TECHNOLOGY Locations: Worldwide, onshore and offshore

Acid Gas Removal and Recovery

SUMMARY

Before natural gas can be transported safely and economically, hydrogen sulfide (H_2S), a highly poisonous acid gas, and other acid compounds such as carbon dioxide (CO_2) must be removed from the raw gas stream in order to meet pipeline sales contract specifications. Sulfur recovery plants are used in tandem with acid gas removal (sweetening) operations to avoid emitting unacceptable quantities of sulfur compounds to the atmosphere. Improvements in gas sweetening, in conjunction with advanced sulfur recovery technologies, make it possible to practically eliminate noxious emissions and recover nearly all the acid gas stream's elemental sulfur for later sale or disposal.

BLUEPRINT ON TECHNOLOGY

Improved technology and practices "sweeten" sour gas for pipeline use and achieve nearly 100 percent sulfur recovery, greatly reducing air emissions

Sweetening natural gas

A RECENT GAS RESEARCH Institute survey concluded that approximately 24 percent of the raw natural gas produced in the lower-48 States contains unacceptable quantities of H_2S, CO_2, or both. To sweeten the high acid content "sour" gas, it is first prescrubbed to remove entrained brine, hydrocarbons, and other substances. The still sour gas then enters an absorber, where lean amine solution chemically absorbs the acid gas components, as well as a small portion of hydrocarbons, rendering the gas ready for processing and sale. An outlet scrubber removes any residual amine, which is regenerated for recycling. Hydrocarbon contaminants entrained in the amine can be separated in a flash tank and used as fuel gas or sold. Process efficiency can be optimized by mixing different types of amine to increase absorption capacity, by increasing the amine concentration, or by varying the temperature of the lean amine absorption process.

Recovering sulfur

Once acid components have been removed from the gas stream, sulfur recovery plants can minimize sulfur emissions and maximize recovery of elemental sulfur—environmental regulations commonly require sulfur recovery levels well over 99 percent. The Claus sulfur recovery process, first developed over 100 years ago, is still the most widely used process today. Between 90 and 95 percent of the total sulfur recovered worldwide uses a variation of this process. Typically, the acid gas feed is partially oxidized to produce SO_2, which is then catalyzed with the remaining H_2S to produce elemental sulfur, of which approximately 94 to 97 percent is recovered for sale. Most Claus plants contain two or three catalytic stages to enhance recovery. To reach higher recovery levels, a sub-dewpoint Claus process is employed, which operates at a lower temperature, causing sulfur condensation and higher recovery. A tailgas cleanup unit is required to obtain sulfur recovery levels as high as 99.9 percent. This converts the sulfur compounds in the tailgas back to H_2S, then transfers it to a low-pressure amine sweetening unit, which recycles the H_2S with some CO_2 to the

ECONOMIC BENEFITS

- Increased access to sour natural gas resources
- Sale of recovered sulfur as a commodity

ENVIRONMENTAL BENEFITS

- Improved air quality through increased sulfur recovery

Claus unit for reprocessing. In most sulfur recovery processes, a tailgas thermal oxidizer incinerates nearly all remaining sulfur compounds and other contaminants before venting it to the atmosphere.

Alternative acid gas disposal methods

In cases in which it is not economically feasible to recover elemental sulfur for sale, industry is developing advanced acid gas disposal techniques. In Canada, for example, where operators have typically flared recovered acid gases if unable to recover sulfur economically, acid gas is now being dissolved in oil field produced water at the surface and injected into subsurface formations. This practice, although still being demonstrated, potentially offers producers a low-cost, environmentally sound acid gas disposal technique when sulfur recovery is not economic.

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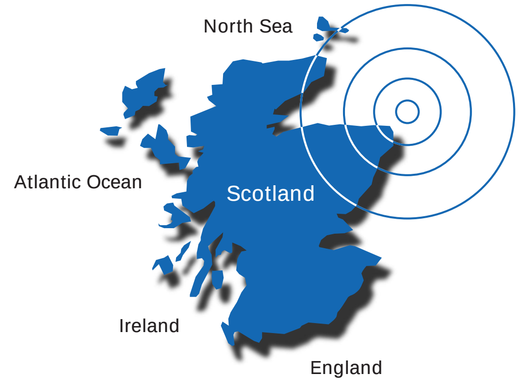
Aerial view of pipeline transporting recovered sulfur to market

CASE STUDIES

Success in the Field



The Scott field experience

Scott field, 130 miles northeast of Aberdeen, Scotland, is the United Kingdom's largest offshore project this decade. Recoverable reserves are estimated at 450 million barrels of oil and 287 billion cubic feet of associated gas. In addition to subsea facilities, the development has twin connecting steel platforms, including a process/drilling platform, drilling and gas treatment modules, and a flaring unit.

Developer Amerada Hess Ltd. realized that offshore production could begin several months before availability of permanent onshore gas processing facilities at Mobil North Sea Ltd.'s St. Fergus terminal, which was scheduled to come on-line on April 1, 1994. To permit early production, temporary gas sweetening equipment was installed in April 1993 to attain pipeline specifications. A single, fixed-bed reactor sweetening unit enabled H_2S content to be reduced by nearly 95 percent. By the middle of October, the Scott field development was producing, treating, and exporting gas, approximately five months ahead of schedule.

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TECHNOLOGY Locations: Worldwide, onshore and offshore

Artificial Lift Optimization

SUMMARY

As reservoir pressure declines, natural processes no longer push the oil to the surface. Artificial lift technology, which includes sucker-rod pumps, electrical submersible pumps, hydraulic jet pumps, plunger lifts, progressing cavity pumps, and gas lift systems, is now used to produce some 65 percent of all oil. Performance of artificial lift systems has been optimized through recent innovations in artificial lift equipment, improved operational design and parameters, and real-time data collection, automation, and control technologies. System optimization not only maximizes production efficiency, but can also decrease on-site power use and extend equipment life. Results include improved profitability, reduced workover wastes, and lower air emissions.

BLUEPRINT ON TECHNOLOGY

Reduced emissions during production and increased productivity result from increasing the efficiency of the systems that raise oil to the surface

Practical measures with attractive environmental and productivity paybacks

SUCKER-ROD PUMPS, the most prevalent form of artificial lift, use arm-like devices to provide up-and-down motion to a downhole pump. Such rod pumping, most effective in relatively shallow and low-volume wells, can be optimized to increase lifting efficiency and minimize energy consumption. Surface and downhole energy losses can be reduced by adjusting key design parameters like pumping mode selection, counterbalancing (to balance loads on the gear box during the pumping cycle), and rod string design.

A number of other advanced artificial lift technologies and practices have improved efficiency in recent years. Real-time data collection, automation, and control techniques now allow operators to monitor pumping performance and downhole conditions continuously, and to control operations accordingly. Variable-speed motors tailor pumping operations to changing conditions. New low-profile rod pumps are attractive options in sensitive urban, residential, and agricultural areas, as well as on crowded offshore platforms.

Gas lift, another common form of artificial lift, pumps natural gas down the well's annulus and injects the gas into the production tubing near the bottom of the well. The gas expands within the production tubing stream, allowing liquid hydrocarbons to be carried to the surface. Gas lift is commonly used when natural gas is readily available, and is especially prevalent offshore. Each gas lift well has an optimum injection rate and pressure. Since the injected gas raises the back pressure in the flow line leading to the field's separation and processing facilities, back pressure in one well affects all wells sharing common flow lines. Using advanced modeling techniques to develop models of multiflow characteristics and to optimize parameters, operators today can design complex gas lift systems that maximize production from all wells in a network, given the system's constraints.

ECONOMIC BENEFITS

- Enhanced efficient production from existing wells
- Lower equipment maintenance costs
- Lower on-site power consumption and costs

ENVIRONMENTAL BENEFITS

- Increased equipment life and fewer failures result in less workover and recompletion operations, reducing the volume of workover fluids and other wastes
- Reduced air emissions due to lower power consumption

Case Studies

Success in the Field

©SPE, 1993

Optimization of sucker-rod pumping can increase production efficiency and minimize energy consumption.

Optimizing artificial lift in Oman

For Petroleum Development Oman (PDO), real-time automation and optimization software was the key to increasing production by some five percent, while saving $7 million annually. Power consumption was reduced and the mean time between pump failures was increased by 35 percent.

PDO used the Shell Oil Foundation System (SOFS) to monitor, control, and optimize over 1,200 wells and production facilities, including both beam-pump and gas lift operations. It collected load, position, and operational data from 900 individual beam pumps and then modeled downhole conditions. The system enabled pumps to be remotely started, stopped, and adjusted, providing an on-line tool to evaluate and optimize pump designs and predict pump performance.

PDO also applied the SOFS to gas lift wells in the Yibal field, creating gas lift performance models for each of 320 wells, matching them to actual field measurements, and using the resulting performance curves to calculate optimal production rates for given lift-gas availability. In a pilot demonstration, 52 wells in the Yibal field were also fitted with electronic instruments to measure lift-gas injection pressure and flow, and tubing-head and casinghead pressures. Ten months of data were used to adjust lift rates, valve settings, and completion strings as necessary. As a result, PDO optimized wells in real-time, achieving a five percent increase in oil production and a 10 percent reduction in the volume of lift gas used. So successful was the pilot effort that PDO decided to extend the program to the entire field.

