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## 1.0 Abstract

The Midwest Geological Sequestration Consortium (MGSC), one of seven U.S. Department of Energy Regional Sequestration Partnerships, began a large scale injection of 1,000 tonnes (metric tons) per day of CO<sub>2</sub> at the Archer Daniels Midland facility in Decatur, Illinois in November 2011. This project is also known as the Illinois Basin – Decatur Project (IBDP). Trimeric Corporation had process engineering design responsibility for the compression and dehydration facility that is used to take atmospheric pressure CO<sub>2</sub> from the ADM ethanol fermentation process and deliver dehydrated, supercritical CO<sub>2</sub> to the injection well. An overview of the project design basis and the requirements that led to the selected process design is presented. An explanation of the equipment selection process is provided. An overall system design review including the multistage centrifugal blower, reciprocating compressors, triethylene-glycol dehydration system, multistage centrifugal pump and the pipeline is presented. Lessons learned during commissioning, startup, and operations to date are discussed. Future project concerns are discussed.

## 2.0 Introduction

### 2.1 Project Background

The Illinois Basin - Decatur Project is a large scale carbon dioxide (CO<sub>2</sub>) sequestration demonstration project, led by the Midwest Geological Sequestration Consortium and funded by the U.S. Department of Energy. The host site is the Archer Daniels Midland facility in Decatur, Illinois. The scope of the project is to compress and dehydrate 1,000 tonnes / day of 99% + pure CO<sub>2</sub> from ethanol plant fermenters and inject the CO<sub>2</sub> in a

saline aquifer 7,000 feet underground. Injection began in November 2011 and will continue for nominally three years until one million tonnes total have been injected. The MGSC will monitor CO<sub>2</sub> subsurface plume migration, groundwater, and surface conditions during the injection period and for three years after injection stops.

## 2.2 Process Design Basis

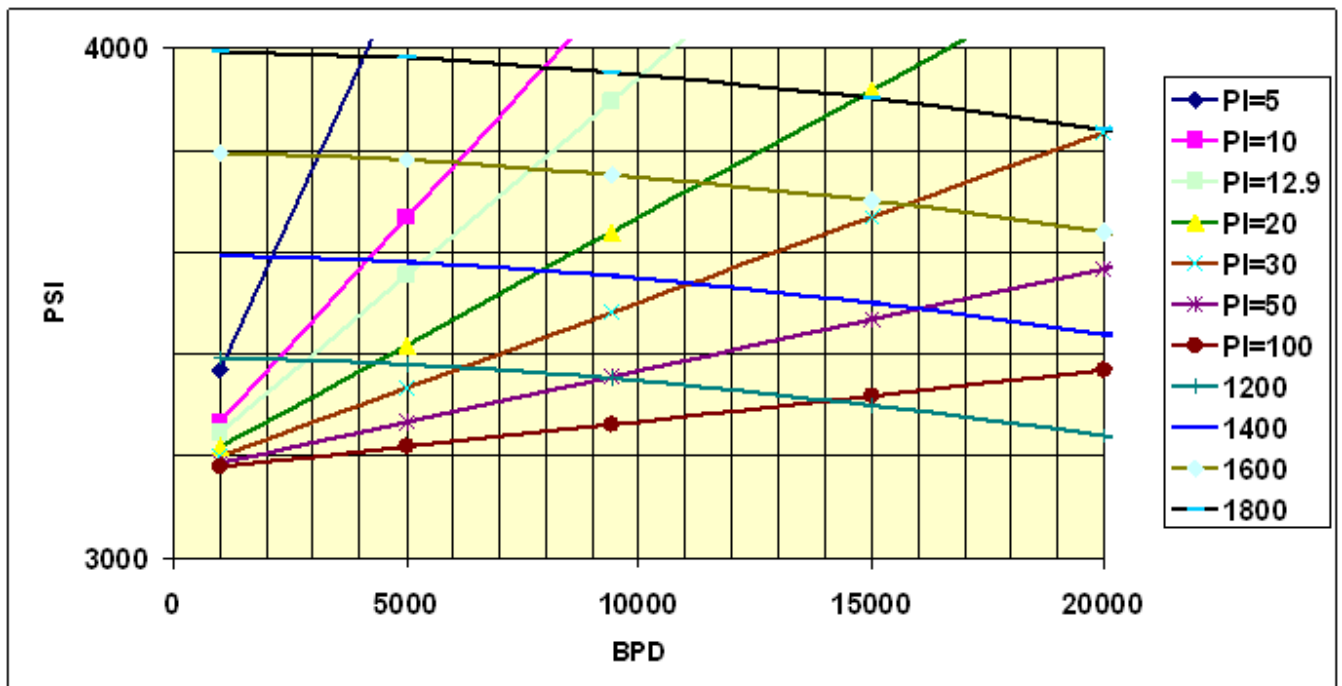
This section discusses the process design basis and related requirements for the project.

