APPENDIX S

OIL AND GAS EXPLORATION AND PRODUCTION

Hoist and cage

Offshore oil drilling platform

Oil tanker

Internal corrosion of oil pipe

Lowering pipe

Maintenance

APPENDIX S

OIL AND GAS EXPLORATION AND PRODUCTION

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SUMMARY AND ANALYSIS OF RESULTS

Corrosion and Prevention

Domestic oil and gas production can be considered a “dinosaur industry” in the United States because most of the significant onshore oil and gas reserves have been exploited. The significant recoverable reserves left to be discovered and produced in the United States are probably limited to less convenient locations, such as deepwater offshore, remote arctic locations, and difficult-to-manage reservoirs with unconsolidated sands. Materials and corrosion control technologies used in traditional onshore production facilities have not significantly changed since the 1970s. The materials and corrosion control technologies required for the more difficult production areas must be more reliable due to the excessive cost of replacement or failure in these locations. Of course, the commodity price of oil will continue to dictate whether or not these new developments will even be considered.

Downhole tubing, surface pipelines, pressure vessels, and storage tanks in oil and gas production are subject to internal corrosion by water, which is enhanced by the presence of CO_2 and H_2S in the gas phase. Internal corrosion control is the major cost item. The total annual cost of corrosion in the oil and gas production industry is estimated to be $1.372 billion, broken down into $589 million in surface pipeline and facility costs, $463 million annually in downhole tubing expenses, and another $320 million in capital expenditures related to corrosion.

Opportunities for Improvement and Barriers to Progress

The majority of the cost-savings for any oil production facility is the prevention of failure in one of the production arteries (downhole tubing, surface pipelines, production vessels). Money lost through lost production far outweighs expenses associated with maintenance.

The high “lifting” costs associated with oil and gas production in the United States put the industry at a distinct disadvantage compared to the Middle East and the former Soviet Union, where the only barriers to increased production are investment capital and political complications. To remain competitive with the world market, maintenance costs must be kept to a minimum. Also, the conservative culture in the oil patch seldom allows for a new, unproven technology to be embraced.

Recommendations and Implementation Strategy

A large portion of the costs for internal pipelines lies in the use of corrosion inhibitors. Optimization of inhibitor usage could be accomplished through the use of more advanced inhibitor treatment schemes, such as active monitoring systems connected to inhibitor pumps to increase or decrease dosage as the corrosivity increases or decreases. Even passive systems could be developed that more accurately couple inspection and monitoring data with treatment schemes.

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The use of corrosion-resistant alloys is currently limited by the high initial capital investment associated with these materials. The development of lower alloy, less expensive corrosion-resistant alloys, particularly for offshore applications, would increase reliability of the major arteries. This development will be inexorably linked to the commodity price of oil.

The use of high-strength, non-metallic composite materials with high-pressure and high-temperature capabilities would significantly reduce the need for corrosion control measures though they may pose other structural limitations. These composites must be produced economically yet remain reliable, and must also gain wider acceptance in the industry for applications other than water handling within the oil and gas industry.

Summary of Issues

Increase consciousness of corrosion costs and potential savings.	A much larger percentage of new domestic oil and gas production will come from remote locations (deepwater offshore, etc.) where corrosion failures will be much more costly to fix. In addition, secondary and tertiary recovery techniques will increase the corrosivity of existing fields. Many problems could potentially be solved simply by using the available improved technologies if there were better awareness of the existence of these technologies. Computerized expert systems and knowledge management tools should be utilized to educate and inform about state-of-the-art materials for corrosion control.
Change perception that nothing can be done about corrosion.	Much of the oil field production technology is based on tried-and-true designs and, as a whole, the industry is extremely conservative. The use of new innovative production strategies would necessarily be accompanied by a more innovative approach to corrosion control.
Advance design practices for better corrosion management.	Advances in materials technology, borrowed from other industries such as aerospace, offer alternatives to conventional designs. Innovative production schemes (such as downhole separation) could reduce the corrosivity of production streams early in the process.
Change technical practices to realize corrosion cost-savings.	Upfront consideration of corrosion control in new construction should be based on all aspects of life-cycle costs, not simply present worth calculations. The total consequences of a leak (including lost production, a more negative public image, and increased scrutiny from regulators) must be factored into these decisions.
Change policies and management practices to realize corrosion savings	Management must be made aware that the lack of immediate corrosion problems does not justify a reduction in expenditures on mitigation, monitoring, and inspection. Throwing money at the problem after a leak occurs should not be considered a cost-effective strategy.
Advance life prediction and performance assessment methods.	More accurate life prediction methods will better enable accurate life-cycle cost estimates when considering the use of advanced alloys and composites. Use of reservoir simulation models, applied to water-cut increases and field souring mechanisms, will help in predicting the behavior of aging fields and would allow for prevention measures to be implemented before the problems take hold.
Advance technology (research, development, and implementation).	Remote monitoring systems for internal corrosion would enable early detection of corrosion control in even the most remote locations. The development and utilization of so-called low-alloy steels would fill the void between carbon steel and expensive corrosion-resistant alloys.
Improve education and training for corrosion control.	Engineering design firms, not oil companies, are designing new platforms and production facilities. Basic education in oil field corrosion control technology needs to be brought into these firms as early as possible in the design of oil production facilities.