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SUMMARY

Only 30 years ago, coalbed methane was viewed primarily as a hazard by the mining industry. To ensure mine safety, ventilation and degasification systems emitted this gas to the atmosphere. Methane is now considered a potent greenhouse gas thought to contribute to global warming. It is also a valuable and significant resource with potential recoverable domestic quantities estimated at 40 to 60 trillion cubic feet. Since the 1970s, Federal tax credits, intensive government and industry R&D efforts, and rapid technology growth have motivated improvements in coalbed reservoir characterization, reservoir engineering, and completion technology. These advances have spurred coalbed methane production and reserve growth, making this unconventional resource a significant component of our domestic natural gas supply.

TECHNOLOGY Locations: Worldwide onshore

Coalbed Methane Recovery

BLUEPRINT ON TECHNOLOGY

Technology has reduced greenhouse gas emissions by transforming coalbed methane into an energy resource

Producing coalbed methane

LARGE AMOUNTS OF methane are stored within coal's internal structure. Most coalbeds are aquifers, in which water pressure holds the gas in an adsorbed state. To produce the methane, water must be pumped from the coal seams to decrease reservoir pressure and release the gas. After desorption from the coal matrix, the gas diffuses through the coal bed's cleats and fractures toward the wellbore.

Some coal seams are too deep to be profitably mined, but methane production may be feasible. In these cases, operators drill into the coal seam, insert production piping, and then perforate opposite the target zone. Typically, the reservoir is then hydraulically fractured to enhance natural fractures or create new ones. Such "stand-alone" coalbed methane sites often require substantial initial dewatering to reduce reservoir pressure, although produced water tapers off as methane production increases. Produced water disposal presents major economic and environmental challenges for operators—these costs alone can determine the feasibility of coalbed methane projects. In areas such as Alabama's Black Warrior Basin, produced water can be used for irrigation or treated and discharged into surface waters. In regions where these waters are more saline, they are reinjected into subsurface geological formations, or in some cases recycled in fracturing applications. In the future, emerging technologies using evaporation, reverse osmosis, ion exchange, and wetlands construction promise more cost-effective water management.

Capturing coal mine emissions

Reduction in reservoir pressure during underground mining operations releases coalbed methane into the mine. To ensure mine safety, this methane is typically vented into the atmosphere in significant volumes—an EPA profile of 79 underground mines in 1996 indicated that they emitted an estimated 46 billion cubic feet of methane. But technological advances, along with utility industry restructuring, utility offset projects, and "green" pricing, are motivating operators to add methane recovery units to their ventilation and drainage systems. Also, the U.S. Environmental Protection Agency's voluntary Coalbed Methane Outreach Program is assisting coal mine operators to identify and exploit ways to recover and use or sell methane. As a result, coal mine methane

ECONOMIC BENEFITS

- Lower operating costs and increased profitability if recovered gas can be used to fuel on- or off-site facilities or to generate electricity for site use or sale
- Depending on quality, recovered gas can be marketed through pipeline sales

ENVIRONMENTAL BENEFITS

- Significantly reduced methane emissions
- Optimized recovery of valuable natural gas resource

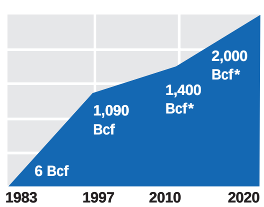
recovery has risen more than 50 percent since 1990.

As technology improves, coal mine methane recovery is likely to increase. Several prototype technologies for using low and variable quality coal mine methane are under demonstration. In the UK, an operator is recovering methane from poorly sealed vent holes in abandoned mines. In the United States, DOE-sponsored field trials in recent years have focused on recovering gob gas.

METRICS

Coalbed methane production growth in the United States

Billions cubic feet (Bcf)

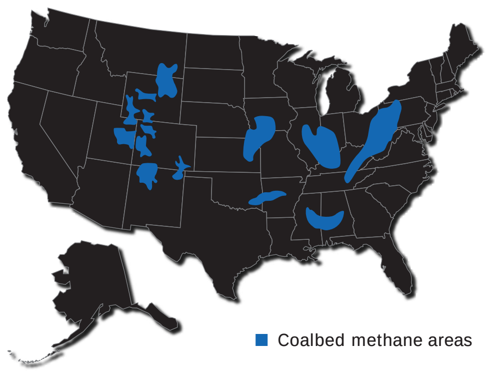


* Estimates assume high technology progress.

Source: Energy Information Administration; Kuuskraa; Gas Research Institute

CASE STUDIES

Success in the Field



Enhanced recovery in the San Juan Basin

Several advanced technologies are in use in the San Juan Basin of northwest New Mexico and southwest Colorado. In the overpressured, highly permeable San Juan Basin fairway, open hole cavitation completions are outperforming conventionally cased and fractured completions by factors of three to seven. In this technique, repeated high-rate, high-pressure injections of air-water mixtures into the coal seam are followed by rapid blowdown. This promotes sloughing of coal into the wellbore, which increases its radius and induces tensile and shear fractures.

San Juan operators are also field testing two new enhanced coalbed methane (ECBM) recovery technologies—displacement desorption with injected carbon dioxide (CO_2) and partial pressure reduction with injected nitrogen. Amoco successfully conducted the first nitrogen flooding field test in 1993 at its Simon 15U-2 well, increasing production fivefold in one year. At Amoco's Tiffany Project, 24 million cubic feet of nitrogen is injected daily into 13 injection wells—the largest commercial demonstration of this technology to date. Since full-scale injection began January 31, 1998, total gas production from 35 production wells has increased from 5 million cubic feet to 17 million cubic feet per day. Furthermore, Burlington Resources is testing CO_2 flood technology at a four-well project at its Allison Unit, with encouraging preliminary results.

In a recent study outlining promising technologies for reducing greenhouse gas emissions, U.S. National Laboratory directors concluded that coalbed sequestration technology is critical. For example, future technology could inject CO_2 from a powerplant stack into coal seams to enhance coalbed methane production, then cycle the methane back to fuel or co-fire the plant, thereby eliminating significant CO_2 emissions.

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TECHNOLOGY Locations: Rocky Mountains, Northern Great Plains, and Canada

Freeze-Thaw/Evaporation

SUMMARY

A new freeze-thaw/evaporation process purifies produced waters from oil and gas production operations by separating out dissolved solids, metals, and chemicals. These typically brackish waters can be made suitable for beneficial use, significantly lowering environmental risks and furthering resource management. Initial field tests indicate that, under specific climatic and operational parameters, the freeze-thaw/evaporation process is highly effective. In these cases, the volume of produced water can be reduced by 80 percent if it is frozen until its solids-laden brine separates, and the resulting purified water thawed and drained off for use or discharge. The isolated pollutants, which can include heavy metals and naturally occurring radioactive materials, are then disposed of separately. For volumes greater than 500 barrels per day, disposal costs and environmental risks can be cut dramatically.

BLUEPRINT ON TECHNOLOGY

New approach promises substantial reductions in produced water volume and associated environmental risks

From wastewater to beneficial by-product

PRODUCING WELLS generate an average of six or seven barrels of produced water per barrel of oil. This ratio generally increases as the field matures, and it may rise as high as 100:1 for marginally productive wells. Due to its sheer volume, the near 15 billion barrels of wastewater generated by exploration and production activities annually is a matter of potential environmental concern.

Produced water handling, treatment, and disposal are expensive. Class II wells for enhanced oil recovery or subsurface disposal wells cost from $100,000 to $1 million each. Water handling costs usually increase as a field matures, eroding profit margins. Most oil fields lose economic viability when the ratio is between 10:1 to 20:1, even if they still hold producible resources. Water-handling costs are often the main factor leading to well abandonment and may make development of unconventional resources, such as coalbed methane, economically unfeasible.

Although not considered hazardous waste under existing Federal legislation, produced waters are governed by Resource Conservation and Recovery Act nonhazardous waste provisions as well as by the Clean Water Act and the Safe Drinking Water Act. Through cost-effective freeze crystallization and evaporation processes, they can be separated into fresh water, concentrated brine, and solids.

Photo: Hart Publications, Inc., and Gas Research Institute

Start-up of freezing operations

ECONOMIC BENEFITS

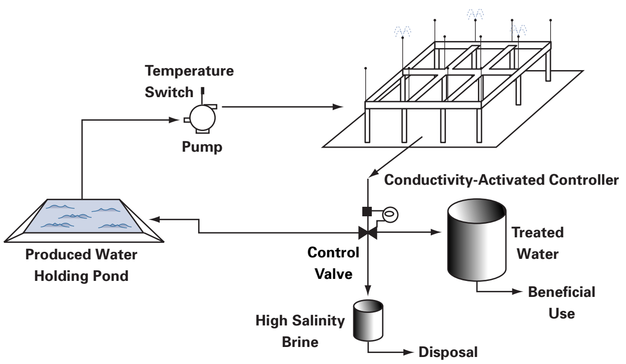
- A low-cost, energy-efficient method of purifying produced water volumes greater than 500 bbl/day
- Reduction of water treatment and disposal costs. DOE-supported field tests in the San Juan Basin estimate treatment costs of 25¢ to 60¢/barrel, compared to current disposal costs of about $1/barrel in New Mexico
- Extended life for mature fields in certain regions
- Improved economic feasibility of developing marginal or unconventional resources

ENVIRONMENTAL BENEFITS

- Produced water volume requiring disposal reduced by 80% in preliminary field tests
- Creation of fresh water to enhance agricultural development in the arid western United States

How the Technology Works

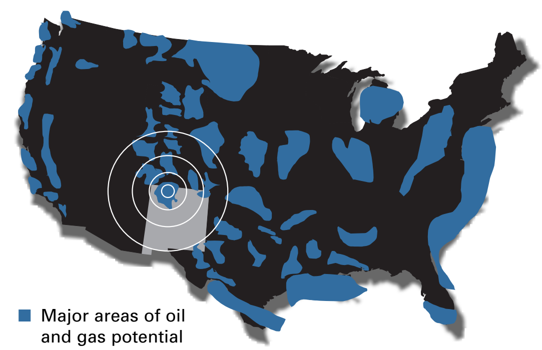
- Produced water is placed in a holding pond.
- When ambient temperature drops below 32°F, water is sprayed on a freezing pad.
- Due to its higher density, brine with elevated concentrations of total dissolved solids separates from the ice.
- When ambient temperature rises above 32°F, ice on the pad melts and purified water drains.
- Brine is disposed of; purified water is discharged or stored for later beneficial use.
- In summer, natural evaporation from the holding pond is substituted for freezing cycles.



