Final Report

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

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About the author

Steven has extensive technical, operational, process and physical metallurgy experience in steelmaking, clean steel technology, thick and thin slab casting and hot rolling of plate, sheet and long products. He has published over 125 papers in process and physical metallurgical research and development and is a peer reviewer for the industry. Steve holds one patent and received numerous metallurgical awards, including the Charles Hatchett Award, and is a member of various metallurgical organizations (AISTech, ASM, ASME, ASCE and ASTM and chaired various committees.) With over 30 years of experience in the steel industry, Steven's expertise is extensive with technical, operational and business-related expertise with a deep commitment to the integration of metallurgical/materials science engineering and environmental considerations that impact both the production process as well as the research engineering. For example, he was granted the Charles Hatchett Award presented at the Royal Society of London (chosen as the best global niobium -related metallurgical paper on the topic of windtowers in 2012 entitled "Evaluation of Low and Medium Carbon Nb-Microalloyed Plate Steels for Wind Tower Applications."

Steven has held positions in major steel divisions responsible for research and operations with accountability for the operational and financial performance. Steven has lead energy savings projects at papermaking, ironmaking and steelmaking facilities. Most recently, Steven was Technical & Market Development Manager for CBMM-North America, the affiliate of CBMM, in the automotive, pipeline/energy and structural/infrastructure sectors. His responsibilities also involved Global Manager of the Structural Sector for CBMM. Steven now consults for CBMM as principal partner Research and Development Resources. The consulting company supports operational, metallurgical, productivity, quality, root-cause analysis, activity-based operational cost analysis, operational mill bottleneck studies, new product development, cost reduction opportunities, failure analysis and business feasibility studies.

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EXECUTIVE SUMMARY

Regarding the proposed pipeline projects for Carbon Capture and Sequestration (CCS) in Louisiana, there are several major areas of metallurgical and operational/maintenance/financial concerns with the projects being considered for significant government funding. These points need to be seriously considered with engineering evaluations performed before the decision is made to spend public funds on costly projects that will not deliver the intended results and divert from true solutions that are needed to combat climate change.

Concerns about CCS and associated pipeline risks are many, including:

1. High risk of steel corrosion failures due to carbonic acid (H_2CO_3) and other impurities such as hydrogen sulfide (H_2S) and nitrogen dioxide (NO_2), in addition to variations of water (H_2O) concentrations in the carbon dioxide (CO_2) transported, and hydrogen embrittlement in some cases, making it 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. The variability in the concentrations (i.e., minimum and maximum values through the process) must be considered when selecting appropriate corrosion resistant materials, and the worst-case scenario needs to be used for material specifications to minimize the risk of failure, which could make CO_2 pipeline material prohibitively expensive.

2. CCS 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. Although capturing CO_2 is technologically possible (as shown in the DOE Petra Nova project), operating the facility on a 24/7 scenario to cover operational and maintenance plant cost on a profitable basis is questionable and requires extensively more research, engineering analysis, design review and pilot plant facilities analyses.

3. 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. It is recommended that the CO_2 pipeline and CCS partners submit the chemical analysis of the CO_2 from all of the parties introducing their waste CO_2 stream into the pipeline. A corrosion study with the submitted CO_2 chemical analysis would then be performed at an independent corrosion laboratory with different grades of carbon and alloyed pipeline steels to quantify the corrosion rate. Only then can a steel be specified for the CCS project.

4. Major risk to pipelines and the surrounding ecosystem is both external and internal corrosion. Numerous mechanisms embrittle the steel in which pipeline corrosion cracks and potential leakage of the CO_2 contaminants into the soil is possible. The soil aeration dynamics indigenous to a given area in the Bayou is a key consideration.

5. From a global perspective, the timeline for a CCS solution is longer term than the current European green hydrogen approach. Petra Nova CCS DOE project is an Enhanced Oil Recovery (EOR) solution and not a pure carbon capture solution, which even so, could not economically substantiate itself. Technical reasons for the premature closure of the plant should be further studied regarding operations, maintenance and capital cost of materials/equipment deficiencies and not just CO_2 yield/recovery.

6. The Louisiana specific environmental impact (including subsidence issues) should be further studied and evaluated by the parties involved in the CCS project. It is beyond the scope of the materials engineering community to predict the environmental/corrosion/contamination impact without a specific understanding of the actual soil chemistry and subsidence conditions through which the pipeline traverses. Laboratory corrosion testing of alternative pipe materials is recommended before construction initiates.

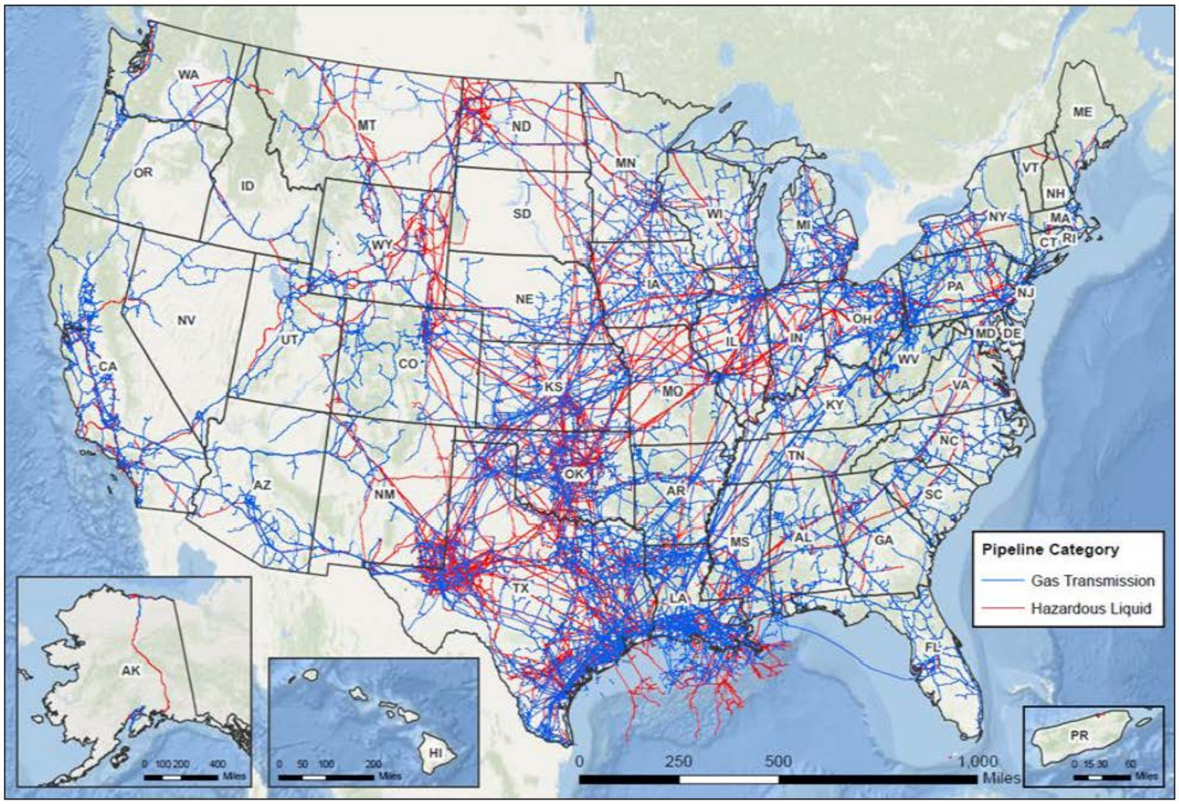
7. Repurposing of pipelines is a deep metallurgical concern from both a corrosion and fatigue/fracture perspective. It must be emphasized that even recently constructed pipelines that were originally designed for natural gas transmission now being considered for transmission of CO_2 produced from the CCS process is a high-risk decision without additional corrosion studies of the proposed pipeline materials.