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SECTOR DESCRIPTION

The domestic U.S. oil industry is based on a finite resource – petroleum crude, thereby, having a limited growth potential. However, the oil industry is expected to remain an industrial force in the U.S. economy for years to come.

Oil production in the United States in 1998 consisted of 3.04 billion barrels (bbl).(1) The per-barrel price of oil has fluctuated greatly over the past 20 years; however, overall it has remained steady. In fact, the price has dropped steadily when adjusted for inflation. Fortunately, the infrastructure costs for producing oil have come down dramatically in the past 25 years, primarily due to advanced technologies that enable much more of the oil in place to be produced. These advancements have saved the domestic oil industry by allowing it to compete on a commodity basis with cheap foreign oil.

Recent History of Oil and Gas Production

Oil and gas are commodities; therefore, the amount of activity in oil and gas production rises and falls with the commodity price.

Figure 1 shows the price comparison between West Texas Intermediate (WTI) crude oil and the San Joaquin Valley (SJV) crude oil from 1991 to 2000, with the difference between the two prices for crude oil plotted as the "differential". WTI crude, also referred to as light sweet crude, is the benchmark most often quoted by investors in the commodity sector. SJV is heavy crude oil, which requires more expensive processing and refining. SJV's spot price is generally well below the WTI crude.

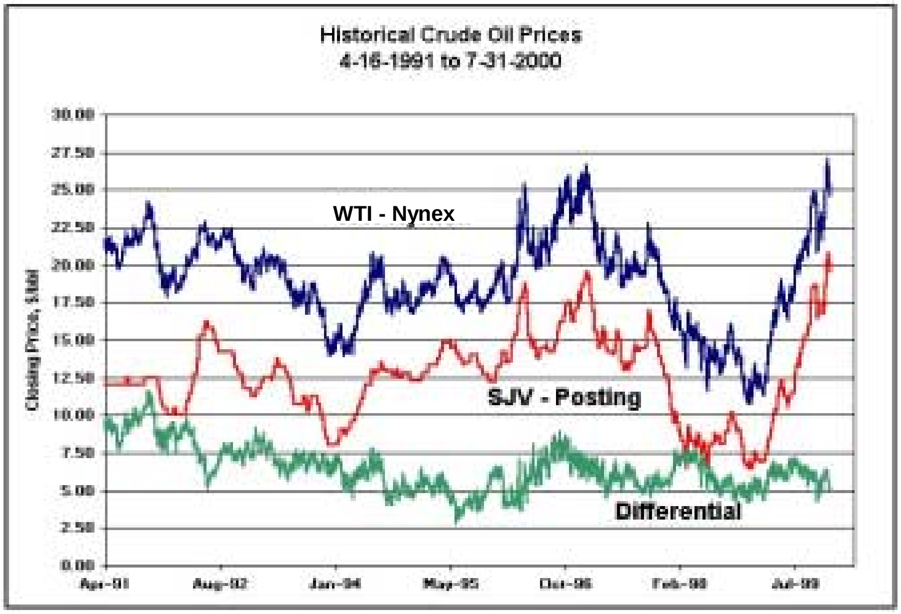

Figure 1. Oil prices in the 1990s.(2)

Table 1 presents the oil production of different countries since 1970. The data show the decline in oil production in the United States balanced by the rise in oil production of most other countries, especially within the Organization Petroleum Exporting Countries (OPEC) cartel. The exception to this is Iraq, whose production has suffered since the Gulf War.

Table 1. Worldwide oil production from 1970–1996.(3)

CRUDE OIL PRODUCTION									
	thousand barrels per day								
	1970	**1980**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**
Non-OPEC "Western"									
United States	9,648	8,597	7,355	7,417	7,171	6,847	6,662	6,560	6,471
Canada	1,305	1,424	1,518	1,548	1,604	1,677	1,742	1,806	1,820
Mexico	420	1,936	2,648	2,774	2,668	2,673	2,685	2,722	2,854
Norway	0	528	1,620	1,876	2,144	2,264	2,580	2,782	3,086
United Kingdom	2	1,619	1,850	1,823	1,864	1,922	2,469	2,565	2,633
OPEC									
Algeria	976	1,020	794	803	772	747	750	764	816
Indonesia	855	1,576	1,289	1,411	1,346	1,327	1,319	1,498	1,516
Iran	3,831	1,662	3,252	3,358	3,455	3,671	3,585	3,612	3,675
Iraq	1,563	2,514	2,080	283	425	448	550	600	600
Kuwait	2,983	1,661	1,235	200	1,050	1,870	2,000	2,007	2,060
Libya	3,321	1,830	1,374	1,509	1,493	1,361	1,380	1,390	1,403
Nigeria	1,090	2,058	1,811	1,867	1,902	1,905	1,883	1,890	2,014
Saudi Arabia	3,789	9,903	6,414	8,223	8,308	8,087	8,000	8,074	8,083
United Arab Emirates	691	1,702	2,117	2,416	2,322	2,195	2,223	2,205	2,217
Venezuela	3,708	2,165	2,085	2,350	2,314	2,335	2,463	2,609	2,955
Other Non-OPEC									
China	602	2,113	2,769	2,785	2,835	2,908	2,961	3,007	3,127
Kazakhstan	NA*	NA	515	530	515	460	405	415	460
Russia	NA	NA	10,325	9,220	7,915	6,875	6,315	6,135	6,010

*NA – Not available

Figure 2 shows that worldwide oil production continues to increase. Figure 3 and figure 4 show the decline in the annual oil production for the lower 48 states and Alaska, respectively. Production costs, of which corrosion control is an increasing percentage, continue to limit domestic production as more oil is imported.

