WORLD’S FIRST 10,000 PSI SOUR GAS INJECTION COMPRESSOR

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ABSTRACT

This paper traces the development of the original sour gas injection (SGI) concept, the methodology used for managing risks, detailed design and testing of compression train components, compressor train shop string tests, and finally testing and operational experience at the Tengiz Field in Kazakhstan. It covers the process that identified the key technical gaps necessary to safely compress combined separator and recompressed sour gas to 10,000 psi (690 bar) with H_2S concentrations of 17 to 23 mole percent. Sour gas injection benefits include enhanced oil recovery, reduced capital and operating expenses required for treating acid gas, and elimination of elemental sulfur as a product. The focus of this paper is on the surface facility main reinjection train, including associated critical support systems.

INTRODUCTION

From the earliest conceptual phases it was clearly recognized that high pressure sour gas injection (SGI) into the Tengiz reservoir involved many unknowns. SGI would stretch existing worldwide technology in several enabling areas. This paper describes risk mitigation in the areas of design; operation; health, environmental, and safety; and construction. Organizational, manpower, technical, and procedural steps are described. The concepts and strategies described are focused on achieving safe, reliable and incident-free operation of the Tengiz gas injection system (Figure 1).

Figure 1. Tengiz Sour Gas Injection Compressor "Island" Station.

Sour Gas Injection Experience Overview

There are two general classes of gas injection plants, namely sour gas plants and acid gas plants. Figure 2 illustrates the basic differences between these two processes. SGI takes dehydrated hydrocarbon gas with H_2S resulting from a basic oil/gas separation process, compresses the gas, and then reinjects it back into the oilfield reservoir. The sour gas has a composition that is usually 25 percent or less acid gas (H_2S + CO_2). The acid gas injection

(AGI) process removes the hydrocarbon component, compresses the resulting combination of 75 percent or more H_2S + CO_2 gases, then reinjects this high concentration back into the oilfield reservoir.

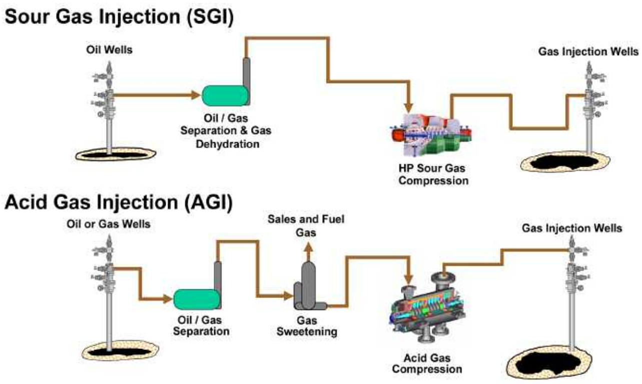

Figure 2. Sour and Acid Gas Injection Processes.

The phase behavior and water holding capability of sour and acid gases are quite different. Acid gas has a large percentage of polar molecules that can react with the polar water molecules to keep it stable in the gas phase. If water-saturated acid gas is pressurized above the dense phase region, the water holding capacity improves even further. As a result, it is often impossible to form a second water-rich phase after making the transition to dense phase. On the other hand, sour gas has a lower percentage of polar molecules and cannot hold as much water. Even after the transition to dense phase, water can drop out if the gas is cooled sufficiently. In a sour gas plant water is a major design concern should the plant have an upset and then handle wet feed that is above the dew point at the coldest operating temperature.

The high pressure injection facility located in the Tengiz Field in Kazakhstan is an SGI process.

Tengiz Field

The Tengiz Field is located on the southern side of the 193,000 square miles (500,000 km^2) Pri-Caspian basin on the northeastern edge of the present day shores of the Caspian Sea. It is one of several large carbonate build-ups found at various depths around the edge of the basin. Other giant oil and gas fields in similar settings include Karachaganak and Orenberg in the north, Zhanazhol in the east, and Astrakhan in the southwest. The Tengiz Field is over 40 square miles (110 km^2) in area at its top and 150 square miles (400 km^2) at its base. It is part of a large ring-like complex 27 miles (50 km) in diameter, which includes the Korolev, Karaton, Tazhigali, and Pustyn carbonate structures. The top of the reservoir is at 12,500 ft (3850 m). The lowest known oil is located at about 18,000 ft (5500 m) subsea. The field is divided into three regions called the platform, rim, and flank.

Tengiz contains volatile, highly undersaturated, sour oil (12.5 percent H_2S) that appears to have uniform composition throughout the reservoir. The stock tank oil density is 48 degrees American Petroleum Institute (API). Original reservoir pressure was about 11,700 psi (800 bar) at 14,000 ft (4150 m). Bubble point pressure of the reservoir oil is about 3600 psi (250 bar). At initial reservoir conditions the gas-oil ratio and oil viscosity were 2242 scf/STBO and 2.2 millipoise (0.22 cp), respectively.

Unique Compression Challenges

The Tengiz location posed several unique challenges to implementation of the very high pressure SGI process. The site is remote and landlocked. Transportation and general infrastructure is limited. Seasonal temperature variations range from $-40°F$ to $104°F$ ($-40°C$ to $+40°C$). Air quality is impacted by sand, dust, and salt from the adjacent Caspian Sea. Communications at site are complicated by the presence of eight cultures speaking five languages. Finally, local environmental requirements as well as formal approval agency review processes within Kazakhstan were emerging and evolving at the start of the SGI in 2000. All these factors complicated the Tengiz SGI technology challenge.

Motivation for Gas Reinjection at Tengiz

Major motivations for SGI at the Tengiz Field were:

- Limited market for elemental sulfur.
- Reduction of SO_2 emissions.
- Improved oil field reservoir performance.
- Enhanced oil recovery.
- Conservation of gas resources for future use.
- Additional information for future asset development.

SGI CONCEPT DEVELOPMENT

Overview

The basic question that was posed at the very beginning of the SGI concept development phase was as follows: "Can very high pressure sour gas reinjection be done safely?" In order to answer this important question a study and information gathering effort commenced in 1989. This involved a small internal team from the end user oil company's technical and production organizations. This team explored the existing background on gas reinjection technology and identified major areas where process knowledge was questionable or unexplored as well as where the technology envelope for equipment and equipment components exceeded field-proven experience.

Project Teams

It was subsequently concluded that SGI represented significant technical challenges never accomplished anywhere else in the world on the scale required at Tengiz. The early SGI project team decided to use nontraditional project approaches. End users were extensively involved on a daily basis from the very earliest conceptual phase. This involvement was a foundation concept of the SGI project effort. Representatives from Tengiz operations, maintenance, drilling, and reservoir functions comprised the core of this group. This early study group represented a broad range of plant and field experience including those having experience in complex high pressure and high H_2S facility operations. The core group was supplemented by technical specialists in several fields. Particular attention was also given to deep involvement of Kazakh nationals who would later operate and maintain the Tengiz SGI facilities.

Commissioning, start-up, and operations strategy for SGI were also developed with a clear focus on the challenges of applying complex new technology in a remote and harsh environment. End user personnel from all functions were deeply involved. In the early design phases of the project, unlike more traditional project teams, the SGI project team consisted of operations, maintenance, drilling, and reservoir personnel. These people were not only involved in day-to-day project decisions but they also worked side-by-side with the contractor engineering, procurement, and construction management (EPCm) engineers in the project design offices. Extensive end user involvement commenced in early feasibility and design phases of the project and continued through procurement and field construction.

Key Project Philosophies

From the earliest 1989 conceptual work it was clear that safety and environmental aspects of sour gas handling were of utmost importance. It was evident that handling very high pressure sour gas required special attention. A "business as usual" approach was clearly inappropriate.

Initial SGI facility operation was planned using sweet natural gas. This was known as SGI Stage 1. This sweet gas operation was followed later by sour gas operation that was termed SGI Stage 2. The decision to start operations on sweet gas and prove high pressure operation of the plant and injection wells was the result of several factors including the toxicity of high pressure sour gas, the challenges of applying new technology in the remote Tengiz location, significant unknowns in surface facility reliability, unknowns in oil field reservoir performance, the harsh Tengiz environmental conditions, and the obvious need for safe, incident-free operation. SGI Stage 1 operation also allowed Tengiz to minimize the duration of the "trial-and-error" period during Stage 2 operation, something that optimized safety and minimized potential environmental impacts.

Key project philosophies had a major impact on design, operation, and maintenance aspects of the facility in both Stage 1 and Stage 2. These guiding project philosophies were the result of the several factors noted above. In order of descending importance they were:

- Safety and environmental impact (protecting people and the environment).
- Operability, maintainability, and reliability.
- Schedule.
- Cost.

Total Integrated System

From the outset, the SGI project was viewed as a "total integrated system" consisting of the oil field reservoir, the pipelines, the surface reinjection facilities, and their associated support facilities. It was clear that each of the individual elements of the "system" was dependent on, and integrated with, the other elements. This "total integrated system" concept was a major reason that SGI implemented the type of cooperative project team structure described earlier.

Multifunctional Work Team

The SGI project endeavored to put technology "champions" in key project positions, to develop high performance cross-discipline teams working closely with key equipment suppliers, and to maximize continuity between project development and execution phases. This teamwork was used extensively, commencing with early study and information gathering effort and continuing through the final construction and operation phases. Important aspects of the teamwork employed at various stages of SGI are briefly summarized below.

Technical Specialist Resources

In traditional projects the use of technical specialist resources is normally rather limited. The usual technical specialist role, if there is one, is commonly short-lived and only occurs during portions of the design phase of the project cycle. In SGI, many technical specialists from the end user's joint venture (JV) partners were directly involved, beginning with the earliest conceptual study phase. It was realized that the sum of JV partner specialist technical resources and the end user technical resources was much greater than the contribution from any one individual in any one company. The concept of using various teams of technical specialists and broadly applying their talents to many leading-edge SGI efforts proved successful. These technical specialists were deeply involved in areas such as oil field reservoir analysis, injection well design, materials science, sour gas processing, environmental evaluations, and critical machinery and support system design. In several cases, specialist resources were seconded to the project team.

High Performance Teams

The concept of a high performance team (HPT) was broadly applied to SGI, initially and most importantly, to the early research and development (R&D) phase in which critical technical issues were being identified and solution paths developed. The purpose of the HPT concept was to create collaborative, interdependent, multifunctional teamwork among all SGI contributors including the end user, JV partner resources, EPCm contractors, and major and critical equipment suppliers and subsuppliers. The HPT concept required model teamwork behavior over a broad span of the project cycle.

Background

The HPT concept began in 1998 with early conceptual technical evaluation work led by the technology company organizations of the operator of the Tengiz Field. The HPT concept emerged out of the process of defining these key project philosophies. It was clear that the success of SGI was significantly influenced by the specific people involved, particularly their teamwork and communication skills. HPT functions and member attributes were subsequently developed. These included:

- Alignment on purpose—Having a shared vision that gives work meaning
- Participative leadership—Being committed to high performance
- Shared responsibility—Feeling personally responsible for the success of SGI
- Recognition—Team recognition for efforts and contributions being more significant than recognition of an individual
- High communication—Willingness to express ideas and opinions in a multicultural working environment with a high degree of trust among team members and ensuring that all surprises are "little" ones
- Rapid response—Identifying and acting on requests, inputs, and opportunities
- Focused on task—Keeping meetings and other efforts focused on results and actively demonstrating that the success of a task is the shared responsibility of both the leader and the contributor(s)
- Boundaryless behavior—Sharing across disciplines, cultures, organizations, and companies without regard to individual affiliation
- Use of creative talent—Fully appreciating and applying individual skills and bringing needed skills to bear in a timely manner
- Proactivity—Actively seeking new and better ways and opportunities for improvement
- Future focus—Viewing change as an opportunity for growth.

Core HPT members for SGI were involved in day-to-day details of the work effort. These members ultimately provided guidance and assistance throughout all project phases by:

- Setting and monitoring adherence to SGI key project philosophies.
- Ensuring effective communication among all other HPT efforts.
- Minimizing individual discipline information silos.
- Establishing selection criteria and helping select members for specific HPT efforts identified by the project.
- Removing technical and nontechnical barriers.
- Monitoring working level progress.
- Providing continuity from start to finish.

R&D High Performance Teams

Several multidiscipline, multicompany teams were formed during the early phases of SGI in order to carry out the critical R&D work on which project success so importantly depended. All teams consisted of a team leader and a core group of team members typically representing several disciplines and often representatives from several companies.

Integrated Project Teams

Crossfunctional project teams consisting of individuals from both the surface facilities and the subsurface reservoir functions were established as well. This type of close teamwork is seldom found in projects. Individuals in the cross-functional SGI teams represented the end user, the EPCm contractor, the injection gas compressor supplier, and in some cases, JV partners. Again, the concept was to improve communication and ensure timely access to all the available knowledge. It was particularly useful to ensure that the expertise and experience of individuals with surface facility background worked closely with individuals having subsurface and reservoir expertise and experience. This integrated working relationship helped to ensure that the SGI effort truly addressed the needs of the total integrated surface and subsurface system.

Meetings

Effective communication is a most critical element of any large project effort. SGI was certainly no exception. Because of the diversity of companies, cultures, and disciplines involved, SGI employed specific meeting tools to improve effectiveness and efficiency. Meetings were primarily conducted in one language (English), a facilitator was often used, complete agendas were issued in advance of meeting dates, and detailed meeting minutes were recorded. Meeting agendas included a statement of the specific purpose and objectives of the meeting, attendee list, specific meeting attendees assigned to each discussion topic, time allotted, objectives of each discussion topic, together with the desired outcome. At the end of important meetings minutes were carefully reviewed by meeting participants to ensure accuracy, understanding, and completeness. Final minutes were then promptly issued. This approach proved to be an effective work and communication process.

Project Development and Execution Process

SGI employed the use of the end user company's worldclass project development and execution process. This process served to improve both decision-making and execution. It also fostered improved planning, collaboration, and communication. In its simplest form, the adopted process was a set of principles that made SGI more efficient. These principles included:

- Focusing on key value drivers for the opportunity.
- Using integrated, multifunctional teams.
- Achieving effective input, communication, and alignment among teams, decision makers, and stakeholders.
- Doing the work needed to support the next decision; being decision driven, not activity driven.
- Consistently applying lessons learned, best practices, and value improving tools.

The development and execution process included an initial assessment of the gap between the current and desired states for a stated SGI opportunity followed by development of a plan for closing the gap. SGI developed five specific steps, called a framing document, which served as an important reference during the life of the project. These steps were:

- Clearly defining the opportunity.
- Understanding and agreeing on the boundary conditions.
- Identifying the stakeholders.
- Defining a successful outcome.
- Developing a process roadmap or work plan.

RISK MANAGEMENT METHODOLOGY

Identification of Critical Risks

One of the first steps in addressing the underlying safety concerns with high pressure sour gas injection was identification of the most significant risks. As shown in Table 1, studies of the feasibility of safely handling very high pressure sour gas injection began in 1989. This initial study effort was followed by a series of successive studies, onsite gas injection facility reviews, and technical surveys, all of which culminated in specific R&D programs for the SGI project that started in 2000.

Table 1. Key Milestones and Study Activities for High Pressure Sour Gas Injection.

