W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project

DOE Award Number DE-FE0003311

Final Scientific/Technical Report

petra nova

PETRA NOVA PARISH HOLDINGS LLC

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Report DOE-PNPH-03311

Key Parties

Petra Nova Owners	NRG Energy, Inc. JX Nippon Oil and Gas Exploration (EOR) Limited
DOE Federal Project Manager	Sai Gollakota National Energy Technology Laboratory (NETL)
DOE Principal Investigator for Petra Nova	Greg Kennedy NRG Energy, Inc. for Petra Nova
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MVA Plan	Bureau of Economic Geology (BEG) The University of Texas at Austin
Petra Nova Operator	NRG Texas Power LLC

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I. Project Summary

The Petra Nova Project (Project) is a commercial scale post-combustion carbon capture project developed by a joint venture between NRG Energy, Inc. (NRG) and JX Nippon Oil Exploration (EOR) Limited (JX). The Project is designed to separate and capture carbon dioxide (CO_2) from an existing coal-fired unit's flue gas slipstream at NRG's W.A. Parish Electric Generating Station (WAP) located southwest of Houston, Texas. The captured CO_2 is dried, compressed, and transported via an 81-mile pipeline to the West Ranch oilfield (West Ranch) in Jackson County, Texas, where it is injected to boost oil production.

The Project, which is partially funded by a grant (Grant) from the United States (U.S.) Department of Energy (DOE) under the Clean Coal Power Initiative (CCPI) Round 3, uses the Kansai Mitsubishi Carbon Dioxide Recovery advanced amine-based CO_2 absorption technology (KM-CDR Process®), which was jointly developed by Mitsubishi Heavy Industries, Ltd. (MHI) and the Kansai Electric Power Co. Inc., to treat and capture at least ninety percent (90%) of the CO_2 from a 240-megawatt equivalent (MWe) flue gas slipstream off of Unit 8 at WAP. When operating at full capacity, the Project captures approximately 5,200 short tons of CO_2 per day, which would otherwise be emitted into the atmosphere, representing the largest commercial scale deployment of post-combustion CO_2 capture technology at a coal power plant to date. Under the Grant, the Project was managed in 3 phases:

- Phase 1: Project Definition / Front End Engineering Design (FEED)
- Phase 2: Detailed Engineering, Procurement & Construction
- Phase 3: Demonstration and Monitoring

On December 29, 2016, commercial operation of the Project was achieved, ending Phase 2 and starting Phase 3, a 3-year demonstration period running from January 1, 2017 through December 31, 2019. The key objectives of Phase 3 were to (a) demonstrate the specific advanced technologies constructed during Phase 2 and (b) monitor the injected CO_2 at West Ranch to demonstrate technologies and protocols for monitoring, verification, and accounting (MVA).

As of the end of Phase 3, Petra Nova captured 3,904,978 short tons of CO_2 (3,542,537 metric tons) that was transported to West Ranch. Total EOR production at West Ranch exceeded 4.2 million barrels of oil and reached as high as 6,000 barrels per day (both values being gross production). Additional volumes have been realized through conventional production. To support the DOE obligation to monitor, verify, and account for the sequestered CO_2 at West Ranch, Petra Nova contracted with the Bureau of Economic Geology (in the Jackson School of Geosciences at The University of Texas at Austin) to (a) design a monitoring program, (b) draft an MVA Plan for DOE review and approval, and (c) working with Petra Nova and the operator of West Ranch to manage and report on the MVA activity.

Of the approximate $1 billion dollar original investment, approximately 60% was spent on the capital investment of the Petra Nova carbon capture and cogeneration facilities and related costs. The balance of the investment covered up-front operating and administrative costs and the Petra Nova share of the CO_2 pipeline and West Ranch improvements. The source of funds includes the DOE Grant ($195 million), financing ($250 million), and sponsor equity.

II. Executive Summary

Carbon Capture, Utilization, and Storage (CCUS) has been viewed by many to be an effective means to address carbon emissions from fossil generation; however, until the construction of the Project, there has been no demonstration of post-combustion carbon capture technology at commercial scale in the United States. The Petra Nova partners, with support from the DOE, were able to demonstrate that a commercial scale carbon capture project can be successfully built and operated. Through these efforts, the Project provides valuable insight on:

- Economies of scale in sizing future facilities and understanding the technologies and equipment required to support large-scale carbon capture projects;
- Processes and skills needed to operate and maintain system equipment, including experiences gained during a variety of start-up and shut-down scenarios and operating during periods of high ambient temperatures;
- The benefits and risks of a standalone cogeneration facility (Cogen Facility) for process steam and power as an alternative to being parasitic to the host coal unit; and
- The process of anthropogenic CO_2 being supplied to an oilfield for EOR operations, including (a) evaluating technologies for monitoring, verifying, and accounting for sequestered CO_2 and (b) understanding the impacts of interrupted supplies of CO_2 on EOR operations during maintenance periods of the Carbon Capture (CC) and Cogen Facilities or the host coal unit.

Petra Nova proved that the employed technology works at commercial scale; however, the Petra Nova team encountered several challenges, as one would expect with any first-of-a-kind large-scale facility. Although the technology has been proven, Petra Nova is at a scale not previously built or operated. The experiences gained by confronting and overcoming these challenges will help others to improve the development of the next generation of carbon capture facilities. Additionally, as is the case for the Project, the economics of large-scale carbon capture facilities are challenging. Experiences at Petra Nova will allow others interested in post-combustion CO_2 capture to better understand how capital and operating costs can be reduced for future facilities.