Source: Hart Publications, Inc., and Gas Research Institute

Case Studies

Success in the Field



Successful DOE-sponsored tests in New Mexico

In 1996, a joint DOE-, Amoco-, and Gas Research Institute-sponsored project reported that the freeze-thaw/evaporation process could economically cut produced water disposal volumes by more than 80 percent and produce purified water suitable for beneficial use or surface discharge. Total dissolved solids concentrations at Amoco's Cahn/Schneider evaporation facility in the San Juan Basin, for example, were between 200 and 1,500 mg/l for the waters resulting from the process, compared with 11,600 mg/l in untreated waters. In addition to this near 92 percent reduction, organic and metal constituents were also significantly reduced in the processed water. In the winter of 1996–97, a more extensive evaluation conducted in more typical weather conditions resulted in almost identical outcomes. These field tests demonstrate the technology's commercial viability for high retention operations in areas with subfreezing winters and warm, dry summers, such as the Rocky Mountains and Northern Great Plains and much of Canada.

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TECHNOLOGY Locations: Stranded natural gas resources worldwide

Gas-to-Liquids Conversion

SUMMARY

Evolving gas-to-liquids (GTL) technology offers the promise of accessing our vast but remote and uneconomic natural gas resources in Alaska's North Slope and the deepwater Gulf of Mexico, significantly increasing our Nation's energy and economic security. GTL technology, on the brink of widespread commercial viability, chemically alters natural gas into stable synthetic liquid hydrocarbons that are far more environmentally friendly and efficient than conventional petroleum-based liquid fuels. Globally, the technology could bring some of the estimated 2,500 trillion cubic feet of known but currently untapped gas to market, accessing an abundant fuel source to produce liquid transportation fuels fully compatible with our existing transportation infrastructure.

BLUEPRINT ON TECHNOLOGY

Gas-to-liquids conversion taps remote sources of gas to produce cleaner transportation fuels and promote energy security

Developing and transporting remote gas resources

ROUGHLY HALF THE world's natural gas is unused because remote locations makes it too expensive to transport to market via conventional gas pipelines or as cryogenically generated liquefied natural gas, due to distance, climate, environmental concerns, political uncertainty, and the large capital investments required. On Alaska's North Slope alone, for example, approximately 25 trillion cubic feet of producible gas-in-place could be accessed with a cost-effective approach such as GTL technology, with the converted liquid transported through existing pipelines and tankers.

The promise of gas-to-liquids

In 1923, German scientists Franz Fischer and Hans Tropsch introduced the first GTL conversion process. The technology can produce a variety of chemicals and fuels—of particular interest is its ability to yield large volumes of sulfur-free diesel fuel. The process involves reforming natural gas into synthesis gas ("syngas") by combining the gas with steam, air, or oxygen, then converting the synthesis gas to liquid hydrocarbons through catalytic reaction, typically with an iron- or cobalt-based catalyst. The liquid products are hydrocracked and stabilized to create transportation fuels and chemicals. Until recently, this process has not been competitive in the petroleum marketplace, although it had been used for political reasons in noncompetitive economies such as Nazi-era Germany and apartheid-era South Africa. Dramatic recent advances in GTL technology focus on improved processes and catalysts, which are reducing costs enough to be more competitive with petroleum-based fuels, depending on gas costs and oil prices.

GTL's potential to fundamentally alter oil and gas markets worldwide has generated significant private sector research and development efforts, and sparked numerous small-scale and pilot studies. The Department of Energy is committed to a

ECONOMIC BENEFITS

- Access to remote uneconomic natural gas resources
- Prolonged access to Alaskan crude oil as a result of sufficient Trans-Alaska Pipeline System (TAPS) utilization
- Creation of a gas-to-liquids industry resulting in thousands of new domestic jobs and potentially billions of dollars in new investments

ENVIRONMENTAL BENEFITS

- Reduced emissions of greenhouse gases and other air pollutants compared with conventional petroleum-based fuels
- Optimized recovery of valuable gas resources
- Reduced flaring of associated gas in remote fields

goal of 200,000 barrels per day of GTL production by 2010 (assuming Alaskan North Slope gas is no longer required for reservoir repressurization), and it plays an active role in technology advances through support of a variety of research and assessment projects. It recently concluded an eight-year, $86 million cost-sharing agreement with a consortium of research and private sector parties. The consortium, led by Air Products and Chemicals, Inc., is working on a revolutionary ceramic membrane technology that promises to cut GTL production costs substantially.

Far-reaching impacts of commercial GTL application

GTL technology mounted on barges or offshore platforms could bring to market liquid transportation fuels from deepwater Gulf of Mexico sites without gas pipeline access. In Alaska, converted gas from the North Slope could be transported through the existing Trans-Alaska Pipeline System (TAPS), from Prudhoe Bay to Valdez, where tankers would deliver these liquids to market. This would have major ramifications for Alaska's oil and gas industry and the state's overall economy. Due to the approximate annual 10 percent decline in Prudhoe Bay oil production rates, pipeline flow may fall below the minimum volume required for cost-effective operations within the next two decades, eventually requiring that the pipeline be shut in. GTL technology could extend TAPS' life by more than 25 years and prevent shut-in of as many as 200,000 barrels per day of the last remaining North Slope crude, protecting valuable jobs and revenue.

Zero sulfur, zero aromatics, high cetane diesel fuel made by Rentech, Inc., a small fuel development company based in Denver, Colorado.

Photo: Rentech, Inc.

ENERGY EXPERTS

The GTL revolution

"GTL will revolutionize the gas industry the way the first LNG plant did...[w]e expect to see a 1-2 million barrels per day GTL industry evolving over the next 15-20 years to the tune of 25-50 billion dollars of investment."

- Arthur D. Little, Inc.

"We're looking to open the door to a vast resource of natural gas that is today beyond our economic reach. This research...could pioneer a way to tap that resource and convert it into valuable liquid fuels that America will need in the 21st century."

- Former Secretary of Energy Federico Peña

"The cost-effective conversion of natural gas to clean liquid transportation fuels...offers a significant potential for greenhouse gas emissions reduction while allowing greater use of domestic natural gas supplies."

- National Laboratory Directors, Department of Energy

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Technology Locations: Worldwide, onshore and offshore

Glycol Dehydration

Summary

The U.S. natural gas production sector operates some 37,000 glycol dehydration systems, which are designed to remove water from unprocessed gas production streams to produce pipeline quality gas. But during dehydration, these systems typically vent methane and other volatile organic compounds (VOCs), and hazardous air pollutants (HAPs) into the atmosphere. Methane, a potent greenhouse gas, is thought to contribute to global warming, and reducing these emissions is of critical environmental importance. Better dehydration systems management, including optimization of glycol circulation rates and installation of flash tank separator-condensers, enables producers to capture up to 90 percent of methane and other emissions. These processes reduce greenhouse gas emissions, improve air quality, and recover substantial gas for on-site use or pipeline sale.

Blueprint on Technology

Effective management of dehydration systems reduces greenhouse gas emissions, improves air quality, and recovers substantial saleable natural gas

Improved practices and technologies

After removing water from a stream of wet natural gas, a typical dehydration system circulates triethylene glycol (TEG) through a reboiler unit to boil off the water and gaseous compounds so that the "wet" TEG can be recycled. At the reboiler, however, methane, and in some cases other VOCs, and HAPs such as benzene, toluene, ethyl benzene, and xylene (BTEX), are vented to the atmosphere. The amount of methane and other compounds vented is directly proportional to the rate at which the glycol circulates through the dehydration system. If the circulation rate is higher than needed to achieve pipeline quality gas, more methane and other compounds are emitted, with no real improvement in the quality of the gas stream.

Consequently, producers are reducing air emissions and recovering valuable methane by combining two advanced practices: first, by installing flash tank separators and condenser units at the reboiler to capture methane, VOCs, and HAPs before they are vented to the atmosphere; and second, by adjusting glycol circulation rates to optimal levels. Using a simple mathematical model, engineers can determine an optimal circulation rate, based on the characteristics of the particular gas stream, the pipeline's water content requirements, and the operator's production needs. These two processes, used in combination, yield significant environmental benefits for the producer in addition to attractive economic benefits, since the recovered methane can be used as on-site fuel or compressed and reinjected into the sales pipeline.