Production costs are not tied directly to commodity price, so when commodity prices drop, the solution is often to abandon or shut down the more difficult, less prolific production wells. When the commodity price fell to below $10 a barrel in 1998, an estimated 100,000 wells in the United States were shut down or abandoned. Because the initial cost of recommissioning these wells would be quite high, most of these are permanently shut down.

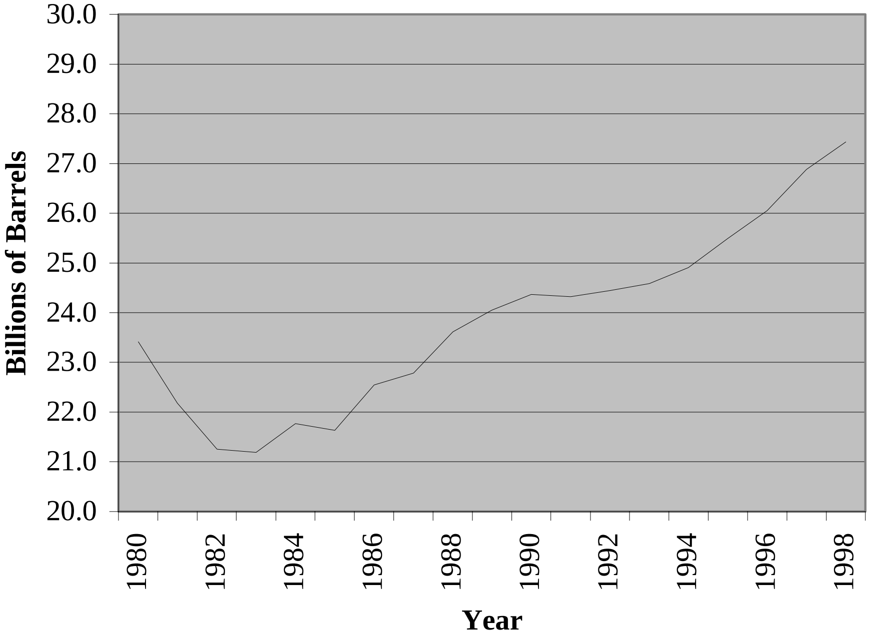

Figure 2. Annual world crude oil production.(3)

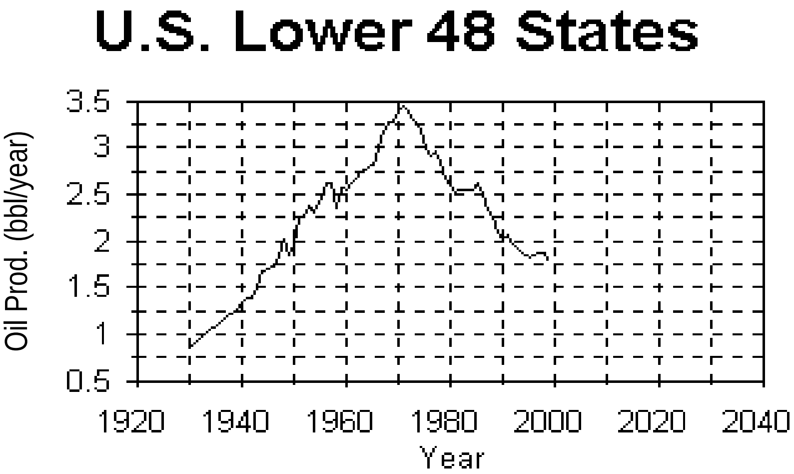

Figure 3. Crude oil production in the lower 48 states.(4)

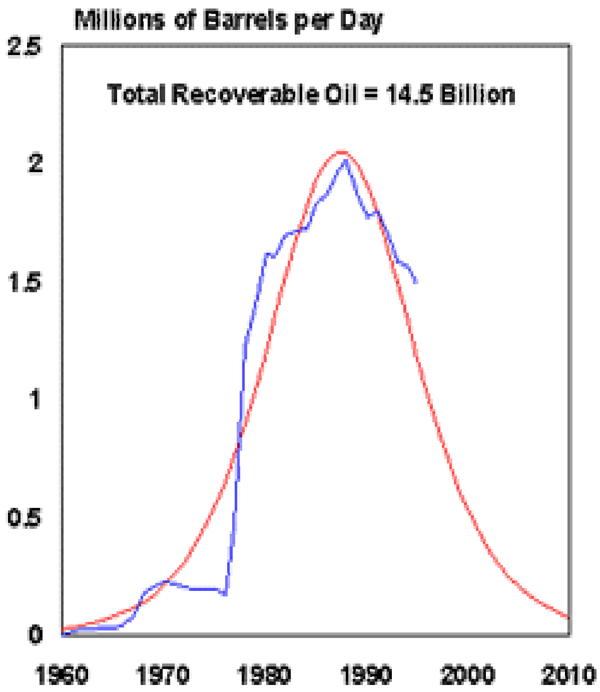

Figure 4. Annual crude oil production in Alaska.(4)

