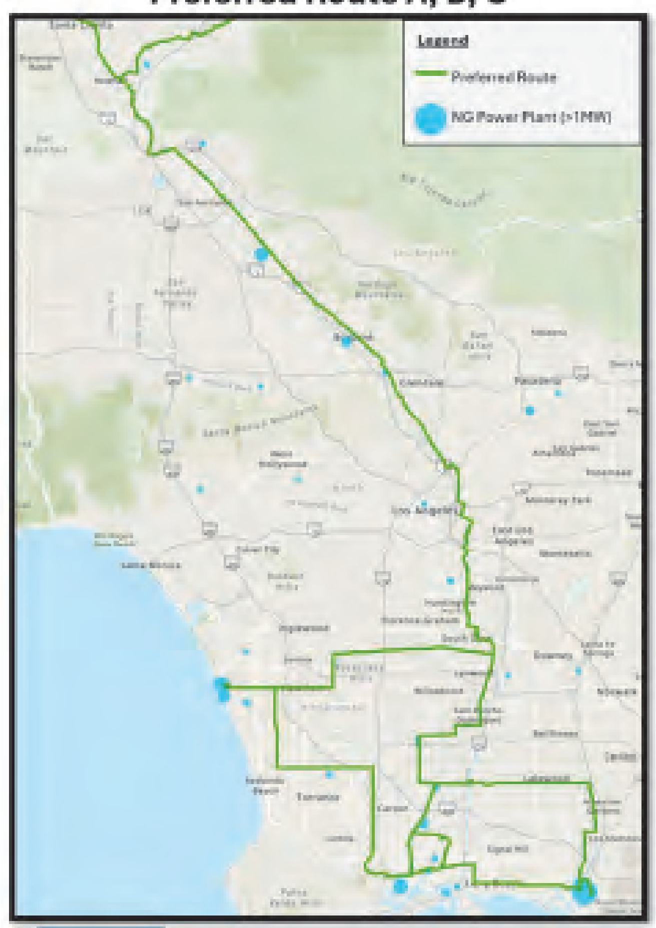
[3] Draft Routing Analysis, p. 43.

SoCalGas should narrow its Phase 2 analysis to Routes A, B, and C and should discard Route D. As discussed below, Route D would fail to serve potential load that would be served by the common segment of Routes A, B, and C, which would extend from near the I-5/I-210 interchange through San Fernando, Burbank, and Glendale, to Los Angeles and then to South Gate:

Preferred Route A, B, C



[4]

SCGC also discourages any further consideration in Phase 2 of what SoCalGas labels "Route Variation 1." Variation 1 would generally follow the I-405 freeway from the I-5/I-405 interchange south to Inglewood, bypassing the eastern San Fernando Valley:

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[4] *Ibid*, p. 61.

[5]

The common segment of Routes A, B, and C through the eastern San Fernando Valley is close to important potential offtake facilities and passes through more level terrain than Variation 1.[6] Angeles Link Routes A, B, or C are superior to both Route D and Variation 1.

II. Route D Would Fail to Serve Major Potential Offtake Sites in Eastern San Fernando Valley and Would Be Longer, Less Level, and More Costly than Routes A, B, and C.

Instead of following I-5 south from Santa Clarita through the San Francisco Valley to Los Angeles and then to South Gate, Route D would bypass the San Fernando Valley entirely by running east from Palmdale toward Victorville. Route D would then turn south following I-15 toward Riverside and then would finally turn southwest to serve demand:

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[5] *Ibid*, p. 58.

[6] *Ibid*, pp. 60-61.

Figure 35. Preferred Route D Map [7]

The best that can be said for Route D is that it would potentially serve more offtake sites that were identified by the Alliance for Renewable Clean Hydrogen Energy Systems ("ARCHES") than Routes A, B, and C:

Table 5. Preferred Route Specific Characterization Comparison

	Route Configuration			
Characterization	A	B	C	D
ARCHES Production Sites	5	5	5	7
ARCHES Offtake Sites	8	8	9	15
Demand Access, %	83%	83%	83%	92%

[8]

However, as can be seen from Table 5, in spite of the number of ARCHES offtake sites increasing from eight or nine for Routes A, B, and C, to fifteen for Route D, demand access only

[7] *Ibid*, p. 58.

[8] *Ibid*, p. 51.

increases by nine percentage points for Route D. Important potential offtake sites in the eastern San Fernando Valley would be left completely unserved under Route D. Additionally, Route D would be longer than Preferred Routes A, B, and C, would be less level, and would cost substantially more than Preferred Routes A, B, and C.

A. Route D Would Leave Important Potential Power Plant Demand Unserved.

SoCalGas says that in its evaluation presented in the Draft Routing Analysis, the "focus was placed on corridors that reside in close proximity to the potential demand sectors for Angeles Link to connect with demand…."[9] However, Route D would leave important power plant demand unserved. Routes A, B, and C would follow a common route through the San Fernando Valley, resulting in all three routes being close to the 576-megawatt Valley Generating Station and the 323-megawatt Magnolia Power Project. Other potential power plant off-take lies east of Routes A, B, and C near the California 134 Freeway, including the Pasadena Water and Power Glenarm power plant.

SoCalGas observes in the Draft Angeles Link Demand Report ("Draft Demand Report") posted on January 17, 2024, that "we do not expect to see total dispatchable capacity requirements to decline significantly from the capacity in place today in SoCalGas' service territory."[10] Instead, there will be a need for approximately nine incremental gigawatts of hydrogen combustion turbine generation by 2045.[11] Thus, the power plants that Routes A, B. and C could serve but which would be left unserved by Route D are likely to be needed in 2045 as well as today.

[9] *Ibid*, p. 18.

[10] Draft Demand Report, p. 52.

[11] *Ibid*, p. 44; California Air Resources Board, 2022 Scoping Plan for Achieving Carbon Neutrality, p. 203, Figure 4-5, "Projected New Electricity Resources Needed by 2045 in the Scoping Plan Scenario."

B. Route D Would Leave Important Potential Mobility Demand Unserved.

Route D would also fail to serve potential mobility demand along or proximate to the I-5 corridor through Los Angeles. Additional demand along I-5 that could be served from Routes A, B, or C but not Route D could arise from high Heavy Duty Vehicle ("HDV") demand along the I-5 truck corridor. SoCalGas expects that "fleet operators will look for diesel replacements that can operate as similarly as possible to diesel trucks today (short refueling times, long range, and a distributed fueling network)."[12] Thus, the HDV demand that would be likely along the corridor served by Routes A, B, and C but left unserved by Route D would be about the same if not more than the current demand for diesel fuel along the corridor.

There are additional potential points of mobility demand along the I-5 corridor that Routes A, B, or C could serve but which would be stranded by Route D. The common segment of Routes A. B, and C is proximate to Hollywood-Burbank Airport. SoCalGas recognizes that there is a "high degree of uncertainty" about the demand for hydrogen from the aviation sector, but SoCalGas's Ambitious Demand Scenario includes aviation demand for clean hydrogen in 2045.[13]

Routes A, B, and C also would be proximate to Union Station in Los Angeles, and they would be proximate to Union Pacific's Los Angeles Transportation Center ("LATC") Intermodal Terminal. Trains and HDVs converge at the Terminal, potentially presenting additional offtake for Angeles Link. Route D would bypass Union Station and the LATC Intermodal Terminal.

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[12] Draft Demand Report, p. 17.

[13] *Ibid*, p. 32.

C. Route D Would Be Longer than Routes A, B, and C.

Out of the four preferred routes identified in the Draft Routing Analysis, Route D would be the longest at 481 miles.[14] Route A would have the shortest length, 390 miles,[15] and Route B would be the next shortest at 406 miles.[16] Route C would be 472 miles long,[17] but it would cost approximately the same as the shortest route, Route A.[18] The loop in Route C north of Santa Clarita would allow for flow splitting, a lower pressure drop, and smaller diameter--hence less costly--pipes in the downstream Angeles Link Central Zone as compared to the downstream pipe diameters required in the Central Zone for Routes A and B.[19]

Route D, by contrast, would be lengthy at 481 miles, 91 miles longer than Route A and 75 miles longer than Route B, and Route D would not have the cost-reducing hydraulic advantages of Route C.[20]

D. The Route for Route D Would Be More Mountainous than the Route for Routes A, B, and C.

Route D would be more mountainous than Routes A, B, and C, increasing Route D's cost. All four preferred routes would incur the cost of traversing the Tejon Pass along I-5, 4,160 feet in elevation. However, Route D would have an added disadvantage. After traversing the Tejon Pass, Route D would backtrack to Victorville and then turn south to traverse the Cajon Pass, 3,776 feet in elevation, along I-15. Thus, Route D presents the disadvantage of traversing both of the major mountain passes into the Los Angeles load center rather than just one.

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[14] Draft Routing Analysis, p. 58.

[15] *Ibid*, p. 55.

[16] *Ibid*, p. 56.

[17] *Ibid*, p. 57.

[18] Draft Pipeline Sizing Criteria, p. 56.

[19] *Ibid*, p. 36.

[20] Draft Routing Report, p. 58.

E. Route D Would Cost More than Routes A, B, and C.

SoCalGas projects that Route D would cost more than Routes A, B, or C. In the Draft Angeles Link Phase I Pipeline Sizing & Design Criteria Report ("Draft Pipeline Sizing Report") posted on July 19, 2024, SoCalGas presented its Class 5 estimates for Routes A, B, C, and D:

Table 18 - Preferred Route Single-Run Configuration Cost Estimate Summary

Single-Run Configuration	Installed Pipe, miles	Pipe Sizes, inches	Approx Total Pipeline Cost*	No. of Compressor Station(s)	Approx Total Compressor Cost*	Approx Total Cost* (CapEx)
Route A	390	16", 20", 24", 30", 36"	$6 B	2 @ 50,000 hp (each)	$3 B	$9 B
Route B	406	20", 36"	$7 B	2 @ 50,000 hp (each)	$3 B	$10 B
Route C	472	20", 24", 30", 36"	$6B	2 @ 50,000 hp (each)	$3 B	$9 B
Route D	481	24", 36"	$8 B	2 @ 50,000 hp (each)	$3 B	$11 B

[21]

Route D would have a total Class 5 estimated cost that would be $2 billion more than either Route A or Route C. Thus, Route D represents a 22 percent higher cost in order to serve only nine percent more offtake, according to SoCalGas' Draft Routing Analysis.[22] SoCalGas does not explain why it estimates that Route D would cost 22 percent more than either Routes A or C. However, the longer length of Route D plus the need to traverse the Cajon Pass as well as the Tejon Pass to reach the Los Angeles Basin likely provide much of the explanation.

If Route D is to be considered at all, only the southern-most portion should be considered as a future expansion of the Angeles Link pipeline from the Central Zone to the Inland Empire.

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[21] Draft Pipeline Sizing Criteria, p. 56. Cost based on Class 5 estimates, which have accuracy ranges of 20% to 50% on the low side, and +30% to +100% on the high side.

[22] Draft Routing Analysis, p. 51, Table 5.

III. Variation 1 Is Even Worse than Route D.

SoCalGas's Variation 1 is even worse than Route D. In addition to leaving unserved the nine percent additional offtake that SoCalGas says would be served by Route D, Variation 1 would leave unserved the entire demand in the eastern San Fernando Valley. SoCalGas does not quantify the amount of offtake that would be left unserved in the eastern San Fernando Valley, but it clearly would be substantial.

The purpose of constructing Angeles Link is to provide clean hydrogen from points of production in the San Joaquin Valley and in the Lancaster area to points of demand. By failing to serve both the offtake that would be served by Route D and the offtake in the eastern San Fernando Valley, Variation 1 would fail to meet the most fundamental objective of constructing Angeles Link, providing clean hydrogen to points of demand.

The ostensible reason for Variation 1 is to avoid disadvantaged communities. SoCalGas presents the following Figure 26 in an attempt to make the case for Variation 1:

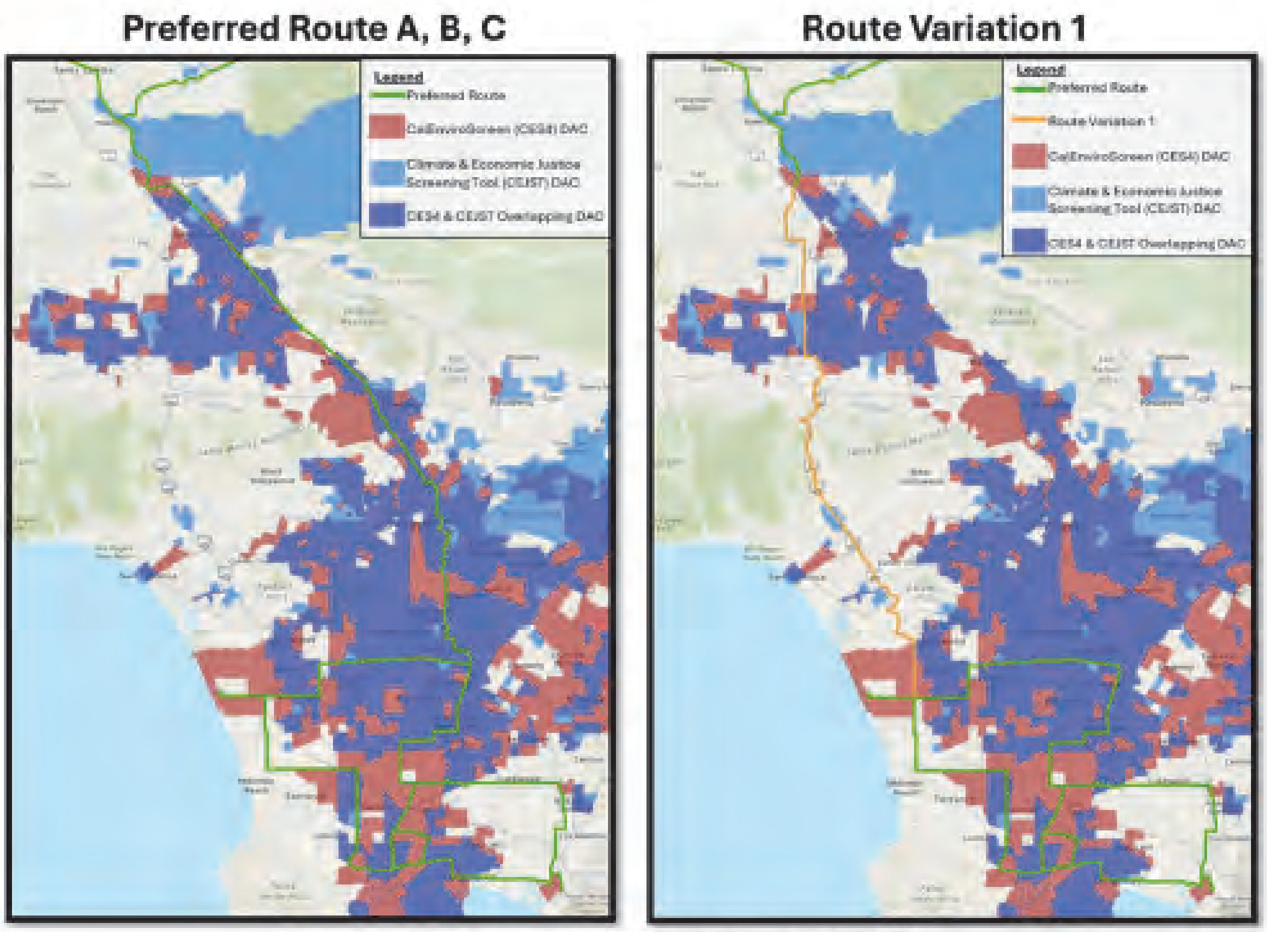

Figure 26. Illustration of Route Variation 1 and DAC[43]

[23]

However, pipelines differ from above-ground structures. Pipelines are underground. Except during the time of construction, pipelines are out of sight. Additionally, given the current stringent Pipeline and Hazardous Materials Safety Administration and California Public Utilities Commission safety requirements for operating gas pipelines, safety concerns are low for all communities including disadvantaged communities.

For the common segment of routes A, B, and C that would be eliminated by Route D and Variation 1, the route is predominently through rights of way that are predominantly if not completely commercial or industrial. Much of the route is under San Fernando Road in the San

[23] Draft Routing Analysis, p. 47.

Fernando Valley. Variation 1 is ostensibly presented to avoid disadvantaged communites, but in addition to being underground and, thus, out of sight, the rights of way avoid neigborhoods.

SoCalGas does not present cost estimates for Variation 1, but it is reasonable to assume that Variation 1 would have increased costs in comparison to Routes A, B, and C, given that the pipeline would have to traverse the Sepulveda Pass to deliver gas to the Central Zone in the South Bay region of Los Angeles County.[24] Thus, Variation 1 would supply less demand than Routes A, B, or C while costing more and simultaneously providing little if any tangible benefit for disadvantaged communities in the eastern San Fernando Valley. SoCalGas should not spend further resources on Variation 1 in Phase 2.

IV. Conclusion.

For the reasons discussed above, SCGC urges SoCalGas not to expand further resources on Route D or Variation 1 in Phase 2.

SCGC appreciates this opportunity to comment on the July 19, 2024, Draft Routing Analysis.

Respectively submitted,

/s/ Norman A. Pedersen

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Attorneys for the **SOUTHERN CALIFORNIA GENERATION COALITION**

Dated: August 21, 2024

[24] Draft Routing Study, p. 15.

SOUTHERN CALIFORNIA GENERATION COALITION
COMMENT ON ANGELES LINK PHASE 1
DRAFT PIPELINE SIZING & DESIGN CRITERIA

August 21, 2024

Submitted via Email to:
ALP1_STUDY_PAG_FEEDBACK@INSIGNIAENV.COM

The Southern California Generation Coalition ("SCGC") respectfully comments on the draft Angeles Link Phase 1 Pipeline Sizing & Design Criteria ("Draft Design") posted by the Southern California Gas Company ("SoCalGas") in the Angeles Link Living Library on July 19, 2024.

I. INTRODUCTION AND SUMMARY

The Draft Design presents a Cost Estimate Summary for Preferred Routes A, B, C, and D in Table 18:

Table 18 - Preferred Route Single-Run Configuration Cost Estimate Summary

Single-Run Configuration	Installed Pipe, miles	Pipe Sizes, inches	Approx Total Pipeline Cost*	No. of Compressor Station(s)	Approx Total Compressor Cost*	Approx Total Cost* (CapEx)
Route A	390	16", 20", 24", 30", 36"	$6 B	2 @ 50,000 hp (each)	$3 B	$9 B
Route B	406	20", 36"	$7 B	2 @ 50,000 hp (each)	$3 B	$10 B
Route C	472	20", 24", 30", 36"	$6B	2 @ 50,000 hp (each)	$3 B	$9 B
Route D	481	24", 36"	$8 B	2 @ 50,000 hp (each)	$3 B	$11 B

[1]

The costs presented in Table 18 are based on Class 5 estimates which have accuracy ranges of -20 percent to -50 percent on the low side and +30 percent to +100 percent on the high side.[2]

[1] Draft Design, p. 56.

[2] *Ibid*.

For the reasons discussed in SCGC's August 21, 2024 comment on the Angeles Link Phase 1 Draft Prelimnary Routing/Configuration Analysis ("Draft Routing Analysis"), SoCalGas should not expend further resources on Route D, narrowing the Preferred Routes to Routes A, B, and C.

SCGC urges SoCalGas to refine the Class 5 estimates presented in Table 18 not only to narrow the accuracy ranges but to substantially reduce the projected costs. The costs presented in Table 18 threaten to make Angeles Link uneconomic.

It appears that the Table 18 cost estimates are stated in 2024 dollars. Thus, SCGC attempted to compare today's rate for gas transportation service on the SoCalGas system to what would be today's rate for transportation service on Angeles Link if the pipeline were constructed at the projected capital cost.

For transportation on the SoCalGas system from points of receipt into the SoCalGas system to deliver natural gas for burn, noncore customers such as the SCGC members currently pay the Schedule No. G-BTS rate for Backbone Transmission Service and the Schedule No. G-TLS rate for local transmission service. The current BTS rate for electric generators is \$0.70913/Dth. The TLS rate for electric generators is \$0.8819/Dth (omitting CARB-related adders). The total of the two charges is \$1.59103/Dth.

SCGC's preferred routes as discussed in SCGC's comments on the Draft Routing Analysis are Routes A, B, and C. The total Class 5 estimated cost for both Route A and Route C is \$9 billion. SCGC calculated the rate required to cover the \$9 billion capital component with no additions for operation and maintenance ("O&M") expense or loaders and with no addition for storage. SCGC assumed that the annual first year capital-related revenue requirement would be ten percent of the total \$9 billion Class 5 estimate total, which would translate into a rate for transportation of hydrogen on Angeles Link of \$5.28/Dth, assuming the maximum throughput of

1.5 million tonnes/year.[3] Thus, the hydrogen transportation rate under this simplified scenario is three to four times the current rate for SoCalGas natural gas transportation service. Of course, today's rate for transportion service includes O&M expense and other costs that are not included in the calculation of the capital-only hydrogent transportation rate of $5.28/Dth.

SCGC urges SoCalGas to not only refine its Class 5 estimates but also to be diligent in reducing the cost of Angeles Link transportation service.

Respectively submitted,

/s/ Norman A. Pedersen

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Attorneys for the **SOUTHERN CALIFORNIA GENERATION COALITION**

Dated: August 21, 2024

[3] The heat content of hydrogen (H_2) is 51,623 Btu/lb x 2.2 lb/kg =113,570 Btu/kg. Stating this in MMBtu or Dth, one gets: 113,570 Btu/kg = 0.11357 Dth/kg x 1000 kg/tonne = 113.57 Dth/tonne. If the pipeline delivers 1.5 million tonnes per year and, assuming a $900 million capital related revenue requirement (10% of $9 billion) for the year, the formula is 1.5 x 10^6 tonnes/year x 113.57 Dth/tonne = 170.355 x 10^6 Dth/year

$$\frac{\$900 \times 10^6}{170.355 \times 10^6 \text{ Dth}} = \$5.28/\text{Dth}$$

Utility Workers Union of America (UWUA),
AFL-CIO, Local 483
P.O. Box 2346
Downey, CA 90242

8/27/2024

Comments to PAG Routing Analysis Study/Pipeline Sizing and Design

My name is Ernest Shaw, and I am President of the Utility Workers Union of America, Local 483 AFL-CIO (UWUA 483) in Southern California. Since 1970, UWUA Local 483 has served as the collective bargaining representative for the workforce that is responsible for transportation and storage of gas and all molecules that pass through SoCalGas' pipelines. We are also responsible for the safety, preventative maintenance, and repair of all SoCalGas gas transmission lines and certain distribution high-pressure supply lines. Local 483's members consistently patrol all of its pipelines daily/monthly/quarterly/semi-annually/annually, via-damage prevention, locate and mark, high pressure standby's, class location survey, special leak survey, leak survey, aerial leak survey, leak survey by boat, internal line inspection (pigging), valve inspections, valve station inspections, and pipeline patrol, and report any and all abnormal operating conditions when found.

UWUA, Local 483's 3,385 miles of jurisdiction spreads across broader Southern California, from the Nevada border to the Arizona boarder to the Mexican border and as far north as Fresno County. Although we are SoCalGas employees, our jurisdiction also includes parts of SDG&E, PG&E, Long Beach Gas and Oil, City of Vernon's Public Utilities, and Southwest Gas service areas. Throughout our jurisdiction, we serve over 21 million California families and businesses. Despite our vast jurisdiction and critical responsibilities, at present, UWUA, Local 483 represents approximately 350 employees of SoCalGas. Our members work oftentimes around the clock to ensure we have a reliable and safe energy pipeline infrastructure system.