The process design basis included the functional design requirements of the surface facilities for the compression and dehydration of the CO<sub>2</sub> for injection.

The CO<sub>2</sub> flow delivery requirement was 1 million tonnes (dry basis) of CO<sub>2</sub> over a three-year period. The surface facilities were designed for 24-hour operation, with a requirement of no more than 30 days total downtime per year including both scheduled and unscheduled downtime. These requirements led to a minimum specified design rate of 995 tonnes per day for the compression and dehydration equipment. A 10% safety factor was added to the minimum specified design rate, so the target equipment design rate was specified at 1,100 tonnes per day.

The project timeline required ordering long-lead equipment items including the compression and dehydration equipment before the required surface injection pressure had been determined. The injection well had not been permitted or drilled so predictions of required surface injection pressures made by project geologists and reservoir engineers were made based on data from the nearest known well, which was some 37 miles away. The state of knowledge regarding the expected surface pressure required for injection at the time the compression and dehydration equipment was ordered was based on model

data as shown in Figure 1<sup>1</sup>. The graph shows the relationship between downhole pressure and fluid injection rate in barrels per day with an overlay of surface pressure and injectivity index curves. The injectivity index (PI) quantifies the pressure increase due to pumping a known volumetric flow rate of fluids into a formation. At a given injectivity index, the downhole pressure increases as the injection flow increases. At a higher formation injectivity index, the increase in downhole pressure is less steep with an increase in fluid flow, allowing more flow to the formation.



**Figure 1 –Downhole Pressure vs. Flow as a Function of Injectivity (PI) and Surface Pressure**  
 During initial injection into the Mt. Simon formation, it was anticipated that due to the initial requirement for displacement of water in the formation by the CO<sub>2</sub>, the injectivity

<sup>1</sup> McKaskle, RW, Fisher KS, Jones, RA, Frailey, SM., Design, Startup, and Operation of a 50 MWe CO<sub>2</sub> Sequestration System, Eleventh Annual Carbon Capture, Utilization & Sequestration Conference, Pittsburgh, PA, April 30, 2012

would resemble that of 5 to 20 PI curves and that after a large amount of water was displaced, the injectivity would follow the 20 to 100 PI curves. Based on these data, it was believed that a CO<sub>2</sub> injection rate of 1,100 tonnes per day (10,000 BPD) into the Mt. Simon formation could be achieved at startup of initial injection and at all times afterwards with compression equipment capable of operating at surface injection pressures ranging from 1,400 to 1,950 psig.

The original Design Basis CO<sub>2</sub> delivery requirements for injection rate, pressure, temperature, and phase condition are summarized in the Table 1.

**Table 1: Design Basis**

<b>Parameter</b>	<b>Units</b>	<b>Design Requirement</b>
Injection Rate	tonne / day	250 - 1,000
Injection Rate	MMscfd	4.8 - 19.0
Flow Control	% of set point	+ / - 10
Surface Pressure	psig	1,057 - 1,950
Surface Temp.	°F	88 – 120
CO <sub>2</sub> Purity	% mol.	> 99
Oxygen Content	ppm	< 100
Water Content	lb / MMscf	< 30
Water Content	ppm	< 633

It was known in the planning stages of the project that insulation of the above ground pipeline would be required to meet the surface temperature requirement of the Design Basis during cold weather.