III. Project Background

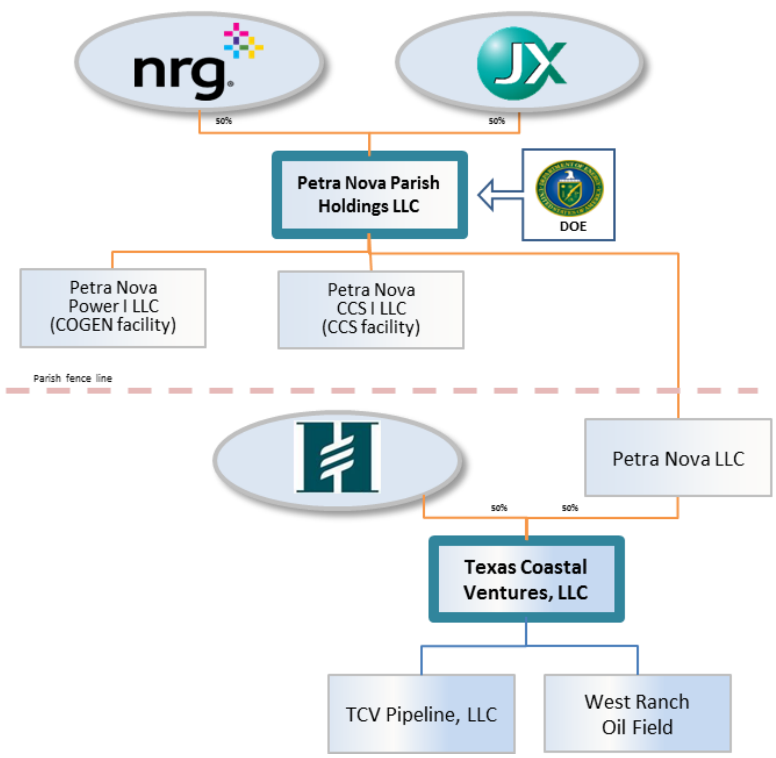
The DOE's CCPI program was an initiative to foster more efficient advanced clean coal technologies for use in new and existing electric power generating facilities. The program, managed by the DOE Office of Fossil Energy (FE) and implemented by the National Energy Technology Laboratory (NETL), was a private-public cost-sharing partnership to promote commercial deployment of advanced technologies to ensure reliability of an affordable electric supply while simultaneously protecting the environment.

As part of the implementation of the American Recovery and Reinvestment Act of 2009 (ARRA), in June 2009, the CCPI - Round 3 Funding Opportunity Announcement (FOA) sought coal-based projects that focused on the capture and sequestration (or beneficial use) of CO_2 emissions. NRG, with support from other stakeholders, applied in August 2009 to build a 60 MWe slip stream post-combustion carbon capture system at WAP. The captured CO_2 would be beneficially used for EOR in a nearby oilfield. The DOE and NRG reached agreement on a plan and entered into a Cooperative

Agreement (CA) in May 2010 for up to $167 million in cost-shared funding, or about 50% of the total estimated project cost at that time (through more recent Legislative and DOE action, cost-shared funding from the DOE increased to $195 million).

Despite the technical feasibility of a 60 MWe capture system, NRG concluded that a 60 MWe project would not be economical. Oilfield simulation models showed that the low volume of CO_2 captured from a 60 MWe system (approximately 20 MMscfd, or 1,150 short tons), when injected into an oilfield, would not induce meaningful oil production. This was found to be true regardless of the size of oilfield modeled. As a result, the DOE agreed to modify the CA to support a 240 MWe Front End Engineering and Design (FEED) study. While the study was being conducted, NRG selected Mitsubishi Heavy Industries America, Inc. (MHIA) as its technology provider given that MHIA already had an operational demonstration capture plant successfully capturing CO_2 from coal-fired flue gas at a sufficient scale (25 MWe, at Southern Company's Plant Barry in Mobile, Alabama). The scale-up design of the Petra Nova 240 MWe CC Facility was based, in part, on operating and technical data obtained from the Barry Project. Plant Barry also provided the added benefit of enabling prospective investors to witness performance and comprehend the prospect of scaling-up to 240 MWe.

In 2011, NRG and Hilcorp Energy Company (HEC), through their respective affiliates, entered into a 50/50 joint venture called Texas Coastal Ventures, LLC (TCV). TCV owns 100% of the working interests in West Ranch. TCV also owns 100% of the CO_2 pipeline, which transports the CO_2 from Petra Nova to West Ranch. In May of 2013, as a result of NRG seeking additional partners and investors in the project, JX purchased 50% of Petra Nova Parish Holdings (PNPH). The DOE again modified the CA in November 2013 to novate the agreement from NRG to PNPH to recognize the final project structure, as illustrated below:



IV. Project Objectives and Results

The specific objectives for Petra Nova identified in the Statement of Project Objectives (SOPO) as agreed to between the DOE and Petra Nova were:

1. Demonstrate successful operation of an advanced amine post-combustion process to achieve 90% CO_2 capture efficiency of the selected size, up to 250 MWe scale.
2. Demonstrate technological advances to the selected amine process aimed at lowering energy requirements of the carbon capture process.
3. Investigate advanced solvents including piperazine. Demonstrate the concept of integrating a cogeneration system into the carbon capture process to provide the energy requirements to operate the system in the form of steam and power.
4. Capture and permanently sequester up to 3,200,000 short tons of CO_2 over a 2-year demonstration period.
5. Demonstrate technologies and protocols for the CO_2 monitoring, verification, and accounting necessary to establish the permanence of the sequestered CO_2 and provide a full accounting for all captured CO_2.
6. Establish the impact of CO_2 capture and sequestration operations on the Cost of Electricity (COE), and provide recommendations necessary for the demonstration technology to achieve a COE reduction.

Objective 1: Demonstrate successful operation of an advanced amine post-combustion process to achieve 90% CO_2 capture efficiency of the selected size, up to 250 MWe scale.

Results: As discussed above, Petra Nova successfully constructed a 240 MWe commercial scale project using the KM-CDR Process®. When operating at 100%, the carbon capture facility (CC Facility or carbon capture system, CCS) is capturing the targeted 5,200 tons of CO_2 per day. Through the 3-year Demonstration Period, the CC Facility captured 92.4% of the CO_2 from the slip stream of flue gas processed.

Objective 2: Demonstrate technological advances to the selected amine process aimed at lowering energy requirements of the carbon capture process.

Results: While minimizing energy requirements was important to minimize operating costs, given the first-of-a-kind nature of the CC Facility, our key goal was to meet the CO_2 capture targets. The scale-up to a commercial system was a monumental step in-and-of itself and provides actual valuable energy information far beyond what a small novel energy efficiency project might deliver. Furthermore, once working as designed, heat integration projects can be optimization opportunities for future enhancements.

In lieu of taking power and steam from the host coal unit, Petra Nova constructed a stand-alone Cogen Facility utilizing a GE 7EA combustion turbine generator (CTG) with a heat recovery steam generator (HRSG). Looking at two representative days in 2019 (one each from summer and winter periods), the electricity requirements are shown below:

	Hourly Average MW Consumed	
Equipment	**January 15, 2019**	**August 31, 2019**
CO_2 Compressor	19.4 MW	20.6 MW
Flue Gas Blower	5.4 MW	5.5 MW
Circulating Water Pumps (2 pumps)	4.0 MW	3.9 MW
Major Pumps (7 pumps)	2.6 MW	2.6 MW
Other (minor pumps, A/C, lights, etc.)	2.6 MW	2.4 MW
Total Carbon Capture Facility Requirements	**34.0 MW**	**35.0 MW**
Water Treatment Facilities	0.3 MW	0.3 MW
Cogen Facility	0.1 MW	0.2 MW
Total Project Requirements	**34.4 MW**	**35.5 MW**
Merchant MW sold to the market	51.0 MW	37.9 MW
Total CTG Output	**85.4 MW**	**73.4 MW**

The carbon capture process also uses up to 500,000 pounds of steam per hour. Most of this steam is generated as part of the Cogen Facility by using the waste heat from the CTG. The balance of steam is produced via duct burners where natural gas is delivered and burned at the HRSG to provide the additional thermal energy needed. In addition to the gas used by the CTG (which ranges from 11.7 to 12.0 MMBtu/MWH), the duct burner fuel ranges from 500 to 1,600 MMBtu/day depending on the ambient temperature.