We are in strong support of the proposed Angeles Link Pipeline system, particularly as we get closer to the energy transition towards a net zero goal of GHG emissions. Building and maintaining the Angeles Link pipeline will create and sustain good union jobs in our respective sectors, while decarbonizing the greater industrial economies of southern California.

In addition, we are in favor of the proposed preferred routes described in the routing/configuration analysis draft report due to its likely proximity to critical hydrogen production sites with known and potential end users in industrial, heavy-duty transportation and power generation applications. Further, using the preferred routing analysis for the proposed pipeline would have likely synergies with potential ARCHES production and off-take sites.

With respect to the pipeline sizing and design criteria draft report, we are in alignment to have portions of the Angeles Link System with parallel lines, or “dual-runs.” Using this approach will ensure a more comprehensive approach for reliability and resiliency. For example, if a portion of a pipeline needs to be temporarily shut down for maintenance, a parallel line or dual run would allow the alternate line to run while the line is being worked on. As it is stated in the draft report, “This pipeline configuration can improve system resiliency during potential disruptions, minimize downtime, and allow for continuous operation.” (Page 21).

Angeles Link offers an achievable opportunity for sectors that of which are difficult if not nearly impossible to fully electrify. There is no safer, more cost effective, and efficient way of transporting energy than through a pipeline. The members of UWUA 483 already possess many of the skillsets and labor-ready requirements to emerge into the energy transition of hydrogen. With that in mind, the members of UWUA 483 strongly support Angeles Link.

Thank you,
UWUA 483 President

[EXTERNAL] FW: Comments Regarding Angels Link Phase One

ALP1 Study PAG Feedback <alp1_study_pag_feedback@insigniaenv.com>

Tue 8/27/2024 12:09 PM

To:Quesenberry, Diana <DQuesenb@socalgas.com>;Ibrahim Elfar, Omar M <OIbrahim@socalgas.com>
Cc:Foley, Jessica <JKinnah1@socalgas.com>;Moreno, Edith1 <EMoreno5@socalgas.com>;Stephanie Espinoza <SEspinoza@arellanoassociates.com>;Chester Britt <CBritt@arellanoassociates.com>;Alma Marquez <almarquez@leeandrewsgroup.com>;Dao, Theresa N <TDao@socalgas.com>;TERM-2024-08-23 Grant, Emily <EGrant1@socalgas.com>;Keochekian A <akeochekian@insigniaenv.com>

Good afternoon,

Please see below for UA Local Union 250's email on the Preliminary Routing/Configuration Analysis and Pipeline Sizing and Design Criteria Draft Reports.

Best,

Julie Roshala
Associate Planner
O: 760-635-1587
M: 650-400-3129
INSIGNIA

From: Ben Clayton <ben.clayton@ua250.org>
Sent: Tuesday, August 27, 2024 11:16 AM
To: ALP1 Study PAG Feedback <alp1_study_pag_feedback@insigniaenv.com>
Subject: Comments Regarding Angels Link Phase One

PAG,

My name is Ben Clayton, Business Manager of United Association Local Union 250 Steamfitters, Welders & Apprentices in Los Angeles Ca.. We currently have 6,500 members and we are in support of the Angeles Link project.

Our pipeline jurisdiction covers transmission and distribution in Santa Barbara, Santa Maria, Ventura, Imperial, Riverside, Imperial, San Diego, L.A. County and a large percentage of our membership will be working on this clean renewable hydrogen delivery system throughout Southern California.

We are also in favor of the four proposed routes and the pipeline sizing in the draft reports. As a supplier of manpower for this project we can help provide these jobs to our members that live in the communities that are affected, wherever the routing is. As far as the sizing, the bigger the better. This is an expensive project, it would be shame to complete then realize we should have gone to a larger diameter or a parallel/dual run system to accommodate the needs of this renewable hydrogen and the potential of ARCHES offtake sites.

Again Local 250 members proudly supports this project.

Regards,

Ben

Ben Clayton
Business Manager / Fin. Sec'y-Treas.
UA Local Union 250
(310) 660-0035

Comments regarding Angels Link Phase One

My name is Hector Carbajal, UA Local 250 member and Business Representative for Pipeline work.

UA Local 250 represent close to 6,600 members, including journeymen, welders, apprentices, metal trade helpers, safety attendants and HVAC&R.

For many years our skilled (pipeliners) members have been building and maintaining pipeline infrastructures throughout Southern California.

I'm writing this letter in support of the proposed Angels Link Pipeline system which will deliver clean and renewable HYDROGEN throughout Central and Southern California.

Angels Link will create a clean energy infrastructure needed in California and ensure a better future for working families and provide job opportunities to people in working class communities who have the skillsets required to adjust to the energy transition.

UA Local 250 and myself are in favor of the geographic regions of the four potential preferred routes identified in the preliminary Routing/ Configuration Analysis Draft Report.

The proposed route from San Joaquin Valley to Los Angeles regions would connect critical production sites with end users in industrial, mobility and power generation sectors and would connect potential ARCHES production and offtake sites.

Sincerely,

Hector Carbajal

UA Local Union 250

Business Representative

(310)912- 2498

Hector.carbajal@ua250.org

Soledad
Enrichment
Action

"Transforming lives since 1972"

o: (213) 480-4200 **f:** (213) 480-4199 **a:** 222 N. Virgil Ave., Los Angeles, CA 90004

Dear SoCalGas,

I am writing to express my strong support for the Angeles Link Project as outlined in the Environmental and Social Justice (ESJ) Community Engagement Plan. The project's commitment to delivering clean, renewable hydrogen to Central and Southern California, including the Greater East Los Angeles area and South Los Angeles, represents a vital step toward reducing greenhouse gas emissions and advancing environmental justice in the region.

Soledad Enrichment Action, Inc. (a community based nonprofit for over 52 years) has been a part of the CBO work group for SoCalGas's Angeles Link Phase One scope. We have attended all the meetings and feel that our voice has been included and respected. Rarely does a large utility agency take such effort in order to engage grassroot organizations that represent those most vulnerable to climate change .

The proactive approach SoCalGas has taken in developing the ESJ Plan, which includes engaging with community-based organizations, faith-based groups, and other stakeholders, is all about doing this once and doing it right. This commitment to transparency and community engagement, particularly in disadvantaged communities, ensures that the voices of those most adversely impacted by environmental and social justice issues are heard and included.

I am particularly encouraged by the plan's alignment with the California Public Utilities Commission's (CPUC) ESJ Action Plan, as well as its focus on creating economic opportunities and improving air quality in communities that have historically been disproportionately impacted by industrial activities. The inclusion of strategies to educate and involve ESJ communities in discussions about the project's impact, and the development of community benefits plans, underscores the project's potential to deliver meaningful and lasting benefits to the region.

Furthermore, the project's commitment to workforce development, with the potential to create thousands of jobs during construction and operation, offers significant economic benefits to communities along the proposed routes. By integrating the principles of equity and access throughout the project's development, SoCalGas is setting a strong example for future clean energy initiatives, including ARCHES.

We understand also, that Phase 1 is a conceptual stage and that Phase 2 will be an even more effortful collaboration with CBO's directly affected by the Angeles Link route. It is commendable that SoCalGas has the foresight to encourage and lay the groundwork to this aspect of Phase 2.

In conclusion and without any reservations, I support the Angeles Link Project and the efforts of SoCalGas to engage with and uplift Black and Brown communities most affected by environmental change and historic injustices. I look forward to being witness to the impact this project will have on both the built and social environment.

Thank you for your commitment to a cleaner, transparent and more equitable future.

Respectfully,

Nathan Arias
President/CEO

8/16/2024
Dear SoCal Gas, Angeles Link,

I am writing to express my strong support for the Angeles Link Project as outlined in the Environmental and Social Justice (ESJ) Community Engagement Plan. The project's commitment to delivering clean, renewable hydrogen to Central and Southern California, including the Los Angeles Basin, represents a critical step toward reducing greenhouse gas emissions and advancing environmental justice in the region.

California Greenworks (an Environmental Justice nonprofit for over 20 years) has been a part of the CBO work group for SoCalGas's Angeles Link Phase One scope. We have attended all the meetings and feel that our input is valued and impactful. Rarely does a large utility/entity take such effort in order to engage grassroot organizations that represent those most vulnerable to climate change.

The proactive approach SoCalGas has taken in developing the ESJ Plan, which includes engaging with community-based organizations, faith-based groups, and other stakeholders, is commendable. This commitment to transparency and community involvement, particularly in disadvantaged communities, ensures that the voices of those most affected by environmental and social justice issues are heard and addressed.

I am particularly encouraged by the plan's alignment with the California Public Utilities Commission's (CPUC) ESJ Action Plan, as well as its focus on creating economic opportunities and improving air quality in communities that have historically been disproportionately impacted by industrial activities. The inclusion of strategies to educate and involve ESJ communities in discussions about the project's impact, and the development of community benefits plans, underscores the project's potential to deliver meaningful and lasting benefits to the region.

Furthermore, the project's commitment to workforce development, with the potential to create thousands of jobs during construction and operation, offers significant economic benefits to communities along the proposed routes. By integrating the principles of equity and access throughout the project's development, SoCalGas is setting a strong example for future clean energy initiatives.

We understand also, that Phase 1 is a conceptual stage and that Phase 2 will be an even more effortful collaboration with CBO's directly affected by the Angeles Link route. It is commendable that SoCal Gas has the foresight to encourage and lay the groundwork to this aspect of Phase 2.

In conclusion, I fully support the Angeles Link Project and the efforts of SoCalGas to engage with and uplift the communities most affected by environmental challenges. I look forward to seeing the positive impact this project will have on both the environment and the residents of Southern California.

Thank you for your commitment to a cleaner, more equitable future.

Sincerely,

Michael Berns, PhD
Director of Projects and Programs
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www.californiagreenworks.org

August 30, 2024

Chester Britt
Planning Advisory Group Facilitator

Emily Grant
Angeles Link Senior Public Affairs Representative
Southern California Gas Company

Alisa Lykens
Director
Insignia Environmental

Subject: Environmental Defense Fund Comments on Pipeline Sizing & Design Criteria Draft Report

Environmental Defense Fund (EDF) shares the following comments to the pipeline sizing & design criteria draft report shared by the Southern California Gas Company (SoCalGas) and the Angeles Link Planning Advisory Group (PAG) Facilitator team. Overall, EDF highlights that any final pipeline sizing and design criteria must adequately address concerns already acknowledged in the Leakage Preliminary Data and Findings and the role of hydrogen as an indirect greenhouse gas (GHG) as acknowledged in the draft report on GHG emissions evaluation.[1] However, the draft report **focuses solely on safety and structural integrity concerns**, failing to account for leakage concerns already acknowledged in other Phase 1 studies.

First, the draft report cites to several key codes and standards relevant to hydrogen pipeline transport, including American Petroleum Institute (API) and American Society of Mechanical Engineers (ASME) standards, which **fall short of the levels of regulation and pipeline integrity needed to address the climate impacts of hydrogen leakage**.[2] These existing codes and standards are focused on safety management and structural integrity of a hydrogen pipeline which are important but insufficient. In its previous PAG meeting feedback, EDF noted the need for more stringent leakage detection methods and standards, given the emerging concerns around hydrogen as an indirect GHG.[3] Pipeline material selection is particularly critical here since a continuous hydrogen leak, as opposed to a single "pulse" of emissions, can have compounded climate impacts

[1] GHG Emissions Evaluation draft report at 79; Leakage Preliminary Data and Findings at 3.
[2] Pipeline Sizing & Design Criteria Draft Report at 12.
[3] EDF Comments on October 18th PAG Workshop Discussions, Nov 3, 2023, at 3.

that can undo much of the environmental benefits expected from hydrogen adoption.[4] SoCalGas should, at a minimum, explicitly note that industry standards do not adequately address the higher climate-effectiveness standards for leak detection; and acknowledge the need to adhere to a more stringent detection and material selection standard to ensure climate-effectiveness of hydrogen adoption via the Angeles Link Project.

Similarly, discussions around hydrogen embrittlement included in the draft report are centered exclusively around structural integrity concerns, while **failing to note their leakage and climate impacts**.[5] The challenge of leaks in the existing natural gas system serves as a direct analogy highlighting the importance of addressing this issue upfront. For decades, methane leakage from gas pipelines was dealt exclusively as an immediate safety risk, which allowed for widespread climate, health, and long-term safety risks to continue unabated.[6] To prevent a similar mistake from happening with hydrogen pipeline transport, the conversation around material selection and pipeline design must extend beyond immediate structural integrity concerns as well. Moreover, EDF believes such comprehensive discussion of various concerns around hydrogen embrittlement must also extend to any potential exploration of repurposing existing gas infrastructure.

Finally, the scenario and route configuration results shared in the draft report further highlights **the need to compare the potential Angeles Link pipeline project with other decarbonization pathways for cost- and climate-effectiveness**. The scenario results in the draft report outline certain logistical and technical assumptions that serve as parameters for potential pipeline configurations. For example, Scenario 2 assumes a pipeline supplying hydrogen from the Lancaster production location to the LA basin—approximately 100 miles apart. However, because of the need to connect to a hydrogen storage facility, the actual route mileage estimated in the draft study is more than three times that distance at 314 miles.[7] Furthermore, the draft report states that access to "potential salt cavern storage in both Arizona and Utah" is assumed for the Blythe

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[4] Ocko, I. B. and Hamburg, S. P.: Climate consequences of hydrogen emissions, Atmos. Chem. Phys., 22, 9349–9368, https://doi.org/10.5194/acp-22-9349-2022, 2022.
[5] Pipeline Sizing & Design Criteria Draft Report at 47.
[6] EDF, "Why are natural gas leaks a problem?", accessible at: https://www.edf.org/climate/methanemaps/leaks-problem. See also, Renee McVay, *Methane Emissions from U.S. Gas Pipeline Leaks*, EDF, August 2023, at 7, accessible at: https://www.edf.org/sites/default/files/documents/Pipeline%20Methane%20Leaks%20Report.pdf.
[7] Pipeline Sizing & Design Criteria Draft Report at 23.

production location, one of the three production locations identified in the report.[8] Given the lack of regulatory clarity around interstate hydrogen transport, assumptions based on out-of-state hydrogen storage is a highly speculative at best—and raises questions around the feasibility of such scenarios.[9] In its comments to the GHG Emissions Evaluation Draft report, EDF highlighted the need to evaluate potential benefits of the Angeles Link project in terms of "optimization and relative efficiencies" in comparison with other decarbonization pathways.[10] A recent research article authored by EDF scientists further reveal the need for dedicated infrastructure—as opposed to repurposing existing natural gas infrastructure—with material and design standards that account for hydrogen's chemical and physical characteristics[11] The assumptions and parameters around pipeline design and configuration further underscore the need for such a comparative approach—which should also take into account the concerns around hydrogen leakage and climate impacts raised in the first two points of these comments.

Respectfully,

Michael Colvin
Director, California Energy Program

Joon Hun Seong
Senior Energy Decarbonization Analyst

Thomas Saito
Schneider Intern, Western Electricity Markets

Environmental Defense Fund
123 Mission Street
San Francisco, CA 94105
Email: mcolvin@edf.org
Email: jseong@edf.org

[8] Pipeline Sizing & Design Criteria Draft Report at 22.
[9] EDF notes that the question around inter-state transport was already raised by Mr. Norman Pedersen representing Southern California Generation Coalition at the October 18, 2023, PAG meeting, and echoed by EDF Feedback Comments submitted November 3, 2023.
[10] EDF Comments on GHG Evaluation Draft Report at 1.
[11] Martin P, Ocko IB, Esquivel-Elizondo S, et al. A review of challenges with using the natural gas system for hydrogen. *Energy Sci Eng*. 2024; 1-15. doi:10.1002/ese3.1861

From:	ALP1 Study CBO Feedback
To:	Quesenberry, Diana; Ibrahim Elfar, Omar M
Cc:	Foley, Jessica; Moreno, Edith1; Stephanie Espinoza; Chester Britt; Alma Marquez; Dao, Theresa N; Lopez, Frank; Keochekian A
Subject:	[EXTERNAL] FW: Comments for Environmental Social Justice Plan
Date:	Thursday, August 29, 2024 3:09:14 PM
Attachments:	image713582.png image322673.png image776832.png image998164.png image834564.png image612172.png image831534.png

Good afternoon,

Please see below for the Coalition for Responsible Community Development's email on the Environmental Social Justice Community Draft Engagement Plan and ESJ Screening report.

Best,

Julie Roshala
Associate Planner
O: 760-635-1587
INSIGNIA M: 650-400-3129

From: Kenta Estrada-Darley <kestrada-darley@coalitionrcd.org>
Sent: Thursday, August 29, 2024 11:06 AM
To: ALP1 Study CBO Feedback <alp1_study_cbo_feedback@insigniaenv.com>
Cc: Ricardo Mendoza <rmendoza@coalitionrcd.org>
Subject: Comments for Environmental Social Justice Plan

To whom it may concern,

Please see below for comments from the Coalition for Responsible Community Development (CRCD), member of the SoCal Gas Angeles Link CBOSG regarding the "Environmental Social Justice Community Draft Engagement Plan and ESJ Screening" report.

- CRCD commends and appreciates the pro-active and comprehensive stakeholder engagement process that SoCal Gas has carried out during phase 1 of the Angeles Link studies. Feedback from stakeholder groups, including the CBOSG, have been incorporated into the ESJ Engagement Plan and reflect a multi-tiered approach to engage communities potentially impacted by the Angeles Link pipeline in a transparent and responsible manner.
- We also commend the efforts of SoCal Gas to secure representation and active engagement from stakeholders from communities of color that have been historically disinvested and disproportionately impacted by environmental justice issues and support efforts to expand this representation as the project moves into phase 2.
- We supports the proactive discussion regarding a Community Benefits Plan that would govern the project and the potential for the project to create pathways into careers with family sustaining wages and meaningful procurement opportunities for local small businesses and looks forward to continued discussions on the plan.
- We are encouraged by the ESJ Plan's alignment with multiple goals from the California Public Utility Committee ESJ Action Plan.
- We commend the efforts of the preliminary routing/configuration analysis to provide alternative routes that will not impact, low-income communities of color that have been disproportionately impacted by environmental justice issues.
- Lastly, we would like to share an additional screening tool, the South LA All In Community Development Index, developed by our agency in partnership with USC Neighborhood Data for Social Change, as an additional layer to identify communities that have been historically impacted by systemic racism and disinvestment through the community development lens of jobs, education, affordable and stable housing and access to capital.

——————————————
Kenta Estrada-Darley | Senior Director of South LA All In

South LA All In
CRCD: 213.743.6193 | **M:** 323.861.2991
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View CRCD's 2022 Annual Report [coalitionrcd.org]

[facebook.com] [twitter.com] [instagram.com] [youtube.com] [linkedin.com]

August 22, 2024
Southern California Gas Company
555 West Fifth Street,
Los Angeles, CA 90013

Submitted via email to ALP1_Study_PAG_Feedback@insigniaenv.com

Feedback on Environmental Social Justice Plan Report

I am writing to express significant concerns about the "Environmental Social Justice Plan" for the SoCalGas Angeles Link Project. The plan, as currently presented, does not go far enough to ensure that disadvantaged communities are actively involved and protected throughout the project.

Key Concerns:

Community Engagement:

The plan does not provide sufficient mechanisms for continuous and meaningful engagement with impacted communities, as required by the Equity Principles for Hydrogen. This lack of engagement risks further marginalizing these communities and undermining the project's legitimacy.

1. **Lack of Specific, Actionable Engagement Strategies:** The plan likely included broad commitments to community engagement but did not outline clear, actionable steps for how this engagement would be maintained throughout the project's lifecycle. Without specific strategies, such as regular community meetings, transparent communication channels, and clear timelines for feedback, the engagement becomes superficial rather than substantive.
2. **Insufficient Inclusion of Marginalized Voices:** The Equity Principles for Hydrogen emphasize the importance of including voices from historically marginalized communities in all stages of project development. The plan may have failed to ensure that these communities were genuinely included in decision-making processes. For example, if the plan only provided for one-off consultations rather than ongoing dialogue, it would fall short of what is needed to ensure continuous and meaningful engagement.
3. **Tokenistic Approaches to Community Involvement:** The plan might have included community representatives in advisory roles without giving them real power or influence over project decisions. This tokenism undermines trust and fails to empower communities to shape outcomes in ways that address their specific needs and concerns. Meaningful engagement requires that these communities have a significant and ongoing role in shaping the project's direction.
4. **Lack of Transparency and Accountability:** Without mechanisms for regular reporting back to the community on how their input is being used or for holding the project accountable to the communities it impacts, the plan risks being seen as a box-ticking exercise rather than a genuine effort to engage. Transparency in decision-making and clear accountability measures are crucial for building trust and ensuring that the project meets the equity standards it claims to uphold.
5. **Inadequate Cultural Competency:** The plan may have failed to consider the cultural and linguistic needs of diverse communities, which is essential for effective engagement. If the

project did not provide information and resources in multiple languages or did not tailor its outreach to culturally specific contexts, it would further alienate the communities it intends to serve.
6. **Limited Opportunities for Ongoing Feedback:** Continuous engagement means providing multiple, ongoing opportunities for feedback and dialogue throughout the project's development and implementation. If the plan only allowed for initial input with no clear pathways for follow-up or ongoing involvement, it would not meet the standard for meaningful engagement as required by the Equity Principles for Hydrogen.

Mapping and Environmental Justice Concerns:

I appreciate that the report includes more detailed and zoomed-in maps, which help provide a clearer picture of the project's impact on different areas. However, it would be more effective if these maps were interactive, allowing stakeholders to explore specific areas in greater detail.

One of the most concerning aspects, made evident by the maps, is that the majority of the project routes through urban areas will pass through environmental justice communities. This seems to be a direct result of aligning the new hydrogen pipelines with existing natural gas lines. As discussed in an earlier meeting, this approach risks perpetuating environmental racism. Historically, natural gas lines were placed in certain areas due to racial and economic discrimination, and overlaying hydrogen pipelines in the same locations continues this legacy of inequality. By doing so, the project may disproportionately impact these communities, which already face significant environmental burdens.

Recommendations:

- Implement interactive maps to allow stakeholders to explore specific areas and understand the impacts in greater detail.
- Reevaluate the pipeline routing decisions to avoid perpetuating environmental racism by overlaying new infrastructure on existing lines that were historically placed due to discriminatory practices.
- Develop a comprehensive strategy for ensuring cultural and linguistic inclusivity in all communication and engagement efforts.
- Establish ongoing mechanisms for meaningful community engagement, ensuring that affected communities are involved in decision-making processes throughout the project's lifecycle.

Strengthening these aspects of the plan is essential for aligning the project with the Equity Principles for Hydrogen and ensuring that it does not perpetuate existing environmental injustices.