### 3.0 Equipment Screening

A study was conducted to identify the preferred equipment configuration for this project to compress the ethanol fermenter vent stream of CO<sub>2</sub> from approximately 1 psig to a maximum of 1,950 psig at the wellhead. The goal of the study was to identify and select the equipment configuration with optimum capital costs, power requirements, and complexity for the three-year research project. It should be noted that the results of the equipment configuration evaluation are highly specific to the project requirements and may not apply to other applications where process and project requirements are different.

#### 3.1 Compression Configuration

The following is a list of the equipment combinations considered for CO<sub>2</sub> compression:

- Blower, Screw Compressors, Reciprocating Compressors
- Blower, Reciprocating Compressors
- Blower, Reciprocating Compressors, Pump
- Blower, Screw Compressors, Reciprocating Compressors, Pump
- Compression, Liquefaction, Pump

The configurations were compared using budgetary purchased equipment costs (+/- 20% accuracy) and the estimated power consumption over a three-year injection period. Each of the configurations utilizing a blower was also evaluated without a blower in order to ascertain the impact of the blower on project costs. It was found that excluding the blower from an equipment configuration significantly increased estimated purchased equipment cost of the subsequent compression equipment in all cases and by an average of 35% and increased the three-year electrical cost by an average of 4%.

Based on the budgetary equipment quotes, utilizing screw compressors for the low pressure stages of compression offered an average of 32% lower capital cost and the total estimated purchased equipment plus three-year electrical costs for these configurations averaged 12% less than configurations that did not utilize screw compressors.

Centrifugal compressors were considered in the evaluation, however; the compressor capacity required for this project was at the very low end of flow rates where centrifugal compressors are applicable. In addition, due to their limited turndown capability and longer equipment delivery times, both of which were important for this project, centrifugal compressors were not further considered.

As a follow up to the options studied above, Trimeric compared refrigeration-based CO<sub>2</sub> liquefaction and pumping approach to the compression approach for this project. The results showed that the liquefaction option had a power consumption that was 38% greater than the reciprocating compressor option. In addition, the level of dehydration required for liquefaction far exceeded the design basis and had a higher capital and operating cost than other dehydration technology that was capable of meeting the project requirements.

### 3.2 Process Cooling Options

Process cooling for this project could have been achieved by either air coolers (fin-fan coolers) or by shell and tube heat exchangers utilizing surplus cooling tower water from an existing cooling water system. From a purchased cost standpoint, the two were comparable, but further comparison of the two showed that shell and tube exchangers

with cooling water option would provide tighter process temperature control within the surface facilities equipment, achieve lower interstage and final compressor discharge temperatures on warm days, be more conducive to the planned indoor installation of the process equipment, and have a smaller overall footprint, which was critical for this installation within the existing ADM facility.

### 3.3 Dehydration

The basis for setting the gas water content specification at 30 lbs/MMscf (633 ppmv) was that it is representative of what might be specified for a commercial CO<sub>2</sub> pipeline transporting CO<sub>2</sub> for enhanced oil recovery or sequestration purposes. This level of dehydration prevents liquid water and/or hydrates from forming and helps to prevent internal corrosion of the 6,400-foot carbon steel pipeline. Triethylene glycol (TEG) and solid desiccant (molecular sieve) dehydration systems were evaluated. A TEG dehydrator will normally dehydrate a CO<sub>2</sub> stream to a water content of 7 lbs/MMscf (148 ppmv) or lower. A molecular sieve system typically dehydrates to even lower water content, typically well below 1 lb/MMscf (21 ppmv). The option of TEG dehydration was selected for this project as it provided an acceptable level of dehydration for the project requirements and provided a good safety margin below the project design basis requirements, while allowing the injection test to be conducted with CO<sub>2</sub> having a water content that is representative of what is to be expected in future commercial applications. The project requirements did not justify higher capital and higher operating costs associated with molecular sieve dehydration.