Objective 3: Investigate advanced solvents including piperazine. Demonstrate the concept of integrating a cogeneration system into the carbon capture process to provide the energy requirements to operate the system in the form of steam and power.

Results: A part of the original project test plan was to demonstrate a piperazine-based solvent developed by the University of Texas at Austin's Department of Chemical Engineering (UT). During Phase 1, an alternative technology provider evaluated the solvent on UT's behalf to predict performance of the alternative solvent within their process. The scope of the study was limited to the solvent portion of the CO_2 capture plant (absorber column to the outlet line of the regenerator/stripper column) and did not include flue gas pretreatment, compression, and reclaiming. The overall plant configuration for the piperazine performance study was based on the original 60 MWe project. When modeling the predicted performance of the piperazine against the technology provider's solvent, the low-pressure CO_2 temperatures from piperazine were higher. These higher temperatures would pose a problem for the downstream CO_2 compressor requiring cooling system upgrades. Additional work would be needed to (a) understand degradation and the resulting byproducts in order to establish reclaiming requirements and (b) determine the annual make-up rate of piperazine. When the Project was scaled up to 240 MWe, it was concluded that further testing of solvents for which the equipment wasn't designed for would not only be suboptimal, it would also void guarantees and warranties and damage equipment. Accordingly, no work was furthered in this area.

In 2013, Petra Nova installed a GE 7EA (nominal 78 MW, summer reference conditions) CTG to serve the Electric Reliability Council of Texas (ERCOT) peaking market until the conversion to the Cogen Facility in 2016 (during the construction of the CC Facility) by adding the HRSG along with other required modifications. As noted above, Petra Nova uses approximately 35 MW for Project power needs with the remainder of the power sold into the local energy market. The CTG was sized to meet the steam needs of the carbon capture process, not the electricity requirements.

One objective of adding the Cogen Facility was to demonstrate that carbon capture can be done without being parasitic to the host coal unit thereby not having a negative impact on local electricity prices. Other advantages include a cleaner burning fuel improving the overall carbon footprint than what would have otherwise been realized if taking steam and power from the host coal unit. The main disadvantage of a standalone source of power and steam is the additional outage risk – i.e., with no back-up supply from the host coal unit, any outage of the Cogen Facility will also result in an outage of the CC Facility. During the 3-year demonstration period, the Cogen Facility resulted in approximately 88 days of incremental outage time for the CC Facility.

Objective 4: Capture and permanently sequester up to 3,200,000 short tons of CO_2 over a 2-year demonstration period.

Results: The target of 3.2 MM short tons was based on an 85% capacity factor times the daily targeted 100% rate of 5,200 short tons per day. Petra Nova has demonstrated that the facility can operate and maintain the targeted CO_2 capture rate of 5,200 short tons per day during all ambient conditions but underestimated the assortment of system challenges with achieving an annual capacity factor of 85%. During the 3-year demonstration period, the CC Facility captured 3,904,978 short tons of CO_2 (see discussion below for further information on sequestered CO_2 as determined under the mass balance accounting activity in the MVA Plan). Factors that impacted our ability to maintain 100% capture levels included:

- Facility forced outages (including the CC Facility, the host coal unit, and the Cogen Facility);
- A partial or full shut-in of the CO_2 pipeline;
- West Ranch's ability to received captured CO_2;
- Weather (a key contributor being the impact on West Ranch from Hurricane Harvey);

- Planned maintenance of the CC Facility, host coal unit, Cogen Facility, and West Ranch facilities; and
- Partial day outages resulting from operational issues (including equipment de-rates, concentration of CO_2 in the flue gas, and ramping of the host coal unit).

Regarding surface losses of CO_2 at West Ranch, refer to the Monitoring, Verification, and Accounting Section in this report discussing the process used at West Ranch to track CO_2 losses.

Objective 5: Demonstrate technologies and protocols for the CO_2 monitoring, verification, and accounting necessary to establish the permanence of the sequestered CO_2 and provide a full accounting for all captured CO_2.

Results: Petra Nova contracted with the BEG to design and conduct a monitoring program to document storage of CO_2. The monitoring program was based on the same principles of several evolving monitoring programs and proved sufficient for this application. The monitoring program was designed to include seven work elements: (1) fluid flow modeling, (2) mass balance accounting, (3) pressure monitoring (AZMI, above zone monitoring intervals), (4) geophysical logging, (5) fluid sampling and analysis, (6) monitoring of underground sources of drinking water (USDW), and (7) soil (vadose zone) definition and monitoring. To establish an appropriate baseline, field monitoring for tasks (3), (5), (6) and (7) started prior to the injection of CO_2 with ongoing monitoring during Phase 3 to identify any changes. A summary of each of the tasks can be found in the MVA Program Section below.

Objective 6: Establish the impact of CO_2 capture and sequestration operations on the Cost of Electricity (COE), and provide recommendations necessary for the demonstration technology to achieve a COE reduction.

Results: As noted above, Petra Nova is not integrated with the host coal unit for power and steam requirements. Operations of the host unit are independent of the CCS Facility. Therefore, Petra Nova does not impact the COE to consumers. Given that the energy requirements are provided by the Cogen Facility and the power output of the Cogen Facility is in excess of the requirements of the Project, excess power is sent to the ERCOT grid increasing supply and theoretically reducing the COE. Therefore, the COE increase to consumers is zero. However, valuable information can still be gathered from this Project in the form of understanding the energy requirements as discussed above when assessing what the impacts could be from future projects.