Year	Activity	Focus
1989	Korolev, Kazakhstan sour gas injection feasibility study	• Existing experience with sour gas handling • Assessment of operational, maintenance and safety problem areas
1996	State-of-the-Art Assessments for Sour & Acid Gas Injection	• Low pressure reservoir injection [140 bar (2030 psi)] • High pressure reservoir injection [600 bar (8700 psi)] • Review of operating and maintenance experience in worldwide high pressure sweet gas injection facilities
1998	Sour & Acid Gas & LPG Injection Feasibility Assessments	• LPG injection [210 bar (3050 psi) & 690 bar (10,000 psi)] • Sour & acid gas injection [170 bar (2470 psi)]
1999	Sour & Acid Gas Compression System Technical Assessments	• Sour & acid gas compression system conceptual designs • Materials of construction for equipment and pipelines in high pressure services involving high H_2S/CO_2 gas mixtures • Phase behavior & physical property data on H_2S/CO_2 rich gas mixtures • Selection of injection gas supplier for project
2000	Sour Gas Risk Mitigation Plan & R&D Programs	• Development and assessment of alternative risk mitigation cases • Materials of construction for sour service • Commencement of critical R&D program for safe sealing of sour gases
2006	Detailed Risk Analysis of Installed Facility and Injection Wells	• Detailed dispersion analysis of potential failures and leak sources based on final as-built design, location, realistic range of ambient conditions, and maximum future H_2S levels that could be compressed • Risk Analysis performed based on current population densities of company and non-company personnel near the proximity of SGI facilities • Results of as-built dispersion analysis and risk review used to develop Operating Protection Zones, Facility Access Control procedures, SGI area wide Field Access Control procedures, Operator manning levels, Outside Operator and Maintenance criteria, Safety Procedures for field work on SGI injection wells, and special protecting people and environment requirements in the SGI facilty and SGI field.

Early risk assessments for high pressure sour gas injection included consideration of environmental impact, process unknowns, machinery sealing and performance prediction, pipeline design, and materials performance. As shown in Table 2, for the surface injection facility alone, it was clear that high pressure sour gas injection posed a significantly greater technological challenge than lower pressure sour gas and high pressure sweet gas injection.

Table 2. Technological Risk Profile for Gas Injection Facilities.

Required Injection Pressure	Relative Risk	
	Sweet Gas	Sour Gas
Low pressure [<70 (1020 psi)]	Very Low	Very low to Low
Moderate pressure [70 bar to 200 bar (1020 psi to 2900 psi)]	Very low to Low	Low
High pressure [200 bar to 500 bar (2900 psi to 7250 psi)]	Low	Moderate
Very high pressure (500 bar to 700 bar (7250 psi to 10,200 psi)]	Low to Moderate	High

A mid-1990's survey of compressor manufacturers showed that about 12,000 centrifugal compressors had been built over a 50-year period but very few were in sour service at pressures above 2900 psi (200 bar). Above 2900 psi (200 bar), even experience with sweet natural gas compression was relatively limited. By the late 1990s significant field experience with sweet natural gas injection at the 7980 psi (550 bar) level had been successfully demonstrated using conventional compressor oil-film shaft sealing technology. This experience was gained primarily from a sweet gas injection facility in Venezuela. Figures 3 and 4 show the worldwide compression experience picture as of the year 2000. The Karachaganak project in Kazakhstan was under field construction at the time the SGI project design effort began. Although Karachaganak was similar in several respects to Tengiz, injection gas process conditions were significantly different and it was not until 2004 that Karachaganak was in actual operation. Kashagan, a later development also in Kazakhstan, benefitted from the Tengiz lead development and qualification of 10,000 psi (690 bar) SGI capabilities. Kashagan, with discharge pressures of 13,600 psi (940 bar), is still under construction.

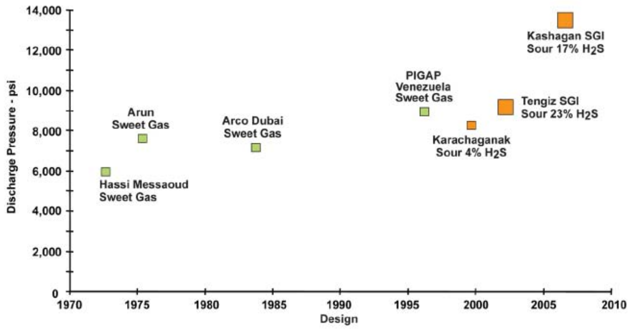

Figure 3. Worldwide Centrifugal Compressor Injection Experience.

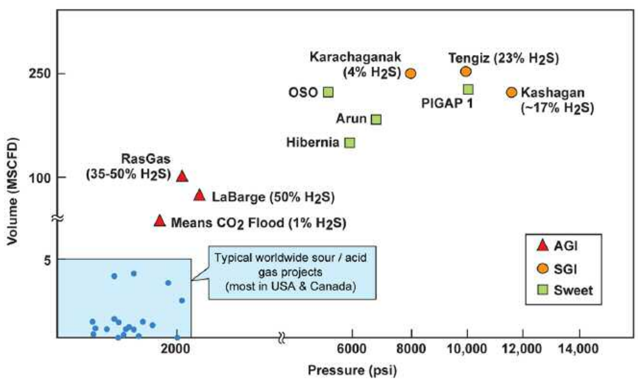

Figure 4. Worldwide Sour and Acid Gas Injection Experience.

Primarily all of the higher pressure sour gas experience in the world up to the 1990s was concentrated in Alberta, Canada. Pressures up to about 5080 psi (350 bar) had been achieved in the field, although most experience was in the injection pressure range of 2030 to 2900 psi (140 to 200 bar). Typically, total facility injection volumes were in the range of 10 MMSCFD (11 Nm^3/hr) or less. Because of these low injection volumes, reciprocating compressors were used for the Canadian applications. For the SGI application at Tengiz, much larger volumes of gas, amounting to about 250 MMSCFD (278 Nm^3/hr), needed to be injected. For all practical purposes this required the use of centrifugal compressors.

Worldwide High Pressure Gas Injection Site Reviews

SGI gathered design, operating, and maintenance information from several worldwide injection facilities, beginning with onsite reviews of several smaller Canadian sour gas injection plants.

Canadian Sour Gas Injection Facilities

In August, 1989, a multidiscipline end user company technical team visited several sour and sweet gas injection facilities in Alberta, Canada. This series of plant visits helped established the challenges of handling high pressure sour gas injection. Major findings were:

- All plants experienced "trial-and-error" operating periods lasting for more than two years.
- Emission releases during the initial "trial and error" operating period were significant.
- Operating costs for sour gas operation were several times higher than comparable sweet gas operation.
- Elemental sulfur formation in the processing equipment and pipelines was a continuing concern.
- Maintaining a high degree of safety awareness was found to be difficult.

The Canadian site visits also helped to highlight the many challenges of operating in remote areas under difficult environmental conditions. In several important ways the Canadian sites were similar to Tengiz.

High Pressure Sweet Gas Injection Facilities

During the 1990s, onsite field visits were conducted at the world's highest pressure sweet gas injection facilities. These facilities were located in Indonesia (Mobil Arun), Abu Dhabi (Arco Dubai), and Venezuela (PIGAP I). At the time of their initial startup, each facility represented the leading edge of gas injection technology. The Indonesia and Abu Dhabi site visits, conducted in the latter part of 1996, helped to identify typical machinery required, process-related commissioning and startup problems, and experience with critical equipment suppliers' technical and field service support.

In early 2000 an end user and JV partner team visited the PIGAP I site located near Maturin, Venezuela. A follow-up team visited the site around mid-2001. These visits helped the SGI project clearly understand the injection experience of the facility owner/operator, to understand overall facility performance, to gather typical reliability/availability information, to gather lessons learned, and to understand equipment supplier performance.

The results of the Indonesia, Abu Dhabi, and Venezuela site reviews, together with earlier experience gained from review of Canadian facilities, were used to help define and finalize SGI's R&D program. Technology gaps were identified by this process. Site visits also helped SGI formulate a project contracting and execution plan for Tengiz. However, it was also recognized that the worldwide facilities that handled large volumes of hydrocarbon gas with appreciable CO_2, also lacked experience handling significant amounts of H_2S in the gas. Tengiz SGI represented an important challenge because the gas stream contained both significant quantities of CO_2 and H_2S, together with significant amounts of heavy end hydrocarbons. Due to metallurgical concerns, elimination of moisture from the injection streams was paramount as well.

"Trial-and-Error" Operating Period

From worldwide experience in high pressure injection facilities, it was recognized that the SGI project could be expected to have an initial "trial-and-error" operating period as well. During this initial period, many facility startups and shutdowns could be expected. Experience indicated that this "trial-and-error" operating period would typically last from three to six months. In some facilities, the period lasted more than one year. Facility shutdown frequency typically averaged about one to two events per day. A general observation from all types of plants was the higher likelihood of incidents occurring during startup/shutdown cycles and major process upsets. This was cause for concern for SGI.

With the above experience in mind, the SGI project planned to start up using sweet natural gas during the expected "trial-and-error" operating period. This approach was favored from both the standpoint of avoiding safety and environmental incidents, allowing operators to thoroughly learn the plant, as well as satisfying the need to gain needed oil field reservoir-related injection data. Also, the concept of total recycle of gas was embraced for the high pressure compression portion of the injection system. During upsets in either the gas supply or the oil field well injection system, the SGI surface facility concept was to block-in the high-pressure compression system and operate the plant in total recycle. This design feature minimized the number of cyclic plant startups and shutdowns. In addition, the high-pressure compression portion of the SGI injection system was designed for full pressurized shutdowns of several hours duration, avoiding the need to blow down the facility to relief. This approach also shortened the subsequent startup procedure.

Lessons Learned Summary Database

A major activity during the earliest phases of SGI was gathering and summarizing lessons learned from projects applicable to the Tengiz application. This included not only the worldwide sweet and sour gas facilities site visit information mentioned earlier but also additional information from visits to several acid gas handling facilities in Canada. The remote Tengiz location, the severe environmental conditions, and the new required high pressure gas injection technology all underlined the importance of learning from the past. The basic purpose of the resulting lessons learned document was to ensure that the know-how gained in the past was integrated into the project effort at every phase, ultimately ensuring that the SGI's key project philosophies would be met.

The potential impact of new technology on the overall success of the SGI project was identified early as an important consideration in the Tengiz application. From experience within the Tengiz JV partners as well as many other petrochemical companies and contractors throughout the world, new technology had been shown to have a powerful influence in the economic results of projects where it was a major component. A study (Merrow, et al., 1988) of very large projects concluded that: "*The incorporation of new technology in a mega project almost ensures that the project will make more mistakes than money. The use of new technology is the only factor that is associated with bad results in all three dimensions: cost growth, schedule slippage, and performance shortfalls. Doing something different—even slightly different—increases cost growth and schedule slippage and dramatically increases the probability of operational problems.*"

This report's (Merrow, et al., 1988) conclusion firmly underscored the value of incorporating past lessons learned into SGI and properly planning needed R&D efforts. Subsequently, over a year-long period a lessons learned experience database was created and widely shared with members of the SGI project team. This comprehensive database represented a collection of best practices contributed by engineers, operators, maintenance personnel, project people, and others. Table 3 summarizes the principle sources of this information resource.

Table 3. SGI Project Lessons Learned Database.

Topic	Location /Application	
Successful gas injection and large projects (all pressures)	• General industry (worldwide)	
Projects having a significant element of new technology	• General industry (worldwide) • Rand Corporation Study of Mega Projects	
Sweet gas injection facility experience	• Mobil Arun (Indonesia) • Arco Dubai (Abu Dhabi) • PIGAP I (Venezuela) • Hibernia Platform (offshore Canada)	• Nemba Platform (offshore Africa) • Gobe (Papua New Guinea) • Mobil Oso (Africa)
Sour gas injection and acid gas handling experience	• General industry (worldwide) • Canadian facilities • Tengiz KTL-1 & 2 (Kazakhstan) • Karachaganak (Kazakhstan)	
Past Tengiz projects (Kazakhstan)	• Debottlenecking • Train 5	• Second Generation • Project 12
Proven methods to improve plant reliability	• Chevron refining	
SGI project (Kazakhstan)	• R&D phase	

During each subsequent phase of the SGI project, the database was again reviewed to be sure that applicable lessons were incorporated into the project design and execution plans. In addition, lessons learned were captured from early SGI R&D efforts and then shared with the project team during the later design phase. Finally, the end user company's "top ten" list of most important general project lessons learned was periodically reviewed with project team members. This "top ten" general project list included many of the same higher level themes that were inherent in the SGI lessons learned database.

Health, Safety, and Environmental Considerations

Because the Tengiz application was unique it was expected to generate risks and hazards not previously encountered. The safety record for the new high pressure SGI project was expected to be equal to or better than the past excellent safety record of the existing oil/gas treating Tengiz facilities. To better understand the range and magnitude of the risks involved, various reviews were conducted. These considered the areas of the facility where release incidents might occur and under what conditions. This was followed by a series of studies and consequence modeling efforts to provide the project with an indication of the potential outcome should an incident be realized and what measures the project could take to reduce the initial event or safely manage the consequences.

H_2S Release and Overpressure Studies—Consequence Modeling

Initially, 14 potentially significant incident scenarios were developed for the entire SGI system as shown in Table 4. For each incident scenario the combinations of wind speed and stability categories (Pasquill) were used to represent day and night as worst possible conditions. Modeling was completed for both a sweet gas release case and the sour gas release case, representing SGI Stage 1 and Stage 2 operating conditions, respectively. Failure sizes for each scenario were selected based on industry standards and end user company operating experience. Models were set up to consider several events such as unignited vapor cloud dispersion, jet fires, and explosion overpressures from delayed ignition. Overall findings of the analysis were generally what would be expected for a facility handling very high pressures and high sour gas concentrations.

Table 4. Potential Incident Scenarios.

Scenario	Scenario Description	Failure Size
1	Feed gas supply (sweet & sour gas cases), valve stem release	2 mm (0.08 in) diameter hole
2	Feed gas supply pipe failure, (sweet & sour gas cases)	10 mm (0.4 in) , 50 mm (2 in) & full bore
3	Failure of booster compressor aftercooler (sweet gas only)	10 mm (0.4 in) & 50 mm (2 in)
4	1st stage injection compressor intercooler failure (sweet & sour gas cases)	10 mm (0.4 in) & 50 mm (2 in)
5	Injection compressor seal gas supply failure (sweet gas only)	10 mm (0.4 in) & 50 mm (2 in)
6	Injection compressor head "O" ring failure (sweet & sour gas cases)	5 mm (0.2 in) equivalent
7	Injection compressor 3rd stage outlet failure (sweet & sour gas cases)	10 mm (0.4 in), 50 mm (2 in) & full bore
8	Failure of flow measurement package (sweet & sour gas cases)	5 mm (0.2 in) equivalent
9	Failure of main injection line (sweet & sour gas cases)	10 mm (0.4 in), 50 mm (2 in) & full bore
10	High pressure injection wellhead valve packing seal failure	5 mm (0.2 in) equivalent
11	Hydrocarbon condensate drum failure	10 mm (0.4 in), 50 mm (2 in) & 100 mm (4 in)
12	Release form producing wellhead	Full bore
13	Producing wellhead failure	
14	Injection wellhead failure	

A number of basic design features were implemented to reduce the risk to personnel and limit the potential for escalation. These changes included:

- Relocating the control room, maintenance building, and fire station a minimum of 0.25 miles (500 m) from the injection facility site for initial sweet gas trials.
- For sour gas operation, relocating full control of SGI 7.5 miles (12 km) from the facility, to the main control room of the main oil and gas processing plant.
- The compressor island facility was originally designated as a normally unmanned facility with attendance for maintenance and inspection only. Consequence modeling study results indicated that entrance to the compressor island should be strictly controlled with all personnel equipped with personal H_2S monitors.
- Fire and explosion protection was provided to the boundary emergency shutdown valves allowing prolonged exposure to jet fire or explosion overpressure impact.