### 3.4 Equipment Selection and Design

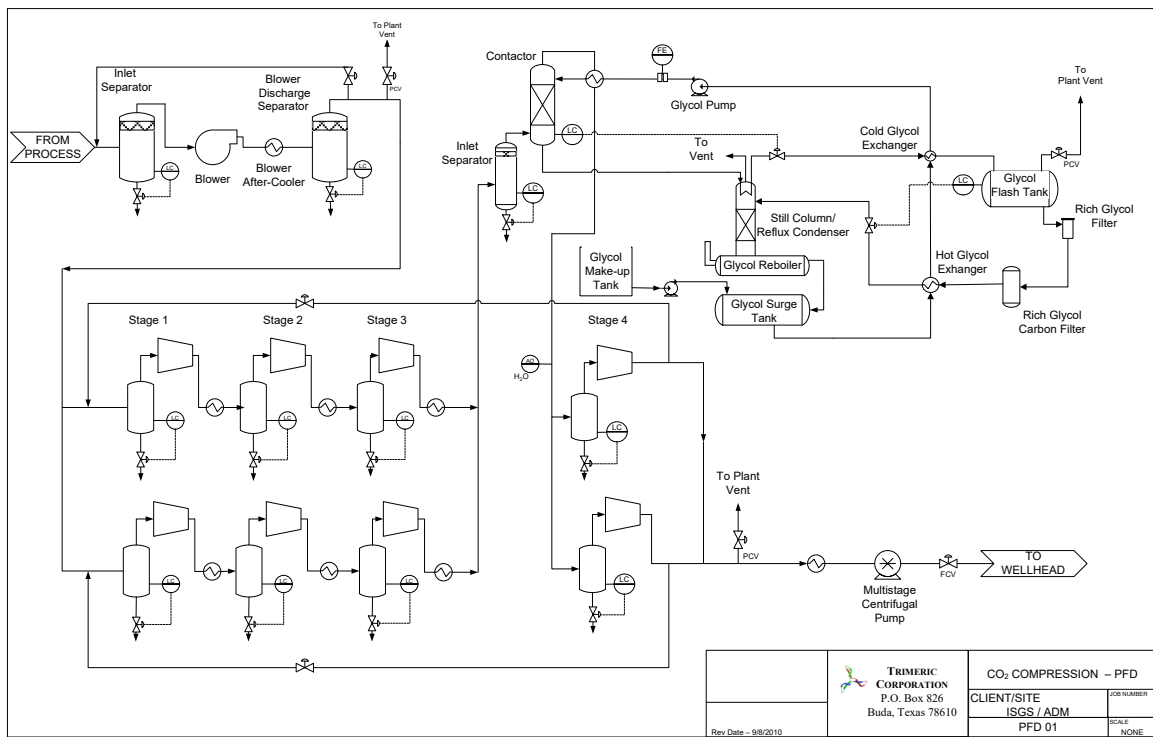
The selected compression equipment had to have a great deal of operational flexibility in order to meet the project requirements for total injection over three years and at varying injection rates across the range of possible required surface injection pressures.

The results of the equipment screening process based on budgetary quotes indicated that the compression configuration that had the lowest purchased equipment costs and three-year electrical costs was the combination of one blower, two screw compressors, one reciprocating compressor, and one pump. However, based on input from equipment suppliers during the firm equipment bid solicitation process, Trimeric and ADM concluded that the costs for the option with one blower, two reciprocating compressors, and one pump were comparable to the option that used screw compressors. The total estimated purchased equipment costs combined with three-year electrical costs for the two options were within 5% of each other for these two options. Eliminating the screw compressors reduced the overall complexity of the system and the number of large equipment skids. Therefore, the option that included a blower, two reciprocating compressors, and a multistage centrifugal pump was chosen.

The reciprocating compressors were designed to operate at a discharge pressure of 1,400 psig followed by a multistage centrifugal pump that can be used if additional pressure is needed to meet the desired injection rate. This option provided the needed flexibility for the possible range of surface injection pressures and avoided having to operate larger reciprocating compressors, designed to operate at discharge pressures up to 1,950 psig, in

a constant and significant turndown situation if a much lower injection pressure was required to meet the desired injection rate. To date, discharge pressures at or below 1,400 psig have been sufficient to meet the required injection rates.

The selected process is depicted in the Process Flow Diagram (Figure 2). Photographs of the installed blower and reciprocating compressor systems are in Figure 3 and Figure 4 respectively.