Sincerely,

Faith Myhra, Organizing Member
Protect Playa Now
protectplayanow@gmail.com

CC:
Emily Grant, SoCalGas
Chester Britt, Arellano Associates
Alma Marquez, Lee Andrews Group

August 22, 2024
Southern California Gas Company
555 West Fifth Street,
Los Angeles, CA 90013

Submitted via email to ALP1_Study_PAG_Feedback@insigniaenv.com

Feedback on Preliminary Routing/Configuration Analysis Report

I am writing to provide critical feedback on the "Preliminary Routing/Configuration Analysis" report for the SoCalGas Angeles Link Project. The report raises serious concerns about the potential impacts on vulnerable communities and fails to align with the Equity Principles for Hydrogen.

Key Concerns:

Environmental and Safety Risks: The report does not sufficiently address the potential impacts of the proposed routes on densely populated and environmentally sensitive areas. The current routing decisions risk exacerbating environmental injustices by disproportionately impacting low-income communities and communities of color.

Recommendations:

Prioritize route selection that minimizes environmental and safety risks, especially in vulnerable communities, in accordance with the Equity Principles for Hydrogen.

These concerns need to be addressed in the final routing plan to prevent further environmental injustices and to align the project with the Equity Principles for Hydrogen.

Sincerely,

Faith Myhra, Organizing Member
Protect Playa Now
protectplayanow@gmail.com

CC:
Emily Grant, SoCalGas
Chester Britt, Arellano Associates
Alma Marquez, Lee Andrews Group

August 22, 2024
Southern California Gas Company
555 West Fifth Street,
Los Angeles, CA 90013

Submitted via email to ALP1_Study_PAG_Feedback@insigniaenv.com

Feedback on Pipeline Sizing and Design Criteria Report

I am writing to provide feedback on the "Pipeline Sizing and Design Criteria" report for the SoCalGas Angeles Link Project. The report inadequately addresses the significant safety risks associated with hydrogen transport and fails to align with the Equity Principles for Hydrogen.

Key Concerns:

1. **Safety Risks**: The report does not fully address the risks of hydrogen leakage, metal embrittlement, and explosions. These issues are particularly concerning for communities that are already overburdened by environmental hazards.
2. **Risk Assessment and Communication**: The report lacks a detailed risk assessment and does not outline specific safety protocols. There is also a need for transparent and continuous communication with affected communities, ensuring they are informed and involved in the decision-making process.

Recommendations:

- Develop a comprehensive safety plan that fully addresses the risks associated with hydrogen transport, with a focus on protecting vulnerable communities.
- Ensure transparent communication and a detailed risk assessment in line with the Equity Principles for Hydrogen.

Addressing these safety concerns in the final report is imperative to protect public safety and align with the Equity Principles for Hydrogen.

Sincerely,

Faith Myhra, Organizing Member
Protect Playa Now
protectplayanow@gmail.com

CC:
Emily Grant, SoCalGas
Chester Britt, Arellano Associates
Alma Marquez, Lee Andrews Group

August 22, 2024
Southern California Gas Company
555 West Fifth Street,
Los Angeles, CA 90013

Submitted via email to ALP1_Study_PAG_Feedback@insigniaenv.com

Feedback on Production Planning & Assessment Draft Report

I am writing to express significant concerns regarding the "Production Planning & Assessment" report for the SoCalGas Angeles Link Project. The report, as it stands, fails to align with the Equity Principles for Hydrogen and does not adequately address the potential environmental justice impacts.

Key Concerns:

1. **Water Usage**: The report lacks a thorough analysis of the substantial water resources required for hydrogen production, particularly given California's ongoing water scarcity. This omission is alarming, as it contradicts the principles of environmental justice by potentially exacerbating water access issues for already vulnerable communities.
2. **Biomass and Biogas**: The inclusion of biomass and biogas as hydrogen sources directly conflicts with the commitment to equity and environmental justice. These methods pose significant environmental and public health risks, especially to low-income communities and communities of color who are already disproportionately burdened by pollution.
3. **Alternative Pathways**: The report's narrow focus on hydrogen production neglects to consider more equitable and sustainable energy alternatives. A broader evaluation of electrification, which aligns more closely with equity principles, is essential.

Recommendations:

- Conduct a more detailed analysis of water usage to ensure sustainability and equity in resource allocation.
- Reassess the inclusion of biomass and biogas, focusing on cleaner, more equitable energy sources.
- Expand the scope of the report to include a comprehensive evaluation of electrification and other alternatives that align with the Equity Principles for Hydrogen.

These concerns must be addressed in the final report to ensure the project does not perpetuate existing environmental injustices and aligns with the Equity Principles for Hydrogen.

Sincerely,

Faith Myhra, Organizing Member
Protect Playa Now
protectplayanow@gmail.com

CC:
Emily Grant, SoCalGas
Chester Britt, Arellano Associates
Alma Marquez, Lee Andrews Group

August 22, 2024
Southern California Gas Company
555 West Fifth Street,
Los Angeles, CA 90013

Submitted via email to ALP1_Study_PAG_Feedback@insigniaenv.com

Feedback on High-Level Feasibility Assessment and Permitting Analysis Report

I am writing to provide critical feedback on the "High-Level Feasibility Assessment and Permitting Analysis" report for the SoCalGas Angeles Link Project. The report falls short in addressing several critical areas, particularly those related to equity and environmental justice.

Key Concerns:

GHG and NOx Emissions: The report does not adequately analyze the potential greenhouse gas (GHG) and nitrogen oxides (NOx) emissions from hydrogen combustion. This is particularly concerning given the disproportionate impact these emissions could have on disadvantaged communities.

Recommendations:

Conduct a detailed analysis of GHG and NOx emissions and their potential impacts on vulnerable communities.

These issues must be addressed in the final report to ensure that the project aligns with the Equity Principles for Hydrogen and protects the most vulnerable populations.

Sincerely,

Faith Myhra, Organizing Member
Protect Playa Now
protectplayanow@gmail.com

CC:
Emily Grant, SoCalGas
Chester Britt, Arellano Associates
Alma Marquez, Lee Andrews Group

August 22, 2024
Southern California Gas Company
555 West Fifth Street,
Los Angeles, CA 90013

Submitted via email to ALP1_Study_PAG_Feedback@insigniaenv.com

Feedback on Environmental Analysis Report

I am writing to express significant concerns regarding the "Environmental Analysis" draft report for the SoCalGas Angeles Link Project. The report fails to adequately address several critical environmental and safety risks associated with hydrogen infrastructure, particularly in the context of densely populated urban areas like Los Angeles.

Key Concerns:

1. Hydrogen Leakage and Safety Concerns

- **Flammability and Leakage Risks**: Hydrogen is highly flammable and prone to leakage, especially when integrated into existing natural gas systems. This presents significant safety risks, particularly in densely populated areas. The report does not sufficiently address these concerns, increasing the likelihood of catastrophic accidents that could endanger public safety (Greenlining Institute, 2024).

2. Increased NOx Emissions and Health Impacts

- **Higher NOx Emissions**: The combustion of hydrogen produces higher levels of nitrogen oxides (NOx) compared to natural gas. This contributes to air pollution and exacerbates respiratory illnesses, such as childhood asthma—a particularly concerning issue in Los Angeles, which already struggles with poor air quality (NBC News, 2024; Earthjustice, 2024).

3. Water Resource Strain

- **Water-Intensive Production**: Hydrogen production, particularly through electrolysis, requires vast quantities of water. In a state like California, where water scarcity is a growing concern, this approach is unsustainable and risks exacerbating drought conditions (Greenlining Institute, 2024).

4. Hydrogen as an Indirect Greenhouse Gas

- **Amplification of Climate Change**: Hydrogen leakage into the atmosphere can indirectly exacerbate climate change by interacting with other greenhouse gases. Hydrogen contributes to the production of tropospheric ozone and extends the atmospheric lifetime of methane, one of the most potent greenhouse gases. This makes hydrogen leakage a significant environmental concern, as it can amplify the climate change impact of other greenhouse gases, undermining efforts to mitigate climate change (Nature Communications, 2023).

Conclusion:

The "Environmental Analysis" draft report does not adequately address the serious environmental and safety risks associated with hydrogen infrastructure. The potential for hydrogen leakage, increased NOx emissions, water resource strain, and the amplification of climate change through indirect greenhouse gas effects are all critical concerns that must be thoroughly evaluated and mitigated. I urge you to reconsider the current approach and explore more sustainable and safer alternatives to hydrogen infrastructure.

Sincerely,

Faith Myhra, Organizing Member
Protect Playa Now
protectplayanow@gmail.com

CC:
Emily Grant, SoCalGas
Chester Britt, Arellano Associates
Alma Marquez, Lee Andrews Group

August 22, 2024
Southern California Gas Company
555 West Fifth Street,
Los Angeles, CA 90013

Submitted via email to ALP1_Study_PAG_Feedback@insigniaenv.com

Feedback on High-Level Economic Analysis and Cost Effectiveness Report

I am writing to provide critical feedback on the "High-Level Economic Analysis and Cost Effectiveness" report for the SoCalGas Angeles Link Project. The following key points highlight significant concerns regarding the project's economic viability and the associated risks.

Key Concerns:

1. Economic Viability Concerns

- **High Costs & Challenges**: The hydrogen infrastructure proposed for the Angeles Link Project faces considerable costs and logistical hurdles, raising serious questions about its economic viability. These challenges mirror those seen globally, where similar issues have led to a slowdown in hydrogen projects, potentially resulting in stranded assets and placing undue financial burdens on ratepayers (Earthjustice, 2024).

2. Overestimated Demand & Economic Risk

- **Demand Overestimation**: SoCalGas has significantly overestimated the demand for hydrogen, projecting figures that are ten times higher than those estimated by California state agencies. This discrepancy is a severe concern, particularly in sectors like transportation and power generation where viable, non-hydrogen alternatives are available. Overestimating demand to this extent makes large-scale hydrogen infrastructure development not only unnecessary but also economically risky (Earthjustice, 2024).

3. Estimated Costs per Mile for Hydrogen Pipelines

- **New Pipelines**: The cost for constructing new hydrogen pipelines is estimated to range from $1 million to $2 million per mile, with costs influenced by factors such as terrain, pipeline diameter, and regulatory requirements (EHB, 2021; IEA, 2022).

4. Example Projects

- **European Hydrogen Backbone**: This large-scale project in Europe estimated costs at approximately $1.2 million to $2.4 million per mile, depending on regional factors (EHB, 2021).

- **Netherlands Halts Hydrogen Project**: The Netherlands canceled its National Hydrogen Pipeline Network due to high costs and unresolved technological challenges, shifting focus to more proven and cost-effective solutions (Reuters, 2023).

Conclusion:

Given the high costs, overestimated demand, and global challenges associated with hydrogen infrastructure, the Angeles Link Project represents a risky investment with questionable economic viability. It is crucial to reconsider this focus on hydrogen and explore more cost-effective and proven alternatives to avoid financial burdens on ratepayers and the risk of stranded assets.

Sincerely,

Faith Myhra, Organizing Member
Protect Playa Now
protectplayanow@gmail.com

CC:
Emily Grant, SoCalGas
Chester Britt, Arellano Associates
Alma Marquez, Lee Andrews Group

August 22, 2024
Southern California Gas Company
555 West Fifth Street,
Los Angeles, CA 90013

Submitted via email to ALP1_Study_PAG_Feedback@insigniaenv.com

Feedback on Project Options and Alternatives Report

I am writing to provide detailed feedback on the "Project Options and Alternatives" report for the SoCalGas Angeles Link Project. While the report presents various options for hydrogen infrastructure, significant concerns arise when considering the broader context of Los Angeles' energy needs and the viability of hydrogen as a primary energy solution.

Key Concerns:

1. Inadequate Exploration of Renewable Energy Alternatives

- The report fails to thoroughly explore alternatives to hydrogen, particularly the potential of 100% renewable energy options. Los Angeles has the capacity to achieve 100% renewable energy by 2030, as demonstrated by comprehensive studies such as the "Clean Energy for Los Angeles" report, which outlines a viable path to full renewable integration. This approach would eliminate the need for large-scale hydrogen infrastructure and align more closely with the city's environmental goals(Clean-Energy-for-Los-An…).

2. Economic Viability Concerns

- The economic viability of hydrogen infrastructure is questionable, especially when compared to the costs associated with renewable energy. The transition to a 100% renewable energy system is not only feasible but also potentially less costly for ratepayers, as highlighted in the "Clean Energy for Los Angeles" report. The report shows that a renewable-based system can be achieved at nearly the same cost as the current trajectory, without the financial risks associated with hydrogen(Clean-Energy-for-Los-An…).

3. Perpetuation of Environmental Inequities

- Aligning new hydrogen pipelines with existing natural gas infrastructure risks perpetuating environmental injustices, particularly in communities historically burdened by fossil fuel projects. The report's failure to address this issue is concerning, especially given that renewable energy alternatives could avoid these negative impacts altogether.

4. Misalignment with Long-Term Environmental Goals

- Transitioning to clean energy should prioritize proven technologies like solar, wind, and energy storage, multi-day demand response, long-term duration storage, microgrids, community based solar and storage projects, and energy efficiency over untested and expensive hydrogen infrastructure.

Recommendations:

- **Reevaluate Options**: Conduct a thorough analysis of 100% renewable energy alternatives, considering their economic feasibility, environmental benefits, and alignment with California's long-term goals.
- **Focus on Equity**: Ensure that any infrastructure development does not perpetuate environmental racism and aligns with the principles of environmental justice.
- **Prioritize Proven Solutions**: Given the economic and environmental uncertainties surrounding hydrogen, it is crucial to prioritize investments in proven renewable technologies.

These recommendations are critical for ensuring that the Angeles Link Project aligns with Los Angeles' environmental goals and does not exacerbate existing inequities.

Sincerely,

Faith Myhra, Organizing Member
Protect Playa Now
protectplayanow@gmail.com

CC:
Emily Grant, SoCalGas
Chester Britt, Arellano Associates
Alma Marquez, Lee Andrews Group

August 30, 2024

VIA EMAIL TO
ALP1_PAG_FEEDBACK@INSIGNIAENV.COM

Emily Grant
Angeles Link Senior Public Affairs Manager
Southern California Gas Company
555 West Fifth Street
Los Angeles, CA 90013

Re: Angeles Link Planning Advisory Group (PAG) Feedback of Air Products and Chemicals Inc. on Production Planning and Assessment (July 2024 Draft); Project Options and Alternatives Report (July 2024 Draft); High-Level Economic Analysis and Cost Effectiveness (July 2024 Draft)

Air Products and Chemicals, Inc. ("Air Products") submits the following feedback concerning the July 2024 drafts of the Production Planning and Assessment; Project Options and Alternatives, and Environmental Assessment; and High Level Economic Analysis and Cost Effectiveness reports.

Air Products expects that the below feedback will be addressed in the final Studies and in Southern California Gas Company's ("SoCalGas") quarterly reporting. Air Products also welcomes any response that SoCalGas may wish to provide to the comments below.

General Comments

SoCalGas was originally authorized to begin recording costs for Phase One in D.22-12-055, issued December 20, 2022. In Phase One, SoCalGas was directed to conduct certain specified feasibility studies, which SoCalGas ultimately divided into fourteen reports. SoCalGas estimated that Phase One would take twelve to eighteen months and was required to actively engage the PAG in those efforts. Unfortunately, SoCalGas has waited until the end of that eighteen-month period to release most of the substantive results of its efforts. Information released prior the draft reports was minimal, and provided little detail, often consisting only of a few PowerPoint slides or bullet points. Drafts of ten of the fourteen reports were released in the final two weeks of July, providing the PAG with a very abbreviated schedule to review and comment – even after SoCalGas provide some modest additional time for some reports. The timing significantly impeded Air Products ability to review and comment on the draft reports, and Air Products does not believe this is consistent with the Commission's intent to provide for PAG engagement.

Production Planning and Assessment Study

The Production Planning and Assessment Study draft assumes that solar power paired with electrolyzers will be the primary renewable energy source and technology. According to the draft report, "[f]or design purposes [the] study assumes renewable energy power requirements will be met with islanded power generation, and potentially local utility distribution power for start-up/shut-down operations" and that these "renewables would be incremental."[1] The study assumes that system curtailments will likely be sporadic and seasonal, and that if production facilities were grid-connected, curtailed energy could be used opportunistically to produce hydrogen.[2] These simplifying assumptions likely minimize costs, and fail to fully address how SoCalGas will ensure that the Link will adequately meet downstream demand. Downstream demand, just as with natural gas demand, will require reliability, including some redundancy to ensure that reliability. It does not appear that the simplified assumptions on which this study is based will provide a system that is sufficiently reliable and redundant or addresses the cost of providing that reliability and redundancy.

In Air Products comments on SoCalGas's Preliminary Findings for this study, it commented that the land requirements appeared to only address real estate needs for solar energy production and for the electrolysis units.[3] In addition to these components, hydrogen production facilities will also require space for hydrogen storage, battery energy storage, liquefaction equipment, purification equipment, blending equipment and other ancillary equipment associated with a typical production facility. The study does not appear to contemplate or incorporate these facilities either. Air Products suggests that the final report include a sample plot plan that shows what SoCalGas contemplates will be included in a typical production facility sized, in conjunction with other facilities, to meet the 1.5 MMTPY of hydrogen throughput assumed in the analysis.

Project Options and Alternatives

The draft Project Options and Alternatives assumes a project with a total throughput of approximately 0.5 to 1.5MMTPY over time.[4] That assumption is inconsistent with the California Air Resources Board's 2022 Scoping Plan, which assumes by 2030, clean hydrogen demand will be about 0.5 MMTPY and about 0.94 MMTPY in 2035, total. The report is thus assuming that the Link would supply up to and potentially above 100% of the total clean hydrogen demand in the state. That wildly overstates the ability of a single pipeline, linked to limited production sources, to supply demand across the state.

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[1] Production Planning and Assessment Study at 53.
[2] *Id.* at 2.
[3] *Id.* at 52; *See* Air Products May 3, 2024 PAG Feedback on the Preliminary Routing/Configuration, Franchise, and Right-of-Way Analyses; Production Planning & Assessment; Plan for Applicable Safety Requirements; Workforce Planning & Training Evaluation; and High-Level Feasibility & Permitting Analysis at 3.
[4] Project Options and Alternatives at 16.

In analyzing reliability and resiliency,[5] the study overstates the scalability of a pipeline system, especially one that is intended to serve demand ranging from 0.5 MMTPY to 1.5 MMTPY. Production and demand development can be very incongruent, which can be difficult to manage. Pipelines must be sized initially to address anticipated demand growth, and production development can fail to track demand growth, or vice versa.

The study also overstates the reliability of a hydrogen pipeline that, at least at the early stages, will be connected to limited supply as it attempts to scale. A pipeline, especially at the lower range of demand, will not have the same resiliency as, for example trucking, which can immediately access multiple sources of supply and deliver to specific locations. The report also misrepresents the reliability of trucking, especially in the transportation sector. Our current transportation sector relies almost exclusively on trucked fuel for refueling stations. It is also much more scalable than a pipeline. A pipeline must be scaled for the maximum flow at each location; in contrast, trucking can easily serve new locations, and quickly adapt to changes in demand.

In Figure 20,[6] the study appears to assume that production costs for all scenarios other than localized hub would be identical. Nor does there appear to be a distinction between in-state and out-of-state production costs. Air Products requests that SoCalGas state the basis for these assumptions in the final report.

The report was limited in its analysis of ammonia as a long-distance carrier for hydrogen, in part, by assuming only shipment from northern and southern California to Southern California ports. The report asserts continuous, reliable power supply as an issue for ammonia production in-state but does not seem to find similar issues with the need for continuous, reliable power need for hydrogen production or compression in the proposed Link project. Overall, the report fails to recognize the long, successful history of producing, transporting and storing ammonia which can be applied to utilizing ammonia as a hydrogen carrier.

High-Level Economic Analysis and Cost Effectiveness

The Cost Effectiveness study suffers from a significant flaw in that it appears to analyze only the costs associated with the high-pressure transmission system—it fails to consider the costs associated with distribution or delivery systems needed to deliver hydrogen from the high-pressure transmission system to end users. To the extent such costs were included, the costs and assumptions on which those economics are based should be specifically set out—for example, the number and type of end users. The final study should separately set out the costs for the distribution or delivery systems, and the assumptions that were used to calculate such costs.

Although other draft reports do address purity requirements, including for fuel cell use versus other types of uses, that issue is not addressed in the Cost Effectiveness study. For example,

[5] *See id.* at 41.
[6] *Id.* at 84.

SoCalGas is relying on the transportation sector to supply much of the demand for the Link. However, purification systems would be needed at each refueling station in order the meet the purity requirements for fuel cell use. The costs associated with these requirements, as well as the impact on demand, could be significant and should be included in the final report.

As noted above in the discussion of the Project Options and Alternatives study, this study appears to assume that production costs for all scenarios other than localized hub would be identical.[7] Nor does there appear to be a distinction between in-state and out-of-state production costs. Air Products requests that SoCalGas state the basis for these assumptions in the final report.

The Cost Effectiveness study also assumes a throughput of 1.5 MMTPY. As noted in the discussion of the Project Options and Alternatives study, this assumption appears unrealistic and inconsistent with CARB's 2022 Scoping Plan. A sensitivity analysis should be done at lower demand levels, to explore the impacts on cost effectiveness in the event the system is substantially oversized.

The draft report assumes a cost of approximately $40/MMBtu for hydrogen, which it compares to the cost of natural gas plus the costs associated with carbon capture and storage. However, the cost comparison fails to take into account the difference in energy density between those two fuels. The comparison should be adjusted accordingly. Given the cost disparity, the draft report should also address the assumptions around drivers for fuel switching for large industrial sources, especially for those sources such as petroleum refineries where CARB's 2022 Scoping Plan assumes a 94% reduction in refinery production by 2045.

The study also assumes a tax credit pursuant to 26 U.S.C. § 45V for production of clean hydrogen. However, based on current proposed tax guidance, this would require compliance with specific provisions commonly known as the 'three pillars'-- incrementality, regionality and time-matching. Thus far, in public meetings, SoCalGas has been non-committal concerning whether it will require the produced hydrogen to meet those requirements. In fact, SoCalGas has claimed that it has not taken a position with respect to the 3 pillars which is untrue given its membership and even board-level position in trade associations where it has taken a position against the three pillars. To the extent that the hydrogen complies—and thus qualifies for a Section 45V tax credit—the costs of such compliance with the three pillars should be included in the study. To the extent such compliance costs are not included, the Section 45V tax credit should also not be included. Addressing these compliance costs is particularly important given that many prospective producers have claimed that compliance will render their projects uneconomic.

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[7] *See, e.g.,* High Level Economics and Cost Effectiveness report at Figure 5, p. 32.

The Production Planning and Assessment study references battery storage, but no battery storage costs appear to be included in the economic calculation. Those costs should either be included or an explanation provided for why they are not included.

The use of depleted oil and gas reservoirs for underground hydrogen storage has not been proven, and salt caverns are not an option in the vicinity of the Link. Therefore, the Cost Effectiveness study would include a sensitivity analysis on the cost of above-ground storage, to illustrate cost impacts if depleted oil and gas reservoirs are ultimately not an option.

The study Assumptions Tables also provides cost assumptions as "discounted total costs",[8] but the study does not explain how those discounted costs were calculated, or the discount rate used. Please clarify these calculations in the final study.

Conclusion

Air Products appreciates the opportunity to provide this feedback concerning the Production Planning and Assessment (July 2024 Draft); Project Options and Alternatives Report (July 2024 Draft) and the High-Level Economic Analysis and Cost Effectiveness (July 2024 Draft).

Respectfully,

Miles Heller Director, Global Greenhouse Gas,
Hydrogen, and Utility Regulatory Policy

[8] *Id.* at Section 7.3 (Assumption Tables).