V. Project Activities

As highlighted above, project activity was conducted in three phases:

- Phase 1: 06/01/2010 – 06/30/2014 - Definition/Front End Engineering Design (FEED)
- Phase 2: 07/01/2014 – 12/31/2016 - Detailed Engineering, Procurement & Construction
- Phase 3: 01/01/2017 – 12/31/2019 - Demonstration and Monitoring

Phase 1: Project Definition / Front End Engineering Design (FEED)

Overview

The purpose of Phase 1 was to develop the Project in sufficient detail to facilitate the decision-making necessary to progress to the next stage of project delivery. As reported above, the original design of a 60 MWe facility was deemed insufficient to meet the CO_2 needs of the oilfield. As a result, Petra Nova decided to move forward with a 240 MWe FEED study using flue gas from WAP Unit 8 to take advantage of the existing wet flue gas desulfurization (FGD) system on Unit 8.

The Project has four primary components:

1. Carbon capture and compression island
2. Balance-of-plant (BOP) and site integration (utilities including water, power, steam supply and water treatment)
3. CO_2 pipeline
4. Oil field EOR with CO_2 monitoring

Numerous design alternatives were explored, and the expanded FEED study confirmed the technical and commercial viability of the 240 MWe sized carbon capture system.

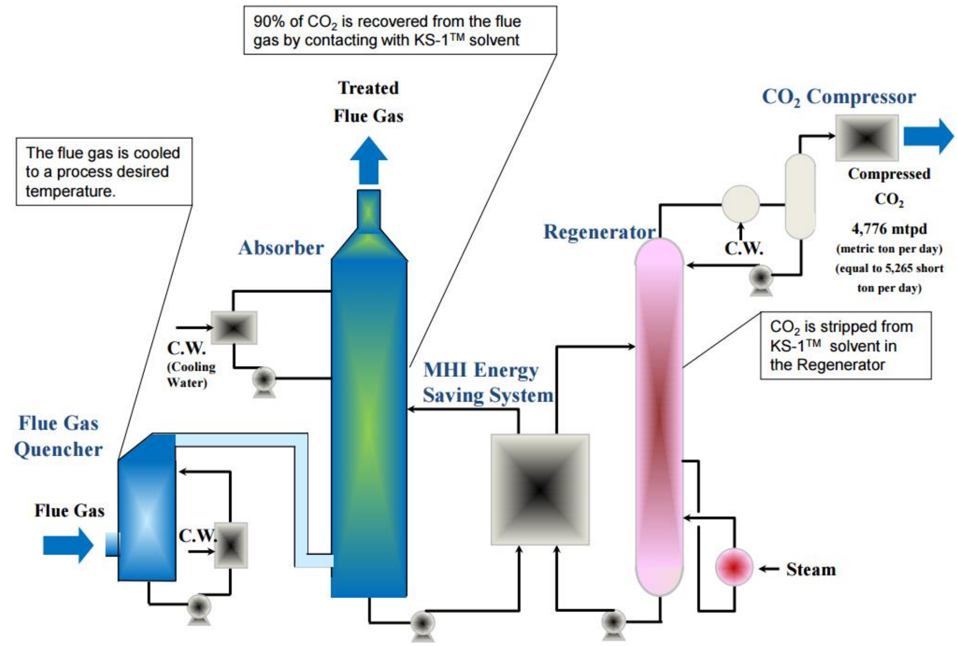
Technology Provider

The Houston Galveston Brazoria (HGB) area status is considered "non-attainment" with respect to Volatile Organic Compound (VOC) emissions and given the volume of gas being processed at Petra Nova, even the small amount of VOCs created challenges for permitting. Consequently, Petra Nova evaluated technology providers based on their VOC emissions. After a careful evaluation of available technologies, Mitsubishi Heavy Industries (MHI), through their US affiliate Mitsubishi Heavy Industries America (MHIA), and their proprietary post-combustion CO_2 recovery system using the KM-CDR Process® was selected as the technology provider.

Petra Nova's decision to use MHI as the technology provider was also, in part, due to MHIA building and operating the coal flue gas post-combustion CO_2 capture plant at Southern Company's Plant Barry near Mobile, Alabama. The Project started operating in June 2011 and, at the time of our technology evaluations, was capturing 500 tons per day, or the equivalent of a 25 MW slipstream of flue gas. This demonstration plant enabled key investors and stakeholders to perform due diligence at an operating facility, discuss operational performance, and better understand the incremental scale-up from 25 MWe to 240 MWe.

CO_2 Capture Process Overview and Description

The KM CDR Process® is similar in overall concept to other amine-based gas treating processes, which have been utilized for many years in the natural gas, petrochemical, and refining industries, except that MHI has adapted and scaled this process to recover CO_2 from low-pressure, oxygen-containing streams, such as power plant flue gas. It uses a proprietary high-performance solvent, KS-1™, for CO_2 absorption and desorption that was jointly developed by MHI and Kansai Electric Power Co., Inc. Below is a simplified process diagram and process description.



Simplified Process Flow Diagram (Generic)

The process consists of three main columns: (1) Quencher, where flue gas is conditioned and prepared for the absorption process; (2) Absorber column, where CO_2 is absorbed into the solvent through a chemical reaction; and (3) Regenerator (or stripper) vessel, where the concentrated CO_2 is released and the original solvent is recovered and recycled back through the process.

The flue gas is first routed to the Quencher for flue gas conditioning (i.e., cooling and trim acid gas removal). Certain constituents entrained in the flue gas, if not removed, would contaminate the solvent, so the gas is scrubbed of these contaminating constituents in a deep polishing scrubber. The flue gas is then cooled because the absorption reaction is affected by the temperature of the flue gas (i.e., absorption of CO_2 in the solvent is an exothermic process that favors lower temperatures). This cooling process causes water to condense out of the wet flue gas.

The cooled and cleaned gas exits the top of the Quencher column where it is pulled through the blower. The blower located downstream of the cooler is used to pull the slipstream from the host unit and overcome the pressure drop through the duct, Quencher and Absorber.

From the blower, the flue gas enters the bottom of the Absorber column and flows upward through the packed column beds where it comes into contact and chemically reacts with the solvent (loading the solvent with CO_2). Counter-current flow through multiple stages of structured packing maximizes contacting surface area and mass transfer rate of the CO_2 into the solvent. The CO_2-depleted gases are then cooled, washed, and vented to the atmosphere.

The CO_2 "rich" solvent leaves the bottom of the Absorber and is routed through a heat exchanger, heating the solvent as it is pumped to the Regenerator. In the Regenerator, the weakly bonded compound is reversed through the application of heat, in the form of process steam, to liberate the CO_2 and leave reusable solvent behind. The liberated CO_2 is sent to a compressor to compress the CO_2 up to the supercritical phase (resembling a liquid but still compressible) for pipeline transport.