Technology of Oil and Gas Production

While oil and gas production has undergone a number of rebirths in its more than 100-year history, the elements of the process remain relatively constant. Oil is found in reservoirs deep underground or beneath the ocean floor, and is extracted vertically through relatively small-diameter, high-pressure tubing. The process extracts oil, water, and mixed gases (simple hydrocarbons, CO_2, and H_2S, possibly also small quantities of N_2 and inert gases) from the rock formations. A sketch of a typical oil field gathering system is shown in figure 5.

Once at the surface, the production stream runs through a control wellhead into horizontal flow lines, normally of larger diameter and running at lower pressures. The flow lines carry the three phases into a separator vessel in which the gas phase flashes to the upper portion. The oil occupies the middle portion and the water drops to the bottom. Gas from the top may be reinjected into the reservoir, refined and marketed, or flared. Water is normally reinjected into the reservoir, and the oil is sent to a pipeline for delivery to a refinery, tanker terminal, or transmission pipeline system. Other oil field processes include gas processing and reinjection, seawater injection, and natural gas liquid (NGL) stripping and blending.

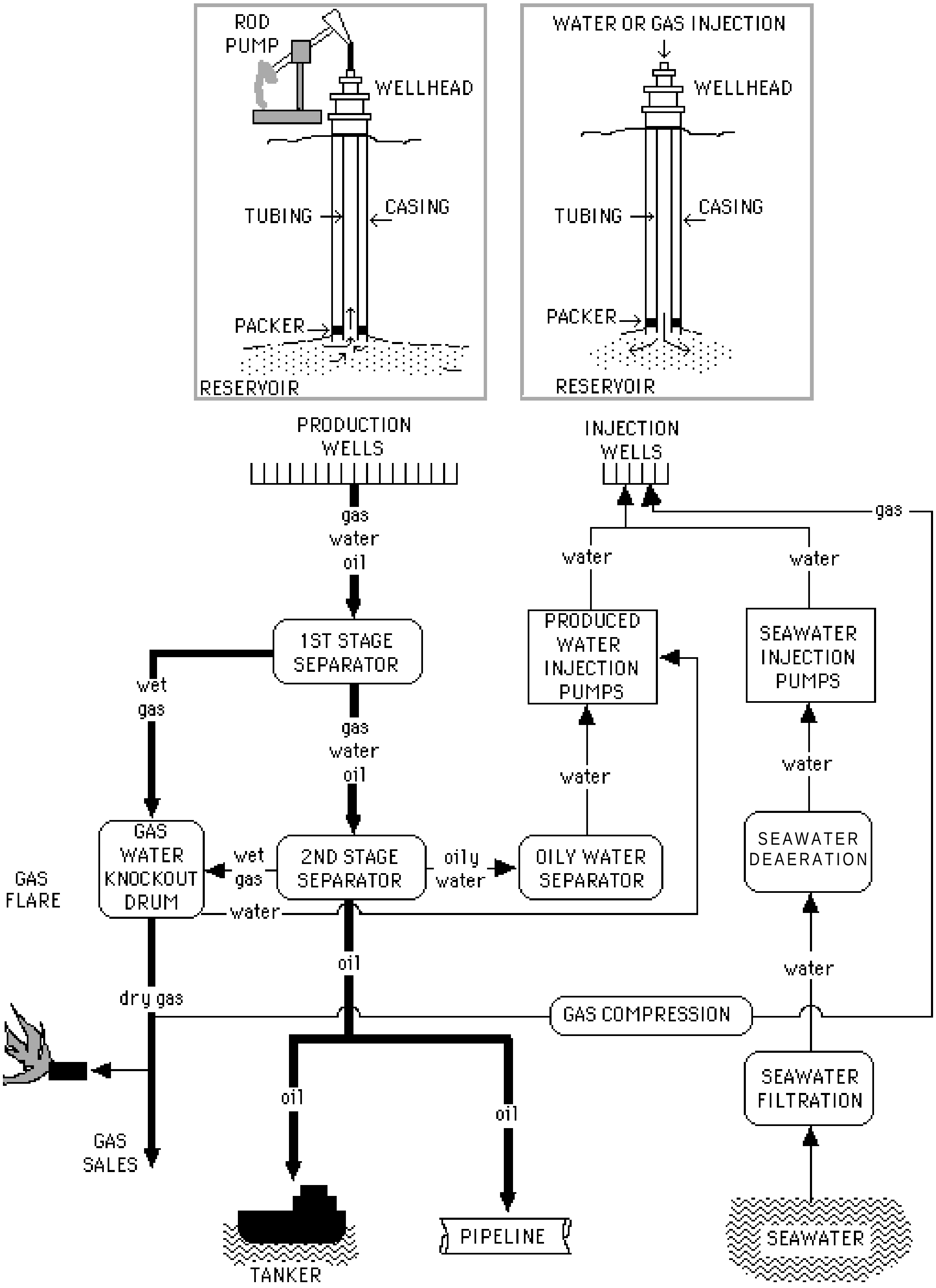

Figure 5. Typical oil and gas production flow diagram.