- Main injection lines were buried as soon as practical after the metering and pigging area.
- A higher level of gas detection was provided to all areas and the detection was linked to the emergency shutdown (ESD) system allowing rapid isolation and shutdown in the event of a major release.
- The injection compressor building was designed to relieve internal overpressures with the use of explosion relief panels.
- In the event of a toxic vapor cloud release, off-plot shelter-in-place buildings and offices were provided to allow personnel to muster for extended periods.
- Piping design configuration and the location of shutdown valves were designed to limit the stored gas volumes as much as possible.
- The number of flanged connections and pipe intrusions were limited to the greatest extent practical.
- Most valves in the high pressure section of the plant used welded construction, tappings were deleted, and instrumentation was nonintrusive where it was practical.
- High pressure and sour gas piping was protected from mechanical impact.
- Shelter in-place facilities were provided around oil field well head activities during the construction phase, together with H_2S escape masks for construction personnel. Coordinated simultaneous construction-operations plans (SIMOPS) were implemented for periods when the construction and nearby drilling activities coincided.
- Special access control and SIMOPS planning were developed.
- No-go zones were identified, requiring breathing air be worn for access.
- Cascade breathing air was implemented inside compressor buildings and in some potentially high risk areas.

Quality Function Deployment

A quality function deployment (QFD) process was employed in the early SGI effort as a method for translating user requirements into an appropriate technical design for the project. This is a cross-functional process that helps ensure an optimum solution. The key elements are the "whats" (which are the user wants and needs) and the "hows" (which are the ways in which these wants and needs can be satisfied). QFD uses a weighting process to identify the relative importance of the needs. This process was completed for each of the critical project quality factors. For SGI these weightings were the key project philosophies mentioned earlier.

During the early phases of SGI the QFD tool was often used to help select the most appropriate design path forward. It was particularly important in the early surface facility R&D efforts. The process was particularly valuable because it minimized individual biases in the decision-making process. Figure 5 shows the results for a typical analysis of an antisurge valve. Option 4 was the most favored approach.

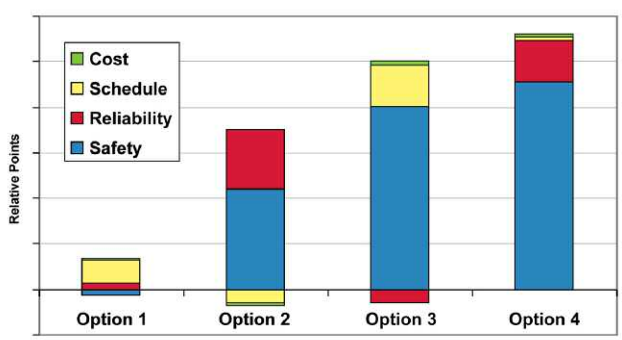

Figure 5. Quality Function Deployment Analysis of Antisurge Valve Design Options.

TECHNOLOGY GAP CLOSURE

From the extensive early study work and the lessons learned database several specific technology gaps in the injection facility were identified. Many of these gaps were focused on safely sealing equipment in high H_2S service, an identified area where risk mitigation was needed.

Technology Gap Closure

In order to close the identified technology gaps three major strategies were identified as shown in Table 5. For the surface facilities, the SGI project team selected the option of funding the R&D effort alone and partnering with a world class supplier. This decision was driven by several considerations listed in Table 5. Later it would be evident that the time to complete the R&D effort was a most critical element, due in large part to the very nature of unknowns in an R&D process itself.

Table 5. Technology Gap Closure R&D Considerations.

Strategy	Description	Time & Effort to Start R&D Program	Overall Cost to Each Participant	Risk of Failure to Meet Technical Objectives	Likelihood of Getting to the Best Answer	Control/ Influence on the R&D Plan	Speed of Completion of the R&D Plan	Technology Ownership (Competitive Advantage/ Licensing)
Joint industry project	Open invitation to interested users, suppliers, and R&D organizations	High	Low	Low	Most	Moderate	Slow	Low
Shared develop-ment	Selected partnering of users, suppliers, and R&D organizations	Moderate	Low	Moderate	Somewhat	Moderate	Moderate	Low
Fund alone	Hire or partner with a world class supplier	Low	High	Moderate	Somewhat	High	Fast	High

Following the decision to fund the R&D effort alone, a team from the end user and JV partner companies was assembled to determine the appropriate supplier partner. This team's specific objectives were to:

- Identify potential supplier partners and select the preferred one.
- Review options and recommend optimum commercial business arrangements.
- Consider implications of future compressor facility expansions at Tengiz.
- Identify and address critical compressor system subsuppliers.
- Develop an "injection compressor island" concept and alternative options.
- Develop the framework and core members of an HPT to make the transition into the early R&D phase of the SGI project.

Identification of Gas Compressor Supplier

One key supplier, the manufacturer of the critical injection compressor, was ultimately selected in late 1999. The selection was based on several factors including:

- Awareness of and responsiveness to health, safety, and environmental issues.
- Experience in high pressure gas compression and gas handling including design, testing, installation, commissioning, and startup.
- Willingness to dedicate quality people to the SGI project and commitment to high performance teamwork.
- Business and organizational experience, flexibility, and commitment.
- Capability in project management.
- Breadth and depth of life cycle support and a focus on total cost of ownership.

Once this gas compressor supplier was selected the supplier's team of engineers was integrated into SGI as a developmental partner. Several months of additional study by the end user and gas compressor supplier personnel followed. Then the SGI project effort was expanded to include various consultants and subsuppliers. Ultimately, the project team involved multicompany, multifunctional, multidiscipline work teams. This team concept proved to be a very effective and an efficient method for addressing the many challenges of Tengiz.

SGI SURFACE FACILITY R&D PROGRAMS

Program Overview

The R&D effort for the surface facilities portion of the SGI project involved closing technology gaps in the three main areas shown in Table 6.

Table 6. SGI Project R&D Program Technology Gaps.

R&D Area	Technology Gap	Risk Mitigation
Fluid properties	No public information on fluid properties at very high pressure	• Additional lab data • Matching lab data to process simulation packages
Machinery	Critical equipment had never been built for these volumes and pressures and handling gas with high levels of both CO_2 and H_2S	• R&D for new dry gas seal, compressor head cover seals, anti-surge valve seal and pressure safety valve seals • Partner with strategic supplier
Materials	Same situation as machinery above for metallic and non-metallic materials and welding procedures	• Lab testing of metallic and non-metallic materials • Partnering with strategic suppliers

The effort to gain accurate high pressure fluid property data and to finalize an appropriate equation of state for performance prediction was finalized within a few months of the start of SGI. Full pressure, full speed injection compressor performance test results in 2003 confirmed the accuracy of fluid property data and equation of state used in the design. Machinery and materials R&D sealing efforts required much more extensive planning, dedication, coordination, cooperation, and time to complete. In one case, the effort required more than four years.

Minimum Leakage Concept

Safe, reliable, environmentally responsible containment of sour gas was the major focus of the SGI surface facility-related R&D effort. SGI initially developed expectations and specific requirements for what was called a "minimum leakage" concept. This helped frame the goals for the individual R&D efforts. Details of the minimum leakage concept were developed using the HPT work concept involving equipment supplier, seal subsuppliers, end user, and its JV partners. Minimizing leakage of sour gas applied to all portions of SGI system (production wells, injection wells, as well as the oil/gas separation, processing, treating, and compression areas, and associated pipelines) from the time of initial startup (new equipment) until several years thereafter. In establishing acceptance minimum leakage limits the team realized that reaching true zero leakage was not practical nor was it necessary. The team also realized that solutions needed to be practical in terms of application to the Tengiz environment.

Practicality of Designs

The SGI equipment and components designs needed to be practical from both an operational and a maintenance standpoint. Designs were avoided that required unrealistic skills or ultra-precision field fit-ups. Key considerations in establishing appropriate designs included:

- Prevailing environmental conditions at Tengiz (remote site with a wide range of temperatures, sand/dust, etc.).
- General skill level of the local Tengiz work force.
- General lack of original equipment manufacturer (OEM) infrastructure and service support.
- Anticipated need for field assembly and fit-up, tolerances involved, and availability of special tools.

Standards for New Equipment

For new equipment and components that had not been put in field service "minimum leakage" implied high quality, robust designs that would pass appropriate industry leakage standards in the as-built condition. Previous site reviews of worldwide high pressure injection facilities underlined the need for improved gas containment.

Requirements for Installed Equipment

The SGI minimum leakage concept was intended to extend beyond just new equipment and the successful completion of shop running and qualification tests. Equipment and associated systems needed to remain safe, reliable, and with "minimum leakage" for extended periods between major scheduled plant maintenance intervals. At Tengiz this ranged from three to five years. Minimum leakage performance expectations also extended over the full range of Tengiz operating conditions, including process pressures and temperatures, process fluids handled, and ambient conditions.

Safe Containment of Gas—High Pressure Sealing R&D

The SGI project's minimum leakage expectations provided a clear target for surface facility R&D efforts. Improved sealing efforts were needed in the following areas:

- Compressor shaft seals
- Compressor casing head cover seals
- Antisurge valve stem seals
- Pressure safety valve seals

In addition, high pressure heavy wall piping fabrication and welding R&D were required because of the sizes and thicknesses required by the SGI application. A concerted technical team effort was also focused on the injection compressor design, particularly the rotordynamic behavior and stability characteristics. Past well-known worldwide compressor problems in high pressure applications underlined the importance of acceptable rotordynamic behavior and stability over the full range of field operating conditions. Eliminating the possibility of these types of design problems in Tengiz field was mandatory in order to avoid lengthy delays, costly shutdowns, and potential seal-related incidents.

Compressor Shaft Seals

Of all the sealing challenges in SGI injection compressor shaft seals were considered the most critical because of the potential to affect safe containment of the highly toxic sour gas. The situation facing the SGI at the commencement of the project in 2000 was as follows:

- Dry gas seal (DGS) technology was the only practical seal technology for high pressure sour gas service.
- Conservative, robust tandem DGS designs were mandatory considering the project's safety and reliability needs.
- Parallel R&D design paths were needed to minimize inherent R&D risks and ensure that a proven seal design was ready when the project needed it.
- A common dimensional envelope for the compressor seal cavity was needed to permit parallel, multiple seal R&D efforts and DGS interchangeability between seal suppliers' designs.
- Thorough shop testing at both the seal supplier's and compressor supplier's shops was mandatory to ensure elimination of field startup problems.

Conventional oil-film type compressor seal technology was deemed unsuitable for the Tengiz application due to the very high H_2S content of the gas stream. There was a long history of problems with oil-film seal deterioration in much less demanding sour services throughout the world. DGS technology was the obvious technology of choice. During the 1990s the petroleum industry had gained considerable experience with DGS technology. Field experience at lower pressures and smaller seal sizes had proven that DGS technology was quite reliable.

The task faced by SGI was to extend DGS seal design technology to the specific Tengiz application. This challenge was complicated significantly by the Tengiz environmental conditions and the nature of the Tengiz process gas stream. At the beginning of the R&D effort in 2000 no similar DGS capability existed anywhere in the world.

As shown in Figure 6, the SGI DGS application represented a significant extension of the technology in terms of the PD ratio (pressure × seal diameter). The challenge was to extend the then current state-of-the-art about 25 percent up to 6160 psi (425 bar) pressure with a 7.125 inch (180 mm) seal diameter. This represented a very steep increase in DGS development, something that was unprecedented over the previous 25 year period that industrial compressor dry gas seals existed.

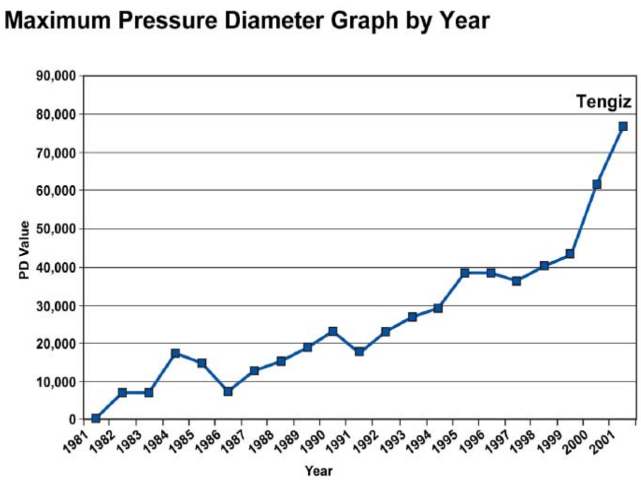

Figure 6. Dry Gas Seal Technology Development Profile.

Without a successful DGS design the SGI project would not be feasible. As DGS design was critical, the early project team elected to pursue parallel R&D efforts with the two leading worldclass DGS suppliers. High performance teams were formed with each supplier. Each team proceeded to develop prototype designs over a 1½ year period. Full-scale prototype seals were then manufactured and the seal suppliers' testing phase began. This extensive testing phase was completed after about one year of trial-and-error development. Following successful development of the prototype seal in early 2002, production version seals were manufactured and exposed to the same exhaustive testing program. Production version seals were then incorporated into the compressor shop testing program as a final demonstration of acceptability. Initially, significant problems were encountered during the full pressure compressor train shop testing. This necessitated additional seal development work prolonging compressor full pressure testing over a period stretching from mid-2003 to late 2004. Acceptable DGS designs were finally demonstrated in the first half of 2005. Although the total DGS design effort took over four years to complete, the SGI project was able to minimize the impact on field construction.

Compressor Casing Head Cover Seals

Field experience gained mainly from the Venezuela sweet gas injection site visit in early 2000 highlighted potential reliability problems with injection compressor casing head cover seal designs, especially in the higher pressure stages. Although this was not a serious problem in process services involving nontoxic gases such as handled by the Venezuela facility, the SGI project team recognized that design and leakage performance improvements were needed for the toxic sour gas service at Tengiz. These particular high pressure seals needed to firmly seat during each casing pressurization cycle while avoiding extrusion into the gap between the casing bore and outside sealing diameter of the head cover. Specific technology gaps in the high pressure head seal design existing at the start of the SGI R&D effort included:

- Lack of reliable sealing at very high service pressures.
- Lack of successful field operating experience in high pressure sour gas services.
- Seal extrusion problems with existing designs.
- The need for a totally redundant seal due to the toxic nature of the sour gas.
- The need to eliminate potential explosive decompression (ED) damage due to rapid decompression during plant depressurizations.
- Evolving and ever more stringent environmental emissions requirements.

