Risks and Potential Impacts from Carbon Steel Pipelines in Louisiana Transporting and Processing Variable Produced Gases (such as CO_2, H_2, CH_4)

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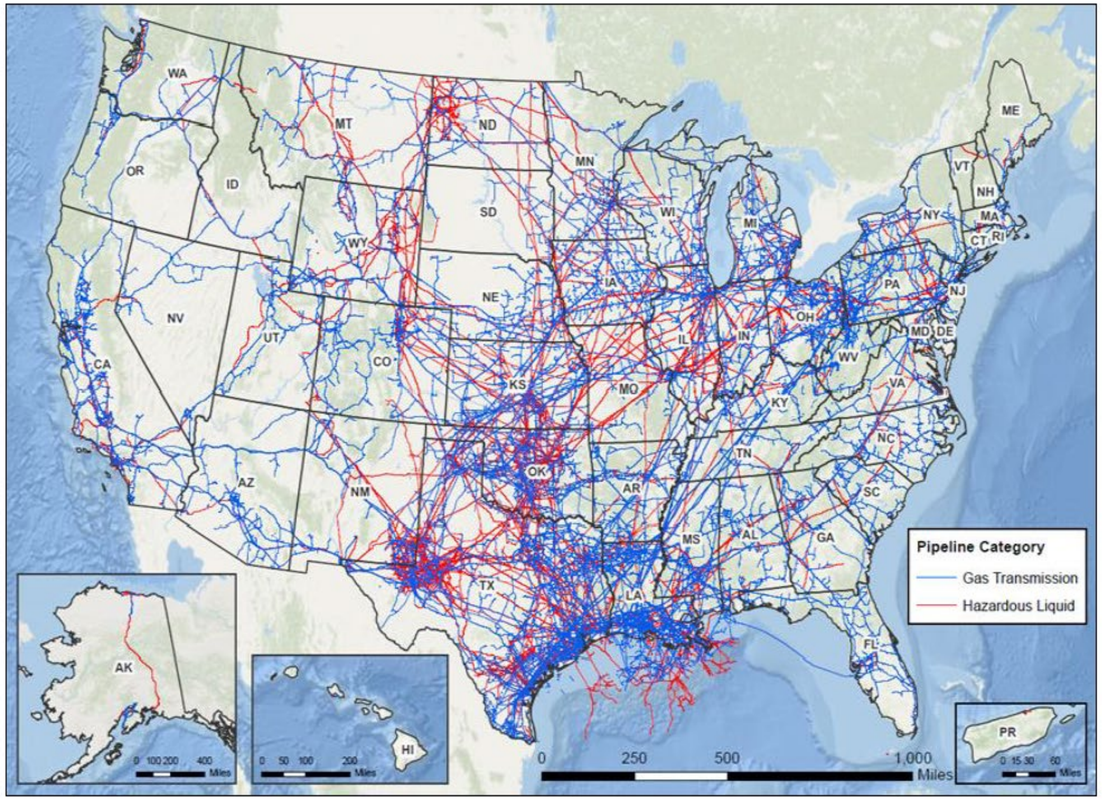
- Introduction
- Background industry profile
- Five top risks/highlights
- Environmental and business implications
- Next steps
- Conclusions

US Hazardous Liquid Network

- The U.S. energy pipeline network includes approximately 3.3 million miles of onshore pipeline transporting natural gas, crude oil, and other hazardous liquids.
- Further segmentation reveals that the U.S. has the most mileage of CO_2 transmission pipelines in the world, consisting of approximately 5,150 miles of hazardous liquid transmission pipelines.

Figure 1. U.S. Natural Gas Transmission and Hazardous Liquid Pipelines



Source: National Pipeline Mapping System, October 5, 2021, https://www.npms.phmsa.dot.gov/Documents/NPMS_Pipelines_Map.pdf

Notes: Map does not show gas distribution or gas gathering pipelines. Hazardous liquids primarily include crude oil, gasoline, jet fuel, diesel fuel, home heating oil, propane, and butane. Other hazardous liquids transported by pipeline include anhydrous ammonia, carbon dioxide, kerosene, liquefied ethylene, and petrochemical feedstock.

Pipeline Steel Grades

Line Pipe	Yield Strength (min)		Yield Strength (max)		Ultimate Tensile Strength (min)		Ultimate Tensile Strength (max)	
	ksi	MPa	ksi	MPa	ksi	MPa	ksi	MPa
X52	52	359	77	531	66	455	110	758
X56	56	386	79	544	71	490	110	758
X60	60	414	82	565	75	517	110	758
X65	65	448	87	600	77	531	110	758
X70	70	483	90	621	82	565	110	758

Conventional carbon steel is currently the primary material used for constructing CO_2 transportation pipelines (typically high strength steels such as X60, X65 and/or X70). There is considerable materials engineering overlap using the same materials for CO_2 pipelines as for natural gas and oil pipelines.

It is anticipated that the industry would follow the same materials approach for the CCUS pipelines without the more costly and deep consideration to upgrade the alloy content of the steel to improve internal corrosion resistance and hydrogen embrittlement risks.

Corrosion, hydrogen embrittlement and the weld heat-affected zone

Applicable to CO_2 as well

& CH_4 issues are a precursor

These properties are three of the greatest risks in current pipeline steels.

1) Especially in vintage, but also in recently constructed pipelines

2) Corrosion costs of onshore gas and liquid transmission pipelines are estimated at $7 billion annually.

3) Root cause analysis of pipeline failures and sources of methane emissions require upgrades in both materials, welding procedures and construction practices.