**Figure 2– Surface Facilities Process Flow Diagram**



**Figure 3 – Blower System**



**Figure 4 – Reciprocating Compressor**

The selected surface facility equipment consists of a single 1,250 hp 4-stage centrifugal booster blower that raises the CO<sub>2</sub> stream pressure to approximately 17 psig. It is

followed by two parallel 3,250 hp 4-stage reciprocating compressors that boost the pressure to approximately 1,400 psig, a TEG dehydration unit, and a 200 hp 26-stage centrifugal pump capable of boosting the pressure to up to 1,950 psig. TEG dehydration is performed between the third and fourth stages in the reciprocating compressors where water content in the CO<sub>2</sub> is at a minimum due to previous compression and cooling steps. Losses of TEG into the CO<sub>2</sub> stream would be too high at pressures after the fourth stage of the reciprocating compressors. Shell and tube heat exchangers using cooling water remove the heat of compression following each compression step, except after the multistage centrifugal pump, which adds a temperature rise of only 10 °F to 15 °F and therefore does not justify addition of a cooler after the pump.

Figure 5 shows the path of the compression on a CO<sub>2</sub> Pressure-Enthalpy Phase Diagram<sup>2</sup>. Note that the selected pressures and temperatures throughout the system remain outside the liquid, liquid/vapor, and solid/vapor envelopes, where serious operational issues could occur. CO<sub>2</sub> temperatures also remain well above 55 °F, above the minimum temperature where CO<sub>2</sub>-H<sub>2</sub>O solid hydrates can form at the process conditions for this project.

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<sup>2</sup> Pressure-Enthalpy Phase Diagram used with Permission of Gas Processors Suppliers Association

