6.0 WELL OPERATIONS PLAN
40 CFR 146.82(a)(8), 146.88-89

MARQUIS BIOCARBON PROJECT

Facility Information

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Well name: MCI CCS 3

Well location: PUTNAM COUNTY, ILLINOIS
S2 T32N R2W
Latitude: 41.27026520 N, Longitude: 89.30939322 W

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6.0 Well Operation Plan

The Well Operation Plan describes the source of the carbon dioxide (CO_2) that will be delivered to the storage site, its chemical and physical properties, flow rate, and the anticipated pressure and temperature of the CO_2 at the pipeline outlet. In addition, this section provides the monitoring that will be performed on the injection well (MCI CCS 3) to confirm that it does not provide a conduit from the storage reservoir to the above confining zone (ACZ) water sources, underground source of drinking water (USDW), or the ground surface.

Prior to operation of MCI CCS 3, Marquis Carbon Injection shall submit to the Director in an electronic form any updates to the proposed area of review and corrective action plan, testing and monitoring plan, injection well plugging plan, post-injection site care and site closure plan; or the emergency and remedial response plan, and the alternative post-injection site care timeframe demonstration submitted in accordance with 40 CFR 146.82(a), which are necessary to address the new information collected during logging and testing of MCI CCS 3 well and formation as detailed in Section 5.0. [40 CFR 146.82(c)(9)]

6.1 Operational Procedures (40 CFR 146.82(a)(10))

This section provides details on the operational design and the composition of the injection stream. Also included in this section are the procedures that will be used for the initial startup of the injection system. The operational design and procedures were developed to ensure no injection occurs between the outermost casing and the wellbore to prevent endangerment of a USDW and maintain mechanical integrity of the injection well.

6.2 Daily Rate and Volume and/or Mass and Total Anticipated Volume and/or Mass of the CO_2 Stream

The design basis is to capture and inject the CO_2 produced at the ethanol-production facility. The average CO_2 flow rate when the system is operational will be approximately 1.2 million tonnes (MT) injected over 355 days/year; this assumes 10 days/year of downtime for system maintenance. The computational model was completed for the maximum annual injection rate of 1.5 MT that would occur over 365 days and will serve as the cap for annual injection, but the actual flow rate will be based on the maximum allowable fracture pressure ([redacted]. The planned injection phase of the project is 6 years; therefore, a total of 9 MT of CO_2 may be injected over the life of the CCS 3 well for Marquis BioCarbon Project. The operational parameters of the MCI CCS 3 well are provided in **Table 6-1.**

Parameters/Conditions	**Limit or Permitted Value**	**Unit**
Maximum Injection Pressure	[redacted]	
Surface (Note 1)		psi
Downhole (top perforation)		psi
Average Injection Pressure		
Surface		psi
Downhole		psi
Maximum Injection Volume and/or Mass		metric tons/year
Average Injection Volume and/or Mass		metric tons/year
Annular System	**Pressures (Note 1)**	**Unit**
Surface Annulus Pressure Operational Parameters (Note 2 & 3)	[redacted]	psi
Maximum Annular Pressure		psi
Operational Packer Differential (Note 4)		psi
Maximum Surface Pressure Applied (Note 5)		psi

Note:

(1) The variability of the compressor could increase the pressure up to a maximum allowable wellhead pressure [redacted]
(2) The annular system will maintain wellhead pressure of the annular fluid between the tubing and long string casing within the permitted values. The annular pressure gauge on top of the annulus head tank will be monitored.
(3) See Section 4.3 for details concerning Annular Pressures and Design.
(4) When not injecting, the system will maintain a minimum annular pressure 100 psi above the pressure of the CO_2 in the injection tubing at the depth of the packer, which will be monitored by the WAMS control system.
(5) Maximum surface pressure applied is delivered from the WAMS and [redacted] the maximum injection pressure which is 90% of the fracture pressure.

Table 6 - 1: Proposed operational procedures.