8. The materials engineering aspects and standard operating maintenance practices for a CCS facility are under development and continuous evaluation is recommended. This evaluation might be supported by a collaborative Materials Science and Engineering Research funded governmental and private industry sponsored project. There are numerous technological unknowns that require further study before facilities and pipelines are constructed. This evolution of CCS corrosive materials development activities would bridge the engineering gap before the facilities/pipelines are constructed.

BACKGROUND OF U.S. ENERGY PIPELINES

The U.S. energy pipeline network includes approximately 3.3 million miles of onshore pipeline transporting natural gas, crude oil, and other hazardous liquids (such as CO_2). Over the past decade, safety incidents in California, Massachusetts, and other states have drawn criticism from stakeholders and have raised concerns in Congress about pipeline safety regulation [1]. 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 [2]. A recent study projected that the U.S. would have to construct 65,000 miles of carbon dioxide pipelines to achieve net-zero emissions in 2050, a whopping 13 times the current capacity. Figure I below illustrates a current map of the existing U.S. natural gas transmission and hazardous liquid pipeline (note the Gulf Coast) [3].

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.

From a safety perspective, uncontrolled pipeline releases methane (CH_4), carbon dioxide (CO_2), nitrogen oxides (NOX), etc.) can result from a variety of causes, including third-party excavation, corrosion, mechanical failure, control system failure, operator error, and malicious acts breaching security. Floods, earthquakes, subsidence and frostline issues can also damage pipelines. The accounting for safety performance is lacking. For example, taken as a whole, the DOT reports that releases from pipelines cause few annual injuries or fatalities compared to other product transportation modes [4]. According to PHMSA statistics, there were, on average, 12 deaths and 60 injuries annually caused by 29 pipeline incidents in all U.S. pipeline systems from 2010 through 2020 [5]. The integrity and accuracy of the measure, the definition and annual injury, health effects and longer-term health complications should be accounted for in these statistics (i.e., such as a Health Impact Assessment for not only the releases and explosions, but compressor stations, pigging operations and other toxic releases.) It would take an ongoing monitoring of actual releases as $C0_2$ and methane leakage are the major causes of greenhouse gas emissions emanating from the natural gas pipeline network. Note the risk still exists for hydrogen (H_2) produced from methane.

Pipeline Steel Grades

The various grades of steel are designated according to a steel's minimum specified yield strength in kilo psi (1 ksi= 6.9 megapascals [MPa]). Table I lists the yield strength and ultimate tensile strength requirements according to the American Petroleum Institute (API) 5L standard (5L pipes are generally used to transport oil, water, and gases). Appendix A outlines steel chemistry details per grade.

Table I. API 5L Yield and Tensile Strength Requirements for X52-X70 Line Pipe Steel [6]

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

The X52 steels (yield strength min of 52ksi designation) are commonly in service for natural gas transport from the early 1950's. However, as pipeline steels have been developed through improved metallurgical and material processing techniques, more modern alloys have been developed specifically for hydrogen and hazardous liquid applications, such as modern X52, X60, X65 and X70. Modern pipeline steels tend to have a lower carbon content, microalloy additions of niobium, titanium and/or vanadium and lower sulfur concentrations compared to vintage pipeline steels. The main difference between a vintage X52 pipeline from the 1950's and its modern counterpart is a higher carbon content of the steel in the vintage X52. Typically, the carbon content can be nearly three times lower in modern steels with improved toughness and weldability [7]. It is important to note even with continuous improvements that the corrosion performance of these various pipeline grades is quite similar.

Higher strength modern steels such as X60, X65 and X70 have also been developed for the purpose of oil and gas transport in harsh environments such as sour gas (a sour gas has higher sulfur content than a "sweet" gas) and have even lower carbon content. Currently X65 is the highest grade approved for sour gas application [8]. Higher grades of API 5L steels, such as X80, X100 and even X120 have in the recent years, received high attention for (onshore) pipeline applications due to their superior high mechanical strength, allowing for thinner pipeline walls and lower costs especially outside the United States [9,10]. 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 CCS 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.

In the evolution into modern pipelines, the need for increased strength with an associated improvement in impact strength, ductility, formability and weldability was the driver. Formability relates to the ductility and bending behavior during pipe formation. The vintage pipelines do not exhibit the superior mechanical properties of modern-day pipeline steels. This same criterion may apply to CO_2 pipeline infrastructure design as well.