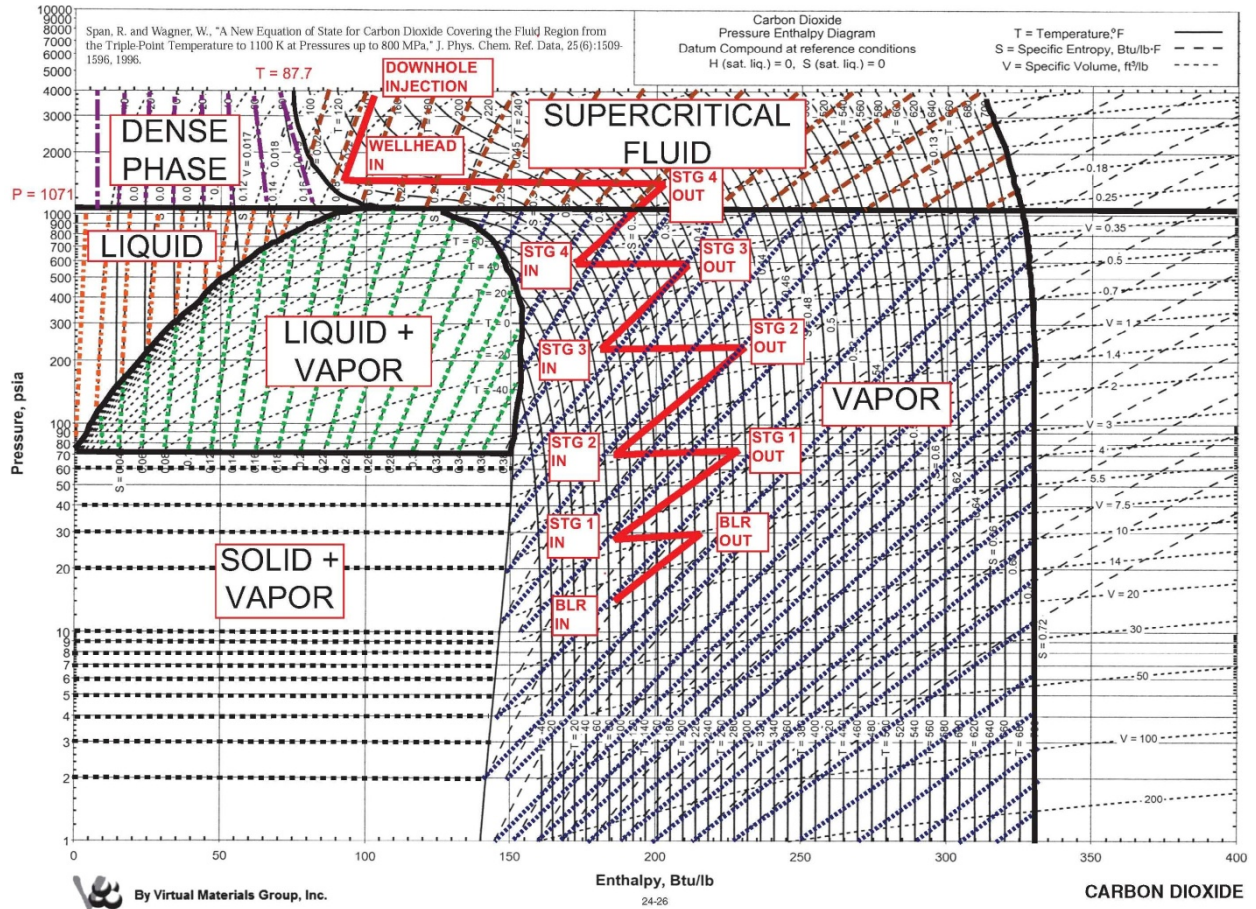


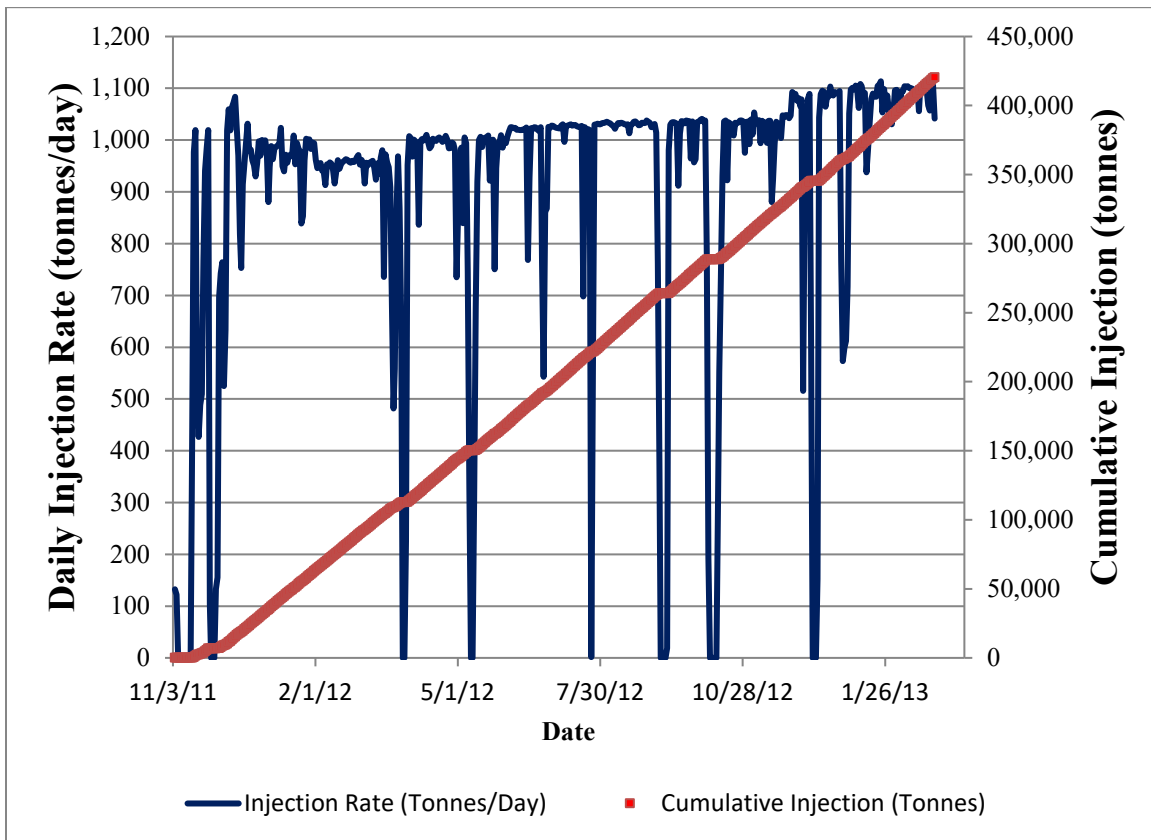
Figure 5 – Compression Path on CO<sub>2</sub> Phase Diagram