To develop safe and reliable designs for the SGI application the R&D plan incorporated a unique number of steps including:

- Deeply involving the head cover seal manufacturer and an expert nonmetallic material design consultant in the actual design analysis process.
- Initially validating finite element analysis (FEA) head seal models by comparing calculations with observed field seal performance results.
- Then using validated FEA models to develop improved head seal designs to avoid extrusion problems and to minimize leakage.
- Conducting lab tests to verify key material properties and gas permeation/diffusion characteristics of materials of construction.
- Using FEA analysis to validate the mechanical behavior of new, improved designs.
- Defining leakage expectations and specific acceptance values.
- Defining appropriate and practical quality requirements for head seal gasket and compressor head manufacture.
- Preparing and demonstrating head and seal assembly procedures and special job tools in the compressor supplier's shop.
- Verifying leakage rates during various compressor suppliers' machinery shop testing programs.

Over more than a year-long period, the R&D effort developed a new high pressure casing head seal design with several improved features as shown in Figure 7. Initial laboratory work by an expert nonmetallic materials consultant included gas diffusion property evaluation for the modified PTFE material chosen as the primary head cover seal material. These tests showed that the individual gas components of the Tengiz process gas take different periods of time to diffuse into and subsequently permeate the seal. This investigation focused on the safety critical component gas, H_2S. It showed that the sour gas component of the mix would take up to 3000 hours to reach a constant state, then producing an estimated leakage volume of gas through the primary seal on the order of 3 ft^3/day (8 cm^3/day). This analysis was considered conservative since the presence of the carbon fiber-filled PEEK backup ring was considered only in terms of its mechanical constraint on the primary seal. The end result of this analysis was to increase the depth of the primary seal by 0.04 inch (1 mm) at its base.

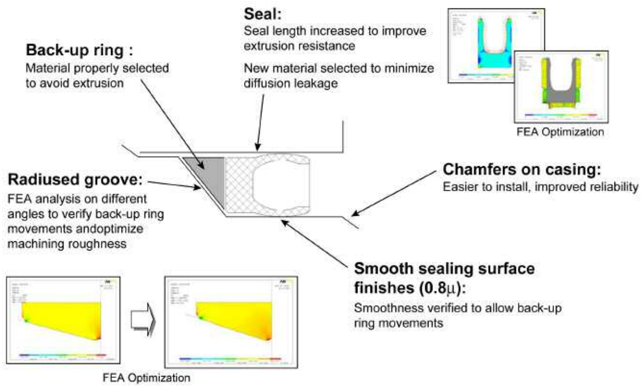

Figure 7. Compressor Head Cover Seal Design Features.

The consultant also conducted tests and evaluations of the head cover O-ring seals on the low pressure compressor casing covers. These evaluations were focused on ED behavior and expected gas permeation rates. They helped to establish O-ring groove design and to assure that O-rings would not fail by ED even under the most extreme circumstances. As a further confirmation of material and design safety, two similar seals were removed from tested compressors and closely examined at 20 times greater magnification. These showed no indication of ED or other damage although they were exposed to greater concentrations of CO_2 than will be found in the process gas associated with Tengiz service.

Tests of the final head cover seal design were incorporated in the compressor supplier's API 617 casing tightness tests as well as the full pressure, full speed shop testing program. Precise measurements of seal leakage were recorded during casing tightness testing. Figure 8 shows typical leakage measurement and the effect of internal pressure on gasket energization and the sealing ability once the gasket was energized. The effects of sealing temperature and pressurization/depressurization cycles on the leakage rate were also captured. The SGI application represented the first time that thorough, precise leakage testing had been conducted on full-scale compressor head cover seals of this type in an industrial application.

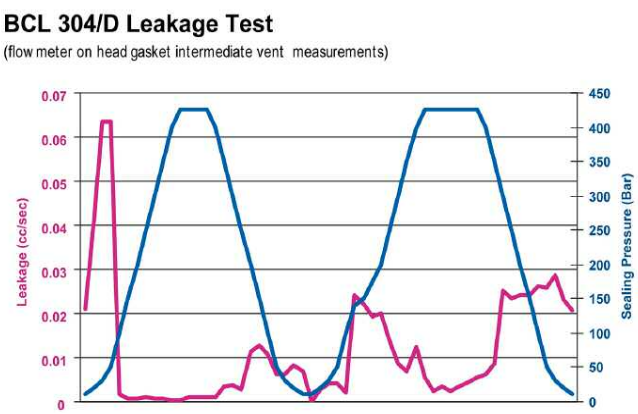

Figure 8. Compressor Head Cover Seal Leakage Rates Versus Sealing Pressure.

The final compressor head seals for SGI were designed with 100 percent redundancy and very low leakage rates. Allowable leakage rate targets were set at 0.03 ft^3/day (0.01 cm^3/sec). This rate represented a fraction of leakage rates typically experienced in similar gas injection compression equipment operating in the field at that time. The final design of the SGI head cover seals was capable of retaining full internal pressure under all operating and environmental conditions, including cyclic pressurizations and depressurizations encountered during compressor startups and shutdowns. Special attention was given to surface finish, seal assembly dimensions, and sealing groove profiles.

To further minimize the possibility of head cover seal reliability problems in Tengiz, detailed assembly procedures were developed. These procedures were demonstrated during the compressor casing assembly in the compressor manufacturer's shop. Modifications to the procedure were made to reflect the best and most reliable assembly methods with due consideration to the Tengiz environment. All job-specific special tools for installation of the SGI head cover seals were also demonstrated during the shop assembly to confirm acceptability.

Antisurge Valve Stem Seals

Reliably sealing the stems of antisurge valves proved to be a very difficult duty due to the wide range of pressure conditions the valve must handle, the need to open rapidly to avert compressor surge, and the range of process and environmental temperatures the stem seals are exposed to. These stem seals operate in a difficult dynamic, and occasionally static, sealing environment. Technology gaps and needs identified at the start of the SGI antisurge R&D program are illustrated in Figure 9. Gaps were:

- Lack of reliable field operating experience in high pressure sour (H_2S + CO_2) gas services.
- The need for a totally redundant stem seal system.
- Ability to reliably seal over the long-term under severe dynamic sealing duty (thousands of valve stroke cycles).
- The need to eliminate potential explosive decompression damage to elastomeric components.
- The need to extend existing stem seal designs beyond current pressure retaining capability.
- Tighter, more stringent environmental emissions goals.

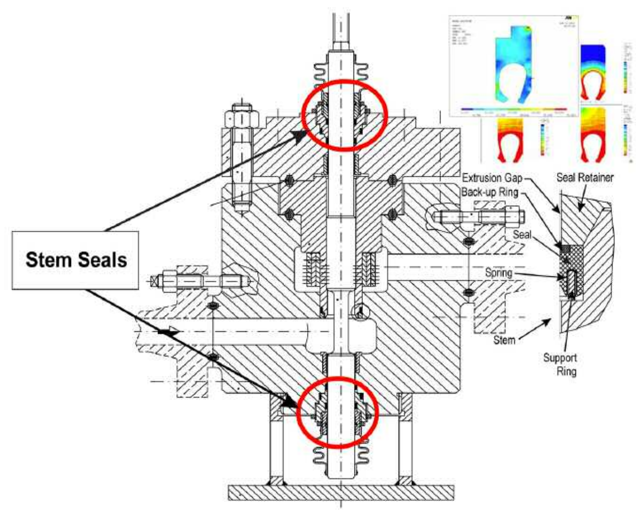

Figure 9. Antisurge Valve Stem Sealing Technology Challenges.

A comprehensive antisurge valve stem seal R&D plan commenced in 2001. The program was completed about two years later and consisted of the following major efforts:

- Selecting a well-proven seal type resistant to ED
- Deeply involving the stem seal manufacturer and a nonmetallic material expert consultant in the actual design analysis process
- Conducting nonmetallic material lab tests to verify time and temperature dependent material properties
- Performing FEA of seal designs to verify extrusion characteristics and estimate gas diffusion rates
- Conducting lab tests to verify ED immunity
- Defining leakage expectations and acceptance values

- Defining appropriate and practical quality requirements for gasket and antisurge valve manufacture
- Preparing and demonstrating antisurge valve and stem seal assembly procedures
- Building a full-scale prototype antisurge valve to verify leakage rates and mechanical wear; static and dynamic testing under the full range of pressure conditions, and thermal transient closely simulating the operating conditions, including at least 2000 full stroke cycles.

The R&D effort accomplished the following targets:

- Completed an FEA that confirmed the antiextrusion capability of the back-up ring design
- Lab results provided an estimation of gas diffusion leakage.
- Analysis and lab tests confirmed immunity to ED damage.
- Developed designs that reduced the risk of seal damage during installation through chamfering/radiusing of seal and mating surfaces
- Developed a specific valve and seal assembly procedure
- Gathered precise data on stem seal leakage performance over the full range of pressure and temperature conditions under both static and dynamic cyclic conditions
- Defined quality requirements for seal dimensions, seal materials, and valve dimensional control/manufacturing

The final stem seal design was subjected to many shop tests. A unique lubrication injection system for the seal area was ultimately developed to ensure the long-term reliability of the stem seal components. The grease lubricant was subjected to fluid compatibility testing to ensure against degradation of critical properties after long-term exposure to Tengiz-like process operating conditions. Autoclave testing with H_2S was part of the lubricant evaluation program. Ultimately, the final design included multiple backup safety features to ensure safe, reliable operation.

Pressure Safety Valve Seals

Typical high pressure safety valves (PSVs) have both metallic and nonmetallic components. Field experience with PSVs in high pressure injection service in Venezuela's PIGAP I injection facility showed continuing leakage problems. The technology gaps that existed in 2000 included:

- No successful PSV history in highly sour service at high pressures.
- Potential fatal flaw design reliance on O-rings; O-rings likely to cause leaks due to ED and/or inadequate low temperature material properties below 32°F (0°C).
- Variable quality of the cast PSV valve bodies.

Similar to other SGI R&D efforts important elements of the PSV R&D work included extensive design evaluation teamwork involving a PSV supplier and an elastomeric material expert consultant, selection of the best materials, and lab testing of all materials by autoclave exposure and ED testing using sour gas similar to SGI service.

Six fluoroelastomer O-rings, a PTFE blow down seal, and a PTFE nozzle seal were extensively lab tested with exposure to methane test gas containing 17 percent H_2S and 4 percent CO_2. These tests were conducted over the full range of SGI pressures representing plant blow down conditions. Following each test each seal was closely inspected and then quartered for an internal inspection. Findings from the PSV R&D lab tests and evaluation effort showed that:

- If temperatures were too high, O-rings fail from explosive decompression.
- As temperatures drop, the stiffness of O-ring materials increases (similar to the cause of the Challenger disaster); temperatures must be kept at 32°F (0°C) or warmer to prevent leaks.
- Critical O-rings will swell during plant blow down with the potential to allow continuous sour gas release to atmosphere during a subsequent PSV actuation.

As a result of the R&D finding, pilot valve design PSVs for SGI high pressure stages were rejected. High integrity, quick acting valves on separate and redundant control were selected instead. For the lower pressure SGI stages conventional spring-actuated valves represented an acceptable choice.

VALUE IMPROVING AND BEST PRACTICES AND CRITICAL DESIGN STUDIES TO MITIGATE RISKS

Various value improving and industry best practices, together with critical design studies, were performed during the design phases of SGI. The SGI project incorporated these practices to ensure the reliability and safety of the new facility. Value improving practices (VIPs) were activities that resulted in significant added-value to the project when they were applied in either the decision making or execution phase. Best practices (BPs) were activities that the general industry agrees adds value to projects.

Major technical study efforts were also applied in the SGI surface facilities. Examples included thorough injection compressor rotordynamics/stability evaluations, process system dynamic simulations, failure modes, and effect analyses, and reliability, availability, maintainability efforts. In addition, many similar studies were carried out for the oil field reservoir portion of SGI.

Below is a brief description of some of the major surface facility SGI practices and studies, all of which were focused on mitigating the risks associated with the SGI application.

Preliminary Hazards Review

The objective of this study was early identification of major hazards, roadblocks, and precautionary measures as well as to provide design guidance to address identified hazards. A formal review process was followed involving end user and EPCm contractor engineering personnel, end user operations representatives, and key supplier personnel. These reviews used a process flow diagram as the lead document. Utilities were not addressed in depth during this review but were later discussed in detail during formal hazard to operations (HAZOP) reviews.

Process Hazard Assessment

The process hazard assessment (PHA) process was used to identify hazards and risks associated with SGI development and by application of mitigation measures, to eliminate or reduce the risks to an acceptable level. The range of studies and activities conducted on the SGI project was extensive. The process followed and the follow-up procedures were robust. Reviews were conducted over a two-year period and involved a wide range of disciplines. PHA included the following activities:

- Control objectives analysis: A rigorous process control review to enable development of the control system design
- Shutdown objectives analysis: A rigorous review of the safety shutdown system to confirm the control system design basis
- Electrical HAZOP: A detailed and formal review of the electrical systems, identifying hazards and operability issues
- Safety integrity level study (SIL): Identifying safety critical functions and assigning loop integrity levels based on failure on demand consequences of trip functions
- HAZOP studies: Rigorous line-by-line analysis to determine hazards associated with deviations from normal operating conditions

and the ability of the design to respond safety. These studies, conducted in dual languages (English and Russian), also considered the operability and maintainability of the plant, covered both SGI Stage 1 and Stage 2 designs, vendor packaged equipment, and all significant design modifications.

Management of Change Procedure

A formal management of change (MOC) procedure was applied to all changes to systems for which a HAZOP review had been completed. Items that require revised or additional HAZOP review due to a change were identified at the time the change occurred and underwent a further HAZOP review. All tie-ins or modifications to existing Tengiz facilities were also included in the MOC procedures.

Safety System Functional Analysis

A safety system functional analysis was completed for SGI on-plot and off-plot facilities. This was a formal roundtable review during which hazards and associated risks were identified. Once a risk was identified, a SIL was assigned. The SIL defined the level of performance of the safety function needed to achieve the desired safety objective. The higher the SIL, the more available the safety function needed to be. Subsequently, operating and maintenance procedures were developed to reflect the requirements of the safety system. The procedures addressed the specific need for functional testing as part of the SIL classification.

Other Studies

In addition to reviews, studies, and assessments mentioned above, other safety-related VIPs were used for the SGI surface facilities including:

- Constructability reviews (ongoing event for safety and SIMOPS activities).
- Controls objectives analyses.
- Reliability modeling.

Failure Modes and Effects Analysis

Unlike root cause failure analysis (RCFA), which is used to analyze failures after the fact, failure modes and effects analysis (FMEA) was selectively used for SGI designs as a systematic process to identify potential failure modes and effects before failures occur. The defined maintenance philosophy for SGI involved performing FMEA. The intention was to define the maintenance strategies for equipment and components. These activities were deployed in the SGI maintenance plan, which resulted in an optimization of tasks and intervals and reduction of unnecessary maintenance interventions, while ensuring that all maintenance added value while maximizing system availability.