The CO_2 "lean" solvent is routed back to the Absorber, through a heat exchanger (the lean solvent is cooled by the rich solvent from the Absorber) to repeat the process. A portion of the cooled lean solvent is diverted through solvent filtration equipment to remove solution contaminants.

Some of the solvent is lost during the process for a variety of reasons including mechanical, vaporization, and degradation. Furthermore, some contaminants, such as heat stable salts (sulfates, nitrates, and oxalates of amine) and thermal/oxidation degradation products, cannot be removed in the solvent filtration package and must be removed through a periodic reclaiming operation. Fresh solvent is added to make up for these losses incurred in the process.

This process requires heat in the form of steam to release the CO_2 from the solvent and power to run the equipment, including the very large CO_2 compressor. The Cogen Facility was constructed to supply these utilities. Finally, a substantial amount of cooling is required (flue gas cooler, absorber cooling section, compressor intercoolers, etc.) that is served with the construction of a cooling tower.

Environmental Impact Statement

Based on the overall scope of the Project, the DOE determined that an Environmental Impact Statement (EIS) should be prepared in accordance with the National Environmental Policy Act (NEPA). NEPA requires a Federal agency to prepare an EIS if it is proposing a major federal action. Accordingly, the EIS process was initiated and the Notice of Intent (NOI) to prepare an EIS was issued on November 14, 2011. The details and related documents of the EIS process can be found on the energy.gov website.

Permitting

There were several permits required to construct the Project, and the key permits identified and discussed during Phase 1 included air and waste water permits. The permit with the longest lead time and most critical to Phase 1 was the Air Permit to construct. Accordingly, in parallel with the expanded FEED study, Petra Nova filed an Air Permit Application with the TCEQ on September 16, 2011, for the CC Facility. Because the eight-county HGB area is classified as severe non-attainment for ozone, new or expanding emissions sources the size of Petra Nova must provide offsets or credits for VOC and nitrogen oxides (NOx). Petra Nova was able to submit enough credits to the TCEQ and as a result, Petra Nova received an air permit for the 240 MWe sized system on December 21, 2012.

Design Approach

The design approach followed a typical development sequence and associated design reviews starting with a design basis document, development and review of process flow diagrams (PFDs) and heat and material balances. This led to the preparation of piping and instrumentation diagrams (P&IDs), equipment specifications, data sheets and plot plans, three-dimensional (3D) modeling and other detailed design activities. Also, as is customary in the petrochemical industry, the Project team carried out a Hazard and Operability Study (HAZOP) which is a method of assessing and evaluating potential hazards to employees or equipment common in the process industry. A HAZOP analysis provides a full review of a process system and systematically questions every part of it to establish how deviations from the design intention might arise and cause system instability. The team documented the cause and consequence of each process fault condition and revealed all the available layers of protection during this process.

Facility General Arrangement

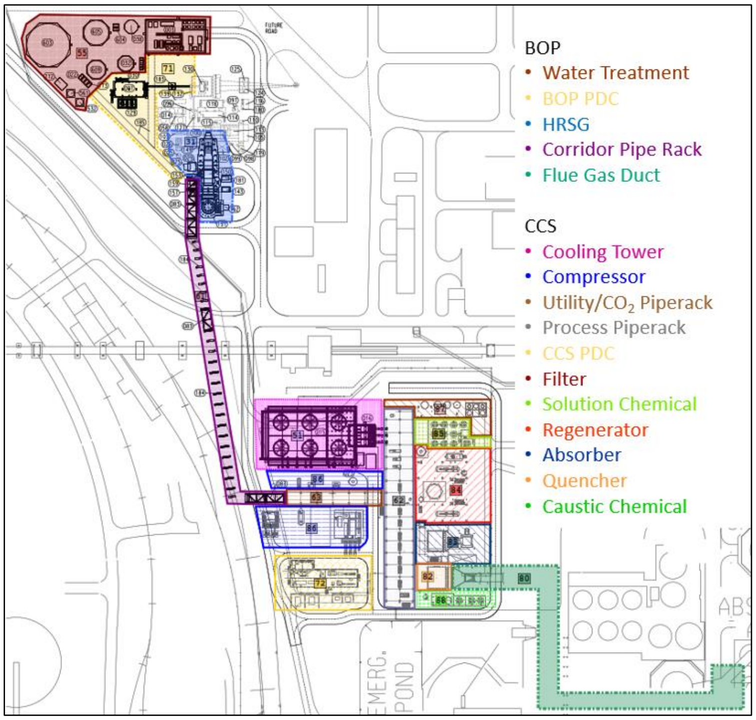
The CC Facility is located on a brownfield portion of a congested operational coal plant. The development and finalization of the general arrangement of the carbon capture process island and BOP equipment was a significant undertaking. WAP Unit 8 uses a wet FGD scrubber to treat the flue gas for removal of SO_2; therefore, the CCS flue gas duct connection interconnection is placed downstream of the wet scrubbers and before the WAP Unit 8 stack. Site constraints factored into the final determination on how and where to locate the carbon capture equipment. The MHI process footprint requirements drove a decision to locate the carbon capture equipment on an approximate 4.6-acre tract of land near WAP Unit 7 and 8 that was occupied with a storage warehouse. This location provided for the CCS footprint with minimal impact on above and below ground relocations and rework. The CCS location also minimized the length of fiber glass reinforced flue gas ductwork (approximately 800 feet) required to transport flue gas from the WAP Unit 8 tie-in to the CCS quencher inlet.

The site for the CCS equipment was not large enough for all the BOP equipment required to support carbon capture operations, which consists of the following equipment:

- Cogen Facility
- Cooling tower
- Water treatment facilities (raw water clarifier, water treatment facility for demineralized water, and waste water treatment)
- BOP/utility pipe rack
- Integration of existing facility site services (raw water, potable water, firewater, ammonia)
- Treated waste water discharge (permitted) via new outfall on Smithers Lake

Integration of this equipment into the final general arrangement was accomplished by utilizing available nearby parcels and optimizing equipment layouts for these areas and interconnection requirements. The figures below illustrate: (a) the BOP and CCS general arrangement of the systems at WAP and (b) a plot plan showing the final arrangement of CCS and BOP facilities.