#### 4.0 Early Outcomes

##### 4.1 Injection Results to Date

The system capacity was designed for 1,100 tonnes / day, which provides a nominal 10% safety factor above the desired 995 tonnes / day injection rate point. The average injection rate during normal operations to date has been approximately 1,010 tonnes / day. Figure 6 shows the daily and cumulative injection rates for the project to date. A permit constraint that placed a lower limit on the injection rate based on the size of the orifice meter plate in use was removed in Dec. 2012. As shown in Figure 6, the injection

rate increased by about 100 tonnes / day following the removal of this administrative limit.



**Figure 6– Injection Rates through February 26, 2013**

There have been some issues that led to unscheduled downtime in addition to periodic maintenance for the compression equipment that is scheduled to coincide with ethanol plant shutdown, when possible. Main issues leading to unscheduled downtime to date are as follows:

- Blower motor failure – windings arced / phase to phase ground due to poor insulation (8 days)
- Motor soft start wiring issues (9 days)
- Cylinder lubrication issues (rupture disk and pump issues) (8 days)
- Ethanol plant outages - cooling water, power, CO<sub>2</sub> supply (3 days)
- Blower motor repair for bearing failure due to low oil level (7days)
- Compressor computer problem (5 days)

The blower motor failure occurred in early November 2011 before injection began in earnest. This was a warranty issue that was repaired by the supplier at no cost to ADM or the project. The motor soft start wiring problems also occurred during part of the commissioning effort and have not been an issue since the main injection effort started. Cylinder lube oil system rupture disks continue to cause short individual compressor outages. ADM is working with the equipment packager and the compressor manufacturer to improve the reliability of the cylinder lubrication systems.

## 4.2 Lessons Learned

### 4.2.1 Insulate Above Ground CO<sub>2</sub> Pipeline

It is common to install CO<sub>2</sub> transport piping below ground, however; since this project was installed in an existing facility, it was not practical to install the 6,400 foot, 6-inch diameter non-insulated pipeline underground. In an effort to reduce costs, the project team decided to begin operations without insulating the pipeline in order to determine if operational experience proved that insulation was necessary. During operations, ambient conditions affected the CO<sub>2</sub> temperature and therefore density at wellhead inlet, which reduced the surface pressure required for a given injection rate in colder weather. As a result, compression equipment control set points had to be modified to operate with lower discharge pressure. Furthermore, variations in ambient conditions caused undesirable variations in the measured subsurface injection pressures. Downhole pressure variations are a concern because over time, they may stress the bonding between casing and the cement in the injection well. The pipeline was therefore insulated in order to minimize ambient temperature effects on CO<sub>2</sub> temperature and density, ensure the wellhead inlet

temperature will remain above 60 °F, which is the minimum limit in the UIC injection permit, and to reduce the impact of ambient conditions on measured subsurface pressures.

#### 4.2.2 Optimize Process Controls for Upset Conditions

The initial process control strategy for discharge pressure control of the blower was inadequate in handling the gas flow when one of the two parallel operating reciprocating compressors shut down, which sometimes resulted in unnecessary shutdowns of the other compressor and the blower. A change in the process controls, where the blower recycle valve operates in addition to opening of the vent valve downstream of the blower in response to high blower discharge pressure, reduced the number of compressor and blower shutdowns that occur when one of the compressors shuts down.

Low pressure shutdowns on the suction and discharge of each reciprocating compressor stage were replaced with differential pressure shutdowns for each stage. This protects the compressor from unsafe high rod-load conditions, but eliminates unnecessary shutdowns when the suction or discharge pressure on a given compressor stage is low, but the machine is still within safe operational limits based on rod-load.