Economic Benefits

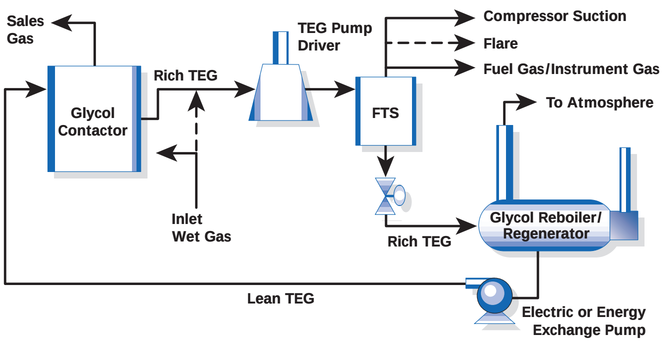
- Reduced energy consumption for circulation pumps and reboiler
- Lower operating costs if captured methane is used to fuel on-site equipment
- Increased saleable gas
- Potential for increased recovery of natural gas liquids

Environmental Benefits

- Reduced greenhouse gas emissions
- Improved local air quality due to reduction in BTEX and VOC emissions
- Enhanced regulatory compliance for upcoming Federal E&P Maximum Achievable Control Technology (MACT) requirements

HOW THE TECHNOLOGY WORKS

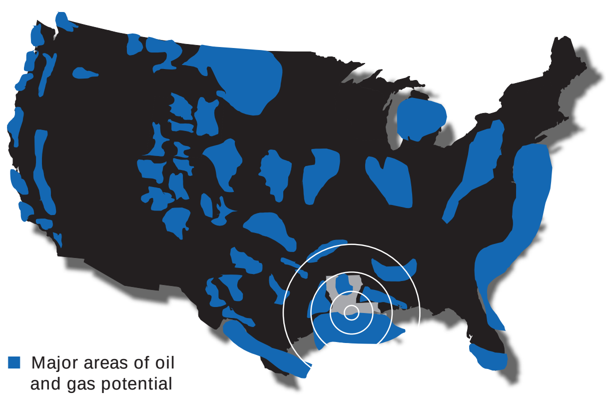
Flash Tanks produce a drop in pressure that causes the methane to vaporize ("flash") from the glycol stream.



In a dehydration process with a flash tank separator, "lean" TEG is sent to the contactor, where it strips water, methane, BTEX, and other compounds from the gas stream before entering the separator. Here pressure is stepped down to fuel gas system or compressor suction levels, allowing most of the methane and lighter VOCs to vaporize (flash). The flashed methane can be captured and used as fuel gas or compressed and reinjected into the sales line. The TEG flows to the reboiler, where water and remaining gases are boiled off, and it is recycled back to the contactor. To prevent discharge of HAPs and VOCs not recovered through the flash process, dehydration systems can also be fitted with air- or water-cooled condensers, which capture additional compounds as they move through the reboiler stack.

CASE STUDIES

Success in the Field



Lower emissions plus lower costs in Louisiana

In the early 1990s, Texaco retrofitted 26 of 27 field-based glycol dehydration systems with flash tank separator-condenser units to reduce emissions of VOCs and BTEX in response to the State of Louisiana's emission control program. In addition to greatly reducing these emissions, it soon became clear that the units also recovered substantial amounts of methane. To determine exactly how much, Texaco staff conducted empirical measurements and used a computer-based dehydrator emissions model developed by the Gas Research Institute. Additional tests analyzed the extent to which flash methane and condenser BTEX recoveries were affected by variances in separator temperature and pressure, and circulation rates.

Results showed methane capture of some 104 thousand cubic feet per day, nearly 38 million cubic feet per year. In total, methane emissions from these units were reduced by 95 percent, from 500 tons to less than 25 tons per year. Under a wide range of tested separator pressures and temperatures, flash methane recoveries ranged from 90 to 99 percent, and condenser BTEX recoveries ranged from 69 to 98 percent. Texaco also found that reducing higher than necessary circulation rates resulted in concomitant emission reductions, even without separator-condenser installation. As an added benefit, Texaco routed the captured gas into a low-pressure gathering system for recompression and subsequent use in its field operations, thus lowering total operating costs.

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TECHNOLOGY Locations: United States

Advanced Data Management

SUMMARY

The exploration and production (E&P) industry is among the most data intensive in the world; various data—from geological to technical to regulatory—must be managed by both industry and government. Advanced data management systems are key to increasing the efficiency of oil and gas recovery and making effective regulatory and policy decisions. With participation by industry, State regulators, and DOE, numerous efforts are under way, such as standardized data collection of State oil and gas statistics, risk-based decision making, detailed online digital atlases of oil and gas plays, and validation methodology for Area of Review (AOR) variances. Initiatives such as these reflect advanced computer technology capabilities, handling massive amounts of data more quickly and cheaply than ever.

BLUEPRINT ON TECHNOLOGY

Data management tools improve information access, increasing resource recovery efficiencies and informing regulatory and policy decisions

E&P data management

E&P DATA GENERALLY fall into five major categories: environmental, geologic, exploration and production, regulatory, and technology. Advanced data management techniques enable: (1) better regulatory, enforcement and compliance decisions; (2) more informed government program and policy decisions; and (3) more efficient oil and gas recovery. "Data management" has different meanings for different technologists. For example, geophysicists may want to interpret 3-D seismic data to locate oil and gas resources, and petroleum engineers may want to interpret production data to enhance recovery; whereas State regulators might use online permitting and compliance data to improve decision-making processes; versus environmentalists, who need habitat surveys and emission reports to inform policy debates. Both government and industry seek to improve their data management systems to support these goals.

Comprehensive State data facilitate decisions

States and DOE are collaborating to enhance State-level oil and gas data collection and management efforts. For example, with DOE support, the Interstate Oil and Gas Compact Commission (IOGCC) is cataloging State data collection efforts and management capabilities and devising uniform standards for State permitting, production, and well statistics. IOGCC and DOE are also bringing key E&P data online to facilitate decision making by industry and States. These efforts include DOE's *Environmental Compliance Assistance System*, which provides information regarding Federal E&P environmental regulations, and IOGCC's framework for helping States develop permitting and regulatory compliance assistance programs.

Enabling cost-effective regulation

Developed by the Ground Water Protection Council with funding from DOE, the Risk-Based Data Management System (RBDMS) was originally designed to manage data for underground injection control programs, enabling

ECONOMIC BENEFITS

- Better data access facilitates more effective business and investment decisions
- Risk-based regulatory decisions lower environmental costs and increase operational efficiency
- More efficient recovery of oil and gas resources, through improved prospect identification and targeting

ENVIRONMENTAL BENEFITS

- Better regulatory and policy decision-making processes, leading to enhanced environmental protection
- Risk-based regulatory structures focus industry and government activities on areas of greatest potential risk

more effective regulatory and operational decision making. The system has been so well received that it is being modified by individual States to include production, geological, and waste management data, as well as enforcement and permitting data. Initial RBDMS success has prompted more than 20 States to form a users' group to help each other implement the system.

Improving AOR verification

Under the Safe Drinking Water Act, operators are required to conduct quarter-mile AOR analyses of disposal and injection wells, but AOR variances may be granted in specific cases. With DOE and American Petroleum Institute support, the University of Missouri-Rolla has developed a scientific methodology for validating AOR variance requests that is expected to provide industry cost savings exceeding $300 million. DOE has also supported development of data management tools and Geographic Information Systems (GIS) to help regulators conduct AOR and variance analyses statewide.

Enhancing oil and gas recovery

Partnering with States and the Gas Research Institute, DOE is supporting both print and digital atlases of producing regions in the United States. For example, a DOE-supported consortium is using GIS technology to develop a digital atlas of oil and gas plays and fields specific to Kansas, Nebraska, the Dakotas, and parts of Montana and Colorado. In these mature regions, advanced technology and data management are seen as the best approaches to extend production and prevent premature well abandonment. To help operators recover more original oil-in-place, the atlas, which currently covers only Kansas, will provide extensive production, petrophysical, and geological data, sophisticated digital maps and imagery, as well as field-specific information on recovery technologies and engineering methods for identifying new or unswept zones.

Electronic permitting in Texas

Through a new DOE-sponsored pilot program, the Texas Railroad Commission is developing a paperless, digital on-line permitting system, which will save the State's operators and regulators millions of dollars and countless labor hours. This fully digital approach will soon enable operators to submit an electronic permit application via an Internet-linked computer, complete with supporting graphical or text attachments. The operator's identity will then be authenticated, and permit fees paid through a secure on-line transaction. Within hours—perhaps the same day, rather than the days or weeks now required—the producer will be notified electronically whether the application has been approved. Although the expected savings per permit application may be relatively small, overall cost savings are expected to be significant; annual savings from drilling permits alone are estimated at between $3 million and $6 million.

Advanced computing leads the way

The Oil and Gas Infrastructure Project—part of DOE's Advanced Computational Technology Initiative—has explored implementing inexpensive mechanisms for online access to well-level oil and gas data from Texas, California, and other States. Such mechanisms enhance producers' access to production and geological data, ultimately enabling more efficient resource recovery.