RISKS AND POTENTIAL IMPACTS OF CARBON PIPELINES

Corrosion, hydrogen embrittlement and the weld heat-affected zone properties are three of the greatest risks in pipeline steels, especially in vintage, but also in recently constructed pipelines. Corrosion is one of the leading causes of failures in onshore transmission pipelines (gas and hazardous liquids) in the United States. It also is a threat to gas distribution mains and services, as well as oil and gas gathering systems [11]. The National Association of Corrosion Engineers (NACE) currently estimates the total costs attributed to all types of corrosion at $276 billion. Corrosion of onshore gas and liquid transmission pipelines represents $7 billion of this total. PHMSA uses specific criteria to identify the incidents that are significant from a pipeline safety viewpoint. An incident is defined as significant if it meets any of the following conditions:

1) Fatality, or injury requiring in-patient hospitalization
2) $50,000 or more in total costs, measured in 1984 dollars
3) Highly volatile liquid releases of five barrels or more, or other liquid releases of 50 barrels or more
4) Liquid releases resulting in an unintentional fire or explosion.

The criteria used in rules and regulations for carbon pipelines require a total overhaul beyond the recent announcement regarding methane emissions (see PHMSA announcement). Root cause analysis of pipeline failures and sources of methane emissions require upgrades in both materials, welding procedures and construction practices. Also, one of the gaps for PHMSA is recruiting manpower expertise with very qualified personnel preferring employment with the oil/gas companies whose compensation salary significantly exceeds PHMSA or regulatory agencies.

<u>External Corrosion and Factors Affecting the Corrosivity of Soils</u>

External corrosion causes more than 90 percent of corrosion-related failure in distribution pipelines. Various forms of external corrosion and failure mechanisms such as hydrogen-induced cracking (HIC), hydrogen embrittlement (HE), corrosion fatigue (CF), stress corrosion cracking (SCC) and microbiologically influenced corrosion (MIC) for oil and gas pipelines are thoroughly reviewed [12]. Underground corrosion necessitates millions of dollars annually for regular maintenance and replacement. The corrosion on the exterior surface of oil and gas pipelines that can induce significant damages over their lifetime is often given less consideration as compared to the internal corrosion for which most protection is provided in practice. The damages caused by the external pipeline corrosion together with the internal material flaws can provoke sudden catastrophic failure of pipelines [12].

Hence, controlling corrosion of the exterior surface of the oil and gas pipelines as well as CO_2 pipelines for their integrity assurance is deemed necessary.

The corrosion behavior of steel has some similarities to corrosion in water. Minor changes in chemical composition are not significant in changing corrosion behavior (i.e., a copper-bearing steel versus a low alloy or mild steel.) Corrosion in soils resembles atmospheric corrosion although the rates are usually higher in soils to a marked degree depending on the type of soil. A metal may perform satisfactorily in one region of the country, but not elsewhere. Reasons for this inconsistent performance may relate to; 1) specific differences in soil composition, 2) pH scale of acidic to basic, and 3) moisture content to define a few. The factors affecting corrosivity of a given soil are: 1) porosity (aeration), 2) electrical conductivity, 3) dissolved salts, including depolarizers or inhibitors, 4) moisture, and 5) acidity or alkalinity. For example, a porous soil may retain moisture over a longer period of time or may allow optimum aeration, and both conditions tend to increase the corrosion rates [13].

The situation is more complex, however, because corrosion products formed in an aerated soil may be more protective than those formed in an unaerated soil. In most soils, particularly if they are not well aerated and stagnant, observed corrosion takes the form of deep pitting. Localized corrosion of this form is more damaging to a pipeline than a higher overall corrosion rate occurring more uniformly.

Culvert Materials

The culvert pipe is intended to provide a pathway for the flow of high volumes of water in low lying regions near any pipelines. Standing water then transcends the resultant risks of subsidence that imposes additional external stress on the "sinking" pipeline. Steel, reinforced concrete and polyethylene culvert pipe materials are all susceptible to some sort of environmental condition. Steel and concrete pipes are subject to corrosion by pH levels and soil resistivity. Concrete pipe is also affected by sulfate levels. Ultra-violet (UV) degradation is a concern with polyethylene pipe. However, some manufacturers provide UV protection in the pipe. Carbon black is mixed with the polyethylene resin to inhibit degradation [14]. The best practice for choosing the appropriate type of pipe is knowing about the environmental conditions and the properties of the different pipe materials. Familiarity with the pH level, soil resistivity, sulfate level, and other general information about the potential for the existing site should help indicate what type of pipe is suitable based on knowledge of the geological conditions.

The purpose of a published Culvert Study report by the Missouri Department of Transportation's (MoDOT) was to assess the results-to- date of their state culvert study. This report will provide some insight as to what has been accomplished in the past, what is being done now, and recommendations for the future [14]. Topics discussed in this report are testing methods, quality of different pipe materials, visual inspections, and life span of pipes with respect to environmental conditions. Some cross application and comparison to the work performed to date in Louisiana may be prudent and supplementary to the Final Report 585 [15].

Internal Corrosion

The streams of different organic carbon-based chemicals such as liquefied natural gas (LNG), methanol, ammonia, CO_2, (to name a few) and the evolution of H_2 transport creates significant metallurgical challenges affecting the pipeline integrity of the current carbon steel pipeline materials (i.e., X52, X60, X65, X70). The variability of the gas composition including H_2S, NOx and SOx impurities, in conjunction with variations in moisture concentrations, creates a highly potential 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 CO_2 pipelines. Current carbon steel low alloy pipelines are susceptible to accelerated corrosion rates in the presence of these acidic compositions. This set of operational conditions becomes a metallurgical mechanistic and laboratory testing project to identify accelerated corrosion rates blending these different organic carbon chemical streams.

In general, corrosion failures result in leaks or ruptures. Leaks are more common. Leaks from gas pipelines generally do not cause property damage, because the escaping gas disperses quickly into the atmosphere. However, leaks from a liquid pipeline can contaminate the soil, groundwater or surface water [16]. Conversely, ruptures in a gas pipeline are more likely to cause an explosion and fire, thus resulting in more fatalities and injuries on average. Note the failures to date are for the most part non-blended streams which would not be the case in CCS pipelines.

Almost all of the corrosion incidents in liquid pipelines have involved onshore lines. The few corroded offshore lines have not caused fatalities nor injuries, because populations do not live in proximity to an offshore failure [16]. However, ecological damage can be excessive (i.e., Kalamazoo river incident).