Site Arrangement



Plot Plan

CCS Components

The final design of the CC Facility consists of the following primary components:

- Flue Gas Tie-in & Duct – WAP Unit 8 tie-in duct assembly including motor driven isolation dampers and flow straighteners, and ductwork that carries flue gas from the tie-in duct assembly to the inlet of the quencher
- Quencher – final flue gas scrubbing and cooling before flue gas enters the absorber
- Absorber/Absorber Stack – CO_2 capture with amine based solvent and final wash of flue gas exiting to atmosphere
- Continuous Emissions Monitoring System (CEMS) – absorber stack continuous emissions monitoring system
- Flue Gas Blower – centrifugal fan used to pull flue gas from WAP Unit 8 (via the flue gas duct) through the quencher and push the flue gas through the absorber
- Regenerator – performs CO_2 release from amine solvent for compression cycle
- Compressor – eight stage integrally geared compressor to compress CO_2 from the regenerator and deliver to transport pipeline
- Dehydration System – triethylene glycol system located between 4th and 5th stages of the compressor for CO_2 water removal
- Solvent/Solvent Storage Tanks – proprietary amine solvent used to capture CO_2 from flue gas
- Reclaimer – a shell and tube heat exchanger (HE) that is used like a kettle boiler to capture solvent process impurities and return pure vaporized amine solvent to the process

- Reboilers – shell and tube heat exchangers used to transfer heat energy to the solvent and regenerator to facilitate the release of CO_2 from the amine solvent
- Process filters – to remove impurities from the solvent
- Pumps – prime mover for solvent, cooling water
- Heat Exchangers – consists of both plate-and-frame and shell-and-tube heat exchanges that provide means of managing and balancing heat transfer in various parts of the process
- Interconnections – CCS tie-ins to existing utility water, potable water, service water, firewater, storm water, sanitary waste, operating I/O (input/output), and CEMS I/O

Balance of Plant

The final design of the BOP systems consists of the following primary components:

- CTG – supplies power to the CCS and exhaust heat to the HRSG (excess power is delivered to the ERCOT power grid)
- HRSG – generates steam for the CCS regenerator & reclaiming processes
- CEMS – HRSG stack continuous emissions monitoring system
- Raw Water Treatment System – treats raw water to produce cooling water system makeup water
- Well Water Treatment System – reverse osmosis (RO) process to produce demineralized water which is used for feed water to HRSG and various needs in the CCS process
- Steam Delivery System – structure, piping, and equipment used to deliver steam from the HRSG to the reboilers and reclaimer
- Steam Condensate Return System – structure, piping, and equipment used to return condensate to the HRSG
- Cooling Water System (located on the CCS site) – cooling tower, pumps, and piping to supply cooling water to the various heat exchangers in the process island
- Waste Water Treatment System – treats trim FGD blow-down waste stream and RO reject prior to discharge to Smithers Lake
- Instrument Air System – provides instrument and plant air for CCS and BOP air uses
- Interconnections – BOP tie-ins to existing utility water, potable water, service water, firewater, storm water, sanitary waste, natural gas, aqueous ammonia, operating I/O, CEMS I/O, and the power grid

Control Systems

- CTG – Dedicated distributed control system (DCS) with local (CTG) and remote (CCS control room) operator interfaces
- CO_2 Compressor – dedicated programmable logic controller (PLC) with remote (CCS control room) operator interface

- CCS/BOP – the balance of control of the CCS process (including flue gas blower) and BOP (including HRSG) resides in a dedicated DCS located in the CCS control room. Local programmable logic controllers (PLC) which control the reverse osmosis system and HRSG duct burner system interface with the CCS/BOP DCS and primary control commands and monitoring are performed from the CCS control room

CEMS

- BOP (HRSG) CEMS – certified analyzers measure stack concentrations of CO, NO_x, and O_2
- CCS (Absorber) CEMS – certified analyzers measure stack exit flow and concentrations of CO, CO_2, Hg, NO_x, and SO_2

Air Quality Compliance

- BOP Compliance Testing – annual emissions compliance testing at HRSG stack for CO, NO_x, O_2, Opacity, NH_3, PM, SO_2, and VOC
- CCS Compliance Testing – annual emissions compliance testing at absorber stack for CO, NO_x, O_2, Opacity, NH_3, PM, SO_2, and VOC
- Leak Detection and Repair – periodic compliance monitoring for fugitive emissions at 2,393 points within the CC Facility

Water Discharge Compliance

- Final Discharge – combined flow of the following three CCS/BOP internal outfalls are discharged to Smithers Lake:
    - Trim FGD Waste Treatment Discharge – Discharge limits on TSS, oil, and grease
    - Cooling Tower Blowdown Discharge – Discharge limit on free chlorine
    - Oily Water Separator Discharge – Discharge limits on TSS, oil, and grease

Waste Generation

- BOP Waste – sludge generated by the raw water clarifier, RO reject, multi-media backwash, and oil-water separator
- CCS Waste – filter waste, reclaiming waste, sludge from the water treatment facility, and lab waste

Health & Safety

Petra Nova and its contractors were closely aligned on their commitment to health, safety, and environmental (HSE) excellence. A zero-incident culture was the primary goal of this behavioral based program. A safe and healthful work environment, with communication of safety issues, and utilization of safe work practices, in addition to providing ongoing safety training for all personnel (including contractors) that support the Project is the culture that is cultivated. All Project personnel (including contractors) adhered to the requirements of the Project Safety Program, which incorporated the industry best practices of Petra Nova, NRG, and TIC. The HSE program was comprehensive in its scope.

Carbon Dioxide Safety

The high-pressure CO_2 piping system, which includes the CO_2 compressor and elevated portion of downstream discharge piping, was identified as a potential safety hazard to personnel should a significant CO_2 release occur during operation. Consultants were hired to perform an analysis evaluating the potential effects of a CO_2 release from an orifice in this section of pressurized pipeline to determine the area in which a harmful concentration of CO_2 could occur during an accidental release. Eight scenarios were evaluated, covering two different release orifice sizes, two different wind speed conditions, and two different ambient temperatures. The results of the consultant analysis were used to determine where to add additional monitoring and personal protective equipment (PPE) for personnel working in those potentially affected areas.

Phase 2: Detailed Engineering, Procurement & Construction

Overview

Phase 2 (July 2014 – December 2016) covered the design, procurement, construction, and commissioning of the fully integrated CO_2 project. This effort included the: (a) carbon capture equipment and interconnections to WAP Unit 8, (b) BOP (e.g., waste treatment, raw and demineralization water treatment, and conversion of the GE 7EA peaking facility to the Cogen Facility, (c) the 81-mile CO_2 pipeline to transport CO_2 from Petra Nova to the EOR/sequestration site, (d) the EOR infrastructure at West Ranch, and (e) the development and implementation (including base-line testing) of the MVA Plan at West Ranch. The Grant did not reimburse the CO_2 pipeline or the EOR infrastructure at West Ranch, these items are listed for completeness.