#### 4.2.3 Modify Heat Exchanger Operation for Winter Conditions

When cooling water supply temperatures are lower than design, ADM lowers the CO<sub>2</sub> discharge temperature set point in order to maintain high enough cooling water flow rates to keep the cooling water return temperatures low enough to reduce the risk of fouling and corrosion in the heat exchangers and in the cooling water return lines.

#### 4.2.4 Cylinder Lubrication Oil Can Collect in the Pipeline

During pipeline blowdown, a brown liquid substance has been observed at some of the drains. A sample of this material was collected and analyzed. The results confirmed that some compressor cylinder lubrication oil leaves the compression facility in the CO<sub>2</sub> and collects in the pipeline.

### 5.0 Future Concerns

#### 5.1 Multistage Centrifugal Pump Needs

Required injection pressures to date have not required the operation of the installed multistage centrifugal pump. The multistage centrifugal pump may be needed to meet the desired injection rate if the performance of the final cooler downstream of the compressors degrades due to fouling or other reasons. If the exchanger is fouled, warmer cooling water supply temperatures during summer months may result in a higher temperature thus lower density stream entering the pipeline. Since the pipeline is now insulated, ambient cooling will not significantly cool the CO<sub>2</sub> in the pipeline. Therefore, the multistage pump might be needed to maintain the required injection rate if performance of the final cooler degrades.

#### 5.2 Design Injection Rate vs. Actual

The injection system was designed for a total injection of one million tonnes of CO<sub>2</sub> over a three-year period. The equipment design injection rate of 995 tonnes per day for 330 days per year took into consideration the estimated amount of time when injection would not be possible due to scheduled and unscheduled compressor shutdowns, as well as external factors such as well testing, loss of utilities, and CO<sub>2</sub> source outages. During the

first year of injection following the initial commissioning phase (December 17, 2011 through December 16, 2012) there were a total of 29 days with no CO<sub>2</sub> injection. There were three planned compressor maintenance outages totaling fourteen days, four days for well testing, seven days due to an unplanned outage for blower motor repair, and four days where there was no source CO<sub>2</sub> available. From December 17, 2012 to date in the second year of injection (through February 26, 2013), there have not been any days with no CO<sub>2</sub> injection and there have been five days where CO<sub>2</sub> injection was limited due to a reciprocating compressor computer problem.

The average injection rate during normal operations during the first year of operation following the commissioning phase (December 17, 2011 through December 16, 2012) was 1,002 tonnes per day, resulting in a cumulative injection of 346,609 tonnes, which exceeds the project target of 333,333 tonnes per year. ADM was operating at reduced injection rates in the first year of injection to comply with the administrative limit on the injection rate based on the size of the orifice meter plate in use. Injection rates have increased since this limit was removed in December 2012.

The average injection rate during normal operations from December 17, 2012 to February 26, 2013 is 1,085 tonnes per day. Overall, since the beginning of injection on December 17, 2011 after completion of the commissioning phase, the average injection rate during normal operations is 1,016 tonnes per day, resulting in a cumulative injection of 420,585 tonnes in 439 days, which equates to 349,690 tonnes per year. Note that the reported cumulative injection includes CO<sub>2</sub> injected during abnormal operations and during the commissioning phase.

## 6.0 Summary

The compression and dehydration system for the Illinois Basin-Decatur Project performs in accordance with process design. The flow rate of CO<sub>2</sub> from the system that is available for injection meets the design criteria of 1,100 tonnes per day. Current performance suggests that one million tonnes of CO<sub>2</sub> injection will be completed in the nominal three-year target for this project.

A decrease in the performance of the final cooler would result in lower density CO<sub>2</sub> entering the pipeline and could lead to the need to use the multistage centrifugal pump to maintain desired injection rates in warmer weather, particularly since the pipeline is now insulated which will reduce cooling of the CO<sub>2</sub> due to heat transfer to the surroundings. Monitoring is underway to track, maintain, and improve system performance over the remainder of the injection period. Trimeric has made and plans to continue making quarterly visits to the site during the injection period of this project to review operations, to help identify process issues and opportunities for process optimization, and to support ADM and the Illinois State Geological Survey during the remainder of the injection phase of the Illinois Basin-Decatur Project.