6.3 Characteristics of CO_2 Delivered to the Storage Site

The CO_2 will be delivered to the well via an appropriately sized in-plant piping, and based on initial design calculations, the anticipated CO_2 pressure at the pipe outlet (i.e., at the well site) will be [redacted] average temperature of [redacted] (**Table 6-2**). Variability of the compressor could increase the pressure up to a maximum allowable wellhead pressure of [redacted] **Table 6-3** details the expected downhole pressures associated with the variations in wellhead pressure, and **Figure 6-1** graphically displays the relationship between the maximum injection pressure at the wellhead and in the reservoir (at the top perforation). At the typical temperature and pressure, the density and viscosity of the injection stream will b[redacted]

Injection Stream Parameter	Wellhead Specification
Ave Pressure (psi)	[redacted]
Ave CO_2 Temperature (ºF)	
Ave Mass Flow Rate (MT/yr.)	
Density (lb/ft^3)	
Viscosity (cP)	
Molecular Weight	

Table 6 - 2: Wellhead Injection Stream Specifications at Typical Operating Conditions

Wellhead Pressure (psi)	Reference Depth (ft MD)	Downhole Pressure (psi)	Differential from 90% Fracture Pressure (psi)
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Table 6 - 3: Wellhead pressures with the associated downhole pressure at a reference depth of planned top perforation [redacted]

Confidential, Privileged, or Sensitive Business Information

[redacted]

Figure 6-1: Relationship between maximum injection pressure at the wellhead (ground surface) and at the reservoir (Confidential, Privileged, or Sensitive Business Information [redacted]).

6.4 Shutdown Procedure

The shutdown procedure will consist of four parts:

1. *The well from the wellhead down.* Downhole in the well a subsurface safety valve will automatically shut in an emergency shutdown situation. This will trap all injected CO_2 in the well and stop any leakage from the injection formation. In a controlled shutdown situation, the master valve and/or wing valve on the wellhead will be shut trapping the CO_2 in the well. A transducer below the safety value and displayed at the well-head will allow measurement of the pressure below the valve in the well. This is important so that during re-startup the pressure can be equalized across the valve before opening the valve and continuing injection.

2. *The in-plant piping from compressor to wellhead.* The wellhead will have at a minimum two shut off valves and several isolation valves to allow isolation of corrosion coupons, flow meters and other equipment without the need to vent the entire pipe. During an emergency shutdown both shutoff valves will close automatically due to upset conditions. During a controlled shutdown the valves will be shut in sync with the compressor shutdown and the well head valves to ensure the CO_2 in the pipe is trapped until injection commences again. During re-startup, the pressure at each end of the pipe will be equalized across the valve and the valve opened to allow continued injection.

3. *The compressor.* The compressor will have the ability to go into recycle mode in case of an emergency shutdown. It will then be able to slowly shutdown and vent trapped CO_2. During controlled shutdown, the valve to the in-plant piping to the wellhead will be shut trapping the CO_2 in the pipe and the remaining small amount of CO_2 in the compressor chambers will be vented up a vent stack. During re-startup the compressor will be brought online and compress against the closed pipe valve until the pressure equalizes and then the valves will be open, and injection will continue.

4. *The connection from the ethanol plant fermentation scrubbers to the CCS compressor.* The CO_2 scrubber exhaust from the ethanol plant will be piped so it can be directed two ways: (1) through the existing scrubber exhaust stack; or (2) at very low pressure, near atmospheric, to the compressor inlet. In the case of an emergency shutdown or controlled shutdown, the CO_2 Scrubber exhaust valve will be switched from the compressor inlet to the existing scrubber exhaust stack. A bleed off valve on the compressor will open to allow any residual CO_2 in the line to be vented to the atmosphere if needed so compressor and plant operations will not be affected. When the compression operations are restarted, the scrubber exhaust valve will be switched and redirect CO_2 scrubber exhaust to the compressor inlet.

In accordance with 40 CFR 146.88(f), if a shutdown (i.e., downhole or at the surface) is triggered or loss of mechanical integrity is discovered, Marquis Carbon Injection must immediately investigate and identify as expeditiously as possible the cause of the shutoff. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required under Section 146.88(e) otherwise indicates that the well may be lacking mechanical integrity, Marquis Carbon Injection must:

(1) Immediately cease injection;
(2) Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone;
(3) Notify Director within 24 hours; See Section 7.1.7.
(4) Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection; and
(5) Notify the Director when injection can be expected to resume. See Section 7.1.7.