CCS Design

The engineering and design of the CC Facility was done by MHI covering the complete spectrum of piping, mechanical, civil, structural, electrical, instrumentation, and process disciplines. Comprehensive design reviews (Design Basis, PFD, HMBs, P&ID, Layout, 3D modeling, HAZOP) provided the necessary confidence that the design satisfied the performance and engineering requirements, established compatibility between major components and battery limits. The Basic Engineering and Design Data (BEDD) document provided the basis for the design and included the following information:

- Codes and standards that served as a basis for design
- Flue gas characteristics
- CO_2 purity requirements
- Ambient site conditions
- Make-up water characteristics

The BEDD did not include detailed technical design requirements, which were prepared as separate discipline-specific documents that governed the technical teams' design. Subsequently, the PFDs indicating the general flow of plant processes and equipment illustrating the pressures and compositions of major streams were developed.

Cogeneration Facility

The Cogen Facility is comprised of a General Electric (GE) 7EA CTG and a HRSG to provide (a) exhaust heat energy to produce steam in the HRSG for the CCS process and (b) power for the BOP and CCS facilities. The CTG also provides revenue as surplus power is delivered to the ERCOT market via a 138kV transmission interconnection. The CTG was originally procured outside of the Grant in the secondary market and installed by Petra Nova in 2013 in simple cycle peaking configuration later to be tied into and used in the Petra Nova process.

In 2016, the simple cycle CTG configuration was upgraded to a cogeneration configuration by integrating the HRSG with the CTG. The CTG exhaust stack was removed to accommodate the installation of a CTG exhaust plenum and the HRSG, which were installed in line with the CTG exhaust flow to minimize back pressure. All necessary interconnecting ductwork, supports, piping, water feed systems, fuel feed systems, chemical feed systems and electrical systems to integrate the CTG, HRSG, and CC Facility were installed during Phase 2. The HRSG converts CTG exhaust energy (and supplemented with duct firing) to low pressure steam which is supplied to the CCS regeneration and reclaiming processes.

The CTG and HRSG are properly matched to meet the steam and power needs of the Project. The CCS uses up to 500,000 pounds of steam per hour. The CTG provides most of the heat needed to produce the required steam. Duct burners were added to the HRSG to provide up to 120 MMBtu/hr. heat input to supplement the CTG exhaust heat input. The HRSG design includes environmental controls (selective catalyst beds) to reduce emissions of carbon monoxide (CO) and Nitrogen Oxides (NO_X) from the CTG exhaust prior to existing the HRSG stack. A 29% aqueous ammonia supply and injection system was also installed with the HRSG for the operation of the NO_X reduction system. The ammonia is supplied from existing storage tanks at WAP.

Balance of Plant Facilities

Waste Water Treatment – Petra Nova installed a temporary physical/chemical (phys-chem) system with the intent to install a permanent facility once all the waste streams were characterized and long-term treatments needs were identified. After characterization of waste streams, it was decided that the rental system was sufficient, and it remained in operation during Phase 3 (further discussed below). The system treats the quencher scrubbing section waste stream, water treatment reverse osmosis (RO) reject waste stream, and multimedia backwash waste stream. After treatment, the effluent from the phys-chem system is discharged to nearby Smithers Lake through a permitted outfall.

Cooling Water – The design of the cooling water system includes a clarifier, cooling tower, circulating water system pumps, piping, chemical injection systems, and chemistry monitoring systems. The clarifier includes a sludge thickener system that dewaters sludge from the clarifier for disposal by vacuum truck. The initial fill and make-up water of cooling water was/is obtained from Smithers Lake. The blow down from the cooling tower is piped to a permitted discharge outfall at Smithers Lake. The fiberglass mechanical-draft cooling tower was designed to deliver cooling water to the CCS at the flow rates and temperatures required under maximum summer ambient conditions with a maximum temperature rise of 14°F.

Demineralized Water – A demineralized (demin) water treatment (DWT) system was designed and installed for the Project. The quality of the source water, from WAP's service water system, requires conditioning with pressure filters, two-pass Reverse Osmosis (RO), and polishing ion exchangers (with offsite regeneration). The demineralized water system includes piping, demineralizer equipment, a 100,000-gallon demineralized water storage tank, supply pumps, electrical and control systems. The demineralized water equipment, except the storage tank, is housed in a building.

Carbon Capture Facility

Flue Gas Supply Duct – A flue gas slipstream for the CCS process is pulled from the transition ductwork in the breeching duct, just upstream of the WAP Unit 8 chimney and downstream of the SO_2 scrubber silos serving WAP Unit 8. The WAP Unit 8 tie-in was designed as a Hastelloy-clad rectangular duct, which houses two guillotine isolation dampers. Downstream of the tie-in, a rectangular duct transitions to a 15 foot diameter round fiberglass reinforced plastic (FRP) duct to the CCS battery limit/Quencher intake. Considerations were made for solids to drop out due to carryover from the desulphurization system with drainage provided due to the saturated nature of the flue gas.

Quencher – The Quencher has two primary functions: (a) flue gas cooling and (b) removal of SO_2 and other contaminants that may remain in the flue gas stream from WAP Unit 8 in accordance with the inlet gas specifications. The bottom section, the trim FGD section, reduces the concentration of SO_2 in the flue gas before entering the CO_2 Absorber. The trim FGD section allows for liquid-gas contact between the flue gas and Sodium Hydroxide (Na_2SO_4) solution. The pH is controlled by adding caustic soda to the Quencher. A portion of the solution continuously discharges to a caustic wastewater receiving tank and ultimately pumped to the phys-chem treatment system. The upper section serves to cool the flue gas to improve the CO_2 removal efficiency in the CO_2 Absorber. Cooling water is circulated within the Quencher via a pump and heat is removed via external plate and frame heat exchangers (Flue Gas Water Coolers).

A Flue Gas Blower serves as the prime mover for the flue gas slip stream. The Flue Gas Blower pulls the flue gas from the WAP tie-in, through the interconnecting duct, through the flue gas exit at the top of the Quencher column, and into the Absorber column.

Absorber – The CO_2 Absorber column is designed to efficiently remove CO_2 from the flue gas stream. The CO_2 Absorber is primarily comprised of two main sections: (a) the CO_2 absorption section in the lower part of the column and (b) the treated flue gas washing section in the upper portion of the column. The Flue Gas Blower forces flue gas upward, the CO_2 lean solvent contacts the flue gas and absorbs 90% of the CO_2 in the flue gas stream. A single pump removes the rich solvent from the bottom of the CO_2 Absorber and transfers the fluid to the Regenerator. Plate and frame heat exchangers are utilized to heat the rich solvent as it is transferred to the Regenerator. The upper portion of the CO_2 Absorber column is designed to maintain water balance and recover amine solvent vapor prior to exiting the vessel. The washing section recycles water to further recover amine within the flue gas. The chimney outlet is designed with a CEMS.