CRITICAL PROTECTION SYSTEMS FOR RISK MITIGATION

The SGI facilities incorporated several protection systems such as flare and relief systems, fire and gas detection systems, H_2S monitors, process gas moisture analyzers, and O_2 analyzers. Because of the toxicity of Stage 2 operations, these systems were particularly critical to SGI and were given very thorough attention in the design phase.

Flare Systems

The flare system designed for the SGI facility was sized for the maximum flare rates for both SGI Stage 1 and SGI Stage 2 operation for either sweet or sour gas flaring. The flare header collects releases from equipment vents, PSVs, and blow down valves and routes them to the flare knockout drums in which any liquids are separated. The flare tip was designed to keep the Mach number below 0.5 during the highest flaring rate and the flare knockout drums were sized to hold cryogenic fluids formed by the highest pressure releases into the flare system.

The flare stack was designed to meet local regulatory tip velocity criteria and to be smokeless during nonemergency flaring cases below a Mach number of 0.2. The flare header system was constructed from stainless steel to withstand the cryogenic temperature that could occur as a result of expansion from the maximum pressure of over 9000 psi (620 bar) to near atmospheric conditions.

Relief System

Pressure safety valves are the primary source of over pressure protection within the SGI facility. PSVs are provided where equipment or large volume sections can be blocked-in in the case of either a blocked outlet or fire relief. In hydrocarbon service all relief valves in SGI have a 100 percent permanently connected spare. The main and spare relief valves are provided with key interlocks to enable safe removal on line. All relief valves in hydrocarbon or sour service relieve to the flare header.

On the third stage of the injection compressor discharge where the relief pressure is in excess of 9000 psi (620 bar), a high integrity pressure protection system (HIPPS) was provided. This initiates blow down of the surface facility process system and shuts off fuel to the compressor driver. As mentioned earlier, PSVs were not used in this high pressure portion of the process because it was not possible to design or manufacture a relief valve capable of the large instantaneous pressure drop across the valve and still maintain the integrity of the valve.

Gas Detection

During SGI Stage 1, gas detection was provided to detect flammable concentrations of sweet natural gas to all areas of the plant and facilities. Location of the gas detectors was based on the health, safety, and environmental (HSE) studies, operator experience, and at locations where equipment failures were considered high risk. In addition, gas detectors were provided within air intakes of turbine drivers and building heating, ventilation, and air conditioning (HVAC) intakes.

During the conversion from Stage 1 to Stage 2 sour gas operation additional H_2S detectors are provided in locations similar to the Stage 1 combustible detectors. The H_2S detectors are provided with two alarm set points, 7 ppm and 14 ppm. These are provided to give low and high alarms and as an input to the voting system for executive actions via the emergency shutdown system.

Aspirating detector systems are provided for the detection of flammable and toxic gases and smoke in air streams such as HVAC systems and compressor air ducts. The aspirator units sample the air streams and pass the sample across the detectors housed in cabinets.

In addition to combustible and toxic gas detection, monitors were provided for the presence of hydrogen within the battery rooms. CO_2 detectors and O_2 deficiency detectors are provided in the off-plot building to monitor air quality when the building is being used as a shelter-in-place.

Fire Detection

Fire detection devices are located throughout the SGI plant to detect the presence of flame, smoke, or heat as determined by the hazard. The detector types used included single frequency infrared flame detectors, rate of rise heat detectors, linear wire heat detectors, and particle smoke detectors.

MOISTURE AND H_2S MONITORING AND O_2 ELIMINATION

Selection of materials for the SGI application depended critically on the level of moisture present during any operating or idle plant condition. The combination of H_2S and CO_2 in the process gas creates potentially severe corrosion and cracking problems.

Excessive moisture also creates a potential hydrate problem. Controlling O_2 in the sour process gas was important in order to avoid sulphur formation, particularly at high pressures. Although the metallurgy selected for SGI was conservative, it was dependent on reliable moisture protection. The project team focused significant attention on reliably monitoring process moisture, H_2S and O_2 and then selecting appropriate materials that avoided adding undue complexity during field construction and subsequent plant maintenance.

Moisture Analyzers

Moisture analyzers were provided to detect the presence of moisture in the feed gas to the SGI plant. The analyzers were based on a triple redundant format because the presence of moisture in the feed gas was identified as a safety critical issue. Excessive moisture, in combination with H_2S and elevated pressures, could adversely impact the injection machinery train as well as initiate very high corrosion rates within the piping. SGI installed moisture analyzers for protection in the following areas:

- Within the feed gas supply downstream of the site battery limit valve for SGI Stage 1
- Within the fuel gas conditioning unit at SGI Stage 2
- On gas supplies from other existing Tengiz plants

SGI systems were designed to control moisture to conservative levels during SGI Stage 1 and Stage 2 operation as well as during plant commissioning. Details of each phase of operation are as follows.

SGI Stage 1

Process gas is sweet natural sales gas from the existing Tengiz plants that had been dried by molecular sieve and passed through a cryogenic facility. This gas contains less than 1 ppmv water and therefore poses no potential corrosion or hydrate problem. Triple redundant moisture analyzers located on the inlet of the injection compressor were designed to trip the compressor if moisture levels exceeded approximately 25 ppmv.

SGI Stage 2

The sour process gas of SGI Stage 2 operation is dried with an acid resistant molecular sieve that reduces sour gas water content to 1 ppmv or less. Two moisture detectors located at the outlet of the molecular sieve unit are provided to indicate moisture levels and alarm if the water content exceeds approximately 10 ppmv. A triple redundant moisture analyzer at the inlet of the injection compressor will trip the compressor if the moisture at that point exceeds approximately 25 ppmv. Moisture trip points are based on the controlling water dew point in the process. Settings are automatically adjusted in the control system based on ambient temperatures in order to reduce inadvertent shutdowns due to drifting moisture readings.

Commissioning

During initial Stage 1 commissioning and during conversion to Stage 2 operation, drying procedures were used to purge and dry hydrotest water and moisture from all systems. Drying procedures included pigging followed by purging with warm, dry air and/or nitrogen. Manual methods were used to test for moisture. A limit of approximately 1 ppmv was used as an acceptance basis for systems prior to being allowed to start up the injection facility.

H_2S Analysers

Analysers were provided to monitor the presence of H_2S in the sweet gas feed supply in SGI Stage 1 and the fuel gas supply in SGI Stage 2. These H_2S analyzers were integrated into the injection gas analyzer package. They were located downstream of the injection plant battery limit valve and upstream of the SGI Stage 1 booster injection compressor suction vessel. These were supplemented by existing H_2S analyzers in the sales gas supply line from existing Tengiz plants. In addition, an analyzer was provided within the vent gas recovery ejector feed gas line to monitor any breakthrough H_2S by means of the compressor seals or vents. For SGI Stage 2 operation an additional analyzer was located in the fuel gas supply line. This analyzer is supplemented by the existing sales gas H_2S analyzers. The resulting design provides significant redundancy.

O_2 Elimination

Elemental sulfur can have a drastic negative effect on both corrosion and cracking of metallic materials. Sour gas and O_2 quickly forms elemental sulfur and water, two aspects that can cause significant corrosion problems. The potential result is equipment damage, plugging, and loss of production.

The only significant source of oxygen contamination in the SGI process is the nitrogen used for buffer gas in the injection compressor DGSs. This nitrogen contains approximately 0.5 percent oxygen and leaves the compressor system through the dry gas seal vent connections. The DGS vent gas is then compressed and mixed with the injection compressor gas turbine fuel gas. By using this approach, the oxygen-bearing gas is prevented from being used elsewhere in the SGI process. In normal operation this design approach essentially eliminates the possibility of the formation of elemental sulphur within SGI due to oxygen contamination in the compressed gas.

The SGI plant commissioning procedure included the step of displacing all nitrogen from sour gas containing systems before sour gas was introduced. Again, this step prevents the oxygen in the nitrogen from forming elemental sulfur. SGI uses manual tests to check for oxygen in purged systems before sour gas is introduced.

Avoiding Inhibitors in Injection System

The SGI plant design avoids both the use of methanol for hydrate protection and the use of corrosion inhibitors. Methanol could lead to moisture breakthrough from the molecular sieves, sieve damage and replacement, and extended downtime. Use of corrosion inhibitors could lead to operational difficulties in the seal gas system and shorten the life of molecular sieves that provide important moisture protection for the process. Elimination of inhibitor injection points within the SGI plant also eliminated the potential for inadvertent introduction of O_2 into the SGI process. Upstream processes feeding SGI were also specifically designed to avoid any methanol and corrosion inhibitor injection.

MATERIALS SELECTION

General Concept

Metallic and elastomeric materials selection for SGI was set by sour gas handling consideration of the Stage 2 operation. Stage 1 operation on sweet natural gas posed no unique problems and generally was not a metallurgical concern.

The normal design basis for SGI is a dry plant. This means that wall loss corrosion of carbon and low alloy steels is not a significant problem. Lab tests indicated that many wet upset incidents could be tolerated before wall loss corrosion became a concern. Even so, a 0.12 inch (3 mm) corrosion allowance was used. Even more important is the operational imperative that dry operation is necessary to prevent hydrate formation at high pressures and that moisture cannot be present in the compressor suction system.

Sulfide stress cracking (SSC) can occur in minutes if a susceptible material under sufficient stress is exposed to wet sour conditions. Any wet upset in a normally dry sour gas plant could cause rapid cracking. To mitigate risk, the SGI project anticipated that wet operation may occasionally occur by accident even though triple redundant monitoring and conservative molecular sieve features were provided. SGI decided to use materials that would not result in cracking in the event of an instant of wetness. If there is a wet upset by accident, all the carbon steel equipment and piping were designed to assure hardness control and stress control to assure cracking would be prevented. One example was the decision to post weld heat treat buried injection pipeline welds to minimize residual stress. Stress analysis in general was much more extensive on this project than is typical for compression plants.

A further conservative approach was used in the materials testing program for SGI. Tests were usually conducted at conditions much more severe than actual process conditions. The result was that materials that were ultimately selected had a higher level of H_2S and CO_2 tolerance without any change to materials or increased risks. The only selection that came close to a limit was the Alloy 825 used in the process gas air coolers.

SGI used extensive material quality control (QC) and quality assurance (QA) steps. This applied to both metallic and nonmetallic materials. Positive material identification was applied to all pressure retaining components. A project specific QC procedure was developed and applied to all nonmetallic components, materials that historically are loosely controlled. These steps help assure that only material meeting design specifications actually were installed up in the equipment and systems. It was another important step to reduce the risk of failures and incidents.

Metallic Materials

A great deal of metallic materials research was conducted for the SGI Stage 2 design. The H_2S partial pressure reaches about 1450 psi (100 bar) in the third stage injection compressor discharge. A level this high is not seen in any other plant in the world. As a consequence, the choice of suitable metallic materials is greatly reduced from those used in more conventional projects. For SGI, a mandatory basic requirement was set that all materials needed to meet the National Association of Corrosion Engineers (NACE) Standard MR0175. It was recognized that entire material classes allowed by NACE MR0175 are not suitable for highly sour service. A few additional classes were also unacceptable because of the extreme H_2S partial pressures in the SGI Stage 2 application. Metallic materials allowed for SGI are summarized below:

- Carbon and low alloy steel that met NACE requirements were used. Process pipe was pipeline strength grade X60. This turned out to be problematic because of the very thick wall required for the 10,000 psi (690 bar) pressure rating. High carbon equivalents and microalloy levels lead to welding problems that were only overcome by heat-by-heat review of composition and specially crafted welding procedures. Additionally, it was found that low temperature toughness degraded as thickness increased. As a result, heat tracing and insulation were required to assure prevention of brittle fracture. Future plants will likely use a different material for process piping because of these problems.

- Steels such as 4130, 8630, 2-1/4Cr were applied. NACE requires that these steels contain 1 percent Ni or less. SGI generally adhered to this requirement. One exception was the compressor shafts that were fabricated from American Iron and Steel Institute (AISI) 4340. The reasons for this specific material selection are described in the compressor materials section below.

- Nickel base alloys where Ni content is 38 percent or more and Mo content is 2.5 percent or more that met NACE requirements were used. This included grades such as 825, 725, 718, and C276. All such grades that needed to be welded needed to be weldable without creating sensitization. X750 was not permitted.

- Cobalt base alloys that met NACE requirements were incorporated in the design. Elgiloy and MP35N were common cobalt-base alloys used for high strength springs.

- Martensitic and duplex stainless steels as well as copper base alloys were banned from the SGI plant. Type 316 stainless was only permitted for use as ring joint gaskets.

Nonmetallic Materials

The use of nonmetallic materials proved to be an extremely important issue to SGI. The desirable seal properties of elastomeric materials for the SGI application included ED resistance, chemical resistance over the full range of process conditions, low temperature sealing capability, and general reliability against seal leakage (meeting minimum leakage standards). Previous plant experience demonstrated that SGI would have a narrow selection of O-ring materials to choose from, especially in high pressure sections of the plant where H_2S and CO_2 were present in the gas stream. Elastomeric material choices evaluated by SGI are shown in Table 7.

Table 7. Elastomeric Materials Considerations for SGI Stage 2 Application.

Material	Consideration
EPDM	• Has great explosive decompression resistance • Can not take exposure to any oil
NBR (Buna-N)	• Can not take exposure to H_2S (quickly hardens)
HNBR	• Can take some H_2S but not the amount present in SGI • Can suffer from explosive decompression at SGI pressures
Viton	• Explosive decompression-resistant versions extrude at SGI compressor discharge temperatures and swell at lower temperatures • Becomes stiff between 0°C (32°F) and -20°C (-4°F). • Will rapidly degrade if exposed to methanol hydrate inhibitors or some types of amine corrosion inhibitors
Aflas	• Testing showed significant compression set and loss of sealing as well as excessive stiffness at temperatures colder than 0°C (32°F)
Chemraz and Kalrez	• Only work at elevated temperatures • Extremely expensive

Because of the above limitations one general conclusion made early in the design phase of SGI was to avoid use of elastomeric O-rings to the greatest extent possible. The alternative selected was energized Teflon® lip seals. Energized Teflon® lip seals were used extensively for valve stem sealing. Most valves were made in accordance with the wellhead standard API 6A PSL4 PR2.

Injection Compressor Materials

Injection compressor materials are summarized in Table 8. These are not stainless steels and will suffer general corrosion if not preserved and used under dry conditions.

Table 8. Second & Third Stage Injection Compressor Materials Selections.