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TECHNOLOGY Locations: Worldwide, onshore and offshore

Improved Recovery Processes

SUMMARY

The goal of evolving oil recovery technologies is increased reserves with less drilling. Despite significant technology advances in primary and secondary production, much of a reservoir's original oil-in-place remains untapped after these phases of the production cycle. Coupled with advanced field management practices, new enhanced oil recovery (EOR) technologies—such as thermal, gas, and chemical techniques—can significantly increase production in some maturing fields. The United States leads the world in sophisticated EOR technology, which currently accounts for about 12 percent of domestic daily crude oil production, a 140 percent increase from daily EOR rates only 15 years ago. In addition to preventing premature abandonment of significant domestic oil resources, these technologies could potentially recover half of the Nation's 350 billion barrels of "discovered, but unrecoverable" original oil-in-place.

BLUEPRINT ON TECHNOLOGY

Thirty years of continuous improvement in enhanced recovery technology has led to significant reserve additions and less drilling

Getting more oil from existing fields

PRODUCTION AT MOST oil reservoirs includes three distinct phases: primary, secondary, and enhanced recovery. During primary recovery, which uses natural pressure or artificial lift techniques to drive oil into the wellbore, only about 10 percent of the oil-in-place is generally produced. Shortly after World War II, producers began to conduct secondary recovery techniques to extend the productive life of oil fields, increasing ultimate recovery to more than 20 percent. Gas injection, for example, can maintain reservoir pressure and keep fluids moving; waterfloods are used to displace oil and drive it to the wellbore. In recent decades, the development and continued innovation of EOR techniques has increased ultimate recovery to 30 to 60 percent of a reservoir's original oil-in-place. In the United States, three major categories of EOR technology—thermal, gas, and chemical—dominate EOR production.

Even though improved EOR technology can significantly extend reservoir life and has been successfully used since the 1960s, historically high costs have limited widespread application. In the last decade, however, dramatic improvements in analytic and assessment tools have led to a greater understanding of reservoir geology and the physical and chemical processes governing flows in porous media.

Today, unconventional approaches such as fieldwide development using strategically placed horizontal wells, or microbial injection to improve recovery may lead to new classes of EOR technology. Innovations in thermal recovery include radio frequency heating, and enhanced gravity drainage with steam in vertically parallel horizontal wells.

Thermal recovery

Thermal recovery techniques account for some 59 percent of daily U.S. EOR production. Used in individual wells or fieldwide, *steam injection and flooding* provide effective recovery of heavy, viscous crudes, which must be "thinned" to enable oil to flow freely to the wellbore. The most common domestic EOR

ECONOMIC BENEFITS

- Worldwide production of approximately 2.3 million barrels per day (760,000 barrels per day in the United States) that would otherwise remain untapped
- Potential recovery of up to half of the 350 billion barrels of discovered, currently unrecoverable, domestic oil
- Increased production from marginal resources

ENVIRONMENTAL BENEFITS

- Fewer new wells drilled due to increased reserves from existing fields
- Less environmental impact due to reduced abandonment of marginal wells and offshore platforms

practice, this process has contributed directly to improved burning efficiencies of both gas and oil, and spawned the cogeneration industry, which uses clean-burning natural gas to create both steam and electricity at attractive prices for oil field operators and utilities. In California alone, for example, existing cogeneration plants generate enough electricity to supply 4.1 million homes.

A second type of thermal recovery, *in-situ combustion*, injects air or oxygen into the formation and uses a controlled underground fire to burn a portion of the in-place crude. Heat and gases move oil toward production wells. This process is highly complex, involving multiphase flow of flue gases, volatile hydrocarbons, steam, hot water, and oil, and its performance in general has been insufficient to make it economically attractive to producers.

Gas-immiscible and -miscible recovery

Accounting for 40 percent of daily EOR production, gas injection is the second most prevalent technology currently in domestic use. Two basic forms exist: immiscible, in which gas does not mix with oil; and miscible, in which injection pressures cause gas to dissolve in oil. *Immiscible injection*, which can use natural gas, flue gas, or nitrogen, creates an expanding force in the reservoir, pushing additional oil to the wellbore. *Miscible gas injection* dissolves propane, methane or other gases in the oil to lower its viscosity and increase its flow rate. In place of the costly hydrocarbon gases used in some EOR projects, miscible gas drives also frequently use carbon dioxide (CO_2) and nitrogen. CO_2 flooding has proven to be one of the most efficient EOR methods, as it takes advantage of a plentiful, naturally occurring gas and can be implemented at lower pressures.

Chemical recovery

Chemical recovery techniques account for less than one percent of daily U.S. EOR production. In an enhanced waterflooding method known as *polymer flooding*, high molecular weight, water-soluble polymers are added to the injection water to increase its viscosity relative to that of the oil it is displacing, raising yields since oil is no longer bypassed. In another chemical recovery technique, *surfactant flooding* (also known as micellar-polymer flooding), a small slug of surfactant solution is injected into the reservoir, followed by polymer-thickened water and then brine. Despite its very high displacement efficiency, this technology is hampered by the high cost of chemicals and their environmental impact.

CASE STUDIES

Success in the Field

Steamflooding increases reserves fivefold at Kern River field

Discovered in 1899 by hand digging a 40-foot well, the giant Kern River field near Bakersfield, California, had nearly 600 wells by 1904. At its peak, primary production was 47,000 barrels/day, but had declined to 9,000 by 1954. Installing bottomhole thermal heaters in the 1950s succeeded in making oil less viscous so that it flowed more easily. Surface steam injection followed in the 1960s, and ultimately fieldwide steamflooding brought production to a peak 140,000 barrels/day in 1986. Production from the field was still over 134,000 barrels/day in 1997. Overall, thermal EOR has increased recovery from 10 percent of oil-in-place to over 40 percent, with ultimate recovery of 50 percent from this 3.5 billion-barrel field. Production is nearly five times greater than possible with primary recovery technology alone. Field life has been doubled, and on its 100th birthday in 1999, Kern River field will still have 7,000 producing wells.

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TECHNOLOGY Locations: Worldwide, onshore and offshore

Leak Detection and Measurement Systems

SUMMARY

Leak detection and measurement systems play an essential part in controlling emissions of methane—a potent greenhouse gas and valuable energy product—from the Nation's massive oil and gas infrastructure. Significant amounts of methane are emitted to the atmosphere during production, transmission, processing, storage, and distribution. New technology facilitates accurate, efficient leak detection and measurement by ensuring equipment and pipeline integrity and timely maintenance and repair. These controls capture saleable natural gas, create safer work places, and protect our environment.

BLUEPRINT ON TECHNOLOGY

New devices to detect and measure gas leaks aim to eliminate greenhouse gas emissions

Overcoming the limitations of conventional systems

Managing leaks in the U.S. oil and gas infrastructure is a formidable task. This complex infrastructure involves nearly 885,000 producing oil and gas wells and related equipment, 265,000 miles of natural gas transmission pipeline, and about 1.5 million miles of distribution pipeline. New technologies overcome drawbacks in standard industry approaches, such as "leak concentration measurement" techniques. These use hand-held instruments, such as organic vapor analyzers (OVAs) equipped with flame ionization detectors, to sample methane concentrations around leaking components. The leak flow rate can be estimated by the predicted relationship between concentration and leak rate. Such devices are easy to use, but accuracy rates are low. Distortions up to three orders of magnitude can occur due to wind conditions, leak velocity, the shape of the component, and the surface distribution of the leak.

Another conventional practice, "bagging," measures leaks by enclosing a component in a nonpermeable bag, adding air (or nitrogen), and then measuring an exhaust stream with an OVA. While highly accurate, bagging is costly, labor-intensive, time-consuming, and impractical when large numbers of components must be tested and measured.

High-flow samplers

Advanced technologies equip the industry to detect leaks with better accuracy and efficiency. The High-Flow Sampler, developed by the Gas Research Institute (GRI) and Indaco Air Quality Services, Inc., samples the air surrounding leaking components using a pneumatic air mover, thus eliminating the need for bagging. Although more expensive than conventional tools, this technology offers the accuracy of bagging and the ease and speed of leak concentration measurements. It can also measure much larger leaks than standard instruments, which typically malfunction above leak detection ranges of 10,000 parts per million.

Backscatter absorption gas imaging

Another new technology, backscatter absorption gas imaging (BAGI), is a state-of-the-art, remote video-imaging tool developed by Sandia National Laboratories, with

ECONOMIC BENEFITS

- More accurate information on leak characteristics and emissions, leading to successful, cost-effective leak reduction strategies
- Increased recovery and usage of valuable natural gas

ENVIRONMENTAL BENEFITS

- Reduced emissions of methane, a potent greenhouse gas
- Enhanced worker safety due to more effective and efficient leak detection

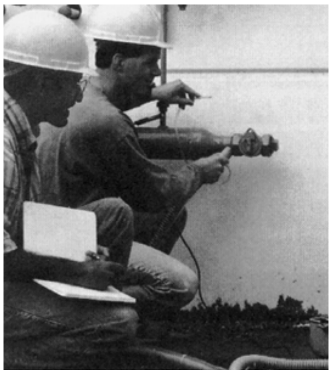

Photo: Hart Publications, Inc., and Gas Research Institute

Field trials of the new High-Flow Sampler promise more effective leak detection and measurement.

support from GRI and DOE. Whereas other surveys are performed with manually scanned point sensors, BAGI technology uses infrared laser-illuminating imaging. If a gas plume is present and resonating within the illumination wavelength, the plume attenuates a portion of the laser backscatter and appears as a dark cloud in the real-time video picture. The equipment can be tuned to the absorption resonances of a wide variety of gases. Remote video imaging, with the superior efficiency of covering an entire area at one time, could greatly simplify leak detection. The latest field trials indicate an impressive detection range, with flow rates as low as 0.1 standard cubic feet per hour at distances from up to 100 meters, and leaks as low as 0.02 standard cubic feet per hour at closer distances. Estimates are that BAGI will increase area leak search rates by a factor of 100 versus existing technology.