6.5 Proposed Carbon Dioxide Stream and Formation Fluids (40 CFR 146.82(a)(7)(iii) and (iv))

6.5.1 Source of the CO_2 Stream

The Marquis Energy - Illinois LLC dry grind ethanol-production facility near Hennepin, Illinois, is the source of the CO_2. The capture and compression of the CO_2 will be conducted by Marquis Carbon Capture, LLC, and the injection of the CO_2 will be operated by Marquis Carbon Injection, LLC.

6.5.2 Chemical and Physical Characteristics of the CO_2 Stream and Formation Fluids

The anticipated chemical composition of the CO_2 is given in **Table 6-4**. Based on samples collected during normal operations and a fermentation drop at the ethanol-production facility, the injection stream will be composed of nearly pure CO_2, with a composition of 99.86% CO_2. A fermentation drop, when a fermenter contents is added sent to distillation, is considered the period during fermentation when the worst-case emissions from the scrubbers would be observed. The chemical balance of the remainder of the injection stream will be composed of trace constituents (nitrogen, oxygen, and triethylene glycol [TEG]) with quantities of approximately 0.1%, 0.05%, and <0.0005%, respectively. Dehydration will be performed to reduce the water vapor content in the injection stream. The target water vapor concentration would be <30 lb/mmscf to limit the corrosivity of the injection stream. The injection system has been designed with corrosive-resistant materials that contact the injection stream to prevent corrosion of the components. Hydrogen sulfide (H_2S) is not expected to be present in the injection stream and analyses will be performed.

Component	Quantity
CO_2	99% +
Oxygen	<0.05%
Nitrogen	<1%
Water Vapor	<30 lb/MMSCF
Hydrogen sulfide (H_2S) (not expected to be present)	0.002%
Total Hydrocarbons	<0.005%
TEG	<0.0005%

Table 6 - 4: CO_2 specifications.

Aquifer samples were collected from various geologic formations in MCI MW-1. The samples from the Mt. Simon aquifer were analyzed for elemental concentrations, isotopic parameters, and general parameters (pH, total dissolved solids, etc.) The laboratory analytical results are included in **Appendix G.** A table compiling the geochemical analytical data obtained from the Mt. Simon is included in **Appendix I.** The analytical data detailing the chemical composition of the Mt. Simon injection zone was utilized for purposes of MCI CCS 3 corrosion modeling and metallurgy review to determine the potential corrosion risk of the Super Chrome 25 (25Cr), highly corrosion-resistant material, was selected for injection well construction. See Permit **Section 4.0**.

Although neither the CO_2 stream or formation waters are expected to be corrosive, the injection materials that come in contact with the CO_2 stream and/or reservoir brines will be constructed of highly corrosion-resistant materials, such as CO_2 resistant cement, and Super 25Cr, which is a Super Chrome Duplex stainless steel. For example, the casing string across the Mt. Simon, cement used, the packer, and deep portion of the tubing with be constructed with the highly corrosion resistant materials that have increased pitting and corrosion resistance to formation fluids combined with CO_2 over Chrome 13 (13Cr) material.

The injection stream will be monitored during the baseline and operational phases of the project. Prior to the start of the injection phase, the CO_2 stream will be sampled for analysis during regular plant operations to obtain representative CO_2 samples that will serve as a baseline dataset. Once the injection phase commences, the CO_2 injection stream will be collected from the CO_2 piping to the wellhead for analysis.

While exhaust flows typically increase during fermentation drops (transfer of fermented mash from a fermenter to the beer well), very little variation (<5%) is expected in the composition of the CO_2 that comes from the fermentation process due to the consistency of the process. In addition, the CO_2 stream will pass through two scrubbers prior to entering the compressor and the pipeline. The injection stream is expected to be 99+% CO_2. As such, quarterly sampling of the CO_2 injection stream should be sufficient to accurately track the composition of the stream. For example, in the first year, samples will be taken three, six, nine, and 12 months after the date injection starts. If a change greater than 10% from the average baseline conditions in any of the components in the CO_2 stream is noted during the quarterly sampling, a second sample will be obtained within 14 days of the receipt of the analytical results for verification. If the verification sample confirms that there is a change in the concentration of one of the constituents that would negatively impact the injection process, the CO_2 stream will then be sampled monthly until the cause of the change is found.