Compressor Component	Material	Comments
Outer Casing & Cover	American Society for Testing & Materials Standards (ASTM) A182 F22 Modified	
Inner Casing & Diaphragms	ASTM A182 F22 Modified	
Ring Joint	AISI 316	
Impellers	ASTM A182 F22 Modified	Heat treated. Hardness < 237 HB
Balance Drum & Sleeves	ASTM A182 F22 Modified	
Shaft	AISI 4340	Low stress (< 10 % Minimum yield strength)
Labyrinths & Honeycomb Seals	Avional 14	Equivalent to ASTM B247 AL 2014
Keys	C45	Carbon steel with 0.45 % C. Hardness 230 to 260 HB
Head Cover Seal	Modified Teflon	Back-up ring material used is carbon fiber-filled PEEK
Head Cover Seal Spring	Elgiloy	Hardness = 51 HRC
Screws Exposed to Process Gas	Inconel 718	

The material selected for shafts was AISI 4340. Fatigue and finite element modeling were performed to verify that corrosion fatigue would not cause a problem. Stresses were found to be under 10 percent of the material's minimum yield strength in regions of the shaft that might be wetted. Full surface penetrant inspection was added to assure no significant surface breaking defects were present as a crack initiator. Shafts were so thick that more than 1 percent Ni had to be added to the low alloy chemistry to achieve through-thickness hardenability. Very strict QC requirements were added to shaft fabrication to assure properties were well-controlled. These included double heat treating to assure no untempered martensite or retained austenite was present.

Worldwide experience in high pressure applications indicated that impeller cracking due to welded fabrication was a fairly widespread problem. The SGI impellers were fabricated using an electro discharge machining process that avoided the need for any welding. Dye penetrant inspection was used to assure no crack initiators were present. Stresses in the SGI impellers are considerably higher than in the shafts. Detailed FEA were performed for all impeller geometries, with special focus on the more highly stressed, localized area in the region of the inlet vane-to-cover juncture. Impellers were heat treated right to the limit for sour service. As a precaution NACE testing was performed to assure the material would not crack at the maximum stress levels. Results showed the threshold stress for cracking was higher than the actual applied stress.

COMPRESSION TRAIN DESIGN

Selection and Application

Starting from the selected concept of sweet gas injection first, then sour injection, the design of the machines was developed. The main concept applied in selecting the machines was to minimize the modifications needed to adapt the compressors from SGI Stage 1 to SGI Stage 2 operation. Compression duty for the rated SGI Stage 2 conditions is summarized in Table 9.

Table 9. Compression Duty Performance for Sour Gas Conditions.

		1st Stage	2nd Stage	3rd Stage
	Compressor Model	BCL405/B	BLC304C	BCL304/D
Suction	Weight Flow Nm^3/hr (MMSCFD)	261.3 (234.1)		
	Molecular Weight	25.04		
	H_2S Content	Max. 17 %		
	Suction Pressure bara (psia)	58.5 (848)	194.9 (2827)	386.1 (5600)
Discharge	Discharge Pressure bar (psia)	196.9 (2856)	388.2 (5630)	622.7 (9031)
	Speed rpm	9965		
	Power @ Gas Turbine Shaft kw (hp)	31364 (42,060)		

SGI Stage 1 condition is characterized by 180 MMSCFD (200 Nm^3/hr) reinjected flow in the design condition while SGI Stage 2 is designed to reinject 275 MMSCFD (307 Nm^3/hr) gas both at a 9040 psi (623 bara) final discharge. The train is driven by a model Frame 5-2D gas turbine coupled to the compressors through a gearbox. It can be operated from 70 percent up to 105 percent of the nominal speed. The 105 percent speed condition of SGI Stage 1 equates to 11,200 rpm and 10,590 rpm for SGI Stage 2 operation. A schematic of the train arrangement is shown in Figure 10.

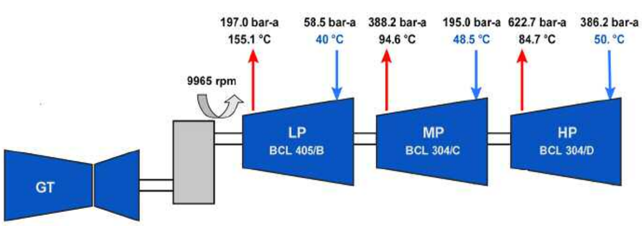

Figure 10. Tengiz Injection Train Arrangement.

Design of the three compressors was developed in such a way that the change from sweet to sour conditions could be managed through a simple replacement of the three compressor bundles and gearbox rewheeling (to adapt the speed ratio). Casings as well as shaft ends (bearings, DGSs and tertiary seals, and couplings) remain the same for the two operating conditions.

Key Design Features

During the early phase of the project the most significant areas of risk were clearly identified and the R&D project was developed in such a way to fill and to close the existing technology gaps. The main areas of risk identified were:

- Sealing concept and design (shaft and casing).
- Compressor rotordynamics (high density conditions).
- Rotating stall.
- Compressor materials.
- Train behavior (both in normal and transient conditions).

For each of the above areas special R&D, computational analysis or testing effort was devoted. In addition to these efforts, the JV partners conducted a technical design audit employing long-established procedures and methods on several of the main areas of turbomachinery risk identified above. The scope of this independent design audit is shown in Table 10.

Table 10. Turbomachinery Train Design Audit Scope.

Type of Analysis	1st Stage	2nd Stage	3rd Stage
Thermodynamics	✓	✓	✓
Rotating Stall	✓	✓	✓
Lateral critical speed	✓	✓	✓
Rotor stability	✓	✓	✓
Morton Effect	✓	NR	NR
Torsional critical speed	NR		
Materials	NR	NR	NR
Thrust Analysis	R	R	R
Gear tooth analysis	NR	NR	NR
Gear lateral analysis	NR	NR	NR
Gas Seals	NR	NR	NR
Key: ✓ = Independent analysis conducted R – Review vendor analysis NR – Not requested			

Compressor Sealing

Shaft Sealing

As schematically illustrated in Figure 10, the high pressure (HP) compressor (denoted as model BCL304/D) is equipped with special piping connecting the area in front of the DGSs inboard ring with the suction of the medium pressure (MP) compressor body (model BCL304/C). This connection is designed to lower the pressure in front of the HP body DGS to about the same level in the MP body (except for the pressure losses inside the pipe). The actual operating pressure of the HP compressor DGSs is close to 2830 psi (195 bar) instead of almost 5650 psi (3906 bar) without this connection.

This choice was made at the time of the R&D phase of the SGI project as a point of risk mitigation. At that time in the year 2000 the highest operating pressure for a tandem DGS was 5080 psi (350 bar) while suction pressure of HP body of Tengiz was 5660 psi (390 bar).

One of the main uncertainties that the project team had to face in defining the DGS design requirements was the plant settle-out pressure (SOP). A conservative estimation in the early phase of the project was 6160 psi (425 bar). This pressure was the result of extrapolation from observed operation at similar worldwide high pressure injection plants.

Starting with this SOP estimation an R&D program commenced with two major DGS suppliers. Reliable shaft sealing was such a critical issue to the success of the SGI project that a parallel seal R&D path was considered an essential risk mitigation step. This R&D program focused on development of a DGS capable of 6160 psi (425 bar) in both static and dynamic conditions. This design pressure guaranteed the full capability of the DGS to operate both in normal plant operating conditions as well as plant transients (mainly settle-out) even if the recycle line in between HP and MP compressor body remained open. Both DGS suppliers were required to develop a DGS design that was able to fit inside the same seal cavity, with the same shaft diameter and bearing span, and obviously under the same operating conditions. This provided a significant dimensional challenge but was necessary in order to allow the plant and compressor train design to proceed in parallel with the DGS R&D effort. This parallel design approach allowed only limited margins of adjustment to the DGSs along their developmental path.

As a risk mitigation it was decided to use the fuel gas to feed the inboard of the DGS. As a further precaution the DGS specification required that the DGS be capable of safely operating with sour gas as sealing gas. This requirement necessitated fabrication of DGSs with special materials suitable for the environment. The cartridge was fabricated from Inconel®. Other components embedded in the seal faces were replaced because they were not tolerant to the aggressive environment. As a part of this R&D effort the two DGS suppliers (denoted supplier A and B) were required to manufacture a prototype seal and to test it statically and dynamically at full pressure.

In parallel to the DGS R&D effort a DGS support system was developed. In particular the system had to be designed to provide sweet clean gas in all the plant operating conditions including transients. It also needed to be compatible with operation of either of the two DGS suppliers' designs. The SOP condition was one of the most demanding conditions in terms of pressure (resulting from the dynamic simulation study). During the development of the project more refined analyses were completed in order to improve the accuracy of the SOP prediction. For the final plant configuration the estimate was 4790 psi (330 bar). The seal gas compression system was designed to reach this level of pressure. The type of machine chosen to provide this duty was a lubricated reciprocating compressor.

Casing Sealing

High casing sealing pressures and the presence of significant amounts of toxic H_2S gas necessitated focused attention on casing sealing. No gas release to atmosphere was allowed. During the R&D phase, activity was focused mainly in two areas:

- Improving the compressor head seal design in order to minimize any gas release
- Developing sealing redundancy and an intrinsically safe design that would be able to guarantee that even in the presence of leaks the gas cannot be released to the atmosphere

The first point was addressed by a three party joint R&D effort involving the machinery OEM, the head seal supplier, and an external specialized R&D laboratory. The first task was to develop a new design concept for the seal using the best of the experience of the supplier. The concept selected was a double ring configuration consisting of a primary soft energized Teflon® seal and a secondary ring fabricated from a stiffer nonmetallic material that was designed to prevent extrusion under any extreme operating or environmental condition. Schematics of the concept are shown in Figure 11.

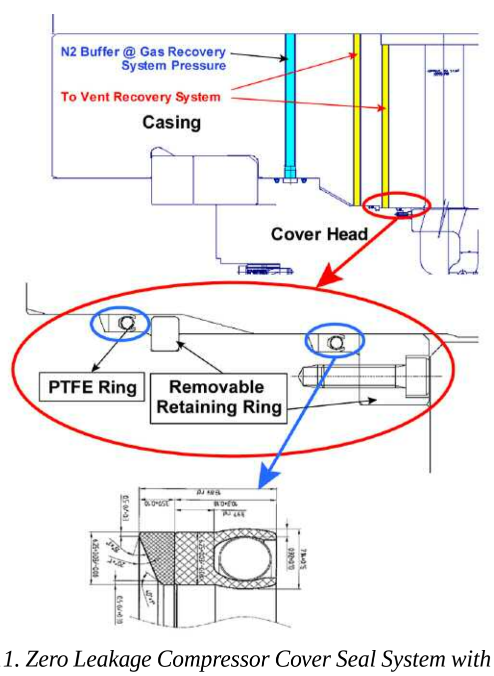

Figure 11. Zero Leakage Compressor Cover Seal System with Details of Head Gasket Design.

Under the action of internal casing pressure the primary ring forces the secondary ring to slide over the cover head surface and then close the gap between the cover head and the casing thus minimizing the risk of the Teflon® seal to extrude. Evaluation of the effectiveness of the design concept was initially carried out using the most advanced FEA tools together with computational fluid dynamics (CFD) tools. The model was able to predict the deformed shape of the two gaskets under the action of the pressure and temperature loads, the leakage due to the diffusion characteristics of the materials, and the behavior of the seals after cyclic loading from three to five years of operations.

The input parameters of the materials such as diffusion properties in the presence of CO_2 and H_2S and time dependent material characteristics were all measured in the external R&D laboratory. Once developed, the concept was applied to a Venezuelan injection compressor installation that suffered seal reliability problems. The same analysis was repeated. Results showed that the new seal design concept was able to achieve essentially zero leakage. Once installed the design demonstrated its effectiveness and good agreement with the predictions.

The intrinsically safe seal design concept was jointly developed by the compressor OEM and the end user. This design consisted of a redundant configuration capable of containing possible leakage coming from the failure of one of the seals without releasing it to the atmosphere.

The concept that was developed consisted of two fully redundant seals, each consisting of a primary and a secondary ring and with special ports on the back of each seal. Ports on the back of each seal had two functions:

- Detection of any release of gases (through a gauge or a flow meter)
- Direction of the eventual leakage to plant piping connected to lower pressure side of the plant so that the gas could be recompressed

As part of the risk mitigation it was decided to instrument the port on the back of the primary sealing element with a flow meter during the full density test carried out at the compressor OEM's shop. During this test it was possible to measure the leak over the full range of operating pressures. Test results confirmed theoretical predictions.

On the outboard side (OB) of the last gasket a 100 psi (7 bar) nitrogen injection was provided in between the two gaskets in order to guarantee that in case of system failure only the nitrogen would reach the atmosphere. The complete casing sealing system was called the zero leakage system as shown in Figure 11.

Rotordynamics

The combination of high pressure and high molecular weight results in a very dense gas for the SGI compressor. In particular, the HP stage of the compressor train (BCL304/D) is required to operate with an average density of 25 lb/ft^3 (400 kg/m^3).

DGS cavity design was heavily influenced by rotordynamics considerations. Cavity dimensions were axially reduced compared to the OEM's standard designs applied up to 1999. Another constraint applied to the project was to apply the same DGS cavity and DGS design for both the MP and HP compressors.

During the early conceptual phase of the project studies were carried out to determine the feasibility and risks of designing a two body compression train. The final decision was to use three compressor bodies to avoid further pushing the technology envelope and introducing significantly more risk to the risk that already existed.

Figure 12 shows the location of the three compressor bodies on the Fulton diagram (Fulton, 1984). In this diagram the horizontal axis represents the average inlet-outlet density, while the vertical represents the flexibility ratio, the ratio between maximum continuous speed, and the first critical speed at infinite rigidity of the bearings. Comparison with past experience clearly shows how the density level for Tengiz, even if referenced, is close to the boundary of industry experience. As widely known throughout the compression industry today, high density results in high forces coming from the seals (both direct stiffness and cross-coupling) and potential instability problems.

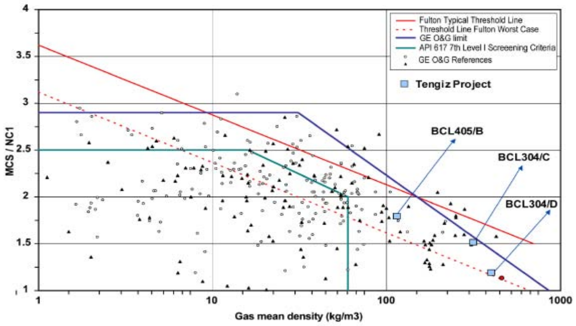

Figure 12. SGI Compressors on Fulton Diagram.

In order to avoid stability problems it was critical in the early design stage to account for all the effects during the stability analysis and to introduce features to improve the damping of the system. Each of the three compressors was designed first to ensure reliability from a mechanical point of view, i.e., low vibrations and reliable behavior over the entire operating range. This was achieved by working on two major design aspects:

- Maximizing rotor stiffness
- Minimizing or mitigating the effect of destabilizing forces due to the gas

Maximizing rotor stiffness was achieved by limiting the number of stages (in particular for the HP bodies) and therefore the bearing span as well as maximizing the shaft diameter through the use of scalloped shaft configuration. The high stiffness results in high first critical speeds, high rotor damping, and the capability to withstand destabilizing forces.

To minimize the major destabilizing forces in the Tengiz design a great deal of attention was focused in the selection and design of the seal on the balance drum of each machine. All of the three machines were equipped with honeycomb balance drum seals. This component, if properly designed, is able to provide effective improvements both to the shaft stiffness and to damping.