CASE STUDIES

Success in the Field

High-tech sampling and imaging matched by effective low-tech approach

In June 1995, a Unocal Spill Prevention Task Group used Labradors and Golden Retrievers to detect underground pipeline leaks in the 40-year-old Swanson River Field in Alaska's Kenai National Wildlife Refuge. The dogs, originally used in law enforcement, were retrained to recognize a nontoxic odorant (Tekscent) injected in the pipelines. In widely ranging temperatures, the dogs successfully detected two faulty valve box seals and leaks in pipelines down to 12 feet underground or under 3 feet of snow. The team inspected about 18 miles of pipelines in two weeks. Unocal's use of this and other innovative environmental technologies earned them an U.S. Department of the Interior "National Health of the Land" environmental excellence award in May 1997.

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TECHNOLOGY Locations: Worldwide, onshore and offshore

Low-Bleed Pneumatic Devices

SUMMARY

Throughout all sectors of the natural gas industry, pneumatic valves, regulators, and sensors use pressurized gases to control or monitor critical equipment. As part of normal operations, pneumatic devices release natural gas, primarily methane, to the atmosphere. Within the industry, pneumatic devices are the single largest source of methane emissions, venting nearly 50 billion cubic feet annually. Older designs leak, or "bleed," an average of 140 thousand cubic feet per year per device, a volume equivalent to an average household's annual use, whereas newer, low-bleed designs emit an annual average of only 8 to 12 thousand cubic feet. Replacing or retrofitting devices, or improving maintenance, can reduce gas emissions substantially, reducing greenhouse gas emissions and potentially saving the industry millions of dollars in lost methane.

BLUEPRINT ON TECHNOLOGY

Energy-efficient "low-bleed" pneumatic devices can dramatically reduce methane emissions and recover lost gas resources

Protecting the ozone layer and saving valuable gas

THE NATURAL GAS production sector uses pneumatic devices to control and monitor gas and liquid flows and levels in dehydrators and separators, temperature in dehydrator regenerators, and pressure in flash tanks. Approximately 250,000 pneumatic devices are used in the production sector alone, venting an estimated 35 billion cubic feet of methane annually, 70 percent of total methane emissions. Specific bleed rates are a function of the design, condition, and specific operating conditions of the device. By definition, a high-bleed device leaks more than six standard cubic feet per hour, although industry operators estimate that most devices typically bleed about three times that rate.

Aggressive replacement, retrofitting, inspection, and maintenance

New, technically advanced low-bleed devices and retrofit kits offer comparable performance characteristics to high-bleed models, yet reduce methane emissions considerably—on average, they vent 90 percent less methane. Although low-bleed devices typically cost more than their high-bleed equivalents, cost-benefit analyses show that replacement or retrofit project costs are typically recouped within months. While it may be impractical to replace all an operation's high-bleed devices at once, operators are finding successful alternatives, such as combining replacements and retrofits, or installing a low-bleed device when an existing device fails or is no longer efficient.

Others have implemented aggressive inspection and maintenance programs. By cleaning and repairing leaking gaskets, fittings, and seals, operators are able to reduce methane emissions substantially. Other effective practices include tuning the device to operate in the low or high end of its proportional band, minimizing regulated gas supply, and eliminating unnecessary valve position indicators.

ECONOMIC BENEFITS

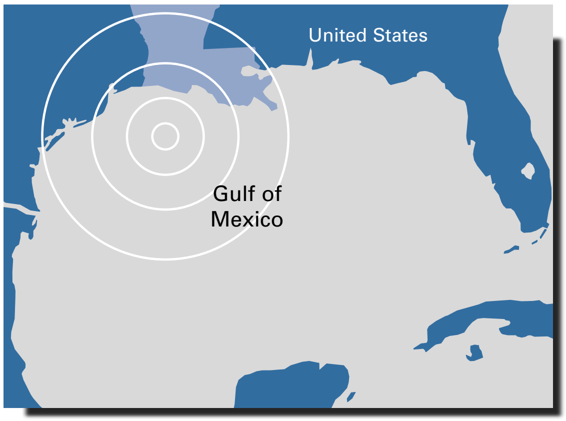
- Increased operational efficiency, as retrofit or replacement can provide better system-wide performance, reliability, and monitoring of key parameters
- Increased saleable product volume, as leaks are minimized

ENVIRONMENTAL BENEFITS

- Reduced greenhouse gas emissions
- Conservation of valuable gas resources

CASE STUDIES

Success in the Field



Chevron retrofits reduce emissions by 90 percent

Chevron installed a low-bleed retrofit valve kit on liquid level and pressure controllers on two platforms in the Vermilion field's blocks 245 and 246, roughly 60 nautical miles south of the Louisiana coast in the Gulf of Mexico. During this pilot test in January 1995, 19 devices were tested on one platform and 30 devices on another. The retrofits yielded average reductions in bleed rates of more than 90 percent. A cost-benefit analysis showed that the retrofitting costs would be recovered in less than two years, with specific payback periods based on the characteristics of the device retrofitted and an assumed natural gas wellhead price of $1.50 per thousand cubic feet.

Marathon survey drives inspection, repair, and replacement program

As an EPA Natural Gas STAR Program partner, Marathon Oil Company recently surveyed more than 155 pneumatic devices at 50 U.S. production facilities. Results indicated that Marathon devices were bleeding 5.1 million cubic feet of methane per year, on par with the annual gas consumption of 57 residential consumers. Consequently, Marathon has now implemented a comprehensive program to inspect, repair, and replace its high-bleed pneumatic devices, saving gas and reducing emissions. In fact, Marathon determined that purchasing expensive leak detection equipment was not even needed to conduct such surveys; only listening was required, because "control devices with higher emissions [could] be identified qualitatively by sound."

Gas Saved by Retrofitting Controllers at Chevron

Location	Unit	Service	Before Retrofit (scf/day)	After Retrofit (scf/day)	Savings (scf/day)
V245 "F"	Fisher 2900	Oil Dump	438	43	395
V245 "F"	Fisher 2900	Suction Scubber	211	0	211
V245 "F"	Fisher 2900	Gas Filter	397	1	396
V246 "D"	Fisher 2900	Oil Dump	328	81	245
V246 "D"	Fisher 2900	Water Dump	567	0	567
Average			**388**	**25**	**363**
V246 "D"	Fisher 2900	Water Skimmer	508	177	331
V245 "F"	Fisher 4150	Fuel Gas Reg.	145	0	145
V245 "F"	Fisher 4160	Sales Gas Reg.	108	0	108
V245 "F"	Fisher 4160	Makeup Gas Reg.	534	12	522
Average			**262**	**4**	**258**
V246 "D"	Fisher 2900	Oil Dump	950	4	946

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METRICS

Since 1991, EPA Natural Gas STAR Producer members, who account for approximately 35 percent of the Nation's natural gas production, have reduced methane emissions from pneumatic devices by nearly 11.5 billion cubic feet, worth an estimated $23 million.

Advanced technology, combined with improved maintenance practices, can reduce methane losses from pneumatic devices by approximately 90 percent.

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TECHNOLOGY

Locations: Deepwater areas of Australia, Brazil, Gulf of Mexico, North Sea, Southeast Asia, West Africa, and elsewhere

Offshore Platforms

SUMMARY

Finding economically viable methods to tap vast deepwater resources is driving innovations in offshore technology. Potential payoffs are immense. An estimated 90 percent of undiscovered global reserves are under 3,000 feet or more of water. Between 1996 and 1998, nearly 75 percent of the 66 oil discoveries greater than 100 million barrels were offshore. Effective new technology includes advanced tension leg platforms (TLPs) and mini-TLPs, which are lower-cost, small-footprint platforms suited to marginal fields. Other offshore platforms include spars, now designed to operate in depths of up to 8,000 feet, semisubmersible floating production systems (FPS), and new-generation floating production, storage, and offloading systems (FPSOs). Ongoing technology refinement continues to optimize recovery, reduce costs, and minimize environmental risks and impacts.

BLUEPRINT ON TECHNOLOGY

Advanced offshore platform technology reduces project duration, costs, and impacts on marine environments

Enhanced recovery with fewer risks

PLATFORM DESIGN is key to cost-effective deepwater field development. Variables include field remoteness, size, and characteristics, water depth and condition, and weather patterns. Today, eight floating TLPs, moored to the ocean floor with high-strength tendons that provide vertical and lateral stability, operate in large, multi-well fields worldwide. TLPs offer the advantages of fixed platforms—space for crew quarters, drilling rigs, and production facilities—with lower investment costs. Maturation of TLP technology has enabled more aggressive production schedules and less exposure to economic risks. Platform construction time has been cut in half. Today's TLP can withstand hurricane-force winds and waves, and its deepwater limits are being extended, perhaps to 6,000 feet. High-performance composites, stepped tendons, cables, and other options can increase tendon stiffness and reduce vertical motion in harsh ocean settings. The conceptual raft TLP, a submerged hull tensioned to the sea floor, would also minimize motion at reduced cost.