COMMUNITIES FOR A BETTER ENVIRONMENT established 1978

August 30, 2024

Southern California Gas Company
555 West Fifth Street,
Los Angeles, CA 90013

Submitted via email to ALP1_Study_PAG_Feedback@insigniaenv.com.

Feedback for Southern California Gas Company on Environmental Social Justice (ESJ) Draft Engagement Plan and ESJ Screening and Environmental and Social Justice Screening

Communities for a Better Environment (CBE) submits this letter of feedback to Southern California Gas Company (SoCalGas) on the "Environmental Social Justice Draft Engagement Plan and ESJ Screening" (Engagement Plan) and "Environmental and Social Justice Screening" (Screening) provided on July 19, 2024.

SoCalGas references the Equity Principles[1] and even includes them (and SoCalGas' response letter as an attachment) but fails to meet the very clear baseline standards laid out in the principles. In fact, SoCalGas both ignores the Equity Principles core precepts and fails to outline their own path for aligning with the principles. SoCalGas states that "[e]ncouraging that community voices are heard and considered is crucial when it comes to establishing trust with environmental justice communities."[2] Unfortunately, SoCalGas mischaracterizes the Equity Principles in the very same section. While the Equity Principles do encourage that community voices be heard and considered, community self-determination necessarily involves individuals explaining their community vision and how such vision can be realized. However, the environmental justice organizations who created the Equity Principles emphasize that full community protections and environmental justice measures should be a starting point for projects, not things communities must fight for in each project.[3] The principles emphasize that

[1] Equity Principles for Hydrogen: Environmental Justice Position on Green Hydrogen in California, COMMUNITIES FOR A BETTER ENV'T (Oct. 10, 2023), https://www.cbecal.org/wp-content/uploads/2024/03/Equity-Hydrogen-Initiative-Shared-Hydrogen-Position-1.pdf.
[2] Engagement Plan at 6.
[3] Equity principles at 2"We insist that new projects protect communities first and do no perpetuate the injustices that polluting infrastructures impose on fence-line communities today."

hydrogen should not be combusted for electric power, used in commercial buildings, or relied on for rail or drayage trucking because of these end-uses' impacts in environmental justice communities. Further, the Principles emphasize the importance of community consent to hydrogen delivery projects. Neither the Engagement Plan nor Screening document outline a plan for implementing community protections or environmental justice measures that align with the Principles. The Engagement Plan does not even acknowledge the core principle of community self-determination. Rather, the plan insists that the pipeline will travel through dozens of California's most polluted communities, and that these communities may be engaged with as the project forges ahead.[4]

A. *ENVIRONMENTAL SOCIAL JUSTICE (ESJ) COMMUNITY DRAFT ENGAGEMENT PLAN AND ESJ SCREENING*

The draft engagement plan mischaracterizes the Equity Principles for Hydrogen, fails to implement the CPUC's ESJ Action Plan 2.0, and ignores key populations and environmental impacts. Rather, the document defers nearly all engagement to a later, theoretical phase.

I. Lack of Engagement Plan Development

The Equity Principles highlight that "[d]iscussions about building new green hydrogen infrastructure must involve the community and its members should be meaningfully engaged." However, the Engagement Plan pays only nominal lip service to actual engagement because it fails to identify a means of dialogue, or the important topics of concern for discussion. Engagement is a core principle of environmental justice, but engagement alone does not make projects just. The goal of engagement with a project is not to be engaged, but to determine whether a dangerous or polluting project lands in environmental justice communities and what its unique impacts will be. Engagement should be thought of as a commitment to following through on a clear set of principles and practices and should represent the difference between mere words on paper and affirmative dialogue with stakeholders.

While it is important that community outreach and implementation is rooted in active dialogue with impacted stakeholders and community members, community engagement should receive the same level of research and development that other significant and essential aspects of project development receive. This means that engagement efforts should be appropriately defined, outlined, and supported with clear strategies for implementation. The Engagement plan does none of this; rather, in a few bulleted sentences it merely identifies engagement plan "strategies" which lack concrete methods of action. SoCalGas has leaned heavily on community partners to develop the bulk of this engagement plan, but it has not followed through in developing robustly researched strategies for meaningful engagement that clearly connect to the

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[4] The one attempt at routing the ALP through fewer environmental justice communities, "Route Variation 1" is not even analyzed in phase one environmental analysis.

many important study areas that the CPUC identified in Decision 22-12-055. Failing to understand these strategies adequately will inevitably lead to failures in implementation, as evidenced in the rest of this letter.

In light of the Hydrogen Equity Principles' inclusion in the Engagement Plan, CBE points SoCalGas to the following framework for engagement provided in the Hydrogen Equity Principles:

> Any new potential hydrogen production project must include the formation of a local oversight committee that will be composed of local stakeholders including local environmental justice, public health, labor, and utility representatives to conduct multiple waves of education and engagement to vet the project with the community. The oversight committee will be responsible for coordinating a series of workshops/presentations that will educate the community on sources of energy, emissions projections, job opportunities, and community benefits and risks. Following this process will include the opportunity for the oversight committee consider local resident feedback to either approve, deny, or make modifications to the plan.[5]

II. No Implementation Strategy

The "Engagement strategies" section of the Engagement plan is misnamed. These small paragraphs are simply descriptions of engagement mechanisms, but they do not include any strategy for implementing these mechanisms in phase two. Notwithstanding the engagement strategies section, the Engagement Plan contains no plan or strategy for implementing community engagement, nor has SoCalGas completed sufficient community engagement thus far. Communities for a Better Environment first notified SoCalGas that it was critical to engage communities along the pipeline route over 18 months ago in April 2023.[6] Prior to this, the California Environmental Justice Alliance and Sierra Club raised this serious issue to the California Public Utilities Commission in the Angeles Link proceeding. Despite this, the Engagement Plan makes clear that no actual engagement work will be conducted. Rather, such engagement is conditional pending approval of a second phase and millions more public dollars in spending.

The Engagement Plan describes a list of actions that SoCalGas intends to take in phase two of the Angeles Link project (ALP) process, improperly deferring and delaying time sensitive matters. With SoCalGas aiming to determine the ALP route in the next phase, should it be approved, it is critical that pipeline communities have the opportunity to understand and respond

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[5] Equity Principles at 5.
[6] Feedback for Southern California Gas Company on Angeles Link Project March 15 and March 16 Public Engagement Meetings, April 14, 2023.

to this decision-making process. As the Equity Principles and CBE's previous comments make clear, such an opportunity involves prior education and engagement with accurate information presented in an accessible manner. No such process has taken place, and even accurate information surrounding the ALP has been hard to come by.[7] Proposed future engagement plans in a later, unconfirmed phase are no excuse for a failure to conduct timely engagement and planning. However, the engagement currently outlined for a future phase is incomplete. Even if the actions are taking place in phase two, then the plan should be developed in phase one. Although the Engagement Plan states that it will "serve as a guide for future engagement with ESJ Communities and DACs in Phase 2," it does not provide concrete steps for conducting that engagement. Despite SoCalGas acknowledging that no one strategy is sufficient, there is no commentary or analysis of when and where each engagement strategy will be useful; how they will be implemented; or what information SoCalGas needs to gather to get fruitful results from these engagement strategies. The ramifications of these failures are deeply evident in the shortcomings of the Screening, explored below.

The Engagement Plan also does not address how the execution of phase one has been frustrating and dishonest, fostering mistrust between PAG and CBOSG members and SoCalGas. The Engagement Plan, Screening, and several prior draft reports have been marred by generalized misstatements with no attribution or source and blatantly ignore ALP's impacts in environmental justice communities. Despite this, SoCalGas claim the "Phase 1 stakeholder engagement process has played a pivotal role in fostering trust, acquiring valuable insights, and establishing the foundation for a community-centric approach to tackling environmental and social justice concerns within the design framework for Angeles Link."[8] From the vantage point of CBE, this is not the case. It is evident from the state of the Engagement Plan that SoCalGas has much work to do to foster trust and embark on a process that fosters truly meaningful engagement.

B. ENVIRONMENTAL AND SOCIAL JUSTICE SCREENING

I. The Screening Provides Incomplete Data in an Opaque Manner and Without Analysis

The Screening draft is a puzzling document. Despite spanning a lengthy 147 pages, it neither assesses existing burdens or conditions nor analyzes environmental impacts of the ALP. Concerningly, it does not identify how close the ALP will be from homes or other sensitive sites. Nor does it identify whether infrastructure (compressor station, intake or offtake point, etc.) will be sited in each "study area."

[7] See for example, CBE's comments on GHG emissions and water, highlighting that the reports ignore key environmental impacts and omit emissions data from analyses.
[8] Engagement Plan at 2.

Furthermore, the Screening does not include any discussion of impacts at pipeline origination or termination points. The Screening draft does not identify key stakeholders or community organizations. The Screening draft also does not integrate the California Public Utilities Commission's Environmental and Social Justice Action Plan 2.0. Nor does the report give environmental justice communities (including some "356 census tracts identified as CalEnvrioScreen or SEJST DAC designations") any sense of what they might expect should the ALP be routed through their neighborhoods. What the Screening draft does is aggregate a small amount of demographic data from public sources and organize it into 13 regional categories. However, this in fact disaggregates the selected demographic from other meaningful and significant data provided in these public tools. Environmental justice communities across California experience impacts from polluting industry neighbors on a daily basis. For example, residents of Wilmington, Los Angeles experience refinery flares, truck traffic, oil spills, powerplant emissions, gas leaks, violent explosions, contaminated land, and more. Residents of Lamont in Kern face the impacts of factory farm pollution, warehouse truck traffic, and drinking water contamination, among other issues. Each of these pollution sources inflicts a unique impact on the community it infiltrates. The Screening report, however, does not clarify how or why areas were segmented, presenting bare numbers without context or analysis. The tools referenced in the Screening utilize census tract numbers for mapping purposes, but they also include the city and county and can be viewed in context of the greater map. Rather than providing a fuller image of ALPs route, the Screening strips the census tracts of their more identifiable markers, such as the city, retaining only census tract numbers for identification. Because census tract numbers are not widely used as an identifying tool, the Screening data cannot be helpful as a rooting point for organizing or community outreach. These failures and omissions must be remedied if the Screening is to be a useful tool for community engagement rather than a summary of basic demographic information.

II. Screening Fails to Provide an Adequate Basis for Implementation of Engagement Strategies

Environmental justice communities throughout California experience daily impacts from polluting industry neighbors. These various pollution sources inflict unique impacts on the communities they affect, and residents are harmed and cope with those harms in different ways. The impacts of the ALP are no different, and environmental justice communities subjected to the project will face new, unique risks unlike those which presently exist in their communities. Hydrogen gas is highly leak prone, highly combustible, invisible, and odorless. Hydrogen leak detection technology capable of safely monitoring the ALP does not yet exist. A broad range of hydrogen end-use technology is still in its infancy, and appropriate pollution controls or safety equipment are not widely available either. Hydrogen production can also produce air, water, and climate pollution. Unfortunately, none of these environmental justice community risks; hydrogen explosion risk; pollution from hydrogen production, leakage, end-use; and project construction impacts are analyzed in the Environmental Justice Screening draft. Despite containing lengthy summaries of various demographic indicators, neither report actually defines why the indicators were selected or how they would be relevant to implementing engagement strategies or mitigating ALP impacts. Without an examination of the specific and novel concerns of a high-volume hydrogen pipeline or of any existing risk factors in the communities along the pipeline route, engagement cannot possibly provide clear, accurate information to stakeholders.

The Screening also does not include key language justice details for various communities, or tribal community demographics. Recognizing the language demographics of communities, a readily available statistic on CalEnviroScreen, is essential to community engagement. As highlighted in the Hydrogen Equity Principles, to "[c]enter community input, continue to elevate EJ voices, and ensure meaningful community participation is present for any hydrogen project[,]" project developers must provide "language access such as interpretation and translation services for non-English speakers, depending on the common languages spoken in the particular community." The Screening utterly fails to prepare to meet language needs because it only flags the percentage of census tracts above the county average of limited English-speaking households for each ALP segment, with many segments higher than 60%, including up to 100%. But inexplicably, even with the knowledge of such high need for translation services, the Screening does not discuss the specific language needs for each community and population along the route, or how SoCalGas will approach meeting translation needs.[9] In a similar failure, while the Screening maps denote tribal land in general, the Screening does not identify the particular Tribes whose lands will be impacted by the project, and there is no discussion of how SoCalGas will engage with Tribes in the Engagement Plan.

III. Impact and mitigation discussion is inadequate

The Screening does not discuss any ESJ Community impacts, but it merely acknowledges that the ALP will cause impacts and then mischaracterizes what those impacts may be. The "Mitigations Measures" section is over twice as long as the "Impact Discussion," and contains more detail about project impacts (albeit still inexcusably incomplete) than the impacts discussion. The existing Water Resources Evaluation, GHG Emissions Evaluation, Nitrogen Oxide and Other Air Emissions Assessment, Plan for Applicable Safety Requirements, Preliminary Routing-Configuration Analysis, and other documents produced by SoCalGas, as well as CBE's and other organizations' feedback to those documents, indicate a long list of adverse ALP impacts.[10] Almost none of these impacts are touched on in the Screening's "Impacts Discussion." The few impacts that are explicitly mentioned deal with ALP construction. Although construction impacts are relevant, discussion of them does not come close to fully

[9] Or each census tract.
[10] These impacts include hydrogen leakage and combustion risk, local emissions from hydrogen production, local emissions from hydrogen use, climate emissions from hydrogen production, etc.

capturing the burden that a multi-billion-dollar hydrogen pipeline will place on environmental justice communities over the coming decades. CBE and other groups have repeatedly requested that SoCalGas identify environmental justice concerns as they relate specifically to these feasibility studies and have frequently flagged them where SoCalGas has not. SoCalGas has even deferred addressing these concerns to the ESJ Engagement Plan and Environmental Report. However, these matters are not addressed or raised at all here in the Screening Report or the Engagement Plan.

It is difficult to plan mitigation measures for impacts which have not been identified. While the "Impacts Discussion" defers any analysis of the ALP's impacts to some hypothetical future point, the "Mitigation Measures" section eagerly explains how SoCalGas will minimize these impacts. The discussion shows that SoCalGas has ignored and continues to ignore stakeholder feedback despite claiming in the very same section that:

> SoCalGas is committed to meaningfully engaging with ESJ communities and DACs, as well as other stakeholders, during all phases of Angeles Link and seeks to identify and address any concerns that are raised by these groups regarding construction and operation of Angeles Link.[11]

As explored at length above, the so-called "EJ analysis" in the Engagement Plan and Screening do not perform adequate analysis at all. These reports do not even mention an array of topics already studied in other feasibility reports and noted by participating stakeholders.

IV. Conclusion

CBE appreciates the opportunity to provide feedback. The lack of forward-looking implementation planning or strategic background development in the Engagement Plan and Screening is deeply concerning. For unclear reasons, SoCalGas has emphasized that phase two is when tangible community outreach will happen, but the Engagement plan and Screening do not include adequate planning and development steps to implement any of SoCalGas's ALP engagement strategies. These reports fail to adequately support a comprehensive framework of community engagement efforts related to the ALP. SoCalGas cannot move forward into the next phase with this woefully insufficient degree of planning in place.

Respectfully Submitted.

Lauren Gallagher
Lauren Gallagher
Theo Caretto

[11] Screening at 137.

Jay Parepally
Communities for a Better Environment

CC:
Frank Lopez, SoCalGas
Chester Britt, Arellano Associates
Alma Marquez, Lee Andrews Group
Angeles Link PAG Service List

August 30, 2024

COMMUNITIES FOR A BETTER ENVIRONMENT
40 years | established 1978

Southern California Gas Company
555 West Fifth Street
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Submitted via email to ALP1_Study_PAG_Feedback@insigniaenv.com

Feedback for Southern California Gas Company on the Preliminary Routing/Configuration Analysis Draft Report

Communities for a Better Environment (CBE) submits this letter of feedback to Southern California Gas Company (SoCalGas) on the Preliminary Routing/Configuration Analysis Draft Report (the "Report" or "Study") provided on July 19, 2024. While the Report incorporates some environmental justice ("EJ") principles for portions of its analysis, it still subordinates equity to maximizing hydrogen transmission from production to offtake sites and capitalizing on connections between the Angeles Link Project (ALP) and the Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES) infrastructure. In addition, regardless of whether hydrogen pipelines are aboveground or underground as they cross through disadvantaged or environmental justice communities, CBE raised numerous, serious safety-related concerns in our feedback to the Safety Study that SoCalGas needs to address in tandem with any routing/configuration planning. This letter describes flaws in the current study and outlines areas in which Preliminary Routing/Configuration Analysis can be improved. Particularly, the Study:

- Should Classify Route Variation 1 as a "Preferred Route" and Explore Additional Opportunities to Minimize Hydrogen Transmission Through DACs/EJ Communities
- Should Prioritize the Combination of Route Variation 1 with Route D and Include a Map of Route Variation 1 with Preferred Route D Only
- Lacks Meaningful Discussion about Informed Consultation with Indigenous Tribes Throughout Potential ALP Routing Areas

I. *The Study Should Classify Route Variation 1 as a "Preferred Route" and Explore Additional Opportunities to Minimize Hydrogen Transmission Through DACs/EJ Communities*

The Report notes that SoCalGas "considered evaluating hydrogen corridors that would avoid DAC [disadvantaged communities] and ESJ [environmental and social justice] communities entirely."[1] However, according to the Report, geological constraints between the San Joaquin Valley and LA Basin, such as mountain ranges and protected national forests, limit

[1] Report at 45.

the possible pathways.[2] The Report rejects the promising concept of not adding pollution burdens to DACs and EJ communities by stating: “Routing completely out of DACs may not be feasible due to various factors including technical challenges and operational considerations that may compromise system efficiency, safety, affordability, and reliability.”[3] More specifically, the Study explains that the preferred route alignment for Angeles Link is along the Interstate 5 corridor because of its location “closer to potential offtake facilities” and because it would traverse “more level terrain.”[4]

If Angeles Link will need to cross through environmental justice communities to some extent and track Interstate 5 for some distance, the goal should be to minimize the percentage of routes traversing such communities, given the disproportionate burden of environmental harms placed on DACs/EJ communities over the course of many decades. Route Variation (“RV”) 1 provides a step in the right direction, showing that SoCalGas can reduce main pipeline route mileage traversing DACs in the LA Basin.[5] Whereas 76-81% of Preferred Routes A, B, and C would cross through DACs, Route Variation 1 could possibly “reduce the distance that traverses DACs to approximately 67-73% of the total route distance, a decrease of approximately 8% by route and overall decreases the percentage of pipeline traversing DACs within LA Basin for these routes by approximately 20%.”[6] This RV is laudable but ultimately just a first step towards limiting environmental injustice.

The Report classifies routes that pass through all three zones (“Central,” “Collection,” and “Connection”) and include connections to two ARCHES segments as “Preferred Routes.”[7] Even if RV 1 itself is located entirely within the Central Zone/LA Basin, the limitation of the preferred route designation as needing to pass through all three zones is simply a discretionary choice made by SoCalGas. Since Route Variation 1 still connects to ALP segments that do cross all three zones and both ARCHES segments, SoCalGas should include RV 1 under the preferred route umbrella. Accordingly, Table 4 (“Preferred Routes A, B, C, D Segments and Zones”)[8] in the Report should be revised to include Route Variation 1; this route variation should not be treated as less serious than the currently designated “Preferred Routes.”

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[2] Report at 45.
[3] Id. at 46.
[4] Id. at 60-61.
[5] Id. at 46.
[6] Id.
[7] Id. at 16, 42.
[8] Id. at 50.

II. The Study Should Prioritize the Combination of Route Variation 1 with Route D and Include a Map of Route Variation 1 with Preferred Route D Only

The Report considers Route Variation 1 and Route D as separate configurations. It refers to RV 1 as "an alternative routing for the pipeline segment that runs parallel to the Interstate 5 (I-5) in the LA Basin"[9] that would exist as "a continuation of Preferred Routes A, B, and C, and replaces a portion of 42 miles of segment Y in the previously identified routes."[10] The Report explains that unlike Routes A, B, and C, "Route D does not contain pipeline segments in LA Basin parallel to the I-5[.]"[11] The Report confirms the distinction when it explains that RV 1 serves as "a potential pipeline pathway for Preferred Routes A, B, and C that would potentially reduce main pipeline route mileage traversing DACs in the LA Basin."[12] Although the Study deems Route Variation 1 and Route D as distinct from one another, these routes could be considered in combination with one another. Preferred Route D reduces the percentage of pipeline distance crossing through DACs to "approximately 69%, which is within the potential Route Variation 1 range."[13] In contrast, the distance percentage with respect to traversing DACs for Routes A, B, and C is 76% to 81%.[14] Therefore, if Route Variation 1 and Route D were to be combined, ALP could reduce the overall distance traveled through DACs/EJ communities.

SoCalGas should also provide a map displaying only Route Variation 1 with Preferred Route D. The Report contains a map of RV 1 with Preferred Routes A, B, C (Figure 36)[15] and a map of Route Variation 1 with all four of the preferred routes (Figure 24).[16] Since the Report lacks an illustration focused entirely on Route Variation 1 and Route D, SoCalGas should include such a map in the final report and seriously consider the adoption of Route Variation 1 paired with Route D.

III. The Study Lacks Meaningful Discussion Regarding Informed Consultation with Indigenous Tribes about Potential ALP Routing

The Report is insufficient regarding discussion of impacts to tribal communities and Indigenous peoples' land. SoCalGas notes it currently has "three members of its CBOSG who represent tribal communities" and that its phase one environmental analysis study "evaluates cultural and tribal cultural resources based on a records search and desktop information."[17]

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9 Id. at 46 ("Figure 24…illustrates LA Basin and includes Routes A, B, and C…Route Variation 1 would be a part of these routes in their entirety[.]")
10 Id. at 59.
11 Id. at 46.
12 Id.
13 Id.
14 Id.
15 Id. at 59.
16 Id. at 44.
17 Id. at 64.

While these are positive qualities of the ALP process, SoCalGas needs to do significantly more regarding meaningful, active engagement with the many native nations whose ancestral territories could be harmed by the construction and operation of Angeles Link. The potential routes of the ALP will likely cross through many tribes' lands, including those of the Gabrielino/Tongva Nation of the Greater Los Angeles Basin. The Report notes that in future phases of the ALP process, SoCalGas "will also perform a detailed cultural and tribal cultural resources assessment, including field surveys, to identify locations of sensitivity along the preferred pipeline routes."[18] Mere compliance with state and federal permitting requirements is no substitution for early project stage consultation and feedback. The longer that engagement is delayed to future ALP phases, the greater the risk that critical land considerations from tribal communities and governments will be missed or ignored.

IV. Conclusion

Communities for a Better Environment appreciates the opportunity to provide feedback on the Report. The Report's conclusion states that "route alignments will be refined in subsequent phases to reduce disruptions to communities and ecosystems . . . ."[19] To better ensure that stated goal, SoCalGas should rectify all issues raised in this letter before issuing a final report to provide sufficient information for stakeholders to properly assess the ALP.

Sincerely,

Jay Parepally
Lauren Gallagher
Theo Caretto

Communities for a Better Environment

CC:
Frank Lopez, SoCalGas
Chester Britt, Arellano Associates
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[18] Id.
[19] Id. at 65.