<u>Carbonic Acid Formation Risk</u>

Carbonic acid (H_2CO_3) is a common inorganic compound formed when carbon dioxide (CO_2) dissolves in water (H_2O). In aqueous solution, a small portion of carbonic acid will further dissociate to form hydrogen (H+) and bicarbonate (HCO_3) ions. The resultant weak acid can corrode, rust or pit steel. The extent of those effects depends upon the chemical composition of the steel and local pipeline environment. For example, there is an increased concern if the pipe and/or storage tanks corrode, crack and a leak occur in which the media (liquid/gas) flows into the waterway and wetlands, thereby potentially contaminating the surface water.

The most common effect of carbonic acid on steel is general corrosion with full or partial breakdown of the steel into its constituent chemical components. Carbon steel will corrode very quickly when it comes into contact with carbonic acid. Corroded carbon steel can weaken, bend or break, posing a significant problem in pipes and valves. Stainless steel, in contrast, resists general corrosion caused by carbonic acid.

<u>Ideal Grade for Safest Transport of CO_2</u>

The Materials Engineering outlining the ideal grade for the safe transport of CO_2 media is complicated. The simple answer is that 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. Moisture levels are of paramount importance in CO_2 transmission and processing. Some of the CO_2 compositions predicted to be transported (including impurities) must be defined by the CCS partners. Without such information, specifying materials is extremely difficult to ensure true-zero accident safety performance and true-zero emissions.

The paradigm materials engineering shift in pipeline steels (including CO_2) will require a leapfrog transition to higher alloyed line pipe steels never seen before in the oil and gas pipeline transmission industry. There are materials that could significantly reduce the corrosion and leakage risks, but the cost of such materials significantly increases the pipeline project cost. Hence, a price tag on safety must be addressed by the oil and gas industry who have been reluctant to comply with more stringent standards and higher quality steel grades. The uncertainties regarding CO_2 transmission and corrosion behavior from CCS are a huge unknown with few miles of CO_2 pipelines in use over long periods of time.

Carbon dioxide pipelines are not new as they now extend over more than 2500 km in the western USA, where they carry 50 $MtCO_2$ per year from natural sources to enhanced oil recovery projects in the west Texas region and elsewhere. Currently, approximately 5300 miles of CO_2 pipelines and projected additional CCS deployed pipelines and additional 11,000 miles by 2030. The carbon dioxide stream should preferably be dry and free of hydrogen sulphide because corrosion is then minimal, and it would be desirable to establish a minimum specification for "pipeline quality" carbon dioxide. However, it would be possible to design a corrosion resistant pipeline that would operate safely with a gas that contained water, hydrogen sulphide and other contaminants; but, as already recommended, additional corrosion studies must be done.

Pipeline transport of carbon dioxide through populated areas requires additional attention be paid to design factors, materials corrosion performance, overpressure protection, and to leak detection [17].

<u>Steel Price Economics</u>

The increase in alloy content to reduce the carbonic acid corrosion risk and the pipeline steel cost comparison is shown below in Table II. Essentially, as the alloy content increases, the corrosion resistance significantly improves, but so does the materials cost for a given project.

Table II. Material Cost Comparison for Steel Pipe and Alloys [18]

Materials	Cost Multiplier
Carbon steel (X70 approximately $2000-$2500 per ton of pipe)	1X
Stainless steel 304L	3 to 5
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**

Several factors have significantly increased steel prices over the past two years including COVID-related as well as increased domestic steel demand, insufficient steel supply and domestic steelmaking capacity shortfalls. Note the plate cost curve applies to pipe as well as structural market segments. The average current price point is at $1950 per ton for the plate segment. Plate metal is any sheet of metal with a thickness of 6mm or more. Essentially, plate steel is used for pipeline applications exceed 6mm (20-25mm is popular thickness for pipe). Plate prices continue to trend on the rise compared to other segments which are declining. Also, some of the import restrictions on pipe from India may further support plate price increases in the USA. Imported steel will likely be needed to build the amount of CO_2 pipelines needed for CCS. Since the US steel industry is at capacity, the lead times for US produced plate steels for pipe are longer than imported steel (even from India and China). In fact, some of the Chinese development of X80 and X100 pipeline steels have improved quality and in some cases, the USA does not even produce these grades. This situation can create a justification for the oil and gas companies to import steel grades that US domestic producers either are incapable of producing or do not match the mechanical and corrosion property performance needed. Figure II illustrates the steel price comparison for the different steel segments of cold-rolled coil, plate, rebar and hot-rolled coil.

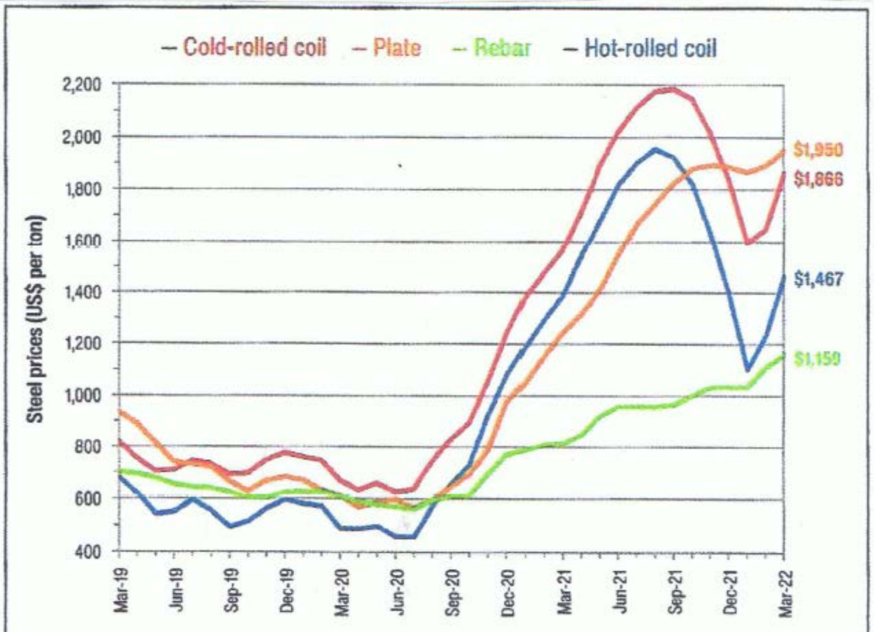


Figure 11: U.S. steel prices.
Source: Platts.