Samples of the injection stream will be collected for chemical analysis to provide data representative of its characteristics. Based on data from historic sampling of the offgas stream from the ethanol plant, the samples will be analyzed for CO_2, N_2, O_2, H_2S, and TEG (**Table 6-6**). Gas concentration analyses will be done by Atlantic Analytical Laboratory (Whitehouse, New Jersey) or a laboratory with similar capabilities. Atlantic Analytical Laboratory specializes in gas analyses and routinely performs specialized analyses on CO_2 for industrial clients.

Group	Constituent	Rational
Gases	CO_2	Major constituent of CO_2 stream
	N_2	Minor constituent of CO_2 stream
	O_2	Indicator of atmospheric contamination
	H_2S	This constituent not expected to be present in CO_2 stream

Group	Constituent	Rational
	TEG	Carry-through gas from the dehydration system

Table 6 - 5: Summary of analytes to be measured in the CO2 stream

6.6 Well Annulus Pressure Maintenance System

The purpose of the annulus monitoring and pressure system is to maintain the annular fluid at a prescribed pressure in MCI CCS3. The automated annulus monitoring system that has been designed for this purpose is part of the comprehensive well annular pressure maintenance system. The well pressure maintenance system includes piping, instrumentation valves, controls, and other equipment to accomplish several functions, including the following:

[redacted]

During injection, the annular monitoring system will maintain the wellhead pressure of the annular fluid between the tubing and the long string of casing within [redacted] The system will maintain at a minimum the annular pressure 100 psi above the pressure of the CO_2 in the injection tubing at the depth of the packer. The annular fluid pressure will be continuously monitored so that CO_2 injection can be halted when the annular fluid pressure falls outside the pre-determined range for a period that exceeds allowable limits. The annular monitoring system consists of a continuous annular pressure gauge, a pressurized annulus fluid reservoir (annulus head tank), pressure regulators, and tank fluid level indication. The annulus system will maintain annulus pressure by controlling the pressure on the annulus head tank using one of the two mechanical pressure pumps and a 2-4% KCl solution. The annulus pressure will be monitored by the annular pressure gauges and the wellhead annulus monitoring system (WAMS), a supervisory control and data acquisition (SCADA) system. The pressure and fluid level in the annulus head tank will be monitored and recorded continuously. One of the two maintenance pressure pumps will turn on when the differential pressure across the packer reaches [redacted]. Any changes to the composition of annular fluid will be reported in the next report submitted to the permitting agency. When the injection system is shut down, the annular pressure will be reduced to reduce collapse pressure on the tubing string. Once injection has ceased, the annulus fluid is expected to begin to cool to the ambient wellbore temperature gradient. This cooling process is expected to cause the annulus fluid to contract. One of the two pressure maintenance pumps will turn on when the differential pressure across the Packer reaches [redacted]. The pump would turn off when the differential pressure [redacted] These setpoints will be adjustable to suit the well pressure requirements.

If there is a loss of power to the annulus system, the pressure transducer and gauge will be monitored and recorded every 4 hours. If a positive annulus pressure of 100 psi cannot be maintained or the pressure above the packer cannot be maintained above the injection pressure to the injection zone, then injection into MCI CCS 3 will be shut down until repairs to the annulus system can be made.

6.7 Monitoring of the MCI CCS 3 well

Marquis Carbon Injection LLC will install and use continuous recording devices to monitor injection pressure, and mass injection rate; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the CO_2 stream, as required at 40 CFR 146.88 (e)(1), 146.89 (b), and 146.90 (b). If one of these monitoring devices (except for the mass flow meter) fail, manual readings and recordings of the data will be made every four hours until the sensor is repaired. If the mass flow meter fails, a secondary or backup flow meter will be used to gather and record the data. The details are described in the following sections.