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CALIFORNIA HYDROGEN BUSINESS COUNCIL COMMENTS ON ANGELES LINK PHASE I DRAFT PRODUCTION PLANNING & ASSESSMENT AND DRAFT PRELIMINARY ROUTING/CONFIGURATION ANALYSIS

August 30, 2024

Submitted via Email to: ALP1_STUDY_PAG_FEEDBACK@INSIGNIAENV.COM

The California Hydrogen Business Council ("CHBC") respectfully comments on the following Angeles Link Phase 1 draft reports posted by the Southern California Gas Company ("SoCalGas") in the Angeles Link Living Library:

1. **Production Planning & Assessment (July 19, 2024)**
2. **Preliminary Routing/Configuration Analysis ("Draft Routing Analysis") (July 19, 2024)**

1. Comments on the Production Planning & Assessment Draft Report

The definition of clean renewable hydrogen in the report is appropriate and current. This definition has not changed during the 2024 California legislative session.

Treasury guidance on the Section 45V tax credit from the Inflation Reduction Act is not yet final. While the three pillars are mentioned in the report as possible criteria for electrolytic hydrogen, they are still an undefined concept and not in statute, and until Treasury releases final guidance it is premature to use these as standard.

Even if some form of the three pillars, or a phased in approach to such, is included in final Treasury Guidance, the recent Supreme Court ruling overturning Chevron deference (Loper Bright Enterprises vs. Raimondo) ends a principle of administrative law that required courts to defer to interpretation of statutes made by government agencies. This decision could limit broad regulatory authority of federal agencies to change legislative intent due to an unreasonably restrictive definition of renewable hydrogen, based on subjective criteria, rather than the objective carbon intensity standard that is already in statute. In the case of the proposed guidance for 45V and other tax credits, Treasury's proposed approach does not reflect a reasonable interpretation, nor the best reading of the statute and therefore should not be included in any Angeles Link plans until such time as final guidance is settled. California RPS standards already exceed federal standards, so the clean renewable hydrogen standard used in the draft report is appropriate. Additionally, the guardrails provided by use of the GREET model to calculate carbon intensity can ensure decarbonization targets are met for all hydrogen, not just electrolytic hydrogen. The CHBC supports the approach proposed in the report to continue this discussion as policy and practice around hydrogen standards evolves.

It is also appropriate that SoCalGas follow the evolution of hydrogen certification standards, which are currently being developed globally, and as these standards evolve, they will inform Angeles Link plans in the coming years and should be updated in Phase 2.

In Section 7.2.2. Mobility Sector Demand, the mobility sector should be broadly defined and consider current sales of diesel fuel, in addition to gasoline. CARB has mandated the transition to zero-emission vehicles through 2045 across transportation sectors including light- and medium-duty vehicles, heavy-duty trucks and buses, forklifts, maritime, and rail. This transition therefore requires replacement of both gasoline and diesel fueled vehicles and the next analysis should account for this.

2. Comments on the Preliminary Routing/Configuration Analysis Draft

The report rightly stresses the importance of proposing potential routes connect hydrogen supply to hydrogen demand centers, while considering impacts on communities and land. In connecting hydrogen production to offtake, there are additional benefits from a common carrier pipeline route that increases access to decarbonized molecules in local communities, as many of the communities with the worst air quality are located on freight and rail corridors.

The connection of potential routes to the ARCHES hydrogen hub projects is critical because ARCHES has already secured offtake in these project regions upon which most proposed routes are overlaid. Additionally, a significant requirement of the U.S. Department of Energy $1.2 billion funding for ARCHES projects is measurable community benefits. The offtake provided by ARCHES projects already represents potential incremental benefits to disadvantaged communities.

That said, this Phase 1 route analysis should be considered a framework, not a final plan. The ARCHES projects are still in the subcontracting phase and until there is assurance on which projects will come to fruition.

As mentioned in previous comments on the draft Production Planning and Assessment report, there is currently uncertainty around hydrogen production incentives. This means that until hydrogen production projects reach a financial investment decision, and begin the build phase, plans for Angeles Link should remain fluid. Options presented in Phase 1 should be further examined in Phase 2 as the hydrogen industry in California continues to evolve and projects break ground. The route should ultimately be where the production plants come online, and demand centers grow.

The CHBC supports routes that can maximize immediate air quality improvements by increasing offtake of hydrogen to reduce criteria air pollutants and diesel, such as in transportation corridors and transit routes. Variation 1 that generally follows the I-405 corridor should not be considered as this route misses municipal load centers and large-scale electrical generation in the LA basin.

One must also consider the importance of aligning access points to follow key transportation corridors, from the ports to the Inland Empire. Some consideration should thus be given to Route D that runs through the Riverside area, while potentially having lower impact than other options on disadvantaged communities according to the draft report. It is justified for the route to follow the I-710 corridor to serve bus and truck fleets, and to address routes where there is known load and offtake to decarbonize in the communities along those corridors. The I-405 corridor in Variation 1 does not represent a major transportation corridor with significant municipal loads like other proposed routes and variations.

The CHBC emphasizes that while these initial routes represent production and demand centers that are planned today, these plans could change based on a number of factors, such as project viability and policy changes. It is therefore advisable that the Phase 2 work reevaluate the status of hydrogen production and offtake projects and fleets at that future time.

Respectfully submitted,

/s/ Katrina M. Fritz

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Dated: August 30, 2024

[EXTERNAL] FW: Review on Nitrogen Oxide (NOx) and Other Air Emissions Assessment

ALP1 Study PAG Feedback <alp1_study_pag_feedback@insigniaenv.com>

Tue 9/3/2024 7:56 AM

To:Quesenberry, Diana <DQuesenb@socalgas.com>;Ibrahim Elfar, Omar M <OIbrahim@socalgas.com>
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Good morning,

Please see below for Reimagine LA Foundation's email on the Nitrogen Oxide (NOx) and Other Air Emissions Assessment Draft Report.

Best,

Julie Roshala
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From: Rashad Rucker-Trapp <rashad.ruckertrapp@reimaginelafoundation.org>
Sent: Sunday, September 1, 2024 4:08 PM
To: ALP1 Study PAG Feedback <alp1_study_pag_feedback@insigniaenv.com>
Subject: Review on Nitrogen Oxide (NOx) and Other Air Emissions Assessment

Good afternoon My Apologies on the late response

This comprehensive and well-structured report provides a thorough analysis of the potential air quality impacts associated with the proposed Angeles Link project. The study's meticulous approach in evaluating both potential emissions increases from new hydrogen infrastructure and reductions from end-users offers a balanced and realistic assessment of the project's environmental implications.

One of the report's most compelling strengths is its rigorous methodology. The authors have carefully considered a wide range of factors, including various demand scenarios, different hydrogen production methods, and diverse end-use applications. This multi-faceted approach lends credibility to the findings and demonstrates a commitment to thorough scientific analysis.

The study's projection of significant overall NOx reductions is particularly encouraging. The estimated reductions of 5,240 tons/year by 2030 and 20,529 tons/year by 2045 in the Ambitious Demand Scenario highlight the project's potential to make a substantial positive impact on air quality in the region. These projections are especially noteworthy given that they account for potential emissions from new infrastructure.

The report's detailed breakdown of emissions reductions by sector provides valuable insights into where the greatest air quality benefits can be expected. The finding that the mobility sector accounts for over 99% of NOx reductions in the ambitious scenario is a crucial point, underscoring the significant environmental benefits of transitioning to hydrogen fuel cell vehicles, particularly in heavy-duty transportation.

Another commendable aspect of the study is its consideration of other air pollutants beyond NOx. The projected reductions in PM2.5, PM10, and VOC emissions offer a more comprehensive picture of the potential air quality improvements. This broader focus on multiple pollutants strengthens the overall environmental case for the project.

The authors' transparency regarding areas of uncertainty and limitations in current data is praiseworthy. By acknowledging these gaps and suggesting areas for future refinement, the report maintains scientific integrity while providing a solid foundation for decision-making.

The inclusion of NOx minimization opportunities through equipment design and post-combustion treatment technologies demonstrates a proactive approach to environmental management. This forward-thinking consideration of mitigation strategies adds practical value to the report.

The study's use of multiple data sources, including CARB models, local air district regulations, and scientific literature, enhances the reliability of its findings. The detailed explanations of calculation methodologies in the appendices provide transparency and allow for thorough review of the analysis.

In conclusion, this draft report presents a compelling case for the potential air quality benefits of the Angeles Link project. Its comprehensive scope, rigorous methodology, and balanced consideration of both emissions increases and reductions make it a valuable resource for policymakers, environmental planners, and stakeholders. While acknowledging areas for future refinement, the study provides strong evidence that the project could contribute significantly to improving air quality in the region, particularly through transformative changes in the transportation sector.

[EXTERNAL] FW: High-Level Feasibility Assessment and Permitting Analysis:

ALP1 Study PAG Feedback <alp1_study_pag_feedback@insigniaenv.com>

Tue 9/3/2024 7:57 AM

To:Quesenberry, Diana <DQuesenb@socalgas.com>;Ibrahim Elfar, Omar M <OIbrahim@socalgas.com>
Cc:Foley, Jessica <JKinnah1@socalgas.com>;Moreno, Edith1 <EMoreno5@socalgas.com>;Stephanie Espinoza <SEspinoza@arellanoassociates.com>;Chester Britt <CBritt@arellanoassociates.com>;Alma Marquez <almarquez@leeandrewsgroup.com>;Dao, Theresa N <TDao@socalgas.com>;Lopez, Frank <FLopez5@socalgas.com>;Keochekian A <akeochekian@insigniaenv.com>

Good morning,

Please see below for Reimagine LA Foundation's email on the High-Level Feasibility Assessment and Permitting Analysis Draft Report.

Best,

INSIGNIA

Julie Roshala
Associate Planner
O: 760-635-1587
M: 650-400-3129

From: Rashad Rucker-Trapp <rashad.ruckertrapp@reimaginelafoundation.org>
Sent: Sunday, September 1, 2024 4:12 PM
To: ALP1 Study PAG Feedback <alp1_study_pag_feedback@insigniaenv.com>
Subject: High-Level Feasibility Assessment and Permitting Analysis:

Good afternoon apologies for the late submission just a lot to review however

This report excels in its comprehensive approach to analyzing the permitting landscape for Angeles Link. The study's systematic evaluation of federal, state, and local jurisdictions demonstrates a deep understanding of the complex regulatory environment surrounding large-scale infrastructure projects. Particularly noteworthy is the detailed breakdown of potential permits required from various agencies, including the Bureau of Land Management, U.S. Forest Service, and California Public Utilities Commission.

The report's consideration of environmental aspects is thorough, addressing both general environmental review processes (NEPA and CEQA) and specific concerns such as impacts on protected species and habitats. The inclusion of estimated timelines for various permits is extremely valuable for project planning and risk assessment. The acknowledgment of potential streamlining legislation for clean hydrogen projects shows foresight and adaptability in the planning process.

The study's approach to analyzing biological and aquatic resources, including the use of multiple databases and a defined biological study area, is methodologically sound. The consideration of both direct impacts and buffer zones demonstrates a nuanced understanding of environmental assessment practices.

The report's discussion of land rights and jurisdictional issues is particularly detailed and helpful, providing a clear picture of the complex land use considerations involved in the project. The inclusion of tribal consultation requirements and cultural resource considerations further enhances the report's comprehensiveness.

[EXTERNAL] FW: Southern California Gas Company: Angeles Link Employment Impact Analysis

ALP1 Study PAG Feedback <alp1_study_pag_feedback@insigniaenv.com>

Tue 9/3/2024 7:59 AM

To:Quesenberry, Diana <DQuesenb@socalgas.com>;Ibrahim Elfar, Omar M <OIbrahim@socalgas.com>
Cc:Foley, Jessica <JKinnah1@socalgas.com>;Moreno, Edith1 <EMoreno5@socalgas.com>;Stephanie Espinoza <SEspinoza@arellanoassociates.com>;Chester Britt <CBritt@arellanoassociates.com>;Alma Marquez <almarquez@leeandrewsgroup.com>;Dao, Theresa N <TDao@socalgas.com>;Lopez, Frank <FLopez5@socalgas.com>; Keochekian A <akeochekian@insigniaenv.com>

Good morning,

Please see below for Reimagine LA Foundation's email.

Best,

Julie Roshala
Associate Planner
O: 760-635-1587
M: 650-400-3129

From: Rashad Rucker-Trapp <rashad.ruckertrapp@reimaginelafoundation.org>
Sent: Sunday, September 1, 2024 4:14 PM
To: ALP1 Study PAG Feedback <alp1_study_pag_feedback@insigniaenv.com>
Subject: Southern California Gas Company: Angeles Link Employment Impact Analysis

Good afternoon

This analysis provides an exceptionally detailed and rigorous assessment of the potential economic and employment impacts of Angeles Link. The use of the IMPLAN input-output model lends significant credibility to the projections, as it's a widely accepted tool in economic impact analysis. The report's breakdown of impacts into direct, indirect, and induced effects offers a comprehensive view of the project's potential economic reach, going beyond simple job creation numbers to show the ripple effects throughout the economy.

The analysis's consideration of both the construction phase and ongoing operations gives a full picture of the project's long-term economic effects. The detailed job creation estimates, breaking down figures for each phase and including indirect and induced effects, provide valuable insights for policymakers and stakeholders.

The inclusion of Diverse Business Enterprise participation projections is a particularly positive aspect, demonstrating a commitment to inclusive economic development and aligning with broader social equity goals. The detailed tax revenue projections, broken down by type (property, payroll, sales) and jurisdiction, add significant value for local and state government stakeholders.

The report's methodology is clearly explained, and the use of multiple scenarios (e.g., different pipeline lengths) shows a thoughtful approach to dealing with uncertainty in project planning. The inclusion of county-level breakdowns of economic impacts provides useful granularity for local stakeholders.

[EXTERNAL] FW: Preliminary Routing/Configuration Analysis

ALP1 Study PAG Feedback <alp1_study_pag_feedback@insigniaenv.com>
Tue 9/3/2024 8:01 AM

To:Quesenberry, Diana <DQuesenb@socalgas.com>;Ibrahim Elfar, Omar M <OIbrahim@socalgas.com>
Cc:Foley, Jessica <JKinnah1@socalgas.com>;Moreno, Edith1 <EMoreno5@socalgas.com>;Stephanie Espinoza <SEspinoza@arellanoassociates.com>;Chester Britt <CBritt@arellanoassociates.com>;Alma Marquez <almarquez@leeandrewsgroup.com>;Dao, Theresa N <TDao@socalgas.com>;Lopez, Frank <FLopez5@socalgas.com>; Keochekian A <akeochekian@insigniaenv.com>

CAUTION! External Sender
This email came from outside the company. If you're unsure whether this message is harmless, click the "Report Suspicious" button.

Report Suspicious

Good morning,

Please see below for Reimagine LA Foundation's email on the Preliminary Routing/Configuration Analysis Draft Report.

Best,

Julie Roshala
Associate Planner
O: 760-635-1587
M: 650-400-3129
INSIGNIA

From: Rashad Rucker-Trapp <rashad.ruckertrapp@reimaginelafoundation.org>
Sent: Sunday, September 1, 2024 4:16 PM
To: ALP1 Study PAG Feedback <alp1_study_pag_feedback@insigniaenv.com>
Subject: Preliminary Routing/Configuration Analysis

You don't often get email from rashad.ruckertrapp@reimaginelafoundation.org. Learn why this is important [aka.ms]

Good afternoon

This report demonstrates an impressive depth of analysis in identifying and evaluating potential routes for Angeles Link. The systematic approach, including the development of Connection, Collection, and Central Zones, shows strategic thinking in system design that goes beyond simple point-to-point routing. The integration of data from other feasibility studies, such as the Production and Demand studies, indicates a holistic approach to planning that considers the entire hydrogen ecosystem.

The consideration of multiple factors in route selection, including environmental, social, and engineering aspects, is particularly commendable. The use of GIS tools and the Pivvot software for detailed attribute analysis of potential routes shows a sophisticated approach to spatial analysis. The report's detailed matrices for each pipeline segment provide a wealth of information for further analysis and decision-making.

The alignment with existing infrastructure, including the consideration of Alternative Fuel Corridors and existing pipeline rights-of-way, demonstrates a practical approach to minimizing new disturbances. The report's consideration of land rights and jurisdictional issues is thorough and provides valuable insights into potential challenges and opportunities in route selection.

The inclusion of Route Variation 1 in response to stakeholder feedback about disadvantaged communities demonstrates responsiveness and adaptability in the planning process. This shows a commitment to environmental justice considerations and community engagement.

The detailed characterization of preferred routes, including their composition by land type, class location, and proximity to existing infrastructure, provides valuable insights for further development. The consideration of future large-scale infrastructure initiatives in the planning process shows foresight and a long-term perspective on regional development.

Overall, this report provides a solid foundation for more detailed route optimization and stakeholder engagement in future phases of the project. Its comprehensive approach and attention to detail set a high standard for infrastructure planning studies.

Best
Rashad Rucker Trapp and Raul Claros
Founders
Reimagine LA Foundation

[EXTERNAL] FW: Message from Raul Claros

ALP1 Study PAG Feedback <alp1_study_pag_feedback@insigniaenv.com>
Tue 9/3/2024 8:03 AM
To:Quesenberry, Diana <DQuesenb@socalgas.com>;Ibrahim Elfar, Omar M <OIbrahim@socalgas.com>
Cc:Foley, Jessica <JKinnah1@socalgas.com>;Moreno, Edith1 <EMoreno5@socalgas.com>;Stephanie Espinoza <SEspinoza@arellanoassociates.com>;Chester Britt <CBritt@arellanoassociates.com>;Alma Marquez <almarquez@leeandrewsgroup.com>;Dao, Theresa N <TDao@socalgas.com>;Lopez, Frank <FLopez5@socalgas.com>;
Keochekian A <akeochekian@insigniaenv.com>

Good morning,

Please see below for the last email received from Reimagine LA Foundation.

Best,

Julie Roshala
Associate Planner
O: 760-635-1587
M: 650-400-3129

-----Original Message-----
From: Rashad Rucker-Trapp <rashad.ruckertrapp@reimaginelafoundation.org>
Sent: Sunday, September 1, 2024 4:21 PM
To: ALP1 Study PAG Feedback <alp1_study_pag_feedback@insigniaenv.com>
Subject: Message from Raul Claros

[You don't often get email from rashad.ruckertrapp@reimaginelafoundation.org. Learn why this is important at https://urldefense.com/v3/__https://aka.ms/LearnAboutSenderIdentification__;!!DHZoJls!ogqwi3o-1XfjkFfYzQciDBQuBMWC0zGirZnQykjU_wmvuN2oWN2hz0-M0RWTmK3d0RYersNpJWyYwNbLYeOGTBcXNwfR$[aka[.]ms]]

To Whom It May Concern:

I write to you today to share my gratitude and appreciation for and to SoCal Gas, for their inclusivity of our black, brown, and indigenous communities in the inner-city of Los Angeles! Through hard earned established relationships that took dedicated time from senior leaders in SoCal Gas like Andy Carrasco, Frank Lopez and Ozzie Peña; SoCal Gas has earned their stripes within our communities of color. Their genuine care for our people in ensuring that we can be respected, invited and taken serious at the social justice table when it comes to environmental justice is second to none! Actually, SoCal Gas is the ONLY utility company or entity who has ever provided this opportunity.

Through longstanding and impactful partnerships, SoCal Gas has earned the respect and license to operate in and with our vulnerable communities. We thank the leadership team for always being transparent and accountable to our households and families. Please accept this note as a testimonial on behalf of the thousands of families that SoCal Gas has helped us serve over the past 4 years via Reimagine LA Foundation.

Warmly,
Raúl Claros, Co-Founder
Reimagine LA Foundation
329 844-5591 cell

[EXTERNAL] FW: SoCalGas Angeles Link – Draft Reports Feedback due this Friday

ALP1 Study PAG Feedback <alp1_study_pag_feedback@insigniaenv.com>

Thu 9/5/2024 9:02 AM

To:Quesenberry, Diana <DQuesenb@socalgas.com>;Ibrahim Elfar, Omar M <OIbrahim@socalgas.com>
Cc:Foley, Jessica <JKinnah1@socalgas.com>;Moreno, Edith1 <EMoreno5@socalgas.com>;Stephanie Espinoza <SEspinoza@arellanoassociates.com>;Chester Britt <CBritt@arellanoassociates.com>;Alma Marquez <almarquez@leeandrewsgroup.com>;Dao, Theresa N <TDao@socalgas.com>;Lopez, Frank <FLopez5@socalgas.com>; Keochekian A <akeochekian@insigniaenv.com>

Good morning,

Please see below for UC Davis's email on the Pipeline Sizing & Design Criteria, Preliminary Routing/Configuration Analysis, Economic Analysis & Cost Effectiveness, and Hydrogen Leakage Draft Reports.

Best,

Julie Roshala
Associate Planner
O: 760-635-1587
M: 650-400-3129

From: Angeles Link Outreach <angeleslinkoutreach@arellanoassociates.com>
Sent: Thursday, September 5, 2024 8:45 AM
To: Lewis M Fulton <lmfulton@ucdavis.edu>; Angeles Link Outreach <angeleslinkoutreach@arellanoassociates.com>
Cc: Lopez, Frank <flopez5@socalgas.com>; Chester Britt <CBritt@arellanoassociates.com>; ALP1 Study PAG Feedback <alp1_study_pag_feedback@insigniaenv.com>
Subject: RE: SoCalGas Angeles Link – Draft Reports Feedback due this Friday

Hello, Lew,

Thank you for taking the time to provide comments. I am forwarding your letter to the team for documentation.

Thank you,
Stevie

Stevie Espinoza
(she/her)
Deputy Project Manager
[arellanoassociates.com] **Arellano Associates**
P • 909.627.2974 Ext. 5021
E • sespinoza@arellanoassociates.com

From: Lewis M Fulton <lmfulton@ucdavis.edu>
Sent: Wednesday, September 4, 2024 4:35 PM
To: Angeles Link Outreach <angeleslinkoutreach@arellanoassociates.com>
Cc: Lopez, Frank <flopez5@socalgas.com>; Chester Britt <CBritt@arellanoassociates.com>
Subject: RE: SoCalGas Angeles Link – Draft Reports Feedback due this Friday

Hello all, here are our (UC Davis Hydrogen group) comments and questions on selected draft reports. For the various questions, you can think of these as suggestions for things to address in the report. But we're also happy to discuss anything that you feel arises from these that you'd like to discuss.

Lew Fulton

Pipeline Sizing & Design Criteria Draft Report:

- How will the risk of hydrogen embrittlement be mitigated? Are there more specific details, including material testing protocols and how things will be continually monitored to ensure optimal performance?
- The report discussed further transient hydraulic analysis that addresses how the system will respond to dynamic conditions (i.e., changes in production and demand). Can you provide more detailed plans for these in the future?
- The cost assumptions and estimates are unclear (specifically materials, labor, and contingencies). Will more specific details be outlined, and how are cost uncertainties managed?
- Are there further plans on how to design pipelines to scale and adapt to long-term growth projections? How will the system grow as more production sites are added?
- What were the criteria for selecting the pipeline routes? Could there be more explanations of how the route decisions were made?
- It seems like storage considerations were shortly acknowledged. Will there be further analysis into how this is crucial to controlling demand fluctuations?