Figure II. 2019 to 2022 Steel Price Date per Segment [19]

The pricing mechanism for pipe depends upon the steel chemistry, pipeline type, diameter, thickness mechanical properties and the current supply-demand situation. For example, with the recent economic conditions experienced in 2021 some steel pipe grades and structural plate materials tripled in selling price per ton including commodity low strength pipe and plate. When one couples the increased price for alloys and microalloys additions to the steel, selling prices can be as much as 5 to 20 times higher dependent upon alloy chemistry.

TRANSPORTATION INFRASTRUCTURE AND FINANCIAL IMPLICATIONS

A transportation infrastructure that carries carbon dioxide in large enough quantities to make a significant contribution to climate change mitigation will require a large network of pipelines. As growth continues it may become more difficult to secure rights-of-way (ROWs) for the pipelines, particularly in highly populated zones that produce large amounts of carbon dioxide. Existing experience has been in zones with low population densities, with safety issues that are more critical in populated areas.

The most economical carbon dioxide capture systems appear to currently favor CO_2 capture, first, from pure stream sources such as hydrogen reformers and chemical plants, and then from centralized power and synfuel plants. The producers of natural gas advocate for stranded reserves from which transport to market is uneconomical. A movement towards a decentralized power supply grid may make CO_2 capture and transport much more costly. It is easy to envision stranded CO_2 financial assets at sites where capture is uneconomic. A regulatory framework will need to emerge for the low greenhouse- gas-emissions power industry of the future to guide investment decisions. Future power plant owners may find the carbon dioxide transport component one of the leading issues in their decision-making including the transport of impure CO_2. For example, traditional current CO_2 pipelines carry 98%CO_2, 0.15/1.15% nitrogen gas (N_2) and 0.11/1.50%CH_4. Moisture levels are typically not reported. Again, the actual complete chemistry information of the CO_2 streams from the Louisiana producers is needed as a top priority.

CO_2 Pipeline Route, Construction, Operational and Maintenance Considerations

The reasons for the incidents at CO_2 pipelines were relief valve failure (4 failures), weld/gasket/valve packing failure (3), corrosion (2) and outside force (1). In contrast, the principal cause of incidents for natural gas pipelines is outside force, such as damage by excavator buckets. A study by Vendrig et al. (2003) has modelled the risks of CO_2 pipelines and booster stations [20]. A property of CO_2 that needs to be considered when selecting a pipeline route is the fact that CO_2 is denser than air and can therefore accumulate to potentially dangerous concentrations in low lying areas. Any leak transfers of CO_2 to the atmosphere are hazardous. If substantial quantities of impurities, particularly H_2S, are included in the CO_2 stream, this chemistry could affect the potential impacts of a pipeline leak or rupture. The exposure threshold at which H_2S is immediately dangerous to life or health, according to the National Institute for Occupational Safety and Health (NIOSH), is 100 parts per million (ppm), compared to 40,000 ppm for CO_2. The Petra Nova project should be analyzed in more detail from a construction, operational and maintenance financial performance focus before the decision to extensively deploy CCS is made. (next section)

Case Study of CCS Power Plant Facility Performance at Petra Nova

A CCS case study is presented from a recent DOE project which has been terminated. Petra Nova was the only coal carbon capture project in the U.S., and was built at a cost of $1 billion, including $195 million of public funding through the U.S. Department of Energy. The project was a joint venture between NRG and Nippon NX, a global oil and gas company based in Japan. Carbon capture, utilization, and storage (CCS) is generating interest across the world with the hope that it could play a significant role in the fight against climate change. However, the industry suffered an apparent setback in mid-2020 when the Petra Nova facility in Texas, then the world's largest CCS facility for a coal-fired power station, was closed down [21]. The lessons learned are:

1) The CCS process for Enhanced Oil Recovery (EOR) is more energy intensive than conventional oil extraction as it requires a $75 per barrel to breakeven.

2) Through December of 2019 with 3-years of operation, there was a 16% shortfall in the total amount of CO_2 captured.

3) Reported operational issues with leaking heat exchanges, calcium deposits in system at seals and unscheduled downtimes affected operational efficiency.

For optimum operation of CO_2 pipelines, flow rates, pressures, temperatures and impurities in the stream must be clearly defined. These factors are then incorporated into the design, engineering, materials selection and operation of the pipelines. The effect of impurities on the phase envelope, pressure drop and critical pressure and temperature has been studied, yet often these recommendations and knowledge are not incorporated into the CCS project cost and feasibility analyses.

It is recommended that more details are obtained from the DOE regarding operational issues, problems, cost of operation and overall Profit & Loss (P&L) statement for the facility. Often, these noted issues are not easily accessible to the public community.

Corrosion Risk and Unproven Large-Scale Materials Performance-Carbonic Acid Threat Mechanism

Conventional carbon steel is the primary material used for constructing CO_2 transportation pipelines (typically high strength steels such as X60, X65 and/or X70). Since CO_2 dissolves in water to form carbonic acid, it can be corrosive depending on impurities in the captured gas even in these high strength pipeline steels. Corrosion resistance and embrittlement are the metallurgical challenges that jeopardize the safety of such current materials designs for transporting CO_2. Recent CO_2 pipeline projects with some publicly documented corrosion problems/failures and other undocumented failures are still under investigation. The influence of H_2S on CO_2 pipeline corrosion is a major safety concern. In 2014, Das published a peer-reviewed paper on the issue [22]. In February 2020, the results of this study of high H_2S impurity in the CO_2 pipeline resulted in a major catastrophic pipeline failure in Satartia, Mississippi resulting in the evacuation of 300 residents in the region of Yazoo County. Responders reported a green cloud from the 24-inch diameter Delphi exploded pipeline, a possible indication of high levels of H_2S. Further investigation indicates that the source of the CO_2 (Jackson Dome) has levels of H_2S at 5 percent (50,000 ppm) [23]. According to a 2014 report by the U.S. Department of Energy's National Energy Technology Laboratory, the Jackson Dome CO_2 stream consists of the highest concentration for any of the Natural CO_2 Source Field [24]. CO_2 concentrations range from 65 to 99.6 percent. Jurassic sediments in the area have tested sour gas since exploration beginning in the 1950s. H_2S is a common contaminant, averaging 5 percent but ranging as high as 35 percent [25]. Naturally occurring subsurface CO2 sources occur in the United States and may contain H_2S. This is a major engineering design problem because it is unsafe to design materials to an average composition. The variability in the concentrations (i.e., minimum and maximum values through the process) must be considered when selecting appropriate corrosion resistant materials, and the worst-case scenario needs to be used for material specifications, which could make CO_2 pipeline material very expensive.