TLP innovations have spawned mini-TLPs with small footprints and permanent tension leg moorings that allow installation close to other platforms. The required investment in conventional TLPs can make their use for smaller discoveries unprofitable. Less costly mini-TLPs can be constructed and deployed swiftly in marginal deepwater fields.

Spar drilling and production platforms—large, cylindrical platforms supported by buoyancy chambers and fastened with catenary mooring systems—have been used for research, communication, storage, and offloading for more than 30 years. The first spar production platform, installed in 2,000 feet at the Gulf's Neptune Field in 1996, was designed for maximum production of 25,000 barrels of oil per day and features a 707-by-72-foot hull enclosing buoyant risers and surface wellheads. Advances have led to units designed to operate in more than 8,000 feet of water. Inherent design versatility and optional hulls

ECONOMIC BENEFITS

- Recovery of significant deepwater oil and gas reserves that may otherwise remain undeveloped; enhanced recovery of marginal resources
- Combined with advanced subsea completion technology, shorter construction and development schedules, leading to reduced costs
- FPSO and FPS deployment facilitates low-cost field abandonment

ENVIRONMENTAL BENEFITS

- Optimized recovery of valuable deepwater oil and gas resources
- Shorter construction and production schedules ultimately reducing operational footprints, and protecting marine habitats and ocean resources

("classic" and "truss") allow flexibility of use, from storage to any combination of drilling, production, and workover, decreasing financial risk. Spars, easily relocated and reused, are also attractive for marginal fields.

Marginal fields, mild climates, and shallow depths were the criteria for using the first FPSO and FPS 20 years ago, but today an estimated 80 units operate worldwide in varied climates and depths. Enhanced FPSOs have a compression system for gas lift, injection, and export, desalters, water injection and natural gas liquids recovery systems, as well as a conventional production system.

FPSOs are selected in remote locations lacking pipelines and fixed infrastructure, marginal fields, and depths too great for fixed platforms, whereas FPSs are used where infrastructure connections are available. Combined with subsea completion technologies, FPSO and FPS platforms are considered critical to industry's move toward 10,000-foot water depths, and many believe that this combination offers the most viable option over 5,000 feet. Compared with spars and TLPs, deepwater subsea completions offer shorter development schedules and more flexibility in location and well number.

CASE STUDIES

Success in the Field

Ram-Powell TLP

Production began in September 1997 at the $1 billion Ram-Powell Unit, a 41,000-ton, 3,570-foot high TLP in the Gulf of Mexico about 80 miles south of Mobile, Alabama. A development joint venture between Shell, Exxon, and Amoco, Ram-Powell employs a permanent crew of 110 and has peak gross production capacity of 60,000 barrels of oil and 200 million cubic feet of gas per day. Twelve 28-inch diameter tendons, each about 3,145 feet long, support the unit in more than 3,200 feet of water, a new depth record for a permanent production platform. Ram-Powell can drill down to 19,000 feet below the sea floor, and has complete oil and gas processing separation, dehydration, and treatment facilities. Estimated recovery from this project is approximately 250 million barrels of oil equivalent.

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TECHNOLOGY Locations: Worldwide, onshore and offshore

Downhole Oil/Water Separation

SUMMARY

New downhole separation technologies promise to cut produced water volumes by as much as 97 percent in applicable wells. Usually, both water and oil are pumped to the surface for separation, but novel mechanisms installed below the surface can now separate the formation's oil and water in the wellbore. Oil is then produced, but water is directly pumped into a subsurface injection zone. This minimizes environmental risks and reduces fluid lifting and disposal costs. Downhole separation can also increase oil production significantly, and this, combined with reduced operating costs, could potentially extend the life of marginal wells or reactivate shut-in wells. Field testing and demonstration projects are currently under way in numerous projects throughout the United States and the world.

BLUEPRINT ON TECHNOLOGY

Emerging technologies for downhole fluids separation can reduce the volume of produced water brought to the surface, while increasing oil recovery

Conventional surface separation

IN TODAY'S TYPICAL oil well, produced water and oil are pumped to the surface for separation, after which the oil is pumped off and the water treated, then reinjected into the ground. This approach brings contaminants up through the well piping, and incurs significant water lifting and handling costs. Emerging downhole separation technologies can minimize the environmental risks associated with produced water handling, treatment, and disposal, and greatly reduce the costs of lifting and disposing of the produced water.

Three promising mechanisms for downhole separation

Downhole oil/water separation involves the use of mechanical or natural separation mechanisms in the wellbore to separate the formation's oil and water. Although not applicable to heavier, low-API gravity crudes, three basic downhole separation techniques are currently under development.

Gravity separation in the reservoir enhances and maintains the gravitational oil/water separation that occurs naturally in reservoirs. The normally level oil/water contact is skewed by the production process, which causes the water/oil interface to rise in a phenomenon called "coning." When the tip of the water cone reaches the perforations in the well casing, the well begins to produce large amounts of water. This technique for downhole separation maintains a flat oil/water zone by using dual perforations in the well casing to produce water from below the zone (for downhole injection into another formation) simultaneously with oil from above the zone. This helps to maintain the natural oil/water gravity segregation and avoids coning.

ECONOMIC BENEFITS
Significant reductions in water lifting and disposal costs
Enhanced oil production
Increased access to marginal or otherwise uneconomic wells

ENVIRONMENTAL BENEFITS
Volume of produced water brought to surface reduced significantly, greatly minimizing risk from contaminants on the surface and to drinking water aquifers
Less drilling of new wells, due to greater recovery from existing wells
Reduced production footprints, as surface facilities may be smaller

Gravity separation in the well casing allows the produced fluids to separate naturally in the well casing, then uses a dual-action pump system (DAPS) to pump the oil up and inject the water downhole. The DAPS has two pump intakes that are positioned above and below the oil/water interface.

Hydrocyclone separation is a promising technique that uses centrifugal force to separate oil and water. Most such systems rely on electrical submersible pumps (ESPs) to push or pull water through the hydrocyclone. While this approach can handle larger volumes of fluids, the higher cost of the hydrocyclone and pump equipment has limited its use to date.

Although developed initially for onshore application, rapid advances in downhole separation technologies are heightening interest in offshore use. For example, a new generation of "intelligent," computer-driven subsea downhole separation systems, currently under development, will remotely monitor and control fluid flow and downhole injection. These systems promise to be particularly useful in multilateral environments, by controlling downhole water injection into a dedicated lateral strategically placed to enhance waterflooding and pressure maintenance.

CASE STUDIES

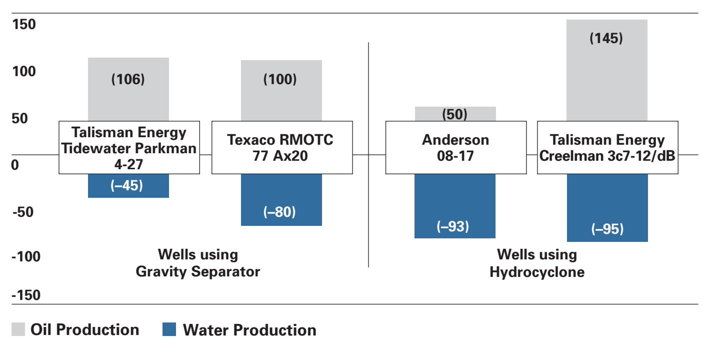
Success in the Field

Significant pilot results

A collaborative Mobil, BP Amoco, Texaco, and Chevron consortium (MoBPTeCh) was chartered to develop innovative solutions to common environmental problems in the oil and gas industry. MoBPTeCh has recently conducted extensive research on produced water downhole separation technologies, with 15 test wells in operation using gravity separation in the well casing. At this time, the project uses rod pumps only, but future tests with ESPs are expected to greatly increase the handling capacity of liquid volumes. Initial results indicate great potential for downhole separation technologies to reduce produced water volumes and increase production.

METRICS

Field trials in Canada and the United States show increased oil production and decreased water production



Source: Argonne National Laboratory, 1999

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TECHNOLOGY U.S. Offshore (Gulf of Mexico, California, and Alaska)

Safety and Environmental Management Programs

SUMMARY

Offshore operations represent over one quarter of the Nation's oil and natural gas production. Since the early 1990s, Federal regulators and industry have successfully cooperated in the development and implementation of recommended practices for voluntary safety and environmental management programs (SEMP) for Outer Continental Shelf (OCS) operations. Using the SEMP approach, industry is responsible for voluntarily identifying potential hazards in the design, construction, and operation of offshore platforms and for implementing specific processes to improve safety and environmental protection. These measures are designed to reduce the risk and occurrence of accidents, injuries, and oil spills. By 1997, almost all OCS production operators were in the process of voluntary SEMP implementation.

BLUEPRINT ON TECHNOLOGY

Implementation helps offshore operators avoid costly injuries, platform damage, and environmental incidents

Standards and training reduce human error

RESEARCH INDICATES that nearly 80 percent of offshore accidents are caused by human error, even when operations are fully compliant with regulations. In response to these risks, Minerals Management Service, in partnership with the American Petroleum Institute (API) and the Offshore Operator's Committee, has delineated voluntary standards that address human and organizational errors and help ensure worker safety and environmental protection as primary operating goals among offshore producers. *Recommended Practice for Development of a Safety and Environmental Management Plan for Outer Continental Shelf Operations and Facilities* (RP 75), first issued by API in 1993, provides safety and operating guidelines for offshore operators of all sizes. These guidelines are especially valuable to small- and mid-sized producers, who may lack the resources and experience of larger companies in developing and implementing such policies. This cooperative relationship between industry and government represents a successful alternative to prescriptive regulations, with MMS' collaboration encouraging industry to focus on risk identification and mitigation instead of mere compliance. Because of widespread RP 75 implementation, MMS has recently announced the continuation of its voluntary partnership with industry and sponsorship of joint industry workshops to share best management practices.