Preliminary Routing-Configuration Analysis Draft Report:

- It appears that the only factor for the forecast of hydrogen demand in Southern and Central Valley, California, is the population of the respective counties. The population might not reflect the true demand of a place. The preliminary study should consider other factors like 'the number of registered AFVs, land-use policies, and the number of planned infrastructure'.
- Northern California might also share the same hydrogen production facilities located at Central Valley. In that case, the supply-demand study and projection of hydrogen production capacities might fail to reflect the real-world numbers. The study should clarify if Northern California would share any resources from this project, and should leave room for the optimal routing of pipelines for any upcoming projects from the northern region.

Economic Analysis & Cost Effectiveness Draft Report:

The mobility section of the reports calculates the 2030 total cost of ownership (TCO) of fuel cell and battery electric trucks for four applications – sleeper cab, day cab, drayage and transit bus. Assumptions for the TCO analysis have been sourced mainly from Argonne National Lab. The following table offers some suggestions on the assumptions made:

	Current Assumption	Suggestion	Source
Operational characteristics	Operational distance of 100,000 miles a year irrespective of the application	Sleeper cab – 120,000 miles per year (300 to 800 miles per day) Day cab – 90,000 miles per year (200 to 300 miles per day) Drayage – 45,000 miles per year Transit bus – 40,000 miles per year	Burke, A. F., J. Zhao, M. R. Miller, A. Sinha, and L. M. Fulton. Projections of the Costs of Medium- and Heavy-Duty Battery-Electric and Fuel Cell Vehicles (2020-2040) and Related Economic Issues. *Energy for Sustainable Development*, Vol. 77, 2023, p. 101343. Link [doi.org]. Fleming, K. L., A. L. Brown, L. Fulton, and M. Miller. Electrification of Medium- and Heavy-Duty Ground Transportation: Status Report. *Current Sustainable/Renewable Energy Reports*, Vol. 8, No. 3, 2021, pp. 180–188. Link [doi.org].
Range improvements	The 2030 range of battery-electric trucks is same as current models	Batteries are expected to have better energy density and efficiency than the current models. Assumptions vary by study, but for example, an ICCT study assumes a 2.1% improvement in efficiency per year. If the range improvements are not considered, better batteries will lead to lower payload penalty and lower dwell cost.	For a review of various studies, please see: Wang, G., L. Fulton, and M. Miller. The Current and Future Performance and Costs of Battery Electric Trucks: Review of Key Studies and A Detailed Comparison of Their Cost Modeling Scope and Coverage. 2022. Link [doi.org].

Review of Angeles Link – H2 Leakage Assessment Draft Report

This assessment does not evaluate potential leakage at end users' equipment, focusing solely on the proposed infrastructure components.

The study identifies potential sources of hydrogen leakage, estimation methodologies, and mitigation opportunities. Literature from the past two decades shows significant variation in hydrogen leakage estimates, highlighting the need for further research to achieve more accurate predictions. Improved sensor detection and direct measurement technologies are essential for better quantification of hydrogen leaks and for assessing the effectiveness of mitigation strategies, which could potentially reduce leakage by over 90%.

However, the study acknowledges a lack of sufficient data to provide detailed leakage estimates specifically for the Angeles Link project, including third-party production and storage. A high-level preliminary estimate was made, but more refined data and detailed infrastructure design are required for more precise predictions. The study also notes the concerns of stakeholders regarding the absence of detailed volumetric leakage estimates and addresses this by incorporating a preliminary estimate based on available literature.

The study's findings on potential leakage and mitigation opportunities related to the Angeles Link project, including production and storage, are intended for Phase 1 and may be refined as hydrogen infrastructure research progresses and in response to feedback from stakeholders. The study identifies potential leakage sources, such as electrolyzers, compressors, storage vessels, and pipelines. Due to insufficient direct measurement data, the total value chain (top-down) approach was chosen as the preferred leakage estimation methodology. Future evaluations could incorporate a component-level approach as more detailed data becomes available.

The study acknowledges the current limitations in hydrogen leak measurement data but anticipates advancements in measurement technologies and methodologies, similar to the progress made in natural gas leak detection. As the design of the Angeles Link infrastructure advances, further refinements in evaluating and minimizing hydrogen leakage are expected.

Conclusions:

We consider this an important issue and look forward to further texting and evaluation results from SoCalGas and its partners to help us better understand the leakage characteristics of different systems and how leakage can be minimized.

We are also concerned about leakage from liquid systems (that could be connected to pipelines with a liquefier after delivery) and would be happy to be part of a broader evaluation of entire supply chains, if SoCalGas were interested in involvement in such a project.

From: Angeles Link Outreach <angeleslinkoutreach@arellanoassociates.com>
Sent: Wednesday, September 4, 2024 3:12 PM
To: Angeles Link Outreach <angeleslinkoutreach@arellanoassociates.com>
Cc: Lopez, Frank <flopez5@socalgas.com>; Chester Britt <CBritt@arellanoassociates.com>
Subject: SoCalGas Angeles Link – Draft Reports Feedback due this Friday

Dear PAG Member:

Draft Reports Available for Feedback

As a reminder, the following studies are available for your review in the **Living Library** [arellanoassociates.sharepoint.com]:

- Draft Report: High-level Economic Analysis and Cost Effectiveness feedback is due **Friday, September 6**
- Draft Report: Project Options and Alternatives feedback is due **Friday, September 6**
- Draft Report: Environmental Analysis feedback is due **Friday, September 6**

Please submit your comments to **ALP1_Study_PAG_Feedback@insigniaenv.com**

If you have any questions, you can reach out to me at 909.263.9280 or **cbritt@arellanoassociates.com**. Thank you again for your feedback and we look forward to your continued partnership in Angeles Link.

Sincerely,

Chester Britt

Planning Advisory Group Facilitator

[EXTERNAL] FW: SCGC Comment on Angeles Link High Level Economic Analysis & Cost Effectiveness Draft Report

ALP1 Study PAG Feedback <alp1_study_pag_feedback@insigniaenv.com>

Fri 9/6/2024 7:41 AM

To:Quesenberry, Diana <DQuesenb@socalgas.com>;Ibrahim Elfar, Omar M <OIbrahim@socalgas.com>
Cc:Foley, Jessica <JKinnah1@socalgas.com>;Moreno, Edith1 <EMoreno5@socalgas.com>;Stephanie Espinoza <SEspinoza@arellanoassociates.com>;Chester Britt <CBritt@arellanoassociates.com>;Alma Marquez <almarquez@leeandrewsgroup.com>;Dao, Theresa N <TDao@socalgas.com>;Lopez, Frank <FLopez5@socalgas.com>; Keochekian A <akeochekian@insigniaenv.com>

3 attachments (5 MB)

2024-07-26 High-Level Economics & Cost Effectiveness Draft Report (1).pdf; SCGC Angeles Link Draft Production Planning & Assessment.pdf; SCGC Angeles Link Draft Pipeline Sizing & Design Criteria.pdf;

Good morning,

Please see below for SCGC's email and attached letters on the Pipeline Sizing & Design Criteria, Production Planning & Assessment, and High-Level Economic Analysis & Cost Effectiveness Draft Reports.

Best,

Julie Roshala
Associate Planner
O: 760-635-1587
M: 650-400-3129
INSIGNIA

From: Norman Pedersen <npedersen@hanmor.com>
Sent: Thursday, September 5, 2024 5:17 PM
To: Chester Britt - Arellano Associates (cbritt@arellanoassociates.com) <cbritt@arellanoassociates.com>; Emily Grant <egrant1@socalgas.com>; ALP1 Study PAG Feedback <alp1_study_pag_feedback@insigniaenv.com>
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Subject: SCGC Comment on Angeles Link High Level Economic Analysis & Cost Effectiveness Draft Report

Chester, Emily,

Thank you for the opportunity for SCGC to comment on the attached 7/26/24 Angeles Link High Level Economic Analysis & Cost Effectiveness Draft Report ("Report"). SCGC's first comment is to reiterate the point raised in SCGC's 8/21/24 Comment (also attached) on the Draft Production Planning & Assessment Report: storage will be essential to provide for the projected power sector ramp requirements. Additionally, the location of the storage is critical. Stored hydrogen will behave hydraulically in a pipeline similarly to natural gas. The fuel will travel at around 20 miles an hour. Consequently, the storage should be located as close to the ramping demand as possible. The storage should be located in or near the Los Angeles Basin to be useful to fast ramping LA Basin power plants.

SCGC's second comment is on the projected capital expenditure on the hydrogen transmission, storage, and delivery system. Table 40 (p. 107) in the Report projects capital expenditures of $11.243 billion for the 310 mile Scenario 7 transmission system, $1.419 billion for the 80 mile delivery system, and $4.603 billion for storage, resulting is a total system cost of $17.265 billion, excluding any O&M costs or loaders. That exceeds the $13.4 billion rate base projected in the Test Year 2024 General Rate Case for the entire SoCalGas system. Using the same methodology used in calculating the estimated rate for the $9 billion transmission and delivery system in SCGC's 8/21/24 Comment (also attached) on the Angeles Link Phase 1 Pipeline Sizing & Design Criteria Draft Report, the estimated rate for the $17.265 billion system would be $10.13/Dth. The cost of the system should be reduced to make the project economical.

Best Regards,

Norman

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CALIFORNIA HYDROGEN BUSINESS COUNCIL
COMMENTS ON ANGELES LINK PHASE I
DRAFT HIGH-LEVEL ECONOMIC ANALYSIS AND COST EFFECTIVENESS REPORT

September 6, 2024

Submitted via Email to: ALP1_STUDY_PAG_FEEDBACK@INSIGNIAENV.COM

The California Hydrogen Business Council ("CHBC") respectfully comments on the following Angeles Link Phase 1 draft High-Level Economic Analysis and Cost Effectiveness Report ("Report") posted by the Southern California Gas Company in the Angeles Link Living Library on July 26, 2024.

1. Comments on the High-Level Economic Analysis and Cost Effectiveness Draft Report

The basis for the draft Report reflects the best information available today. As noted in the CHBC comments on the Hydrogen Production Planning & Assessment draft report, there are many uncertainties that will inform more refined analyses in Phase 2 studies, including cost effectiveness. These include: 1) final hydrogen production (and other) tax credit guidance from Treasury; 2) which of the currently planned hydrogen production projects in California will proceed through a final investment decision; and 3) to be established hydrogen certification requirements.

With respect to the identified Hydrogen Delivery Alternatives, the CHBC agrees with the approach of the Report. While hydrogen prices are high today, the Report findings are consistent with industry knowledge that it is cost-effective to deliver hydrogen by pipeline and that hydrogen can also be a cost-effective decarbonization pathway for hard-to-decarbonize and hard-to-electrify sectors. It is important to consider that two-thirds of energy consumed in California today comes from molecules. The projected costs and affordability of decarbonizing molecules are relatively less than the current costs projected for electric transmission upgrades and decarbonization efforts, and this has been contemplated in the Report.

The Report represents an initial economic and cost analysis with assumptions and variables based on what is known or predicted today. Validation of many of these assumptions comes from the U.S. Department of Energy ("DOE") National Clean Hydrogen Strategy and Roadmap. Legislative language set forth in Section 40314 of the Infrastructure Investment and Jobs Act (Public Law 117-58), also known as the Bipartisan Infrastructure Law ("BIL"), specifically amends Title VIII of the Energy Policy Act of 2005 (EPACT-2005) by adding Section 814 - National Clean Hydrogen Strategy and Roadmap ("Roadmap"). Section 814 states that carrying out the programs in the BIL includes transportation corridors and modes of transportation, including transportation of clean hydrogen by pipeline and rail and through ports. The Roadmap includes milestones for hydrogen delivery at scale today and that in the future "gaseous pipelines are commonly used when demand is predictable for decades and at a regional scale of thousands of tonnes per day." This regional scale in part refers to the economies of scale predicted to be engendered by the hydrogen hubs, including the California ARCHES hub. The ultimate hydrogen production capacity and locations in ARCHES will further inform updates to costs, in addition to design and routing, in Phase 2 of Angeles Link.

According to the Roadmap, in the 2030-2035 timeframe the DOE intends to collect data, including emissions data, from demonstrations of bulk hydrogen distribution (e.g., through pipelines or carriers) in real-world environments to inform research, development, demonstration, and deployment that reduces cost.

The DOE Hydrogen Shot, launched June 7, 2021, seeks to reduce the cost of clean hydrogen by 80% to $1 per one kilogram in one decade. The 2023 DOE Pathways to Commercial Liftoff: Clean Hydrogen report predicts that if state-of-the-art advances in hydrogen distribution and storage technology are commercialized and potential end uses come to fruition, 2030 midstream costs could be at $0.1/kg at 600 tpd, 300 km, 12" OD or $0.1/kg at ~5000 tpd, 1000 km, 42" OD.

With the significant strategies for cost reduction of hydrogen planned by the DOE, and research, development, and demonstration underway at national laboratories and private industry, the approach laid out in the Report is justified. The CHBC therefore recommends that Angeles Link proceed with the proposed design and then review costs again in Phase 2 based on outcomes of the current uncertainties outlined above and updated forecasts at that time. With this updated information, Phase 2 would also be the appropriate juncture to review affordability and cost allocation, when there is a better sense of viability and location of hydrogen production facilities, assured end user demand of ARCHES projects, and certainty of tax credit guidance.

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Respectfully submitted,

<u>/s/ Katrina M. Fritz</u>
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Dated: September 6, 2024

September 6, 2024

Comments of the Public Advocates Office on Southern California Gas Company's Angeles Link High-Level Economic Analysis and Cost Effectiveness Draft Report

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) provides these comments on Southern California Gas Company's (SoCalGas) *Angeles Link High-Level Economic Analysis and Cost Effectiveness* (Cost Effectiveness Draft Report), which was issued on July 26, 2024.

SoCalGas must prove Sufficient, Safe Underground Hydrogen Storage Exists for its Levelized Cost of Hydrogen Storage Cost Assumption

The Cost Effectiveness Draft Report provides an updated comparison of the Levelized Cost of Hydrogen Analysis for the Angeles Link and several non-pipeline alternatives.[1] In the Cost Effectiveness Draft Report, SoCalGas continues to assume that the 'Angeles Link Pipeline System', as well as 'Gaseous' and 'Liquid Trucking' alternatives, will benefit from being able to use underground hydrogen storage (UHS) whereas the other alternatives must rely upon much more expensive above-ground storage (*see* Figure 1).[2,3] This assumption plays a substantial part in making the Angeles Link the "the most cost-effective delivery method when compared to the identified Hydrogen Delivery Alternatives for Phase 1 purposes."[4] Significantly, without this assumption, the Angeles Link Pipeline System would rank only slightly more cost-efficient than 'Liquid

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[1] The 'Angeles Link Pipeline System' is compared against the Hydrogen Delivery Alternatives of 'Liquid Hydrogen Shipping', 'In-Basin Production w/ Power T&D', 'Methanol Shipping', 'Gaseous Trucking', 'Localized Hub', and 'Liquid Trucking'. *Angeles Link High-Level Economic Analysis and Cost Effectiveness* (Cost Effectiveness Draft Report), Figure 2 at 13.

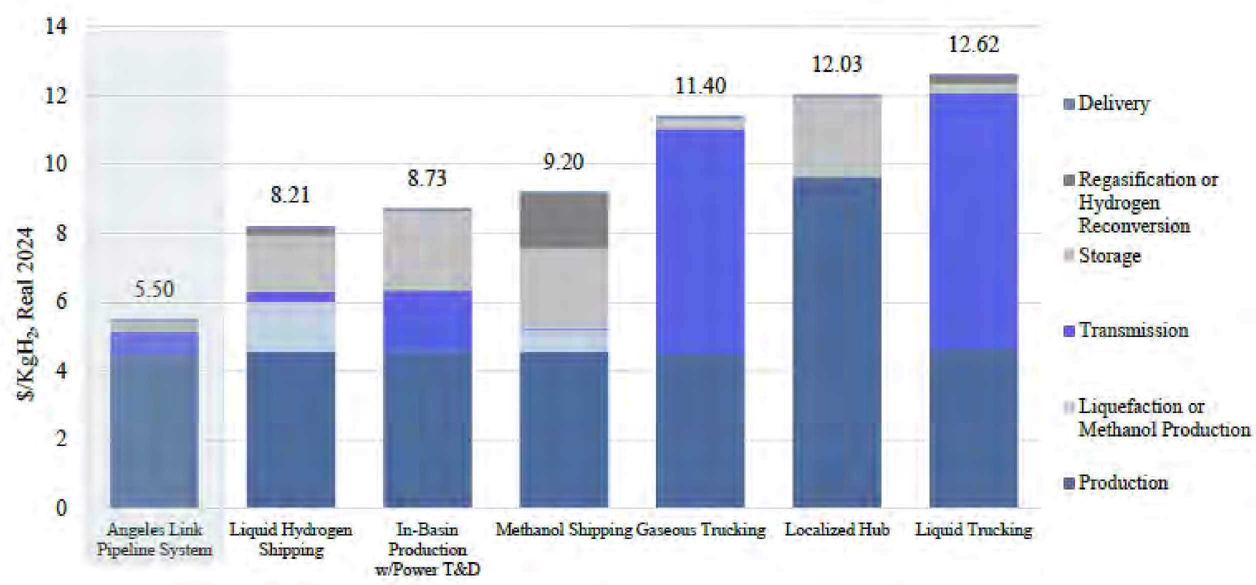
[2] "For Angeles Link and the trucking alternatives (gaseous and liquid), identified routes allowed for access to underground storage sites, therefore, underground storage costs were assumed. Delivery alternatives with production sites that did not overlap with the identified geological storage sites, were assumed to rely on above ground storage." Cost Effectiveness Draft Report, at 13

[3] Table 41 shows Depleted Oil Field UHS costs $3,968 (US$MM) compared to Above Ground Liquid Storage cost of $28,013 (US$MM). This means the levelized cost of UHS is estimated at over six times less expensive than above-ground storage solutions. Cost Effectiveness Draft Report, at 110.

[4] Cost Effectiveness Draft Report, at 14.

Hydrogen Shipping' and 'In-Basin Production w/ Power T&D'.[5] As Cal Advocates stated in previous comments,[6] SoCalGas's cost assumptions for the Angeles Link are optimistic as they rely on two as yet unproven facts: 1) that there is sufficient UHS available and 2) that the UHS is safe to operate.

Figure 1 - Cost Effectiveness of Angeles Link vs Hydrogen Delivery Alternatives, taken from the Cost Effectiveness Draft Report, at 32



SoCalGas' own analysis highlights the knowledge gaps that are inherent to UHS. Analysis in the *Angeles Link Production Planning & Assessment Draft Report* (Production Draft Report) catalogued the availability of underground hydrogen storage in a region spanning Southern California, Arizona, Nevada, and Utah[7] and calculated a composite value to rank the feasibility of UHS in each oil and gas field in California.[8] While this research is helpful to show availability of storage locations, it does not address the fact that conversion of oil and gas fields to hydrogen storage is both an unproven technology and without precedent in a commercial setting. The Production Draft Report stated:

> There are currently no permitted examples of UHS in depleted reservoirs, and engineering and geological requirements for UHS are currently not defined. The lack of a regulatory framework may result in delays and challenges to implementation.[9]

[5] Cost Effectiveness Draft Report, Figure 2 at 13.
[6] Cal Advocates' Informal Comments on *SoCalGas Angeles Link Pipeline Sizing Preliminary Findings*, at 3-5.
[7] *Angeles Link Production Planning & Assessment Draft Report* (Production Draft Report), at 87.
[8] Production Draft Report, Appendix C, at 87-111.
[9] Production Draft Report, at 77.

The Production Report later identifies seven concerns for bringing UHS depleted oil and gas fields to commercial success. These concerns include the lack of commercially operable projects to properly estimate capital and operational costs.[10] Given the skepticism evident in SoCalGas's own Production Report, SoCalGas needs to explain and provide support for why it believes the operation of UHS using depleted oil fields is a viable option, that will be commercially available and feasible in the timeline proposed in the Cost Effectiveness Draft Report.

Most critical to the issue of utilizing depleted oil and gas fields for UHS are the many unanswered safety questions that need to be resolved before such facilities can be deemed safe to operate. In its Informal Comments on Pipeline Sizing Preliminary Findings, Cal Advocates cites the UCR Study commissioned by the CPUC which notes twenty major safety issues related to storing hydrogen inside of depleted oil and gas fields.[11] Rather than provide answers to these questions, SoCalGas's Production Draft Report either repeats or raises new safety concerns: these unaddressed safety concerns include hydrogen losses due to microbial activity,[12] leakage of hydrogen due to penetration through sealing rocks or wellbores,[13] and embrittlement of casings and tubing of existing storage field infrastructure.[14] These safety concerns must be addressed before SoCalGas can assume that UHS is feasible in depleted oil and gas reservoirs in California.

Conclusion

If SoCalGas insists on relying on UHS to make the case for the cost effectiveness of the Angeles Link, then it must provide substantial evidence to support its assertion that its pipeline project will be able to leverage safe underground storage at a levelized cost that is six times less expensive than its above-ground storage counterparts.[15] If no additional evidence related to the suitability and safety of the depleted gas and oil fields is

[10] Production Draft Report, at 73.
[11] "Hydrogen is known to have serious detrimental effects on underground porous reservoirs. Twenty different hydrogen related phenomena have been observed that have negative effects on porous reservoirs' performance as storage facilities for methane-hydrogen gas blends. The most serious of these is bacterial growth and activity, resulting in loss of gas volume, potential for H_2S production and damage to reservoir itself [44]." UCR Study, at 15.
[12] One of the seven listed concerns for commercial application of depleted oil and gas reservoirs for UHS includes "Potential for loss of hydrogen by microbial activity." Production Draft Report, at 73.
[13] "However, due to the unique properties of hydrogen gas, there remain uncertainties with respect to the movement and recoverability of hydrogen injected for storage in depleted reservoirs, primarily relating to loss of hydrogen via biological and geochemical activity, and leakage through sealing rocks and improperly sealed wellbores." Production Draft Report, at 77.
[14] "Additionally, interaction of hydrogen with existing field infrastructure originally implemented for oil and gas storage and extraction may cause adverse effects such as embrittlement of casing and tubing, which has the potential to lead to well integrity issues and potential leak pathways." Production Draft Report, at 77.
[15] Table 41 shows Depleted Oil Field UHS costs $3,968 (US$MM) compared to Above Ground Liquid Storage cost of $28,013 (US$MM). This means the levelized cost of UHS is estimated at over six times less expensive than above-ground storage solutions. Cost Effectiveness Draft Report, at 110.

provided, then SoCalGas should make the safe and prudent assumption that only aboveground storage would be available to operate with the Angeles Link.

September 6, 2024

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Southern California Gas Company

Alisa Lykens
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Subject: Environmental Defense Fund Comments on Planning Advisory Group Draft Reports

Environmental Defense Fund (EDF) shares the following comments on draft reports from the Angeles Link Planning Advisory Group Facilitator team on the topics of high-level economic analysis and cost-effectiveness; project options and alternatives; and environmental analysis. Overall, EDF believes it is important to **compare the full range of alternatives and their impacts**—especially in areas where there are acknowledged gaps in the reports—if SoCalGas were to proceed in requesting regulatory approval for this project. Additionally, EDF expresses concern that certain **assumptions around the economic analysis of a potential hydrogen pipeline and alternatives appear overly generous** towards hydrogen applications.