AREAS OF MAJOR CORROSION IMPACT

Corrosion in Oil Field Environments

Oil field production environments can range from practically zero corrosion to severely high rates of corrosion.(5) Crude oil at normal production temperatures (less than 120 °C) without dissolved gases is not, by itself, corrosive. The economics of controlling corrosion in many oil fields are dependent on efficient separation of crude oil from other species. While the rates may vary, the species causing the most problems are nearly universal. CO_2 and H_2S gases, in combination with water, define most of the corrosion problems in oil and gas production. Other problems include microbiological activity and the solids accumulation.

The mechanisms of CO_2 corrosion are generally well defined; however, the reality inside a pipeline becomes complicated when CO_2 acts in combination with H_2S, deposited solids, and other environments. H_2S can be highly corrosive, but can, in some cases, form a protective sulfide scale that prevents corrosion. Microorganisms can attach to pipe walls and cause corrosion damage. Solids, such as formation sand, can both erode the pipeline internally and cause problems with under-deposit corrosion, if stagnant.

Oxygen is not found in oil reservoirs and much is done to ensure that no oxygen enters the production environment; however, in many cases, a few parts per million (ppm) of oxygen will enter the pipelines, greatly exacerbating corrosion problems.

External corrosion problems in oil and gas production normally are similar to those found in the pipeline industry, but since the lines are shorter and smaller in diameter, their economic impact on the total cost of production is limited. Atmospheric corrosion of structures and vessels is a problem for offshore fields and those operating near marine environments. Improvements in the quality of protective coatings for offshore environments have dramatically reduced the frequency of repainting platforms and tanks.

TRENDS IN DOMESTIC OIL PRODUCTION

As previously described, the annual production of crude oil depends mainly on the cost of extraction, the amount of oil in the ground, and its price in the global market. In order to compete economically, production costs must be decreased using advanced technologies.

A consequence of the advanced technologies that enables higher total production from a reservoir has been an increase in the corrosivity of oil production environments. Secondary and tertiary recovery techniques applied to old oil fields enable them to produce economically for many years after their predicted decline. The drilling of wells in deep water and in otherwise inaccessible areas offshore, adds to the complexity of production. Corrosivity is increased for the following reasons:

- Oil, water, and gas are produced in every oil field. Water is reinjected downhole to maintain reservoir pressure and stability, and often water flooding (using seawater or fresh water sources) is used to drive oil out of the formation. As a field ages, the water cut, or the ratio of water to oil in the fluids produced, increases to levels of 95 percent or higher depending on the economics of production. As the oil industry matures and the number of old oil fields relative to new fields increases, the amount of water produced increases and the internal corrosion increases.
- Water injection from seawater or fresh water sources contributes to “souring” of oil fields with H_2S, usually resulting in an increase in the corrosion rate, which sometimes requires a complete change in the corrosion strategy. These water sources may necessitate biocide

injection and will require deaeration to avoid introducing new corrosion mechanisms into the existing system.

- Tertiary recovery techniques are often based on miscible and immiscible gas floods. These gas floods invariably contain a high percentage (often 100 percent) of CO_2, which dramatically increases the corrosivity of the produced fluids.
- Due to the high cost of failure and the inability to rehabilitate facilities in deep water, offshore production in deep water necessitates the use of high-alloy steels and other more exotic corrosion control measures. A similar need for advanced measures exists in the production of high-pressure, high-temperature offshore oil and gas fields where conventional corrosion mitigation is not possible.

The American Petroleum Institute (API)(6) has recently forecast that there are approximately 200 billion barrels of recoverable oil remaining in the United States and the continental shelf associated with the United States, or about 70 years of production at current rates. This "recoverable" oil includes mostly difficult production, such as deep water, unconsolidated sands, heavy oils, remote arctic fields, and tertiary recovery on existing fields.

Corrosion in oil and gas production varies from location to location. Corrosion can be classified into one of three general categories of internal corrosion caused by the produced fluids and gases, external corrosion caused by exposure to groundwater or seawater, and atmospheric corrosion caused by salt spray and weathering offshore. Of these, internal corrosion is the most costly since internal mitigation methods cannot be easily maintained and inspected.

Overall corrosion costs can most easily be evaluated on a cost per barrel of oil produced basis. In this way, as new wells are drilled or unproductive wells are shut down, the sinusoidal variation in total spending for a particular production area makes more sense.