"We have seen strong evidence that adoption of SEMP can not only accomplish public objectives in the areas of promoting safety and environmental protection... it can also make good business sense by avoiding or containing accident and pollution costs. The vast majority of OCS operators have undertaken, in earnest, to develop and implement SEMP plans."
Minerals Management Service, 62 Federal Register 43346, 8/13/97

ECONOMIC BENEFITS
Fewer accidents and equipment failures, thereby reducing operating and remediation costs
Potential avoidance of fines and litigation due to reduced risk of accidents and pollution

ENVIRONMENTAL BENEFITS
Reduced risk of spills, fugitive air emissions, blowouts, and accidents
Better protection of sensitive marine ecosystems and habitats
Enhanced worker safety, leading to fewer job-related injuries and illnesses

CASE STUDIES

Success in the Field

DOE and its partners blaze a trail to safety

To allay small- and mid-sized producers' concerns over the perceived costs and burdens of RP 75, DOE recently supported a real-world pilot implementation project with Louisiana-based Taylor Energy Company. The goal was to develop a single-model SEMP that could be shared throughout the industry, streamlining redundancies and reducing costs, particularly for smaller, independent companies.

Taylor, assisted by subcontractor Paragon Engineering Services, Inc., developed and implemented an 11-part SEMP at seven offshore platforms in the Gulf of Mexico. First, existing site safety procedures were updated for incorporation into the new safety program. Next, Taylor developed company-wide documentation of its safety and environmental program management, safety procedures, and safe drilling and workover practices, as well as a pocket-sized safety handbook summarizing these practices. In addition, Taylor performed risk-based hazard analyses at each site and issued site-specific operating procedures for startup, normal, and emergency response. Employee training on these general safety guidelines and all site-specific safety practice followed. Finally, Taylor audited the program to verify its successful implementation, using an OSHA-based audit protocol that included document review, visual inspection, interviews, and written testing.

While long-term outcomes are pending, Taylor's lost-time accident rate declined significantly at the pilot sites over the 30-month project period. DOE and MMS expect similar experiences at other companies, including eventual operating cost reductions due to SEMP and the resulting downward trend in accidents.

Taylor is sharing its experience and offering recommendations to others in DOE- and MMS-sponsored workshops and publications, including technical conferences, trade shows, and leading trade journals. These presentations have enabled many small- and mid-sized producers to learn firsthand about the program, leading to more effective SEMP implementation at their own facilities.

An effective plan addresses how to:

- Operate and maintain facility equipment
- Identify and mitigate safety and environmental hazards
- Change operating equipment, processes, and personnel
- Respond to and investigate accidents
- Purchase equipment and supplies
- Work with contractors
- Train personnel

A fully implemented SEMP covers all phases of offshore operations, including design, construction, startup, operation, inspection, and maintenance of new, existing, or modified drilling and production facilities. (API RP 75)

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TECHNOLOGY Worldwide, onshore and offshore

Vapor Recovery Units

SUMMARY

Vapor recovery units can significantly reduce the fugitive hydrocarbon emissions vaporizing from crude oil storage tanks, particularly tanks associated with high-pressure reservoirs, high vapor releases, and larger operations. These emissions are typically made up of 40 to 60 percent methane, a potent greenhouse gas, along with other volatile organic compounds (VOCs), and hazardous air pollutants (HAPs). U.S. crude oil storage tanks emit an estimated 26.6 billion cubic feet of methane per year, representing a significant portion of the oil and gas industry's total annual methane emissions. While vapor recovery units are only feasible for a minority of existing tanks, this technology can capture over 95 percent of these emissions and compress them for use on-site or for sale. These units help protect our environment from harmful air pollutants and greenhouse gases.

BLUEPRINT ON TECHNOLOGY

Vapor recovery units cut up to 95 percent of light hydrocarbon vapors vented from crude oil storage tanks, while recovering valuable gas

Resources that vanish into thin air

CRUDE OIL STORAGE tanks hold oil for brief periods of time to stabilize flow between production wells and pipeline or truck transport. During storage, light hydrocarbons dissolved in the oil vaporize and collect below the tank roof. The chief component of this gas is typically methane, although other gases such as propane, butane, ethane, nitrogen, and carbon dioxide may be present. These vapors also contain HAPs such as the BTEX compounds (benzene, toluene, ethylbenzene, and xylene). As the oil level in the tank fluctuates, these vapors often escape into the air, either through *flash losses* (due to pressure changes during transfer of crude oil), *working losses* (due to the changing fluid levels and agitation of tank contents associated with the circulation of new crude through the tank), or *breathing losses* (due to daily and seasonal temperature and pressure variations). The amount of gas lost depends on the stored oil's gravity, the tank's throughput rate, and the operating temperature and pressure of the oil being added.

The advantages of vapor recovery

Vapor recovery systems can capture more than 95 percent of these fugitive emissions and recover substantial amounts of gas for use or sale. In addition to onshore use, they are also employed in offshore settings such as marine crude oil loading terminals. Producers may opt to pipe the recovered vapors to natural gas gathering pipelines for sale as a high Btu-content natural gas, or to use the gas to fuel on-site operations. Alternatively, they may strip the vapors to separate natural gas liquids (NGLs) and methane. In some cases, vapor recovery units will reduce emissions to below the actionable levels set out in Title V of the 1990 Clean Air Act Amendments. By installing vapor recovery systems, producers may be able to avoid permitting charges, emissions fees, and other regulatory costs.

ECONOMIC BENEFITS
Lower operating costs if captured gas is used to fuel on-site equipment
Gas recovered for sale as a high-Btu natural gas
Gas recovered and stripped to separate NGLs and methane, if volume and NGL prices are sufficient
Potential avoidance of regulatory permitting and compliance costs

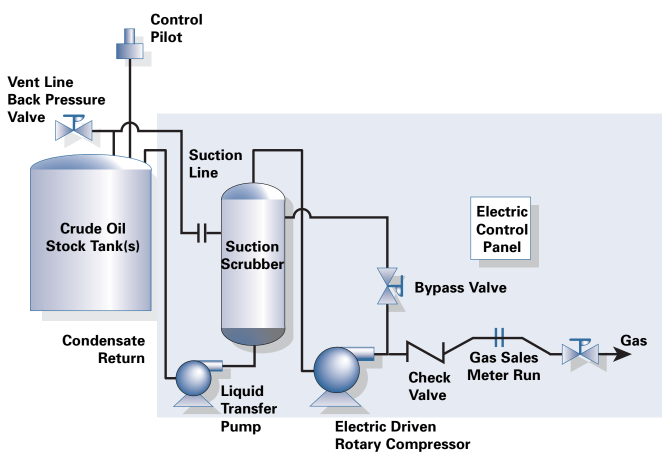
ENVIRONMENTAL BENEFITS
Significantly reduced greenhouse gas emissions
Improved local air quality, due to reduced emissions of VOCs and HAPs
Optimized recovery of a valuable natural resource

How the Technology Works

In a typical recovery system, hydrocarbon vapors are drawn from the storage tank under low pressure, usually between 0.25 and 2 psi, then piped to a separator "suction scrubber," which collects any condensed liquids. Any recovered liquids are usually recycled back to the storage tank. The vapors then are compressed, metered, reused, or resold.

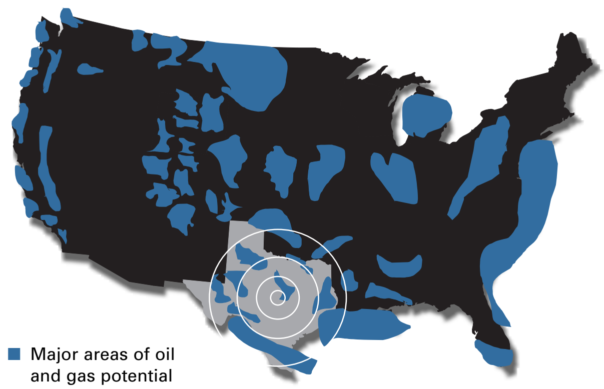
To prevent the creation of a vacuum in the top of the storage tank as vapors are removed, the unit is equipped with controls that shut down the compressor, permitting reflow of vapors into the tank as necessary. These systems can recover practically all the hydrocarbon vapors that would otherwise be lost to the atmosphere with negative environmental impacts.

Vapor Recovery Unit



Case Studies

Success in the Field



Vapor recovery units succeed in the Austin Chalk field

In 1992–93, Union Pacific Resources (UPR) installed 27 vapor recovery units on its crude stock tanks in the Austin Chalk. UPR's horizontal wells in the area are high-rate producers with high gas-to-oil ratios. Under these conditions, gas-oil separation is difficult, leading to high volumes of gas in the tanks. The vapor recovery systems proved very effective in reducing high emissions levels and generating profits. UPR recovered an average of 2,015 thousand cubic feet of gas per day, equivalent to the annual gas consumption of 23 residential consumers. The recovered natural gas netted UPR an additional $700,000 in revenue over a one-year period.

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