CO_2 Pipeline Models

Modeling has become a predominant element of the engineering design process. One challenge is that the current CO_2 pipeline models rarely consider the effects of impurities in the determination of design parameters [26]. This Peleteri et al 2017 study [26] focuses upon pipeline transportation of impure CO_2. It is well documented that there are major impurities in captured CO_2 from power plant stations and gas processing facilities. The main contaminants are; 1) nitrogen, 2) methane, 3) hydrogen sulfide, and water. These contaminants affect both the processing and the materials corrosion performance. From a processing perspective, impurities affect the density and viscosity (the stickiness or fluidity of a substance) of the CO_2 stream thereby impacting on the fluid phase, pressure and temperature of the stream. Conditions for severe corrosion are possible depending on the concentration levels of contaminants [26].

CO_2 Corrosion Phenomena and Resolution Status

The corrosion phenomena of carbon steel plate in aqueous CO_2 have been studied for the last 50 years without consistent, cost-effective solutions. Limited studies of 13% chromium (Cr) stainless steels have shown adverse corrosion issues as well. And yet, with these significant materials engineering concerns, the CCS initiative hopes to get billions in public money to pursue projects without considering the cost to build the transport pipeline systems, not to mention the growing public resistance to pipelines, especially those carrying hazardous materials such as CO_2.

Steel companies may endorse CCS for the potential revenue but are not responsible for the potential corrosion once the material has been produced to meet specifications. It is assumed that transportation and injection into a well can be safely conducted with only very pure CO_2. However, in the case of carbon capture, the introduction of impurities, variations in moisture content and blended CO_2 compositions change the materials engineering requirements as the corrosion risk has not been studied and characterized. It is not possible to specify a pipeline steel chemistry with unknown concentration and inconsistent chemical composition of the gas being transported through the pipeline. There are numerous materials engineering-corrosion-environmental issues with different capture systems as well as long-term behavior under storage conditions that are not well understood, but there are serious issues that could lead to catastrophic failures if CCS infrastructure is widely deployed in a region.

As studied by Dugstad, et.al., CO_2 experiments were performed in an aqueous phase containing elemental sulfur, sulfuric and nitric acid in addition to oxygen (O_2). H_2S can form as well when the CO_2 stream contains water, NO_2, SO_2, and O_2 in concentrations within the limits suggested in many of the published recommendations for maximum impurity concentrations in CO_2 [27]. This study demonstrates that much more information is needed with additional testing of the characteristics of the blended flue gas impurities.

CO_2 Pipeline and Safety Considerations

An overview of some of the key factors and areas of uncertainty affecting integrity and accurate hazard assessment of CO_2 pipelines employed as part of the CCS chain requires further study before billions of dollars are invested in an uncertain CCS technology that have tremendous financial and environmental implications if unsuccessful. Major risks include corrosion, hydrate formation, hydrogen embrittlement and propensity to fast running ductile and brittle factures in CO_2 pipelines and associated processing equipment. 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 [28].

Compressor Considerations

Although outside the scope of this report, compressor stations are a critical component of the pipeline system. Pressure and flow control in the gas transmission system depends on a number of compressor stations at which several compressors operate in serial and/or parallel. Unlike the gathering system and the distribution system which are characterized by low pressure, small diameter pipelines, the transmission system is characterized by long, large diameter pipelines operated at high pressures. The efficient performance of the gas transmission system thus poses a challenge in maintaining the safe regulation of pressure such that gas and CO_2 demands at off-takes are met. Off-takes are smaller diameter transmission pipelines in the overall system. Compressor station/unit failures are extremely challenging for gas transmission, including CO_2 . An evaluation of the impact of failures on gas transmission capability is a significant issue for gas operators.

OTHER CONSIDERATIONS

Materials Science and Engineering Research Funded Governmental and Private Industry Opportunities

The materials engineering and engineering aspects and standard operating maintenance practices for a CCS facility is under development and continuous evaluation is recommended. Based upon these facilities' operational performance to-date to date, the majority of the published performance studies relate to the chemical engineering process and not the materials' performance. Materials are a significant fraction of the capital and operation/maintenance cost. Currently, there are recommended corrosion resistant materials suggested for this CCS processes which are in service, materials engineering performance has been both costly and not best materials engineering practice.

There is an opportunity to develop new materials and/or upgrade many of the current CO_2 pipelines and facility components to higher value-added alloys and improved corrosion resistant behavior. From a corrosion point of view, the materials-of-choice must perform over a wide range of environments due to the different CCS processes. High CO_2 levels mean that wet process environments tend to be acidic and unprotected carbon steel should not be used. In some cases, an upgrade to stainless steel may not meet the corrosion resistant requirements. Therefore, government funding in this materials engineering research initiative is needed to both develop materials to construct safer and more economical pipelines and CCS facilities as well as perform corrosion experiments on existing materials based on the blended CO_2 gas chemistry including impurities. There is a huge scientific knowledge gap in this sector of materials and corrosion engineering.

The True Zero versus Net Zero (Carbon Neutral) Approach

The differentiation between a true zero versus net zero emissions approach is crucial considering the magnitude of the current greenhouse gas GHG calamity. Unlike true zero emissions, net zero or carbon neutral implies some carbon/GHG emissions continue to be produced. Net zero still allows for some form of offsetting through carbon dioxide removal or negative emissions for example using CCS.

The net zero emissions approach has created a fossil fuel application for the enhanced oil recovery (EOR) process of recovering oil by pumping CO_2 into the ground. This recovered oil is then combusted by the consumer creating more CO_2 - a truly questionable circular approach. Other CO_2 applications produced from waste flue gas are limited for good reasons including corrosive impurities, so additional costs to purify the CO_2 may be needed.