Oil field production can be divided into downhole costs, including vertical tubing and miscellaneous accessories and surface facilities, which include horizontal piping, production vessels, and storage tanks. Another category would be offshore production costs, including downhole and surface components; however, there is the added expense of offshore platforms or subsea production equipment.

Operational Expenditures

Downhole Tubing

Corrosion economics for the oil wells in the majority of the U.S. onshore oil fields are characterized by very low mitigation costs and carefully monitored replacement and/or failure costs. This is contrary to operations offshore and in the arctic, in which the costs of lost production and/or the high cost of replacement make corrosion prevention a higher priority.

The figures for a typical onshore operation in the United States, consistent with API data, provide the following:(7)

- the average failure rate is 0.6 failures per year per well,
- approximately 30 percent of all failures are corrosion-related, and
- the average cost of a failed well is $3,000.

Using these numbers, there are 0.18 corrosion-related failures annually per well in the United States and the failure cost due to corrosion is $540 per well for every well in the United States. API statistics reported that there are currently 553,000 operational oil wells in the United States and 304,000 gas wells. The cost of corrosion for the downhole portion of the oil and gas industry is then:

0.18 failures x $3,000 per failed well = $540 per well
53,000 oil wells + 304,000 gas wells x $540 per well = $463 million.

Surface Production and Processing

A major American oil field, which produces 270,000 bbl per day (4 percent of total daily domestic production), provided some estimates with regard to the current (1999) annual corrosion costs in different aspects of production (see table 2).

Table 2. Detailed annual costs of corrosion for one large oil field.[8]

	COST ($ x thousand)
INSPECTION COSTS	
Overhead	$492
Tangential Radial Tomography Inspection	$1,409
Ultrasonic Inspection	$361
Other	$1,054
TOTAL INSPECTION	**$3,316**
MONITORING COSTS	
Coupons	$924
Bacteria Monitoring	$13
Laboratory Analysis	$40
TOTAL MONITORING	**$977**
REPAIRS	**$600**
ENGINEERING STAFF	**$1,416**
CORROSION INHIBITOR (chemical alone)	**$13,533**
TOTAL	**$19.84 million**

Another field, operated by the same company and producing 246,000 bbl per day, reported the following costs (see table 3):

Table 3. Costs for various corrosion expenses for one large oil field.[9]

CORROSION EXPENSE	**COST ($ x thousand)**
Inspection, monitoring, and staff costs	$9,625
Repairs	$1,350
Corrosion inhibitor (chemical alone)	$7,200
TOTAL	**$18.175 million**

The average distribution of these costs is shown in figure 6.

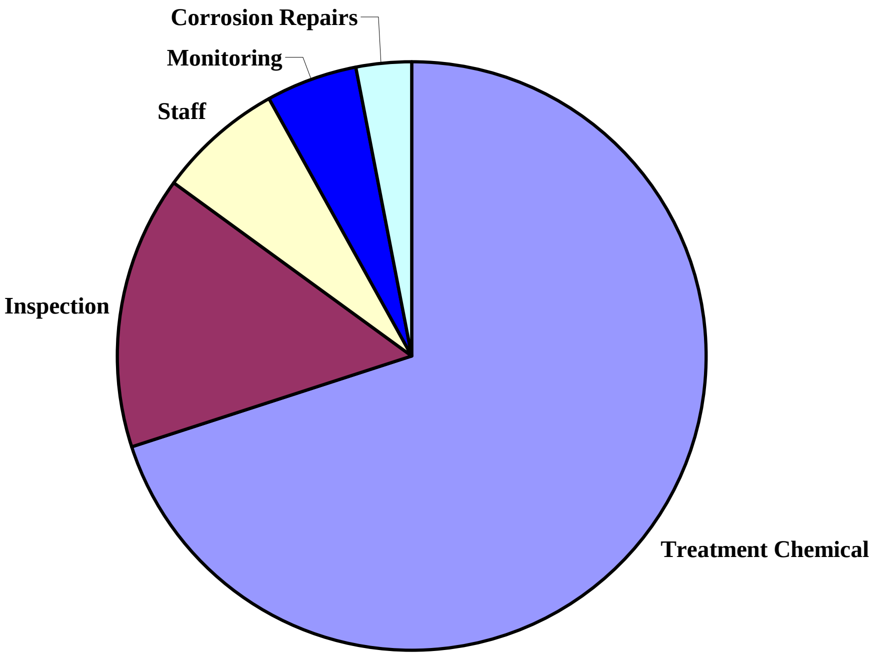

Figure 6. Cost of corrosion in oil production field by activity.

The choice of corrosion control activity would vary greatly with production environment, area, and company philosophy; therefore, some oil fields will use very little treatment chemicals, although the cost of alternatives (alloys, plastic liners, etc.) will fill this void.