From the earlier work of Camatti, et al. (2003), the stiffness and damping properties of the honeycomb type seal are strictly related to the shape of the gap. Diverging shapes can easily lead to negative honeycomb stiffness and result in a net depression of the first critical speed of the rotor. Special attention was given to guarantee the control of the honeycomb gap shape along the entire operating range. Honeycomb analysis and design was part of a learning process during the SGI project. Much of the present state-of-the-art knowledge resulted from work done during this project.

Lateral analysis of each machine was carried out for all the worst operating conditions. Each component was modeled in detail. In particular the shape of the gap between the honeycomb and the balance drum was calculated by means of FEA by taking into account the casing, the discharge diaphragm, the seal, and the balance drum. Figure 13 shows a detail of the model from the MP compressor.

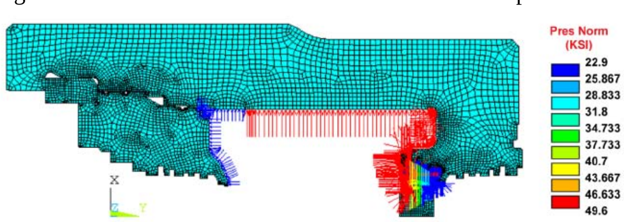

Figure 13. FEA Model Used to Predict Honeycomb Gap Operating Shape.

For each of the worst operating conditions a sensitivity analysis of logarithmic decrement of the rotor versus honeycomb gap shape was calculated. Figure14 shows the results of an analysis for one of the operating points. The shape of the honeycomb was ultimately chosen in order to guarantee enough margin from the cliff of the curve under all the conditions as well as to ensure, on the other side, the best effect in terms of damping. Once the operating shape was defined, the cold shape of the honeycomb could be easily derived from FEA. Once the rotor was finalized a full API report was produced.

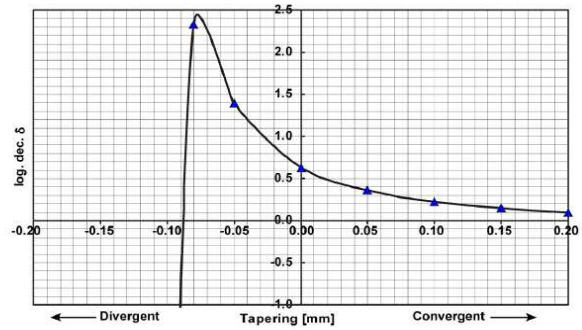

Figure 14. Sensitivity Analysis of Logarithmic Decrement Versus Honeycomb Gap Shape.

In addition to the standard API analysis a rotor response analysis in the full density operating condition was completed for all three machines. The scope of the analysis included identification of possible critical speeds inside the operating range once the compressors were started in pressurized conditions, a common plant situation. Due to the strong effect of the honeycomb, first critical speeds of all three machines in pressurized conditions were found to be significantly different compared to first critical speeds calculated in no load conditions. In particular for the MP compressor (BCL304/C), the first critical appeared in the lowest part of the operating range although it was quite damped. For the HP compressor (BCL304/D) the first critical speed in full load condition was found to be above the maximum continuous speed. For the low pressure (LP) compressor (model BCL405/B) the effect was significantly lower. The first critical speed remained well below the minimum operating speed. Based on the results of the analysis it was decided to carry out a pressurized unbalance test of the MP compressor (BCL304/C) in order to highlight the eventual presence of the critical speed.

Rotating Stall

Rotating stall is one of the most significant phenomena that is known to become increasingly more severe with the increase in the discharge pressure of a centrifugal compressor. For typical reinjection machines commonly characterized by relatively low flow coefficients, this phenomenon tends to be important inside the free vortex diffusers, in particular at the entrance. Once the compressor is approaching the left part of its operating range usually the last stages tend to operate in such a way that the discharge flow angle from the impellers tends to reduce. Rotating stall phenomena in free vortex diffusers appears once the actual diffuser inlet flow angle is lower than a critical flow angle.

Correlations exist from literature to predict the critical flow angle. One of the most widely used approaches to predict the critical flow angle is the Nishida-Kobayashi (N-K) criteria. Reference to this formula can be found in Fulton and Blair (1995). For each of the Tengiz compressor designs the free vortex diffusers have widths that were defined on the basis of the following:

- N-K criteria
- CFD analysis
- Model testing activity done on similar stages of the MP compressor configuration
- Parametric model testing activity on last stage configurations.

CFD analysis of each stage was carried out including the upstream return channel, impeller, and free vortex diffuser. For the last stage the effect of volute flow distortions as outlined by Baldassarre and Fulton (2007) was included.

N-K criteria and CFD analysis showed a good level of mutual matching. The experimental activity completed on last stage configurations as summarized by Baldassarre, et al. (2002, 2003), allowed assessment and confirmation of the effect of volute flow induced distortions to the entrance of the diffusers and finally their effect on critical flow angles for different diffuser lengths. The same activity allowed optimization of the inlet shape of the diffuser. Experimental validation showed improvements of 5 percent or more going from standard to optimized pinch shapes.

All the above analysis resulted in avoidance of all rotating stall problems both during the shop test phase as well as in plant operation on site.

Train Behavior During Normal and Transient Conditions

Two sets of studies were performed at system level: one including the entire system, the second considering the seal gas system. The focus of the first study was to predict the trend of process parameters in both static and dynamic conditions as well as the behavior of each component. The study was aimed at identifying the SOP conditions and relevant time trend in order to have the right data to size the different plant components including separators, coolers, valves, piping, and compressors.

In particular, process pressure and temperature trends on the scrubbers allowed prediction of the amount of liquid formation inside these components and the required sizing to remove all the liquids. Another important outcome of the study was identification of the trend of the pressures and flows during both plant start-up and trip conditions and avoidance of compressor surging.

COMPRESSION TRAIN SHOP TESTING

Testing Concept

The concept applied to machines and component testing was to start from the individual component level and then assemble these components as an entire train. This approach was envisioned as a way to mitigate potential problems on site where they would prove to be much more difficult to resolve. Each of the major components was individually tested at the OEM facilities prior to a final full load string test at the compressor OEM's facility. Shop tests were developed and carried out to verify both mechanical and thermodynamic behavior in both sweet gas and sour gas operating conditions.

Component Testing

Major machinery and major support auxiliary systems were subjected to individual testing. The model Frame 5-2D gas turbine was subjected to a thermodynamic performance and no load mechanical test in order to measure the power and to verify the mechanical behavior. The gas turbine auxiliary skid was also functionally tested. The main gearbox (used to increase the speed from the gas turbine to the compressors) was no load, full speed tested at the gear manufacturer's shop under vacuum conditions according to the API 613 requirements in order to verify the mechanical behavior. Both the sour and sweet wheels were subjected to this shop testing. DGSs were exhaustively tested over the full range of pressures and speeds at both seal suppliers' shops prior to being shipped to the compressor's OEM shop.

Centrifugal compressors were tested using standard API mechanical running tests and American Society of Mechanical Engineers (ASME) PTC10 Type II thermodynamic tests. Both the sour and sweet bundles underwent these same tests always using the same compressor casings. The MP compressor (BCL304/C) was also subjected to a pressurized unbalance test. Unbalance was placed on the balance drum.

Compression Train Shop String Test

The train string test at the compressor OEM's shop test facility in Florence, Italy, was arranged in two phases:

- First phase with sour bundles and gear
- Second phase with sweet bundles and gear

This sequence was selected so that the final tested equipment could be shipped to the field ready for initial operation under sweet gas conditions. String testing was arranged in such a way to test both the machines (gas turbine, gear, compressors), gas turbines inlet and exhaust systems, major auxiliaries, condition monitoring system, and the DGS system. The job unit control panel was included in the test as well. The unbalance test on MP compressor (BCL304/C) was carried out during the initial phase of the sour string test.

The string testing procedure was initially divided into three separate days of testing for both the sweet and sour configurations. Several start and stop cycles and full speed, full pressure, full power operations were included in the test procedure in order to verify the behavior of each component (compressors, gearbox, gas turbine, DGSs, compressor head seals, and auxiliary support and control systems).

Each compressor was equipped with the standard ASME PTC10 Type 1 probes plus additional probes to measure the eventual leakage from the head gaskets. Special instruments (accelerometers and temperature probes both on the faces and the stationary parts) were included inside the DGSs in order to monitor their behavior. During the string testing both the full power and the full density condition (inlet/outlet densities) were reached.

The string test highlighted some important problems that if discovered at the Tengiz site could have results in lengthy delays. The two most significant issues identified were:

- Gearbox issue: Gearbox vibration problems mainly related to the coupling of torsional and lateral natural frequencies. This problem was primarily important in the horizontal direction where the high speed rotor was exhibiting larger vibrations. The problem was solved by changing the type of bearing from a three pad design to a four pad design. The four pad design configuration introduced additional stiffness in the direction that required more.

  A problem of gear teeth scoring was also discovered. Inspection and a thorough investigation revealed that the scoring phenomenon was due to a poor lubrication of the sliding surface of two corresponding teeth (one on the pinion and one on the low speed shaft). The problem, clearly confirmed by the use of a camera, was due to a lack of alignment between the oil injectors and the mating teeth. By a simple realignment of the oil injectors it was possible to completely eliminate the problem.

  Inspection also revealed a crack on one gear tooth. This problem was related to a forging defect coming from the heat treatment.

- DGS issue: At the end of the sour full density string test the first failures of the DGSs started to appear with DGS supplier A's seals. The first failures appeared in June 2003. As summarized in Figure 15 most incidents were catastrophic failures of the OB seals. The problem took several months before the real root cause of the failures was found. More extensive DGS instrumentation was found to be essential to the understanding of the failure sequence. With adequate instrumentation the root cause was found to be a result of low speed contact between the rotating and stationary rings of the OB seals during train coastdown. This contact led to a progressive deterioration of the seal face surface roughness and a consequent increase in the seal face liftoff speed. This increase led to more and more severe contact at higher speeds during subsequent train coastdowns. Finally, cyclic contact led to the initiation of heat cracks on the seal faces. Start-up of the train to the full speed with the seal face cracks eventually resulted in catastrophic failures. As shown in Figure 16 the spike in OB temperature at low speed (below 100 rpm) confirmed the failure mechanisms, i.e., low speed face contact due to insufficient film stiffness. While the DGS supplier A continued efforts to solve the identified face contact problem, DGSs from supplier B were installed in the string test loop.

Configuration	Date	/B DE	/B NDE	/C DE	/C NDE	/D DE	/D NDE
Sour Stage 2	16/06/03	0205-0190	0205-0191	0207-0358	0207-0359	0210-0504	0210-0505
Sour Stage 2	17/09/03	0207-0360	0207-0361	0204-0177	0204-0178	0207-0358	0207-0359
Sour Stage 2	23/09/03	0207-0360	0207-0361	0204-0176	0204-0178	0207-0358	0207-0359
Sweet Stage 1	23/01/04	0207-0360	0207-0361	0207-0358	0207-0359	0204-0177	0210-0505
Sweet Stage 1	13/03/04	0207-0360	0207-0361	0210-0504	0204-0178	0204-0176	0110-0390
Sweet Stage 1	14/07/04	0205-0190	0205-0191	0207-0358	0210-0505	0204-0177	0207-0359
Sweet Stage 1	24/09/04	0205-0190	0205-0191	0204-0177	0210-0505	Not Present	Not Present
Sweet Stage 1	05/10/04	0205-0190	0205-0191	Not Present	Not Present	Not Present	Not Present

No face/seat contact marks
Touch
Catastrophic failure
Not Inspected

Figure 15. DGS Failure Events.

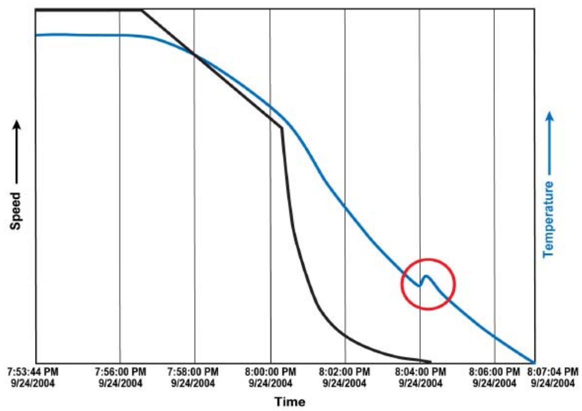

Figure 16. Temperature Spike of Outboard Thermoelement During Coastdown.

Because of lengthy delays in completion of the string testing program due to DGS problems and the need for the machinery in the field to allow plant construction, all equipment was shipped to site. In parallel, a comprehensive program was formulated to continue DGS testing and verification of a satisfactory and reliable design. A decision was made to complete a final seal endurance test using a replica of the Tengiz MP compressor casing while incorporating the job MP bundle. A model PGT25 shop gas turbine was used as a driver. Endurance testing was conducted at Massa, Italy.

Before starting the testing campaign the endurance test rig was validated with the original DGSs from supplier A in order to prove that they also would fail in this new loop configuration. The result was achieved during the first three days of testing. During this test it was also possible to confirm the RCA of the problem, i.e., the failure was caused by OB face contact at low speed leading to surface deterioration and increase in the liftoff speed finally leading to catastrophic failure. This exponential effect is shown by Figure 17 where spikes in temperatures tend to appear at higher speeds after each coastdown and with larger amounts of energy involved.

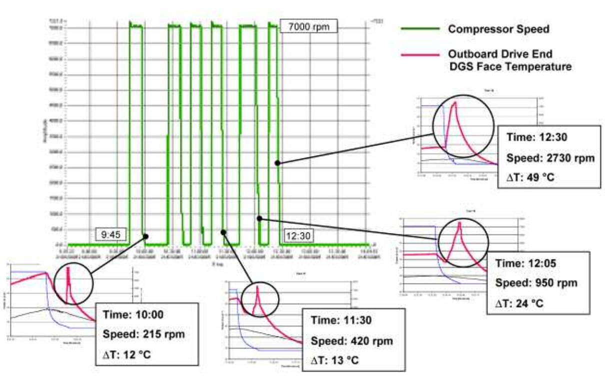

Figure 17. Face Contact Speed Increases with Each Run.

After validating that the endurance test rig could produce a failure with supplier A's seal, DGSs from supplier B were tested first, followed by redesigned DGSs from supplier A. Both supplier B's and supplier A's seals successfully passed all endurance testing at Massa. Supplier A's new design incorporated different materials on the stationary face of the OB. Materials were selected to mitigate the worsening of the surface finish during low speed operations.

Endurance testing was arranged in such a way to have the first three days of test using the same procedure applied during the entire Tengiz train in Florence. This step was included to make sure the new single casing test rig could replicate the earlier failures in the entire train. Once there was confidence that the endurance test loop could produce the failure, and then DGSs were subjected to 13 days of endurance tests. The entire endurance test period incorporated a total of 140 hours of operation and 40 starts and stop cycles. The DGSs were instrumented with thermoelements on the OB faces in order to detect early signs of face contact.

After a thorough assessment between the Tengiz Field JV partners and the compressor OEM, it was decided to initially use DGSs from the supplier B during initial SGI Stage 1 operation.