6.8 Monitoring Location and Frequency

Marquis Carbon Injection LLC will perform the activities identified in **Table 6-7** to monitor operational parameters and verify internal mechanical integrity of the MCI CCS 3 well. All monitoring will take place at the locations and frequencies shown. All of the data recorded on a continuous basis will be connected to the main facility through a SCADA system.

Parameter	Device(s)	Location	Min. Sampling Frequency (Notes 1 & 2)	Min. Recording Frequency (Notes 2 & 3)
CO_2 stream surface injection pressure (wellhead)	[redacted]	[redacted]	[redacted]	[redacted]
CO_2 downhole injection pressure	[redacted]	[redacted]	[redacted]	[redacted]
Mass injection rate	[redacted]	[redacted]	[redacted]	[redacted]
Annulus surface pressure	[redacted]	[redacted]	[redacted]	[redacted]
Annulus downhole pressure	[redacted]	[redacted]	[redacted]	[redacted]
Annulus fluid volume added	[redacted]	[redacted]	[redacted]	[redacted]
CO_2 surface injection temperature	[redacted]	[redacted]	[redacted]	[redacted]
CO_2 downhole injection temperature	[redacted]	[redacted]	[redacted]	[redacted]
Wellbore temperature profile	[redacted]	[redacted]	[redacted]	[redacted]

Notes:

1. Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
2. Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.
3. If system communication is lost for greater than 30 minutes, manual field monitoring of gauges will be conducted every 6 hours or twice per shift for both CO_2 surface injection pressure and annulus surface pressure. Logs will be maintained in the facility records.

Table 6 - 6: Sampling devices, locations, and frequencies for continuous monitoring of CCS3

6.8.1 Continuous Recording of Injection Pressure

The injection pressure will typically [redacted] normal operations but is expected to fluctuate within a range [redacted]. Well parameters will be monitored during these conditions and any anomalies outside of the normal operating may indicate that an issue has occurred with the well (i.e., loss of mechanical integrity, blockage in the tubing, etc.) or may be caused by a change in injection flowrate. Anomalous downhole pressure measurements would trigger the need for further investigation of the cause of the change (40 CFR 146.89 (b)).

The wellhead pressure of the injected CO_2 will be measured by an electronic pressure transducer with analog output mounted on the CO_2 line. The transmitter will be electronically connected to the SCADA system, which can shutdown the system or change the flowrate depending on the pressures measured at the wellhead.

6.8.2 Continuous Recording of Injection Mass Flow Rate

The mass flow rate of CO_2 injected into the well will be measured by a Coriolis mass flow meter. This flow meter will be placed in the compressor building in the CO_2 delivery line prior to the well and connected to the SCADA system. The meter will have an analog output (Micro Motion Coriolis Flow and Density Meter Elite Series or similar). The meter will be maintained and calibrated according to the manufacturer's specifications.

6.8.3 Continuous Recording of the CO_2 Injection Temperature

The temperature of the injected CO_2 will be continuously measured for the well by an electronic thermocouple. The thermocouple will be mounted in a temperature well in the CO_2 line at a location close to the pressure transmitter near the wellhead. The transmitter will be electronically connected to the SCADA system. The thermocouple will be calibrated prior to the start of injection operations, and the calibration will be checked periodically (e.g., quarterly) during regular instrument checks. The thermocouple for measuring surface injection temperature will be recalibrated annually or it will be replaced with a calibrated thermocouple.

6.8.4 Downhole Pressure and Temperature

The CO_2 injection pressure and temperature will be monitored on a continuous basis. The down hole pressure will be monitored to ensure that it does not exceed 90% of the fracture pressure of the injection zone per 40 CFR 146.88 (a). 6.88 (a) the injection process will be automatically shut down to ensure that 90% of the injection zone fracture pressure is not exceeded.

Downhole pressure and temperature will be continuously monitored during the after starting injection). The continuous monitoring data will also be used with the mass flow rate and used to model the plume formation. The downhole pressure and temperature data will be recorded once every minute from the transducer and thermocouple placed in the tubing within the injection reservoir.