#1 Corrosion Risk

- Internal
- External
- Pipe and culvert materials
- Carbonic acid, nitric acid, sulfuric acid & hydrogen sulfide

#1 Corrosion Risk

- The variability of the CO2 gas composition including H_2S, NOx and SOx impurities, in conjunction with variations in moisture concentrations of exported CO2
- High risk of carbonic acid (H_2CO_3) corrosion in CO2 pipelines.

$$\text{H20 +CO2} \rightarrow \text{H2CO3}$$

- Moisture and variations in temperature and pressure in pipeline operation creates a high potential for the corrosive attack of carbon steel pipelines via H_2S, Nitric acid (HNO_3) and sulfuric acid (H_2SO_4) and carbonic acid (H_2CO_3) corrosion in CO2 pipelines.

#2 Operational Risk

- The actual chemistry, including residuals, of the $C0_2$ stream being processed is an unknown and needs to be defined.
- More information is needed with additional corrosion testing of blended CO_2 flue gas impurities being transported to the CCS facility.
- The control of the moisture level in the CO_2 is important and affects corrosion behavior.
- Operation pressure and temperature control

#3 Risk Petra Nova Performance

- Industry suffered a setback in mid-2020 when the Petra Nova facility in Texas, then the world's largest CCUS facility for a coal-fired power station, was closed down.
- The CCUS process for Enhanced Oil Recovery (EOR) is more energy intensive than conventional oil extraction as it requires a $75 per barrel to breakeven.
- Through December of 2019 with 3-years of operation, there was a 16% shortfall in the total amount of CO_2 captured.
- Reported operational issues with leaking heat exchangers, calcium deposits in system at seals and unscheduled downtimes affecting operational efficiency.

#4 Unproven Technological, Financial and Environmental Risk

- Research has documented the necessity for special consideration of the impact of impurities within the CO_2 feed from the various capture technologies on these possible hazards.
- Knowledge gaps exist in both the modelling of outflow and the subsequent dispersion of CO_2 following the accidental rupture of pressurized CO_2 pipelines which need to be further identified.
- CO2 corrosion data demonstrates that much more information is needed with additional testing of the characteristics of the blended flue gas impurities.

#5 Materials & Corrosion Engineering Gap for CO2

- Define impurity limits in CO_2 for maximum impurity concentrations in CO_2 and corrosion behavior
- The corrosion phenomena of carbon steel plate in aqueous CO_2 have been studied for the last 50 years without consistent, cost-effective solutions (even 13% Chromium alloys corrodes)
- Possible pipeline materials and significant cost increase versus carbon steel pipe
- Cladded pipe may be an option (pipe having a metallurgically bonded corrosion-resistant layer on its internal or external surface).

Materials Cost Comparison

Current pipeline materials

Possible alloy materials

Materials	Cost Multiplier	
Carbon steel (X70 approximately $2000-$2500 per ton of pipe)	1X	
Stainless steel 304L	3 to 5	**(CRA Clad CS pipe cost 4 to 7 times)**
Stainless steel 316L	4 to 6	
Nickel 200	19 to 38	
Monel-Inconel-Incoloy	12 to 20	
Hastelloy	25 to 38	
AL alloys	4	
Copper	3	
Lead	1	
Gold	14,000	
Platinum	**17,000**	

1) Essentially, as the alloy content increases, the corrosion resistance significantly improves, but so does the materials cost for a given project. Cladded pipe is increasing especially in offshore sour gas areas, saltwater regions to name a few.
2) The Materials Engineering outlining the ideal grade for the safe transport of CO_2 media is complicated. It depends upon the chemistry of the transport media and the processing conditions during transport which is influenced by the temperature and pressure in the pipe.

Inflation Reduction Act & Financial Implications

- Increasing the government subsidy for capturing CO_2 from polluting sources from $50 to $85 per metric ton.
- But raising the incentive to $85 per ton means projects that capture carbon dioxide from industrial facilities with lower CO_2 concentrations, like natural gas processing facilities, steel mills and cement plants which could become financially viable.
- The cost of operating a CCS facility is a huge unknown (i.e., Petra Nova)
- Satartia, Mississippi CO_2 pipeline failure should be included in cost/risk CCS analysis

Financial Implications and Solydra Case Example

- Like Solyndra where early claims did not ring true- is the administration’s support of CCS founded upon reality or wishful thinking?
- Is the Biden administration willing to take the risk of an even more costly failure if CCS cannot deliver needed results in time cost effectively?

Conclusions

- High risk of steel corrosion failures due to carbonic acid and other impurities such as hydrogen sulfide and NO_2, in addition to variations of H_2O concentrations in the CO_2 transported, and hydrogen embrittlement
- It is difficult if not impossible to specify steel grades that could be safely used over time to carry such corrosive products have not been fully characterized with consistency.
- CCUS is not a well-proven operational/maintenance technology as demonstrated with documented case studies of natural and anthropogenic CO_2 production exhibiting many operational issues of concern that would make this technology exorbitantly expensive to safely deploy at the scale necessary to achieve required results.

Conclusions

- The variations in the chemistry of the CO_2 streams being introduced into the pipeline will produce an inhomogeneous mixture of CO_2 plus impurities that create an internal corrosion risk.
- Major risk to pipelines and the surrounding ecosystem is corrosion (both external and internal) with numerous mechanisms that embrittle the steel ultimately pose conditions in which pipeline corrosion cracks and potential leakage of the CO_2 contaminants into the soil is possible.

Conclusions

- From a global perspective, the timeline for a CCUS solution is longer term than the current European green hydrogen approach.
- Laboratory corrosion testing of alternative alloy pipe materials is recommended before construction initiates.
- Materials Science and Engineering Research funded governmental and private industry sponsored projects and opportunities abound for this evolution of CCS/CCUS corrosive materials development activities before the pipelines are constructed.
- Numerous financial, environmental and technological unknowns need to be investigated thoroughly before construction commences.

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