Because the extent of internal corrosion in a particular oil field environment is largely a function of the amount of water produced, as a field ages and the water cut increases, corrosion control will become more costly. Increased water often is accompanied by increased levels of bacteria and H_2S, and in cases where miscible gas is reinjected, increased levels of CO_2. Below are figures expressed in terms of corrosion costs per barrel of produced fluid:

Average cost/bbl of produced oil:	$0.20
Average cost/bbl of produced water:	$0.07 to $0.09

The total amount of crude oil and natural gas liquids (NGLs) produced in the domestic United States is approximately 7.9 million bbl per day (*Oil & Gas Journal*, Aug. 2, 1999). Using the figures supplied above for a cost per barrel, that translates into a $1.58 million-per-day cost of corrosion for upstream oil production facilities, or an annual cost of $577 million annually. This figure includes only infield piping and facilities, and does not include cross-country pipeline transportation.

Capital Expenditures

Onshore

A report on internal corrosion for the oil and gas industry in the United States$^{(10)}$ estimated that the annual capital expenditures were $4.0 billion, of which $320 million (8.0 percent) were directly related to corrosion control. The most significant area for these expenditures was the use of corrosion-resistant alloys (CRAs) in downhole tubing and downhole equipment. Other capital expenditures include galvanizing; (OEM) coatings; and alloy valves, fittings, and equipment internals for surface facilities.

Offshore

Offshore oil and gas production works on a different economic basis than onshore production. First, the cost for doing any construction, maintenance, or inspection offshore can be up to 10 times higher than the cost of performing the same activities onshore. The material costs naturally become a smaller percentage of the total cost of the corrosion mitigation operation.

Second, because offshore drilling and completion costs are so much higher than onshore costs, only offshore wells with a high potential production and a long service life are drilled and completed. Field equipment service life must be longer to keep the operations economical; therefore, the facilities and piping must be designed to avoid replacement.

Finally, offshore production requires either expensive subsea completion technology or the construction of a platform to support the production equipment. Not only does the process equipment need corrosion mitigation, but the support infrastructure also needs protection and maintenance. It has been estimated that 60 percent of all maintenance costs in offshore production are corrosion-related.(11)

Offshore capital expenditures (CAPEX) represent a much higher proportion of costs offshore relative to onshore. A detailed study of the cost of corrosion for two particular offshore production fields(11) estimated that the cost of corrosion for the offshore facilities was $0.40 per barrel produced in comparison to $0.20 for onshore facilities.

The offshore fields studied utilized CRAs for tubulars and pipelines. This incrementally represented 6.6 percent of the total construction costs in this field. The operational expenditures (OPEX) were therefore minimized, limited to inspection and maintenance painting, and amounted to only $35,000 annually, or $0.0015 per bbl. The other field, which utilized CRAs but had a greater percentage of coated/cathodically protected carbon steel, showed an OPEX of $0.05 per bbl. In general, it was concluded that the CAPEX was directly related to the corrosivity, while OPEX was proportionally related to the life of the field.

Production offshore in the United States is only about 2 percent of total domestic production. This number is expected to grow incrementally over the next 15 years. Currently, offshore wells being drilled in the United States make up 15 percent of all new production wells. As onshore production declines, the offshore wells, particularly deep-water wells, will offer a frontier for domestic production.

SUMMARY

The total cost of corrosion in the U.S. oil and gas industry is estimated at:

$577 million in surface facilities + additional 2% for offshore OPEX = $589 million,
8% corrosion costs x $4 billion total CAPEX = $320 million, and
153,000 oil wells + 304,000 gas wells x $540 per well for downhole OPEX costs = $463 million.

The total estimated annual cost of corrosion in the oil and gas industry is therefore $589 million + $320 million + $463 million = $1.372 billion.

CASE STUDY

Installation of a Subsea Gathering System for a Natural Gas Production Field

The pipeline design for a new gas production facility for a major oil company(12) consisted of several short 20-cm- (8-in-) diameter subsea gathering lines (flow lines), emptying into a 19-km (30 mi), 50-cm- (20-in-) diameter subsea transmission gas pipeline (trunk line). The pipeline was to bring wet gas from an offshore producing area to a dehydration facility onshore with a design life of 20 years.

The internal corrosion rate of the pipeline system was estimated, through the use of corrosion prediction models, to be 300 to 400 mils per year (mpy); an unacceptably high rate for standard carbon steel pipelines. Because of the corrosivity of the system, several corrosion mitigation options were considered. These options were:

- Carbon steel treated with a corrosion inhibitor.
- Internally coated carbon steel with a supplemental corrosion inhibitor.
- 22 percent Cr duplex stainless steel.
- 625 corrosion-resistant alloy (CRA).

An economic evaluation of each of these included risk assessments and life-cycle cost estimates.

Options for Flow Lines

In the case of bare carbon steel with a supplemental corrosion inhibitor, the installed cost of a line was estimated to be $763,000. Based on the corrosivity of the system, it was predicted that half of the flow lines would have to be replaced over the life of the field. The cost of replacing the lines, based on present-worth calculations, was $549,000, for a total cost of $1.312 million. In addition, the risk of losing corrosion control due to malfunction of the injection system was considered to be quite high. External corrosion protection through coating and cathodic protection was $490,000.

For internally coated carbon steel with a supplemental corrosion inhibitor, the installed cost of a line was $1.033 million. Part of this cost would be the installation of internally coated, weldable sleeves that fit into the ends of the pipeline sections to provide a 100 percent coated line. The supplemental corrosion inhibitor was necessary to inhibit uncoated spots (holidays) in the pipeline. Either installation damage or in-service damage may cause the holidays. Again, external corrosion protection through coating and cathodic protection was $490,000.