European True Zero Ironmaking/Steelmaking Approach

The time is now to prioritize a true zero approach over net zero when at all possible. An illustration of this opportunity is the significant difference between one European steel company's true zero approach compared to the larger steel industry net zero approach. The HYBRIT process or Hydrogen Breakthrough Ironmaking Technology is a joint venture between SSAB, mining company LKAB and Swedish state-owned power firm Vattenfall launched in 2016 [29]. SSAB committed to eliminate the use of fossil fuels in steelmaking with this electricity coming from fossil-free sources. By the end of this decade, the European Union is attempting to cut overall CO_2 emissions in the 27-nation bloc by 55% compared to 1990 levels. This effort is encouraged by making companies pay for their $C0_2$ emissions and with government incentives.

The small SSAB Lulea pilot plant operates as a research facility, and thus far has produced several hundred tons of steel. The next step is an upscale and construction of a larger demonstration plant to begin commercial deliveries by 2026. SSAB's definition of true zero means zero-emission with no negative emissions options or meaningful carbon offsets. True zero emissions also apply to emissions caused by purchasing, including imported goods and international flights and shipping [29].

According to a recent report published by UK FIRES, a research program sponsored by the UK Government, reaching true zero is possible through our current technologies and incremental lifestyle changes [30].

It is apparent that we cannot wait for breakthrough technologies to deliver true zero emissions by 2050. Instead, in the UK, they plan to respond to climate change using today's technologies with incremental change. This offers several opportunities for growth but requires a public discussion about future lifestyles. It is now a law in the United Kingdom that they have to cut greenhouse gas emissions to zero by 2050. There are parallels the US can learn from the UK approach with policies that will support no longer burning fossil fuels. CCS may, in actuality, only delay the necessary steps to get to true zero. Breakthrough technologies such as cars powered by hydrogen fuel cells, may already exist, but have not yet captured even 5% of the world market. There is much more that can be done with the technology of today that has not been leveraged, and funding CCS may detract from funding and incentives to leverage existing more viable options.

Blue and Grey Hydrogen vs. Green Hydrogen vs. CCS Implications

The report from a European research team led by the European Technology and Innovation Platform for Photovoltaics was published in the September 7th journal Solar RRL and concludes that "during this decade, solar hydrogen will be globally a less expensive fuel compared with "hydrogen produced from natural gas with CCS [blue hydrogen]" [31]. This is a much different scenario than the argument being made by supporters of blue hydrogen, such as the gas industry and others who are claiming that within a decade green hydrogen will still be at least double the cost of blue hydrogen.

While there is still some question about how dirty blue and grey hydrogen are, no one argues that they will ever be cleaner than green hydrogen. Green hydrogen is clean now whereas blue hydrogen advocates promise that this fuel may be less dirty at some point in the future, but even then, will never have zero emissions.

Recent Climate Bill

The climate bill's projected emissions cuts rely heavily on carbon capture – it would mean thousands of miles of pipeline. The sweeping climate, energy and health care bill expected to go to a vote in the U.S. House on Friday contains about US$370 billion to foster clean energy development and combat climate change, constituting the largest federal climate investment in history [32]. Notably, one linchpin of the bill's climate provisions is a set of incentives to substantially expand technologies that capture carbon dioxide and either store it underground or ship it for reuse. A recent study projected that the U.S. would have to construct 65,000 miles of carbon dioxide pipelines to achieve net-zero emissions in 2050, a whopping 13 times the current capacity. There are currently about 5,000 miles (8,047 km) of carbon dioxide pipelines in the United States, mainly in Texas and Wyoming, where the gas is pumped under oil and gas fields to increase pressure and boost production. But developers would need to build another 65,000 miles for the country to permanently store enough carbon to reach net zero emissions by 2050, according to a 2021 report from the White House [33].

ASTM Technical Committee-Liability and Climate Change Disclosures Standards Revisions

ASTM International's environmental assessment, risk management and corrective action committee (E50) has approved revisions to two of its standard guides on disclosure of environmental liabilities (E2173) and disclosures attributed to climate change (E2178). E2178is the description of two approaches to climate change adaptation disclosures (low impact and high impact). Disclosure requirements can communicate findings through one to four pages of reporting tied to the current balance sheet, income statement and cash flow statement. The revisions to E2178 will assist users to determine how recent and upcoming climate change adaptation impacts, both positively and negatively) will in aggregate be immaterial, manageable or unaffordable to a given enterprise.

CONCLUSIONS

1. 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 in some cases.
2. 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 flue gas impurities being transported to the CCS facility.
3. Corrosion tests should be performed on different candidate materials before a specific pipeline grade is specified.
4. The control of the moisture level in the CO_2 is important and affects corrosion behavior.
5. The pipeline specification should be based upon the actual contents of the pipe which can change according to the route and individual contributors to the gas stream, with necessary

steps taken along the route to limit corrosive moisture levels and chemicals in the CO_2 . Traditional X65 and X70 materials may not apply.

6. Carbon capture and sequestration requires a great deal more study to be safely employed , with necessary restrictions and adequate regulations which will likely be costly to implement.
7. Due to the potential harmful air pollution and GHG effects, not only the pipeline material itself needs to be studied, but additional leakage points like valves and fittings. Compressor station emissions, blowdowns and leaks need to be quantified before deploying CCS technology on a larger scale with compressor station and pipeline pigging emissions factored into the rate of capture.

This is not to say that carbon capture and sequestration should not be done at all, but it requires a great deal more study to be safely employed and will be quite costly to deploy. It is not a single solution as some would suggest as an excuse to keep burning fossil fuels but needs to be a small part of a much more broad and diversified approach that includes incentives and disincentives to reduce and eliminate the production of CO_2.

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Appendix A

Pipeline Grades and Designations

ASTM - A106/A106M SPECIFICATION FOR SEAMLESS CARBON STEEL PIPE FOR HIGH-TEMPERATURE SERVICE:

	Composition, %		
	A	B	C
Carbon, max[A]	0.25	0.3	0.35
Manganese	0.27-0.93	0.29-1.06	0.29-1.06
Phosphorus, max.	0.035	0.035	0.035
Sulfur, max.	0.035	0.035	0.035
Silicon, min.	0.1	0.1	0.1
Chromium, max[B]	0.4	0.4	0.4
Nickel, max[B]	0.4	0.4	0.4
Molybdenum, max[B]	0.15	0.15	0.15
Copper, max[B]	0.4	0.4	0.4
Vanadium, max[B]	0.08	0.08	0.08

[A] For each reduction of 0.01% below the specified carbon maximum, an increase of 0.06% manganese above the specified maximum will be permitted up to a maximum of 1.35%. [B] These five elements combined shall not exceed 1%.