The purpose of the Phase 1 studies is to gain insight into whether the potential Angeles Link project would be a cost- and climate-effective decarbonization pathway for end-users in the Los Angeles basin; and, in turn, would be a just and reasonable use of ratepayer funds if SoCalGas decides to proceed with the project. To make this determination, the full range of alternatives and impacts must be accurately compared. The draft reports, however, fall short in taking a comprehensive comparison of alternatives and their impacts. For example, the High-level Economic Analysis and Cost-Effectiveness Report compares hydrogen retrofit generation with 12-hour lithium-ion long-duration energy storage to examine the cost-effectiveness of various alternatives for electricity supply.[1] Other long-duration energy storage options such as pumped

[1] High-level Economic Analysis and Cost-effectiveness Report at 19.

hydro, thermal, or iron-air technology—some of which may be more technologically mature, cost-effective, or more suitable for the expected end-use cases than lithium-ion battery storage—are not considered. The draft report and the analysis should be expanded to cover the full range of potential alternatives for the various end-uses examined; or at a minimum, provide detailed justification of why certain alternatives were chosen for comparison over others. The current draft report, however, does neither.

Similarly, while the Environmental Analysis Report lists out various alternative decarbonization pathways and their respective potential environmental impacts, their magnitude or comparative impacts are not included.[2] EDF acknowledges that at this preliminary stage, providing an exact comparative analysis may be difficult. However, detailed analysis would be necessary if SoCalGas decides to move forward with requesting regulatory approval for the Angeles Link project—and as such, represents a critical knowledge gap in the reports.

Moreover, the comparative cost-effectiveness of the hydrogen pipeline and other alternatives as claimed in the report must be understood within the broader context of their climate- and environmental impacts. For example, the High-level Economic Analysis and Cost-Effectiveness Report finds that hydrogen-fueled kilns are more cost-effective than to electrification alternatives.[3] While cost-effectiveness is a key factor, it is also important to keep other factors in mind—including environmental impacts, technological maturity, end-user preferences, and the impact on local communities. Whether hydrogen is the most suitable decarbonization pathway for a specific end-use is a decision that must be made comprehensively, taking into account various factors including, but not limited to, cost-effectiveness. Similarly, the High-level Economic Analysis and Cost-Effectiveness Report finds that clean renewable hydrogen is a less cost-effective option for refinery use than hydrogen abated through CCS.[4] However, EDF studies have shown that such "blue" hydrogen (*i.e.*, hydrogen from fossil fuel reformation coupled with CCS) applications can be an ineffective climate solution, due to concerns around leakage and the role of

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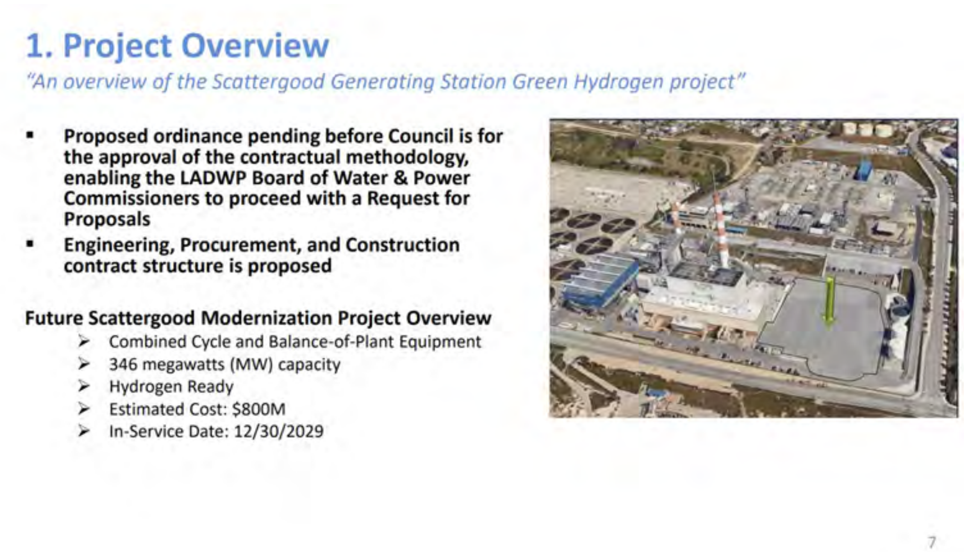
[2] Environmental Analysis Report at ES-9.
[3] High-level Economic Analysis and Cost Effectiveness Report at 19.
[4] Ibid, at 21-22.

hydrogen as an indirect gas.[5] It is important not to conflate "cost-effective" with "lowest-cost" to justify less environmentally and climate-robust options.

In addition to the broader comments above, EDF highlights specific concerns around the assumptions and parameters used in the High-Level Economic Analysis and Cost-Effectiveness Report. Certain assumptions appear overly generous in favor of hydrogen use-cases over other decarbonization pathways; and granular details are unavailable due to the use of a proprietary modeling tool.

For example, the report finds that the capital expenditure costs (CAPEX) for hydrogen combustion turbine retrofit would range from \$156/kw to \$260/kw; it also assumes that the net capacity factor for a retrofit hydrogen turbine would be around 9-11% when used to meet peak demand.[6] Such figures, however, are at odds with details shared by some planned or realized retrofit projects. In 2023, the LA City Council approved a \$800 million dollar project to retrofit the existing gas-fired power plants located at Scattergood Generation Station.[7]



[5] Ocko, I. B. and Hamburg, S. P.: Climate consequences of hydrogen emissions, Atmos. Chem. Phys., 22, 9349–9368, https://doi.org/10.5194/acp-22-9349-2022, 2022.
[6] High-level Economic Analysis and Cost Effectiveness Report at 101.
[7] Roth, Sammy, "L.A. is shutting down its largest gas plant — and replacing it with an unproven hydrogen project", *The Los Angeles Times*, Feb. 8, 2023. Accessible at: https://www.latimes.com/business/story/2023-02-08/l-a-is-shutting-down-a-coastal-gas-plant-and-replacing-it-with-hydrogen

The project would replace exist units 1 and 2 with an overall capacity of 346 MW—or *$2,300/kw*—and is expected to be operational extremely infrequently with a capacity factor closer to 1-5%.[8] The details from the planned Scattergood project, in comparison with figures provided in the draft report, raises the concern that the economic assumptions behind the report may be too generous. Furthermore, many of the specific figures in the report cite a model used by WoodMackenzie and studies from the National Petroleum Council.[9] Without having access to the model used by the consultants, it is impossible for PAG members to accurately understand the assumptions behind the report or the engage with them. EDF strongly urges that steps be taken to provide access to the model and its assumptions, in order for PAG members to engage with the Phase 1 feasibility study process more constructively.

Respectfully,

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[8] LADWP, "Scattergood Modernization Project", February 3, 2023. Accessible at: https://clkrep.lacity.org/onlinedocs/2023/23-0039_rpt_DWP_02-03-2023.pdf. See also, LADWP Presentation to the Board of Commissioners; record accessible here: https://ladwp.granicus.com/MediaPlayer.php?view_id=2&clip_id=1960.

[9] High-level Economic Analysis and Cost Effectiveness Report at 101.

September 6, 2024

Southern California Gas Company
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Submitted via email to ALP1_Study_PAG_Feedback@insigniaenv.com

Feedback for Southern California Gas Company on the Environmental Analysis Draft Report

Communities for a Better Environment (CBE) submits this letter of feedback to Southern California Gas Company (SoCalGas) on the Environmental Analysis Draft Report (the "Draft Report") provided on July 26, 2024. This letter raises several concerns with the Draft Report's scope and content.

The Draft Report notes that the study was prepared pursuant to California Public Utilities Commission Decision 22-12-055 ordering paragraphs 5(e), (6i), and 6(n). In addition to the Draft Report, SoCalGas has produced a Preliminary Routing-Configuration Analysis Draft Report, a Project Options and Alternatives Draft Report, and a High-Level Feasibility Assessment and Permitting Analysis Draft Report. SoCalGas also produced reports on Angeles Link project (ALP) air pollution emissions, water resource requirements, safety, routing, and more. Yet, the Draft Report does not offer a clear explanation of why critical aspects of project planning were left out of the most detailed report on existing conditions and ALP impacts at regional and local levels. Given the Phase 1 feasibility study and feedback process' high volume of lengthy documents, SoCalGas should have organized a much more streamlined and comprehensive review process.[1]

The Draft Report omits key details and study topics, in addition to its curtailed scope, which SoCalGas must remedy. Particularly, the Report:

- Does Not Include Topics Necessary to Analyze ALP Environmental Impacts and Downplays the Environmental Hazards of Transporting 100% Hydrogen by Pipeline
- Omits Extant Conditions in Multiple Study Areas by Paraphrasing Inapposite Descriptions of Project Impacts and Available Mitigation Measures from Disparate Study Areas

[1] CBE appreciates the two-week extension SoCalGas granted for stakeholders to provide feedback on eight feasibility study reports but emphasizes the substantial amount of staff time required by CBOs and other parties to review reports and offer critical feedback.

- Does Not Evaluate the Environmental Impacts of a Major Route Variation Designed to Reduce the Impact of ALP on Disadvantaged and Environmental Justice Communities

I. *The Draft Report Does Not Include Topics Necessary to Analyze ALP Environmental Impacts and Downplays the Environmental Hazards of Transporting 100% Hydrogen by Pipeline*

The Draft Report does not analyze hydrogen production impacts on energy demand, water, or air quality; hydrogen usage impacts; or hydrogen safety impacts, which cannot be severed from ALP construction or operation and maintenance. The explanation that the Draft Report is simply a high-level desktop study does not excuse the omission. The report's analysis and discussion are succinct, and do not go into great detail regarding impacts. Rather, the Draft Report simply classifies studied potential impacts as "No Impact" or "Potential Impact" with a brief description of the Study Area's existing conditions. The report suggests that more detailed analysis would occur in formal CEQA and/or NEPA environmental review in the future.[2]

Hydrogen production and end-use facilities are not severable from the ALP transmission pipeline. Nor are the direct and novel safety risks of transporting high volumes of pure hydrogen through crowded urban areas. Without hydrogen production at the pipeline's starting point and end-use in the Los Angeles basin, the ALP as proposed cannot be constructed. The ALP cannot reach its endpoint without transporting high volumes of pure hydrogen into crowded urban areas. Likewise, without inclusion of these features in the environmental analysis, the analysis is not complete. The ALP study process has already netted sufficient data to include hydrogen production, end-use, and safety-impacts in the Draft Report. It is simply that this information is left out of this report.

a. <u>The Impacts of Hydrogen Production and End-Uses are Identifiable but Omitted</u>

SoCalGas must revise each impacts section to include each of these considerations in order to accurately analyze the ALP's environmental impacts. Specifically, the Draft Report should analyze whether hydrogen production or end-use facilities will be located in each Study Area. If such siting is potentially the case, then the Draft Report should include the impacts of that essential infrastructure in the Study Area discussion. While "the location of production facilities, storage areas, appurtenances, and end users are not known"[3] with certainty, neither is the route of ALP which the Draft Report examines. Nonetheless, the Draft Report examines impacts of the pipeline based on proposed routing. Surely, SoCalGas can project where hydrogen

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[2] Draft Report at ES-4.
[3] *Id.* at 1-3.

production and use may be located given that the ALP's production needs, throughput volume, and possible hydrogen demand have all been calculated in other ALP Phase 1 studies.

b. Hydrogen is a Hazardous Material

The Draft Report does not incorporate adequate discussion of hydrogen safety risks and safety measures. As CBE raised previously, hydrogen is a hazardous material which has unique characteristics distinct from natural gas.[4] It is more leak prone and more easily combusted than natural gas, current leak detection and safety technology are not adequate to protect communities from the risks of hydrogen, and the repeated guarantee that the ALP will be "subject to the same safety considerations as a natural gas pipeline," is no solace for environmental justice communities.[5] The Draft Report itself notes: "The transportation of hydrogen gas carries an inherent risk of upset that could result from an inadvertent strike or dig-in by a third party, a leak, or other release of hydrogen."[6] While natural gas pipelines also pose leakage risks from strikes or dig-ins, as CBE described in our feedback to the Safety Study,[7] hydrogen poses different dangers than natural gas and requires *additional* safety considerations. Therefore, SoCalGas's conclusion in the Draft Report that the Angeles Link "hydrogen pipeline would be subject to the same safety considerations as a natural gas pipeline"[8] is inaccurate and insufficient. Regardless of whether hydrogen pipelines are aboveground or underground as they cross through disadvantaged or environmental justice communities, the Draft Report must analyze hydrogen specific risks in greater detail and care toward each Study Area's unique characteristics to accurately analyze the existing conditions and environmental impacts of the ALP.

II. The Draft Report Omits Extant Conditions in Multiple Study Areas by Paraphrasing Inapposite Descriptions of Project Impacts and Available Mitigation Measures from Disparate Study Areas

SoCalGas dismisses regional differences in Study Areas which artificially minimizes the studied ALP impacts. Study Area 1A is entirely within the largely rural San Joaquin Valley and includes sparsely populated portions of Fresno, Kings, and Kern counties.[9] Study Area 1A is centered around potential ALP Segment C, which does not cross through any major population center. The Draft Report notes there are "[n]o schools, day-care centers, or preschools located

[4] CBE, Feedback for Southern California Gas Company on the Plan for Applicable Safety Requirements Draft Report, Jul. 19, 2024.
[5] Draft Report at ES-7, 3-36.
[6] *Id.* at ES-7.
[7] CBE, Feedback for Southern California Gas Company on the Plan for Applicable Safety Requirements Draft Report, Jul. 19, 2024.
[8] Draft Report at ES-7.
[9] *Id.* at 3-3.

within" 0.25 mile[10] or 0.5 mile[11] of Segment C in Study Area 1A. Study Area 1B covers relatively less populated (compared with Study Areas 2, 3A, 3F, and others) portions of northern and northeastern Los Angeles County, including the cities of Lancaster, Palmdale, and Santa Clarita.[12] Per Table 3.2-19,[13] there are 23 schools and 25 day-care centers within 0.5 mile of Study Area 1B's Segment B.

Study Area 2 includes urban, densely populated portions of Los Angeles and Orange counties and cities like Los Angeles, Carson, Inglewood, Long Beach, South Gate, and Torrance.[14] Study Area 3F includes portions of the City of Los Angeles, Bell, Huntington Park, Lynwood, Maywood, South Gate, Vernon, and more.[15] The Draft Report notes that 137 schools and 168 day-care centers are located within 0.5 mile of the six possible segments of ALP in Study Area 2.[16] Similarly, there are 159 schools and 133 day-care centers within 0.5 mile of Segment Y in Study Area 3F.[17]

Clearly, there are many more sensitive receptors near ALP segments in Study Areas 2 and 3F than in Study Area 1B and Study Area 1A. The Draft Report states that potential hazardous material emissions or impacts near these many sensitive receptors could be avoided or mitigated as detailed in Section 3.3.6.3 for Study Area 2 and 3.9.6.3 for Study Area 3F. With respect to hazardous material transport, use, or disposal in Study Area 2 more generally, the Draft Report states:

> [C]onstruction and O&M activities would be anticipated to have a potential for temporary or permanent impact to the public or the environment in the event of an accident or spill during the routine transport, use, and/or disposal of hazardous materials during construction and O&M activities. Most of the Potential impacts could be reduced through the implementation of the AMMs detailed in Section 3.3.6.3 Potential Avoidance and Minimization Measures.[18]

Yet, Section 3.3.6.3 tells the reader to refer to the Potential Avoidance and Minimization Measures (PAMMs) for Study Area 1A and Study Area 1B which are significantly less populous than Study Areas 2 and 3F and contain significantly fewer co-hazards.[19] By avoiding accurate,

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[10] *Id.* at 3-36
[11] *Id.* at 3-33.
[12] *Id.* at 3-51.
[13] *Id.* at 3-76.
[14] *Id.* at 3-93.
[15] *Id.* at 3-365.
[16] *Id.* at 3-135.
[17] *Id.* at 3-394.
[18] *Id.* at 3-134 to 3-135.
[19] *Id.* at 3-137 to 3-138. For a description of those proposed PAMMs, *see* Draft Report at 3-38, 3-81.

region-specific analysis, the Draft Report fails to identify necessary, location-specific safety measures.

Not only are the PAMMs not tailored to the unique characteristics of each study area, but they are also not tailored to the unique hazardous properties of characteristics of hydrogen. Without any justification for making such a claim, the Draft Report states that "impacts that could be anticipated within Study Area 2 would not be expected to differ from those identified within Study Areas 1A and 1B."[20] According to SoCalGas for Study Area 3F, likewise, the "impacts that could be anticipated within Study Area 3F would not be expected to differ from those within Study Areas 1A and 1B."[21] These are just a few instances of numerous, similar conclusory statements made throughout the Draft Report that lump together extremely different locations and sets of conditions.

The hazardous materials PAMMs for Study Area 1A do not include any measures related to schools since there are no such sensitive receptors in that Study Area. For schools and daycare centers in Study Area 1B, the hazardous materials PAMMs for are: (1) "Transportation and disposal routes could be sited at locations well outside of schools or day-care centers" and (2) "Pipeline segments could be sited away from schools or day-care centers." So, the PAMMs for these more sparsely populated study areas suggest that potential ALP-related dangers could be sited further away from the sensitive receptors. SoCalGas must explain how it is that the abovementioned siting-related PAMMs, which could possibly suffice in low density Study Area 1B, could plausibly apply to the extremely high densities of Study Areas 2 and 3F. Otherwise, it must identify additional safety measures tailored for densely developed areas.

III. The Draft Report Fails to Evaluate the Environmental Impacts of a Major Route Variation Designed to Reduce the Impact of ALP on Disadvantaged and Environmental Justice Communities

SoCalGas' Preliminary Routing-Configuration Analysis Draft Report identified a routing scenario, "Route Variation 1," which limited the ALP's traversal of disadvantaged communities in the Los Angeles area. Unfortunately, the Draft Report claims SoCalGas did not have enough time to analyze this fifth scenario because it "was identified late in the Phase 1 analysis." CBE raised the need to plan pipelines routes around, not through, environmental justice communities in response to SoCalGas' Preliminary Routing & Configuration Assessment study description at the earliest available opportunity provided by the ALP's community engagement process.[22] CEJA and Sierra Club raised the very same issue to the CPUC in 2022, *over a year before phase*

[20] Draft Report at 3-138.
[21] *Id.* at 3-397.
[22] CBE, Additional Feedback for Southern California Gas Company on Angeles Link Project Phase One Technical Approaches, at 2, Nov. 3, 2023.

1 study descriptions were released.[23] The Equity Principles for Hydrogen document, which SoCalGas has reviewed and responded to, raises the need to site dangerous energy infrastructure outside of environmental justice communities. The Routing Study itself did evaluate Route Variation 1 in a fair amount of detail, and CBE provided detailed feedback about that route variation.[24] It is not clear why SoCalGas and its contractors did not have enough time to evaluate Route Variation 1 in the Environmental Analysis when the Routing Study was released to ALP process participants a week before the Environmental Analysis Draft Report.

The claim at this late stage that SoCalGas lacked time to evaluate the alternative route is not excusable. Pipeline routes that avoid further burdening environmental justice communities should have been planned from the outset. Instead, the single "variation" of the ALP that does so is not incorporated in the Environmental Analysis or Environmental Justice Analysis draft studies. As SoCalGas was informed over two years ago:

> The community in Wilmington is 90% Latinx and is rated in the top 90% most polluted and vulnerable to health impacts.[a]
>
> The life expectancy in Wilmington is the sixth lowest of the 35 community plan areas in Los Angeles.[b] These impacts are not accidental. The history of redlining and white flight in Los Angeles is intertwined with the racially discriminatory siting of fossil fuel infrastructure and other polluting facilities.[c]
>
> The Wilmington community fights for environmental and climate justice, a phrase that bears far more weight for the families living in the shadows of refineries. Community members have been seeking to phase out oil extraction, refining and transportation for decades. By following SoCalGas' existing rights-of-way through Los Angeles, the Angeles Link Project could exacerbate existing environmental injustices. It is absolutely imperative that the clean energy future does not replicate the injustices of the past by giving new life to pipelines and polluting these communities anew.[25]

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[23] A. 22-02-007, Opening Brief of Sierra Club and the California Environmental Justice Alliance, at 37-38, July 29, 2022.
[24] CBE, Feedback for Southern California Gas Company on the Preliminary Routing/Configuration Analysis Draft Report, Aug. 30, 2024.
[25] A. 22-02-007, Opening Brief of Sierra Club and the California Environmental Justice Alliance, at 37-38, July 29, 2022. (Internal citations reproduced here:

a. Yvette Cabrera, This Young Environmental Activist Lives 500 Feet from a Drilling Site, HuffPost, (Apr. 19, 2018), https://www.huffpost.com/entry/ashley-hernandez-environmentaljustice_ n_5ad7ad3fe4b03c426daaeab3.
b. Adam Mahoney, Deaths Have Spiked in This Polluted Port Community. Grist, (Mar. 31, 2022), https://grist.org/health/excess-deaths-wilmington-california-covid-pollution/.
c. CalEPA, Pollution and Prejudice: Redlining and Environmental Injustice in California, (Aug. 16, 2021), https://storymaps.arcgis.com/stories/f167b251809c43778a2f9f040f43d2f5.).

IV. Conclusion

CBE appreciates the opportunity to provide feedback on the Draft Report.[26] While the Draft Report begins to identify key issues for environmental analysis, its lack of discussion on serious areas of concern mean that the identified ALP impacts and proposed mitigation measures provide only a fraction of the whole picture. CBE encourages SoCalGas to seriously address the issues identified here before issuing a final Environmental Analysis report.

Sincerely,

Jay Parepally
Theo Caretto

Communities for a Better Environment

CC:
Frank Lopez, SoCalGas
Chester Britt, Arellano Associates
Alma Marquez, Lee Andrews Group
Angeles Link service list

[26] At this time, CBE reserves comment on the Draft Report's hydrogen delivery and non-hydrogen options/alternatives analysis and refers SoCalGas to CBE's prior feedback on alternatives as well as the Equity Principles for Hydrogen.

September 9, 2024

Submitted via email to ALP1_Study_PAG_Feedback@insigniaenv.com.

RE: Feedback on Draft Reports of the Angeles Link Project and CBOSG Process

Food & Water Watch, as part of the Community Based Organization Stakeholder Group (CBOSG), submits this letter of feedback regarding the preliminary data and findings of the Angeles Link Project by the Southern California Gas Company (SoCalGas) and the CBOSG process. Concerns relating to the preliminary data and findings and the CBOSG process are as follows:

Draft Reports:

High-level Economic Analysis and Cost Effectiveness:

> The report fails to adequately address the cost impact the Angeles Link Project would have on SoCalGas ratepayers. Despite SoCalGas' claims that a hydrogen buildout would be cost-effective, there is no clarity on how this would actually benefit ratepayers. The cost and scale of building these hydrogen pipelines would be substantial. Given that California currently has only 27 miles of hydrogen pipeline, Angeles Link would require substantial expansion of pipeline and compressor station networks. Depending on the routing choice, Angeles Link could ultimately cost billions of dollars.
>
> Additionally, as hydrogen is currently not regulated as a public service utility, cost recovery for Angeles Link would depend on how California law treats hydrogen. And given how SoCalGas recently filed a petition with the California Public Utilities Commission to approve rate hikes on their customers to fund hydrogen pilot programs, it is likely that SoCalGas will have ratepayers face increased rates to cover the cost for their hydrogen buildout. This would be an unnecessary burden on ratepayers. At a time when ratepayers throughout California are facing constant rate hikes and struggling financially, it is irresponsible to pursue hydrogen while not taking into account how it will affect working class Californians.