For duplex stainless steel, the installed costs were calculated to be $1.77 million; however, due to the duplex stainless steel allowing for higher production velocities, it was calculated that 15-cm- (6-in-) diameter flow lines could be used, which would result in a 25 percent savings, reducing the installed cost to $1.33 million. The higher velocities were the result of a perceived lower amount of solids built up from scale and corrosion products. In addition, the lower external surface area to be coated and cathodically protected reduced this additional cost to $370,000.

The 625 CRA was the only option that would not require external coating and cathodic protection. The cost of this option, which was not given serious consideration, was estimated to be $11.3 million for a 20-cm- (8-in-) line and $8.5 million for a 15-cm- (6-in-) line.

Options for the Trunk Line

All of the above were considered as possible alternatives for the 50-cm (20-in) pipeline.

Bare carbon steel with corrosion inhibitor was not considered to be a technically sound option because maintenance pigging facilities, necessary for solids removal, were not possible with a subsea completion. The effectiveness of a bare carbon steel system with inhibitor is severely curtailed by the presence of solids, which build up inside the pipeline. Pigging facilities also allow in-line inspection pigs to be run, providing a way to monitor corrosion inhibitor effectiveness and subsequently adjust the inhibitor dosage when needed.

Internally coated carbon steel with supplemental corrosion inhibitor was estimated to cost $15.26 million installed, but required the specially coated internal sleeves to bridge the coating across the welds. Again, the supplemental corrosion inhibitor was necessary to inhibit holidays in the pipeline. A corrosion rate at the holiday, based on experience and statistical models, was estimated to be 2 mpy. A 32-mm (1/8-in) corrosion allowance was added to the steel as insurance against inhibitor delivery problems as well as start-up problems.

The duplex stainless steel pipeline was estimated to cost $19.84 million installed. Costs for large-diameter duplex pipes are proportionally much higher than for the 15-cm to 20-cm (6-in to 8-in) piping evaluated for flow line usage.

For all of these cases, external coating and cathodic protection would again be necessary to prevent external corrosion. The cost of this was estimated at $7.84 million or an additional 46 percent over the installed cost of each pipe.

The 625 CRA was not seriously considered for this application because of the high initial cost, estimated to be $77 million.

Risk Factors

The chance for success was estimated from known field histories of each technique, as well as analysis of the corrosivity of the system and the level of sophistication required for successful implementation (see table 4).

Table 4. Estimated probability of success for different material selection options.

OPTION	CHANCE FACTOR FOR SUCCESS
Bare Carbon Steel + Inhibitor	65%
Coated Carbon Steel + Supplemental Inhibitor	90%
Duplex Stainless Steel	95%
625 CRA	98%

Based on these risk factors, it was decided that the attractive economics of the coated carbon steel with a supplemental corrosion inhibitor was preferred over the duplex stainless steel, despite the perceived higher risk of the coated system.

Table 5. Total installed cost for all pipelines (bold underline indicates options that were selected).

LINE DESCRIPTION		BARE CARBON STEEL (“NO CORROSION” CASE)	CARBON STEEL WITH CORROSION INHIBITOR	COATED CARBON STEEL WITH SUPPLEMENTAL CORROSION INHIBITOR AND CORROSION ALLOWANCE	DUPLEX STAINLESS STEEL ALLOY (22% CR)	625 ALLOY
Flow Lines	Pipe + Internal Corrosion Protection	$970,000	$1,310,000	$1,030,000	8 in dia = $1,770,000 **<u>6 in dia = $1,330,000</u>**	8 in dia = $8,850,000 6 in dia = $6,650,000
	Cathodic Protection and External Coating	0	$490,000	$490,000	8 in dia = $490,000 **<u>6 in dia = $370,000</u>**	0
Trunk Lines	Pipe + Internal Corrosion Protection	$9,260,000	N/A	**<u>$11,160,000</u>**	$17,160,000	$77,000,000
	Cathodic Protection and External Coating	0	$7,840,000	**<u>$7,840,000</u>**	$7,840,000	0

N/A – not available 1 in = 25.4 mm

The “No Corrosion” case in the first column indicates the physical cost of installing a steel pipeline so that the additional costs due to corrosion control measures can be more clearly seen. The costs for cathodic protection (CP) and external coating are add-ons to the pipe, since the considerations for external corrosion are different and completely separate from the considerations for internal corrosion.

The total cost for the pipelines in the gas field was [$1,330,000 for 15-cm (6 in) duplex SS flow line] + [$370,000 for CP and external coating on 15-cm (6-in) duplex SS flow line] + [$11,160,000 for internally coated trunk line] + [$7,840,000 for CP and external coating on the trunk line] = $20,700,000 for the pipelines in the field. In the “no corrosion” case, the total cost is $970,000 for flowline + $9,260,000 for trunk line = $10,320,000 for the pipelines in the field. Therefore, corrosion concerns doubled the cost of the pipeline installations in the field.

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