Note: ASTM A53 is one of the most widely used material standards for Steel pipes that are used in the Oil and Gas and other process industries. Grade B of ASTM A 53 is more popular than other grades. These pipes can be bare pipes without any coating, or they may be Hot-Dipped or Zinc-Coated and manufactured by Welding or by a Seamless manufacturing process.

In Oil and Gas, A53 grade pipes are used in structural and non-critical applications. They should not be used in hydrocarbon services or any high pressure and temperature services.

ASTM A53 Chemical Composition and Mechanical Properties of ASTM A53 Pipe

https://hardhatengineer.com/astm-a53-grade-a-garde-b-types-dimensions/

Type	**E and S**	**E and S**	**F**
Grade	**A**	**B**	**A**
Carbon	0.25	0.3	0.3
Manganese	0.95	1.2	1.2
Phosphorus	0.05	0.05	0.05
Sulfur	0.45	0.45	0.45
Copper*	0.4	0.4	0.4
Nickel*	0.4	0.4	0.4
Chromium*	0.4	0.4	0.4
Molybdenum*	0.15	0.5	0.5
Vanadium*	0.08	0.08	0.08
* The sum of these five elements must be less than 1.00 %.			

Types and Grades Tensile Strength -MPa Yield Strength – MPa

Type E and S – Grade A	330	205
Type E and S – Grade B	415	240
Type F – Grade A	330	205

ASTM API 5L

API 5L is normally used for both seamless steel pipes and welded steel pipes, but ASTM A106 is specially for seamless carbon steel pipes which can be used for high-temperature and high-pressures service.

Key Changes API Specification 5L, 46th Edition

- Updated and expanded requirements for mill jointers (differentiate between double-jointers and mill jointers; avoid welding consumables environmental contamination; require qualification standards; new process testing requirements; clarify offset and undercut requirements; standardize marking requirements; reference weld repair annex);
- Updated requirements for pipe end squareness;
- Updated requirements for hardness testing on PSL 2 pipe for sour service and PSL 2 pipe for offshore service;
- New annex for strain-based design requirements (PSL 2 pipe for applications requiring longitudinal plastic strain capacity)

API 5L Grade B pipe is **a common grade pipe for oil and gas pipeline transmissions**. It also called L245 Pipe refer ISO 3183, named by minimum yield strength 245 MPa (35534 Psi). Equivalent material ASTM A106 B or ASTM A53 B, which have similar value on chemical composition, mechanical properties, and applications.

Steel Grade	Mass fraction, % based on heat and product analyses a,g						
	C max b	Mn max b	P max	S max	V max	Nb max	Ti max
Seamless Pipe							
A	0.22	0.90	0.30	0.30	-	-	-
B	0.28	1.20	0.30	0.30	c,d	c,d	d
X42	0.28	1.30	0.30	0.30	d	d	d
X46	0.28	1.40	0.30	0.30	d	d	d
X52	0.28	1.40	0.30	0.30	d	d	d
X56	0.28	1.40	0.30	0.30	d	d	d
X60	0.28 e	1.40 e	0.30	0.30	f	f	f
X65	0.28 e	1.40 e	0.30	0.30	f	f	f
X70	0.28 e	1.40 e	0.30	0.30	f	f	f
Welded Pipe							
A	0.22	0.90	0.30	0.30	-	-	-
B	0.26	1.2	0.30	0.30	c,d	c,d	d
X42	0.26	1.3	0.30	0.30	d	d	d
X46	0.26	1.4	0.30	0.30	d	d	d
X52	0.26	1.4	0.30	0.30	d	d	d
X56	0.26	1.4	0.30	0.30	d	d	d
X60	0.26 e	1.40 e	0.30	0.30	f	f	f
X65	0.26 e	1.45 e	0.30	0.30	f	f	f
X70	0.26e	1.65 e	0.30	0.30	f	f	f

a. Cu ≤ = 0.50% Ni; ≤ 0.50%; Cr ≤ 0.50%; and Mo ≤ 0.15%

b. For each reduction of 0.01% below the specified max. concentration for carbon, and increase of 0.05% above the specified max. concentration for Mn is permissible, up to a max. of 1.65% for grades ≥ B, but ≤ = X52; up to a max. of 1.75% for grades > X52, but < X70; and up to a maximum of 2.00% for X70.

c. Unless otherwise agreed NB + V ≤ 0.06%

d. Nb + V + TI ≤ 0.15%

e. Unless otherwise agreed.

f. Unless otherwise agreed, NB + V = Ti ≤ 0.15%

g. No deliberate addition of B is permitted and the residual B ≤ 0.001%

Material Grades: https://www.prosaicsteel.com/api_5l_gr_b_carbon_steel_seamless_pipes.html

High Temperature Seamless Pipe	ASTM A106 Gr. B/C, API 5L Gr. B, ASTM A53 Gr. B
Heat Exchanger Seamless Tube	ASTM A179
Low Temperature Seamless Pipe	ASTM A333 Gr. 3/6
Low Temperature Seamless Tube	ASTM A334 Gr. 6
High Yield Seamless Pipe	API 5L Gr. X42/X46/X52/X56/X60/X65/X70/X80 PSL-1/PSL-2
High Yield Seamless Pipe	ISO 3183 Gr. L245, L290, L320, L360, L390, L415, L450, L485
Atmospheric & Low Temp EFW Pipes	ASTM A671 Gr. CC60/CC65/CC70

High Pressure & Moderate Temp EFW Pipes	ASTM A672 Gr. B60/B65/B70/C55/C60/C65/C70
High Yield ERW/SAW Pipe	API 5L Gr. X42/X46/X52/X56/X60/X65/X70/X80 PSL-1/PSL-2
High Yield ERW/SAW Pipe	ISO 3183 Gr. L245, L290, L320, L360, L390, L415, L450, L485