Project Options and Alternatives:

> Although the report accurately identifies electrification as an alternative to the Angeles Link Project, it severely overlooks the benefits of electrification. This is likely due to how electrification would impact SoCalGas' profits, rather than a good faith analysis of electrification. While SoCalGas claims that the hydrogen in the Angeles Link Project will

be used for “hard to electrify” sectors, ” in reality the industrial sector accounts for a small percentage of SoCalGas’s forecasted demand for the project. Even when it comes to trucking, there are numerous alternatives to hydrogen fuel such as overhead charging by connecting directly to power lines for longer trips.

Electrification would also have a significantly smaller water footprint. In the February 2024 water report commissioned by SoCalGas, it claimed that water requirements to produce the hydrogen transported in the project would range from 5,608 to 16,824 acre feet per year. That’s equivalent to the amount of water that between 104,000 and 313,000 average Californians use in their homes annually.

Environmental Analysis:

The report fails to adequately address how the construction and implementation of hydrogen infrastructure would impact water resources and air quality. Given that at this time the exact pipeline routes of the Angeles Link Project have not been determined, nor have other key factors such as production facilities and storage areas, then we are not being presented with an accurate representation of the environmental impacts.

Although the report does acknowledge that the transportation of hydrogen has safety risks, particularly due to leakage, this is not reflected in the safety considerations. Given that hydrogen is more volatile than natural gas and more prone to leakage, it does not make sense that SoCalGas is considering applying the same safety considerations to hydrogen pipelines as it does for their potential hydrogen ones. At minimum, different safety considerations would need to be implemented. At the same time, current leak detection and safety technology for hydrogen does not adequately protect frontline communities. SoCalGas does not account for this lack of technology.

As Food & Water Watch has stressed throughout Phase 1 of the Angeles Link Project, SoCalGas’ plans for the transportation and use of hydrogen is not in the best interest of ratepayers, frontline communities, nor our climate. We strongly believe that the California Public Utilities Commission should not approve this Project entering Phase 2. Electrification should be the path forward for California’s energy future.

Sincerely,

Andrea Vega
Southern California Senior Organizer
Food & Water Watch

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CALIFORNIA HYDROGEN BUSINESS COUNCIL
COMMENTS ON ANGELES LINK PHASE I
DRAFT FRAMEWORK FOR AFFORDABILITY CONSIDERATIONS

October 4, 2024

Submitted via Email to: ALP1_STUDY_PAG_FEEDBACK@INSIGNIAENV.COM

The California Hydrogen Business Council ("CHBC") respectfully comments on the following Angeles Link Phase 1 Draft Framework for Affordability Considerations ("Framework") posted by the Southern California Gas Company in the Angeles Link Living Library on September 20, 2024.

1. Comments on the Draft Framework for Affordability Considerations

The CHBC appreciates the early analysis and consideration of affordability in Angeles Link Phase 1. While the basis for the draft Report reflects the best information available today, as noted in the CHBC comments on the draft High-Level Economic Analysis and Cost Effectiveness Report, there are many uncertainties that will inform more refined analyses in Phase 2 studies, including affordability and cost effectiveness.

In addressing Ordering Paragraphs 5(a) and 6(k), the report appropriately provides a framework to analyze affordability at the future time when project specifics and costs are more certain. The Framework outlines a process to delve into the rate design and cost allocation when more variables, such as project design and routing, are known. Importantly, the Framework has sufficiently referenced and demonstrated that there is potential for hydrogen to be part of a lower cost energy scenario than electrification alone.

It is also appropriate to outline an assessment of non-ratepayer opportunities for funding, although these may also be variables that change during the course of Phase 2, such as available federal funding. Some of the additional funding opportunities identified in the Framework, like innovative rate design and utility hydrogen procurement, represent paradigm shifts that may be needed to facilitate the energy transition. Both the non-ratepayer opportunities and the additional opportunities should be further explored into Phase 2 and revisited in a subsequent report. These innovations can more broadly inform how this type of infrastructure may be funded in the future.

Respectfully submitted,

/s/ Katrina M. Fritz
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Dated: October 4, 2024

October 4, 2024

Chester Britt
Planning Advisory Group Facilitator

Emily Grant
Angeles Link Senior Public Affairs Representative
Southern California Gas Company

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Director
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Subject: Environmental Defense Fund (EDF) Comments of Draft Framework for Affordability Considerations

EDF appreciates the opportunity to comment on the draft framework for affordability considerations as part of the Angeles Link Phase 1 studies. EDF's comments below will focus on providing general feedback on issues around funding a potential Angeles Link project, rather than details of potential funding opportunities identified by SoCalGas in the draft framework.

Throughout the Angeles Link Proceeding and the Public Advisory Group project, EDF has emphasized that its position is not one of blanket opposition against hydrogen adoption or even of a potential hydrogen pipeline project. Instead, EDF is interested in ensuring that any and all hydrogen adoption is focused on end-uses where hydrogen offers the most cost- and climate-effective decarbonization pathway; and that any potential Angeles Link Pipeline project is right-sized and designed with important environmental, climate, and environmental justice considerations in mind. If hydrogen is indeed identified as the most cost- and climate-effective decarbonization pathway for certain end-uses (*e.g.*, industrial high heat) and if a potential pipeline project—with the appropriate guardrails—is identified as the most appropriate means for hydrogen supply for these end-uses, EDF believes non-ratepayer funding and other innovative financing mechanisms will be important to explore. The transition to a decarbonized future will require substantial investments in the short term, while its benefits will be diffuse and realized over a longer timeframe. Non-ratepayer funding and financing mechanisms can help bridge that gap; and ensuring that ratepayers or end-users are not forced to pay for a decarbonization pathway that may prove critical in the broader goal of meeting California's ambitious climate goals.

That all being said, it is important to reiterate the preconditions that need to be met. To have a discussion on how to fund a hydrogen pipeline project, the need for hydrogen and—more specifically—the need for a *hydrogen pipeline* must first be established. Non-ratepayer funding and/or fixed charges suggested by SoCalGas in the draft framework should not be seen as a fallback mechanism that can somehow justify a less (or worse yet, not) cost- and climate-effective decarbonization pathway. In fact, such funding sources and mechanisms would only add to the need to put in place important environmental, climate, environmental justice, and economic guardrails.

Various parties, including EDF, have identified major concerns with level of hydrogen demand and associated project costs that SoCalGas has provided in the Phase 1 studies. While recognizing SoCalGas' engagement with and feedback to party comments, EDF continues to express the concern that Phase 1 studies continue to assume extremely high levels of hydrogen demand—above levels projected by California Air Resources Board Scoping Plan updates—and conflates the need for hydrogen supply in the state or the need for hydrogen supply infrastructure in general with the need for the potential Angeles Link pipeline project. For example, the draft affordability framework cites report published by EDF and E3 highlighting the need for clean firm power assets to support California's decarbonized energy future.[1] While the report does include hydrogen as an "all-of-the-above" clean firm power option, it is also important to note that the report should not be read as somehow endorsing the need for the potential Angeles Link pipeline project. Again, the need for and benefits of the Angeles Link pipeline should be determined by the specific demands that can be served by the project as well as other project details—and these considerations should serve as the basis for any future discussions around affordability, non-ratepayer funding, and other innovating financing mechanisms.

[1] Draft Affordability Framework at 9.

Respectfully,

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October 4, 2024

Southern California Gas Company
555 West Fifth Street
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Submitted via email to: **ALP1_Study_PAG_Feedback@insigniaenv.com**

RE: Feedback for Southern California Gas Company on *Angeles Link Phase 1 Draft Framework for Affordability Considerations*

The Green Hydrogen Coalition ('GHC') is appreciative of SoCalGas' effort to implement Angeles Link, the nation's first dedicated common carrier renewable hydrogen pipeline, as it is an essential component of California's goal of economy wide decarbonization and our transition away from fossil fuels. The GHC is a California educational 501(c)(3) non-profit organization that was formed in 2019 to recognize the game-changing potential of "green hydrogen" to accelerate multi-sector decarbonization and combat climate change. The GHC's mission is to facilitate policies and practices that advance green hydrogen production and use across all sectors of the economy to accelerate a carbon-free energy future and a just energy transition.

Background/Basis for GHC's Comments

From 2020-2023 the GHC launched and completed HyBuild Los Angeles, a multi stakeholder independent system planning effort to determine if it is commercially and technically possible to create a mass-scale green hydrogen ecosystem to displace fossil fuels across multiple sectors. This effort was geared toward first identifying potential multi-sectoral buyers/demand for the renewable hydrogen and then architecting the needed scaled production and transport infrastructure to serve that demand. Findings from this effort were highly encouraging. The GHC found that achieving a mass-scale green hydrogen economy to rapidly displace fossil fuels in several hard to abate sectors is indeed technically and commercially possible. It will require shared, scaled infrastructure; namely green hydrogen pipeline transport connected to underground geologic storage of hydrogen. This infrastructure combination affords the lowest cost pathway to achieving mass-scale supply assurance and low delivered cost to enable widespread adoption of GH2. The successful implementation of Angeles Link is thus a gating factor for Southern California's realization of a green hydrogen economy and a faster transition away from fossil fuels economywide. The GHC is pleased to see that many of the assumptions and findings in the SoCalGas draft reports are consistent with the HyBuild LA findings.

Green Hydrogen Coalition

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GHC Comments: **Angeles Link Phase 1 Draft Framework for Affordability Considerations**

The GHC appreciates the efforts of SoCalGas in pulling together this Angeles Link Phase 1 Draft Framework for Affordability Considerations ("Draft Framework") as part of the Angeles Link project. It is clear that SoCalGas has conducted significant study and analysis of the Angeles Link project and its potential benefits and impacts, and engaged, listened to, and incorporated the feedback of stakeholders in putting this Draft Framework together.

The GHC agrees that there is a critical need to emphasize and safeguard ratepayer affordability as part of the clean energy transition. Based on the analyses presented in the Draft Framework and associated draft reports, clean hydrogen delivered by the Angeles Link project presents a cost-effective pathway for the state of California to meet its net-zero mandate. That said, and as identified in this Draft Framework, SoCalGas and state agencies must take continuing action to ensure project cost effectiveness and ratepayer affordability. It needs to be an ongoing effort throughout the project development process, but both SoCalGas and the state can best and more specifically, address ratepayer impacts once a preferred project route is identified and additional project details developed.

Given clean hydrogen's essential role in enabling California to meet its net-zero mandate, the GHC recommends that the Commission take into consideration all its potential benefits when considering cost-effectiveness and affordability, including those benefits for which it is difficult to calculate the direct dollar value. Relatedly, the GHC emphasizes the need to consider a broad base of consumers and ratepayers that can receive these benefits, and accordingly evaluate affordability with the lens of this broader base paying for the infrastructure.

As evaluated in the studies cited in the Draft Framework, GHC's own analyses as part of its HyBuild Los Angeles Initiative[1], and the success of ARCHES in being awarded federal funding[2], by in part, demonstrating the value proposition of clean hydrogen, the benefits of using clean hydrogen are significant, especially for those difficult to decarbonize economic sectors.

The GHC further shares the following specific comments and feedback on the Draft Framework.

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[1] Green Hydrogen Coalition. "HyBuild Los Angeles." Accessed October 3, 2024. https://www.ghcoalition.org/hybuild-la.

[2] ARCHES. "California's Renewable Hydrogen Hub Officially Launches. - Arches H2," July 18, 2024. https://archesh2.org/arches-officially-launches/.

Importance of Valuing the Essential Role of Angeles Link Toward Deep Decarbonization of Difficult to Decarbonize Sectors

As the Draft Framework identifies and has widely been discussed as a challenge to meeting clean energy targets, it is particularly difficult to decarbonize certain sectors of the economy. This includes industrial processes which require high heat or chemical processes that cannot be electrified. It also includes heavy duty ground and maritime transportation, where electrification is not cost effective or infeasible. These sectors currently obtain their energy through fossil fuels, and to decarbonize, it is recognized that large quantities of clean fuels will be needed.

The GHC emphasizes that low-cost mass scale clean hydrogen is a proven and cost-effective pathway to transition these hard to decarbonize sectors, a sentiment that is widely shared throughout the energy industry and amongst a broad spectrum of stakeholders. However, achieving low-cost mass scale *delivered* clean hydrogen will require pipeline delivery of the clean hydrogen to these hard to decarbonize loads.

The GHC's HyBuild Los Angeles Phase 2 Report found that in a regional best-case- scenario, clean hydrogen and green ammonia produced from clean hydrogen serve a total of 13.5% of the Ports of Los Angeles and Long Beach's energy needs to fuel port equipment, transoceanic and port vessels by 2030. This translates to a demand of 455 kt (kilo-tonnes) per year of clean hydrogen.[3] Given that trucks have a capacity of between 2,000 to 6,000 kg hydrogen,[4] this is equivalent to between 75,000 to 230,000 trucks each year. These trucks would also need to be powered by electricity, clean hydrogen, or another clean fuel. Meeting this scale of demand necessitates a pipeline.

Importance of Valuing the Essential Role of Angeles Link Toward Supporting Electric System Reliability and Resiliency and Repurposing Existing Powerplant Infrastructure

With the energy transition retiring dispatchable fossil resources and shifting the electric grid to increasing dependence on weather dependent variable renewables, there is an increasing need for clean firm dispatchable resources to ensure electric system reliability and resiliency. Clean renewable hydrogen, delivered by Angeles Link, can provide a critical and cost -effective mechanism of both reliability and resiliency for ratepayers across Southern California, particularly as a long duration energy storage solution that can enable repurposing of existing powerplant infrastructure, a

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[3] Green Hydrogen Coalition. "Report | HyBuild Los Angeles Phase 2 Report," March 23, 2023. https://www.ghcoalition.org/ghc-news/hybuild-la-phase-2-report.

[4] "Summary of the California State Agencies' PATHWAYS Project: Long-Term GHG Reduction Scenarios," Energy+Environmental Economics, https://www.ethree.com/public_proceedings/summary-california-state-agencies-pathways-project-long-term-greenhouse-gas-reduction-scenarios/

path that will improve affordability of the power sectors energy transition. The GHC emphasizes this potential and recommends SoCalGas and the Commission take this potential value into consideration when considering affordability.

The need for resources to maintain electric reliability is clear. The impacts of climate change have resulted in more frequent grid stress events in the state, where increasing and unprecedented temperatures test the ability of the system to meet ever increasing load. This is an environment where imports from the Northwest are less available due to their own grid stress events, water availability patterns for hydroelectric resources are shifting, and the replacement of dispatchable fossil resources with solar and wind limit the flexibility of system operators to respond to grid stress.

In such an environment, low cost- clean hydrogen, delivered at scale to existing and repowered thermal electric generators, fuel cells and/or linear generators can deliver clean, firm, dispatchable power to support the grid and supplement wind and solar resources, limiting the need for significant renewable overbuild. This clean dispatchable resource can work in concert with other forms of energy storage resources to ensure reliable operations across timescales. The LA100 study by the National Renewable Energy Laboratory conducted a scenario modeling analysis to evaluate a pathway to 100% renewable electricity for Los Angeles. NREL found that meeting this target is achievable, and wind and solar resources, supported by battery storage, serves most of the energy need. However, renewable firm capacity, powered by a clean fuel such as clean hydrogen, will be key element to maintain reliability and meet the final 10-20% of energy needs. Absent this, Los Angeles would require a significant overbuild of renewable generation, and even then, would likely not be able to meet energy reliability needs due to its constrained transmission and distribution system.[5]

Beyond grid stress events, climate change is also increasing risks to the grid, leading to the potential for multi-day grid contingency events. This includes increased wildfire risk to grid infrastructure that necessitates responses such as multi-day Public Safety Power Shutoffs. During these Shutoffs or other contingencies, the grid needs resources to maintain frequency and provide back-up power to critical loads. As with reliability, clean hydrogen can also be a critical source of grid resiliency.

In a contingency event where centralized generation or transmission capacity is unavailable, for example, due to wildfires, mass-scale clean hydrogen can power dispatchable resources to meet load and maintain grid frequency, keeping the grid operational. In a situation where the grid does get disconnected, a clean hydrogen powered resource, coupled with energy storage, can provide a large black start resource to bring the grid back up. In the California Independent System Operator's (CAISO) annual Summer Loads and Resources Assessment for 2022, it found that contingency

[5] "Powering California's Future with Clean, Affordable and Reliable Energy," California Municipal Utilities Association, 2022 (p. 16)

Green Hydrogen Coalition

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measures it had taken had avoided outages. However, given increasing demand and potential climate related risks, CAISO found that the grid continued to have a high degree of vulnerability during summer months. CAISO cited that new resources are moving it to the right direction, but the grid continues to fall short of meeting its reliability risk target for 2022.[6] This has changed somewhat in 2024, given more moderate temperatures and increased hydro availability, but CAISO still identifies potential extreme and emergency events as posing critical grid risk.[7]

In addition to being a resiliency resource for the grid, clean hydrogen can also serve as a resiliency resource for critical loads, providing back up generation using distributed resources such as modular, scalable linear generators and fuel cells to maintain electricity supply to critical loads. For example, the in-construction Calistoga Resiliency Center will leverage clean hydrogen and energy storage to enable a cost -effective clean microgrid that can provide 8.5 MW of power over 48 hours to the local community during Public Safety Power Shutoff events.[8] It will power downtown Calistoga and nearby areas, aiming to keep critical facilities like fire stations and police stations operational during[9] Further, because the Calistoga Resiliency Center includes onsite hydrogen storage assets, in the event of an outage that exceeds 48 hours, the Center can simply arrange to have hydrogen delivered to extend its duration.

Another element to the need for grid reliability and resiliency is the question of how a multiday outage might impact- energy affordability for Californians? In the absence of an abundant, clean dispatchable fuel, ratepayers and consumers will continue to rely on fossil fuel resources to provide back-up power to critical loads[10] and electric system operators to maintain system reliability and resiliency.[11] This given the increasing volatility in fossil fuel prices can lead to price shock, leading to a significant negative impact on the affordability of energy supply. In the summer of 2022, elevated temperatures led to unprecedent system load (driven by air conditioning), this was coupled by lower than expected solar and wind output, and limited energy imports due to hot temperatures in the Northwest. This significantly escalated real -time market prices as typically uneconomic generation

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[6] California ISO. "2022 Summer Loads and Resources Assessment." May 18, 2022. https://www.caiso.com/documents/2022-summer-loads-and-resources-assessment.pdf

[7] California ISO. "2024 Summer Loads and Resources Assessment." May 8, 2024. https://www.caiso.com/documents/2024-summer-loads-and-resources-assessment.pdf

[8] Energy Vault. "Project – Calistoga Resiliency Center." Accessed October 3, 2024. https://www.energyvault.com/projects/calistoga.

[9] Balaraman, Kavya. "Energy Vault Starts Building Green Hydrogen Storage Project." PV Magazine International, February 28, 2024. https://www.pv-magazine.com/2024/02/28/energy-vault-starts-building-green-hydrogen-storage-project/.

[10] For outage durations beyond the reach of commercial battery systems.

[11] For large scale spinning reserve and contingency reserve needs that cannot yet cost-effectively be fulfilled by battery systems.

resources that run on fossil fuels were turned on. In this situation, the prevailing price of the fossil fuel to operate these resources set the market clearing price and the cost to use these expensive resources and maintain supply was ultimately born by ratepayers.[12] A renewable fuel alternative like renewable hydrogen will help mitigate the impact of these fossil fuel price shocks.

Accordingly, from a ratepayer affordability perspective, low-cost mass--scale- clean hydrogen delivered by pipeline can provide grid reliability and resiliency, limiting the need for redundant back-up infrastructure and reliance on expensive and volatile fossil fuels.

The Affordability Framework Should Factor in Taxpayer and Environmental Benefits of Additional Clean Hydrogen Production Pathways, Including Converting Municipal Mixed and Organic Waste to Clean/Renewable Hydrogen Instead of Sending this Waste to Landfills

Regarding the affordability of the clean hydrogen that Angeles Link would transport, and, accordingly, the relative cost-effectiveness of the project, the GHC recommends further research/study on converting municipal mixed and organic waste that cannot be composted or recycled into clean hydrogen. This pathway could serve as an early-stage hydrogen feedstock for Angeles Link within LA county, as electrolytic hydrogen production ramps up elsewhere.

There are several California based companies working on technologies to convert waste to clean hydrogen, presenting the potential for significant state economic development value. For example, the SGH2 Lancaster plant in Lancaster, CA will be a waste to hydrogen plant producing up to 3.8 million kg of clean hydrogen per year, saving the City of Lancaster between $50 to $75 per ton in landfilling and landfill space costs.[13] In fact, analysis conducted at Lawrence Livermore National Laboratory finds that biomass gasification (including municipal solid waste) to produce hydrogen fuel has the largest potential for carbon removal at the lowest cost[14] and a study by the University of California and Stanford finds that hydrogen production from municipal solid waste has the best economics (internal rate of return) relative to all biomass feedstocks.[15]

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[12] Public Advocates Office. "Preliminary Analysis of California's Resiliency During The September 2022 Heat Wave." https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/220922-caladvocates-sept-22-heat-wave-analysis---full.pdf

[13] SGH2 Energy. "World's Largest Green Hydrogen Project to Launch in California." Accessed October 3, 2024. https://www.sgh2energy.com/worlds-largest-green-hydrogen-project-to-launch-in-california.

[14] Lawrence Livermore National Lab, Getting to Neutral Report: https://str.llnl.gov/past-issues/januaryfebruary-2022/path-carbon-neutral-california

[15] Gilani, H.R., Ibrik, K. and Sanchez, D.L. (2023), Techno-economic and policy analysis of hydrogen and gasoline production from forest biomass, agricultural residues, and municipal solid waste in California. Biofuels, Bioprod. Bioref., 17: 988-1002. https://doi.org/10.1002/bbb.2492.

Converting waste destined for landfill to hydrogen can also serve as a mechanism for significant taxpayer savings in avoiding the processing of solid waste. For example, currently, Los Angeles spends $700 million per year processing solid waste to send to landfills![16] This does not include the toxic emissions from diesel-fueled trucking of this waste to distant landfills.

Summary – GHC Recommends that SoCalGas and The Commission Take Into Consideration All Potential Benefits of Clean/Renewable Hydrogen When Considering Cost-effectiveness and Affordability, Including Those Benefits for Which it is Difficult to Calculate the Direct Dollar Value.

In summary, the GHC applauds SoCalGas' efforts in putting together this comprehensive Draft Framework for Affordability and encourages SoCalGas to continue to strive for affordability as it continues progress towards developing the Angeles Link project. The GHC also strongly encourages the Commission and state agencies to consider pathways to enable customer and ratepayer energy, reliability and resiliency affordability, many of which SoCalGas has laid out as options in its Draft Framework.

The GHC appreciates the opportunity to submit comments on the Draft Framework and looks forward to participating in the final October PAG meeting and to the opportunity to further comment as additional analyses are completed.

[16] City of LA 2023-2024 Adopted Budget; solid waste collection and disposal cost is budgeted at $669,819,775 for 2023-2024; an additional $1,328,074,031 is budgeted for wastewater collection and treatment page 6: [2023-24 Budget Summary_FINALrev.pdf (lacity.gov)]

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