FIELD TESTING AND INSPECTION

Field Factory Acceptance Test

In order to fully prove out the DGS solution on all three compressor stages, a field factory acceptance test was conducted at the SGI plant site, in compliance with an agreement made prior to releasing the train for shipment from the compressor OEM's factory to site. The field test was essentially a duplication of the shop testing conducted in Florence, with specific requirements to assure similar conditions that were present at the time of the prior DGS failures. The requirements included a sequence of starts, speed step changes, speed holds, idle holds (hot and cold) followed by restarts, together with both pressurized and depressurized shutdowns. Given that the planned three-day test program was originally intended to demonstrate satisfactory mechanical and thermodynamic performance, repeating the program in the field afforded the opportunity to reaffirm both performance areas at the installed site and under sweet gas (SGI Stage 1) conditions. The test was conducted in March 2007. It used the sweet gas bundles and gearing together with the second DGS suppliers' seals. This test followed about 1500 hours of initial SGI Stage 1 operation. The effort was fully supported with end user, EPCm, compressor, and DGS supplier representation.

Testing was completed within four days and revealed performance results that were very consistent with those obtained in Florence, both mechanically and thermodynamically. The train mechanical performance was satisfactory up to maximum continuous speed, even with an intentionally elevated lube oil temperature of 149°F (65°C).

Using primarily remote field instrumentation and site gas analysis, thermodynamic performance was also found to be satisfactory and consistent with that measured in the Florence shop tests. These results confirmed that there were no apparent changes in the train behavior that might have resulted from shipment, installation, or commissioning activities.

Compressor Shaft Sealing Tests and Inspections

All three compressor casings were equipped with seals from the seal supplier B. While the HP seal design, common to both the MP and HP stages, had undergone testing in a compressor casing in both Florence and Massa, the DGS supplier B's LP design was being operated in this train for the first time. Key to proving out the seals on site was completing the predefined testing sequence with seals having accumulated at least 40 start/stop cycles and 140 hours. Upon completion of the test sequence, the counts on these parameters were 57 and 1530, respectively, with the excess cycles and hours resulting from initial SGI Stage 1 operation that preceded the test. Compliance with the test procedure was stringent, meeting or exceeding 14 of 17 parameter requirements, with only minor deviation in the three remaining parameters.

The seals performed satisfactorily through the entire field factory acceptance test. Although not caused by the seals, daily drainage of the seal cavity areas was the only operational issue. As previously mentioned, this activity was not unexpected at the time of the test. A small amount of primary seal hang-up observed on one of the HP compressor seals during sweet gas operation appeared to fully resolve itself over the course of the testing. Successful completion of the field testing provided additional evidence of an effective solution to the earlier DGS failures in the shop and demonstrated both reliable short-term operation of the LP seal design and trouble-free operation of DGSs in the full train.

A team composed of representatives from the end user, EPCm, and both the DGS and compressor suppliers conducted a detailed inspection of all six seals according to prewritten procedures. The inspection showed DGSs to be in generally good condition, although contaminated on many surfaces with at least a film of oily liquid. Varying degrees of solids contamination was also observed in most of the seals. This solids contamination was considered to be the cause of some accelerated wear of two dynamic sealing elements, most pronounced in the HP compressor seal that had exhibited the hang-up behavior mentioned above. With the possible exception of combining with solids in the worn dynamic sealing element locations, liquid contamination did not appear to cause any damage to the DGSs despite having a significant bonding effect on the faces during the disassembly. Results of the post-test inspections were reviewed and used to develop improvements to the seal system, DGSs, and compressor designs for SGI Stage 2 operation.

During the plant shutdown to carry out the detailed DGS inspections, the gearbox was also inspected and found to be in very good condition, confirming the effectiveness of the final fixes of realigning the lube oil spray bar and providing proper heat treatment of the gear rotors.

OPERATIONAL EXPERIENCE

Sweet Gas (SGI Stage 1)

The nominal two year run time planned for sweet gas operation was significantly reduced as a result of facility construction and commissioning delays and complications. Total injection train run time was limited to roughly 2700 hours (about 3½ months) of noncontinuous operation, and included almost 90 start/stop cycles. A significant portion of run time was in injection plant recycle operation. Injection volumes ranged from 40 to 165 MMSCFD (45 to 184 Nm^3/hr) at pressures typically around 7540 psi (520 bar). This reduced operating time still afforded a mentoring period in which to expand the operating personnel skill set for the more complex SGI equipment compared to that of the basic oil/gas separation plants already in operation in Tengiz. In addition, during the latter half of the SGI Stage 1 operating period, operations and maintenance were conducted as if the plant were operating with sour gas in an effort to help validate procedures and further prepare personnel.

The initial portion of SGI Stage 1 operation had an expected number of problems. These were limited primarily to instrumentation and control system "tuning,' including reconfiguration of the original distributed control system (DCS) and gas turbine interface starting logic. Overall, the injection train and support equipment exhibited satisfactory mechanical and thermodynamic performance. While lower than expected discharge pressure requirements allowed for potentially higher injection rates, limited wellhead availability precluded this opportunity during SGI Stage 1. Although not a significant impact to the train reliability or even the sweet gas operating time, observed liquid contamination of the seal gas did require root cause analysis and design change activity during the SGI Stage 1 operating period. The root cause effort led to additional design change-related work scope expansion during the plant conversion from Stage 1 to Stage 2.

Liquid Contamination of Seal Gas

A small degree of liquid contamination of the seal gas was expected by the very nature of delivering an external supply of dense phase seal gas using a lubricated reciprocating compressor. This issue was initially identified during concept selection in 1999. It was addressed during the project design by selection of synthetic lube oil and a relatively conventional coalescing filter system. A limited amount of early laboratory testing showed negligible absorption of a synthetic polyalpha olefin (PAO) based oil with polyisobutylene (PIB) additives. Therefore, this oil was selected for cylinder and packing lubrication of the seal gas compressors. A system test of the seal gas supply system was not conducted at the factory to better assess the performance of the system with this oil. During the Florence and Massa reinjection compression train tests, however, significant liquid contamination of the factory test loop by the supplied seal gas was observed. This prompted efforts to better understand and control the liquid contamination issue. These efforts included an FMEA study. This study identified a higher likelihood of even the PAO-based oil being absorbed in the gas than initially anticipated. However, the study was clearly complicated by a lack of test data and limited simulation capability to quantify the behavior of synthetic compressor cylinder lube oil and gas mixtures at these pressures. Contingency plans were developed. These included design and construction of a site pressure letdown test rig to determine how much liquid dropout would occur at the seals, operating procedure modifications, and evaluation of alternative synthetic polyalkylene glycol (PAG) oils. Attention to the issue was temporarily reduced in priority during the busy SGI Stage 1 construction and commissioning phase once field testing of the seal gas revealed no appearance of oil or other liquids at the pressure letdown test rig. Unfortunately, the combination of test rig hardware layout and the test procedure likely led to a false negative result. The field test indicated condensation of oil estimated to be in the gas at a concentration of about 30 ppm.

The discovery of unexpectedly large quantities of oil in the seal gas system prior to extended SGI Stage 1 operation resurrected the issue. The discovery triggered an extensive RCA effort and quickly led to the practice of regularly draining the seal cavities of all six compressor seals at both the seal gas inlet chambers and the primary vent chambers. While operational changes significantly reduced the amount of oil from that of the initial discovery, the regular draining practice was continued because the small but consistent quantities of oil found were considered sufficient to flood the respective chambers well within the expected operating window. Successful operation of the seals with regular drainage intervals, along with the lack of a confirmable and timely solution to the contamination problem led to design changes in the seal cavity drain system. These changes were intended to ensure safe drainage capability suitable for SGI Stage 2 operation. This drain system change was considered to be a temporary solution until a system for delivering drier seal gas could be progressed to a high level of confidence.

The RCA effort during Stage 1 operation prompted more thorough and extensive testing of oils at Tengiz conditions. Testing confirmed that typical methods of lube oil separation, including coalescing and charcoal filtration, were essentially ineffective at the 4790 psi (330 bar) seal gas delivery pressure, especially since most of the oil was expected to be absorbed in the gas phase. As shown in Figure 18, the estimated dew point curve of the oil and gas mixture also appeared to preclude other gas treatment strategies such as heating, particularly at about the 2900 psi (200 bar) sealing pressure of the MP and HP compressors. While the most recent lab testing has shown significantly less absorption of PAG-based oil in a simulation gas at Tengiz conditions, the testing is not accurate enough to verify zero absorption and a clear ability to eliminate the seal cavity drain practice and system. It is important to recognize that had Tengiz plant operation begun directly with sour gas (SGI Stage 2), the drain facilities for these chambers would have been blinded and banned from use during normal operation. Long-term solutions to this issue are being studied for potential future implementation including changing the seal gas compressor cylinder lube to a PAG oil, alternative compression designs, and better suited oil separation systems.

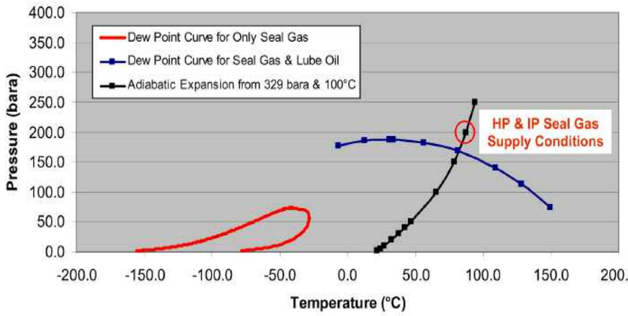

Figure 18. Dewpoint Characterization of Seal Gas Contaminated with Cylinder Oil.

Sour Gas (SGI Stage 2)

Sour gas operation at Tengiz began in 2007. The process experienced normal startup availability issues related to inadvertent shutdowns and ancillary equipment malfunctions. However availability is improving rapidly as expected. As demonstrated during Stage 1, injection pressure requirements were significantly lower than the design of 9000 psi (620 bar), with compressor discharge pressures in the range of 7610 to 8340 psi (525 to 575 bar). Flow rates normally ranged from 90 to 179 MMSCFD (100 to 200 kNm^3/hr). The lower operating rates and winter conditions resulted in unexpected intermittent condensate formation in the injection gas supply line to the SGI plant. However, the SGI plant slug catcher protected the injection compressors from any immediate damage.

No significant compressor train problems were encountered when restarting the injection train following the compressor bundle and gear set change out for Stage 2 operating conditions. However, during the disassembly of the MP and HP compressors, pitting in the head gasket groove sealing surface was discovered. During Stage 1 operation no prior detection of compromised sealing was evident. The pitted surface condition was determined to be a result of corrosion triggered by moisture in the gasket groove area. With only limited ability to improve the gasket sealing surface condition at site, a more sophisticated leak-off venting and monitoring arrangement was installed during the Stage 1 to Stage 2 conversion. Leakage measurement testing was conducted to assure gasket behavior was not significantly compromised.

To date, the injection train has demonstrated good reliability. Inspections conducted on the seal gas compressors during the Stage 1 to Stage 2 conversion revealed problems that have resulted in lower than expected reliability. These high pressure reciprocating compressors were not considered to be exceptional with regard to the industry experience envelope. Problems included accelerated piston ring wear with unusual nonuniformity, premature piston wear in the piston ring grooves, and cylinder liner coating failure. All three of these problems were observed on the third stage of the seal gas compressor. This stage consists of one, single-acting cylinder. A full RCA and solution for the piston ring wear is still pending. The piston problem is being addressed with a material surface upgrade. The liner failure is considered to be an isolated manufacturing issue.

CONCLUSION

Success of high pressure SGI was largely attributable to very early team efforts in the conceptual phase of the project to both identify and address required areas of new technology. The team included the JV partners as well as the compressor supplier. Once technology gaps were identified, a comprehensive R&D program commenced early on and was later completed in time to provide the needed technology solutions. Much of the R&D effort focused on dependable gas sealing both in the turbomachinery train and critical components within the plant. Redundant sealing designs and alternative supplier designs were effectively employed to reduce project risk. Fundamental compressor layout and design choices were later proven flawless by extensive testing.

Faults in the original DGS design became apparent during full load testing of the compression train. Timely shipment of the compression train was allowed by development of an alternate compressor for testing the DGSs until reliability was ultimately proven.

Safe sour gas injection with 23 percent H2S is now proven technically ready to the 10,000 psi (690 bar) pressure level. A strong emphasis on safety, setting high standards, attention to detail, persistence, involvement of the right people resources at the right time, as well as extensive shop testing, proved to be key elements to achieving this technology status today.

NOMENCLATURE

AGI	= Acid gas injection
AISI	= American Iron and Steel Institute
API	= American Petroleum Institute
ASME	= American Society of Mechanical Engineers
BP	= Best practice
CFD	= Computational fluid dynamics
DCS	= Distributed control system
DGS	= Dry gas seal
ED	= Explosive decompression
EPCm	= Engineer, procure, construct, and manage contractor
ESD	= Emergency shutdown
FEA	= Finite element analysis
FMEA	= Failure modes and effects analysis
HVAC	= Heating, ventilation, and air conditioning
HAZOP	= Hazard to operations
HSE	= Health, safety, and environmental
HIPPS	= High integrity pressure protection system
HP	= High pressure
HPT	= High performance team
JV	= Joint venture
km	= Kilometer
LP	= Low pressure
MOC	= Management of change
MMSCFD	= Millions of standard cubic feet per day
MP	= Medium pressure
Nm^3/hr	= Normal cubic meters per hour
NACE	= National Association of Corrosion Engineers
N-K	= Nishida-Kobayashi
OB	= Outboard
OEM	= Original equipment manufacturer
PHA	= Process hazards analysis
ppm	= Parts per million
ppmv	= Parts per million by volume
PSV	= Pressure safety valve
QA	= Quality assurance
QC	= Quality control
QFD	= Quality function deployment
R&D	= Research and development
RCFA	= Root cause failure analysis
scf	= Standard cubic feet
SGI	= Sour gas injection
SIL	= Safety integrity level
SIMOPS	= Simultaneous construction-operations plans
SOP	= Settle-out pressure, psi (bar)
SSC	= Sulfide stress cracking
STBO	= Standard barrel of oil equivalent
VIP	= Value improving practice

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ACKNOWLEDGEMENT

This paper is dedicated to Pier Luigi Ferrara, an eminent engineer and pioneer in the field of turbocompressors. Mr. Ferrara was instrumental in developing many of the early foundation concepts on which the Tengiz sour gas injection project was based. He was also a key member of the project management team.

The authors would also like to thank TengizChevroil and its joint venture partners Chevron, ExxonMobil, KazMunayGas, LukArco, also Parsons Fluor Daniel, GE Oil & Gas (Nuovo Pignone), John Crane, Flowserve, and Maag, and major technical consultants (ODS, MERL, NILM-OSU, and RMT) all of whom contributed in many ways to the pioneering SGI effort. Special thanks are expressed for the perseverance of the many specialists and testing engineers involved in finding the root cause of failures and developing timely and sound technical solutions to critical problems found during the extensive shop testing phase. Advancement in the state-of-the-art of worldwide sour gas reinjection capability would not have been possible without this dedication and pursuit of technical excellence.