6.9 Control and Alarm System

This section describes the process that will be implemented to safely halt CO_2 injection in the event of an MCI CCS 3 well or equipment failure or if the injection pressure exceeds the predetermined level. The injection process will be monitored by pressure, temperature, and flow monitoring devices connected to the MCI CCS 3 well, compressor, pipeline, a series or valves, and the SCADA system. The monitoring system will be capable of detecting when injection conditions are out of acceptable limits and responding by either adjusting conditions or halting injection. The system is designed to operate automatically with minimal operator intervention. This section presents the following:

- A brief overview of the monitoring and control system
- A description of the automatic shutdown of the compressor, including the annular pressure, injection pressure, and flow rate that will trigger pumps shutdown

The well control system architecture and functionality, including process alarms, plant interlocks, shutdown alarms, and automatic shutdown sequence are described below.

6.9.1 Control System Overview

The proposed control system for the well is controlled by Marquis' DCS and is connected to the pressure, temperature, and flow monitoring instruments. The controls of the compressor have their own PLC/SCADA that communicates to the DCS, in-plant piping, and MCI CCS 3 well. Alarms, run enable, and other critical signals will be passed between the compression system and the MCI CCS 3 well through the SCADA and DCS system. User privileges and other security measures will be implemented to limit access to and control of the DCS, SCADA, and well control equipment.

Injection pressure will be determined by the pressure of the CO_2 at the wellhead of the MCI CCS 3 well. The compressor will have a variable-speed drive, which will be controlled to limit the CO_2 injection pressure and flow rate. A control valve will be installed on the CO_2 pipeline at a location upstream of where the pipeline connects to the wellhead. Adjustments to the injection pressure can be made with the control valve if necessary to stay under the injection pressure limit.

6.9.2 Process Alarms and Automatic Shutdown

Alarms will be implemented throughout the injection system and monitored by both the DCS and SCADA operator. Alarms are of three types: process (non-shutdown) alarms, shutdown alarms, and interlock alarms. Process alarms will be used to alert the control room operator whenever process variables are out of the accepted operating range, and operator or maintenance action may be required. Shutdown alarms will indicate critical conditions. An active shutdown alarm and/or plant interlock will trigger an automatic shutdown sequence in which the CO_2 injection process is automatically shut down by the well control system.

6.9.2.1 Process Alarms (Non-Shutdown)

Process alarm designations will indicate the relative value of the process variable versus the normal value. For instance, a low-pressure alarm will indicate that the process pressure is lower than the normally expected pressure. Process alarms will include low and/or high alarms that notify if a process variable deviates from the set point or expected value. Discrete inputs from binary devices such as pressure switches or alarm contacts may require action. Process (non-shutdown) alarms will be used for the parameters listed in **Table 6-8**.

Additional details about the process control instrumentation, including instrument numbers and a list of process alarms, are provided in the following sections.

Alarm	**Function**
Confidential, Privileged, or Sensitive Business Information [redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Table 6 - 7: Process (non-shutdown) alarms

6.9.2.2 Shutdown Alarms

The CO_2 injection process will be automatically shut down under two conditions. One shutdown condition will occur when the annular fluid pressure falls outside the pre-determined range for a period that exceeds allowable limits. The other primary shutdown condition will occur when the CO_2 injection pressure exceeds the maximum allowable injection pressure specified in the permit. Additional automatic shutdowns will be implemented because of plant interlocks, as described below. Operator intervention will be necessary to restart the injection process after an automatic shutdown sequence. Shutdown alarms will be used for the following parameters:

- Annular fluid pressure, MCI CCS 3 well (low-low or high-high alarm)
- CO_2 injection pressure (high-high alarm).

6.9.2.3 Plant Interlocks

Plant interlock status signal(s) will be sent from the well control system to the SCADA. The plant interlock will indicate whether conditions in the system are acceptable for the injection process to occur. During injection operations, the plant interlock will be used to initiate an automatic shutdown sequence in the event of equipment malfunctions, critical alarms, or other conditions in the system that warrant a shutdown of the injection process. During startup operations, the plant interlock will act as a run permission command for the injection process to start up.