Regenerator – The cylindrical Regenerator pressure vessel was designed for the purpose of removing the CO_2 from the rich solvent fluid by heating the amine solvent to temperatures required to release the CO_2. This system operates at very low relative pressures (approximately 10 psi). A pair of shell and tube reboilers serves to transfer heat from low pressure steam supplied by the HRSG to the solvent solution in order to facilitate the release the CO_2 in the regenerator. The released CO_2 vapor exits the top of the regenerator and is cooled by the CO_2 gas condensing unit prior to entering the 1st stage of the CO_2 compressor.

Reclaiming – The CCS process incorporates a solvent reclaiming system which is designed to remove impurities such as heat stable salts (HSS), soluble metals, suspended solids (primarily iron), and amine degradation products from the lean solution. The Reclaimer is designed to operate as a simple batch distiller. The unit includes systems to control usage of reflux water and demin water and a caustic soda solution.

Compressor – An integrally geared eight (8) stage centrifugal compressor is used to compress the CO_2 released in the regenerator to a supercritical gas which is delivered to the pipeline. This type of compressor was selected because it offered the best combination of economics, efficiency, and power consumption for the CCS application. The compressor design consists of a bull gear that is driven by a 28,700 horsepower motor which incorporates a soft starter. The bull gear drives four (4) pinion gears, each having two compression stages. The compression stages are split into four low pressure (LP) and four high pressure (HP) sections. The compressor motor soft starter is used during motor starts to slowly increase voltage to the motor while controlling ramp up to full speed. Shell and tube heat exchangers (intercoolers) are incorporated into the CO_2 compressor design package. Intercoolers serve to cool the CO_2 gas after each of the first five compression stages. An additional shell and tube heat exchanger was installed on the compressor discharge piping prior to the pipeline delivery point. This heat exchanger performs final cooling on the supercritical gas and maintains temperature at required pipeline specifications.

Dehydration System – A dehydration (DH) system which utilizes triethylene glycol (TEG) to remove moisture from the CO_2, operates between the 4th and 5th stages of compression. The DH system is very similar to those used on natural gas systems for dehydration. The system key components are the contactor column, still column, reflux condenser, flash tank, gas/water exchanger, glycol/water exchanger, and reboiler. At the end of Phase 3, modifications were being planned to address efficiency loss in the compressor intercoolers (resulting in higher inlet temperature into the DH system) as further discussed below. A primary purpose for the DH system is to reduce the water content of the CO_2 gas to required transport pipeline specifications to minimize corrosion.

Supporting Equipment/Systems

In addition to the components detailed above, the following equipment and support systems are also included:

- A power distribution center (PDC) and control room building with a DCS was included to power, control, and operate the CCS and cogeneration facilities.
- A dedicated laboratory for the purpose of analyzing liquid and gas in the CC and Cogen Facilities to confirm operational plant conditions.
- A solvent filtration system to remove particulates that may accumulate in the solvent. The filtration system takes a side-stream of solvent from the circulation loop through a single booster pump which pulls the lean solvent and pumps it through the filtration system.
- A solvent delivery receipt, storage, and make-up system ensures solvent levels are maintained during normal operation. The system consists of solvent storage tanks, a solution

sump tank, a single solution sump pump and filter. The system is configured to allow clean solvent to be injected into the rich solution pump suction for make-up purposes and act as a system drain collection point to support equipment draining during periodic maintenance.

- A compressed air system to handle the air demand required to support the new BOP and CCS processes.
- A utility corridor between the BOP island and the CCS battery limit. The utility systems included within this corridor include: (a) steam supply line, (b) condensate return line, (c) instrument and service air lines, (d) demin water line, (e) cooling water lines, and (f) electrical cable tray and conduits.
- Various tie-ins to existing plant systems for support services include: (a) ammonia (Cogen SCR), (b) fire water loop, (c) service water, (d) utility water, (e) potable water, (f) oily-water separator, and (g) storm drainage.

Construction Process

On March 3, 2014, Petra Nova executed a joint Engineering, Procurement, and Construction (EPC) Agreement with both MHIA and TIC (jointly, the Consortium). Concurrently with the execution, a limited notice to proceed was issued to the Consortium, which allowed for work to proceed on project controls, engineering, site preparation work, warehousing, and permitting. On July 15, 2014, full notice to proceed was issued following the closing of the Project's financing. The construction process lasted for 30 months with the commercial operation date (COD) of the facility being reached on December 29, 2016.

Fabrication of the quencher and absorber towers was performed on-site rather than having sections fabricated in an off-site shop and shipped to the Project site. The Consortium believed that the size of these columns warranted onsite fabrication and would provide for better quality oversight. To support the effort, a laydown area was established allowing for the fabrication away from the actual Project footprint. A Texas-based steel plate fabricator supplied the steel plate for the effort. Fabrication of the first set of absorber and quencher modules was not as efficient as planned, and the Consortium fell behind the early schedule due to a learning curve associated with the fabrication fixtures, tight working conditions, and tight module tolerances specified in the MHIA design. A crew of welders was added to the nightshift, and production was restored to planned levels. A total of eight absorber modules and five quencher modules were completed, transported from the laydown area, and erected in their final positions.

Major vessels such as the regenerator, reclaimer, reboilers, and final discharge cooler were fabricated by two South Korean suppliers. The regenerator fabrication was started by a different supplier than the one that supplied the reclaimer, reboilers, and final discharge cooler. The regenerator was transferred to the second supplier for completion when the first supplier filed for bankruptcy and could not complete the work. Before shipping the regenerator from the final fabrication shop, a pneumatic leak test was performed (rather than a hydro leak test due to the amount of water required for a hydro test). The regenerator was delivered to site as a complete single unit and set on its foundation with multiple heavy lift cranes. The planning and execution effort to deliver the regenerator (approximately 170 feet tall and 26 feet in diameter) to the Project site from an off-loading point on the San Bernard River miles from the site required months of studying, planning, and coordinating with the Texas Department of Transportation and local utilities.

Fabrication errors delayed the delivery of the CO_2 compressor; however, they were corrected, and test results were within specifications and inspections during disassembly revealed no issues. The compressor was packaged, and air freighted to Houston in order to preserve the Project construction schedule. As key construction activities were completed, areas of the Project were handed off to the commissioning team for systems checkout and preparation for operation in advance of demonstration testing and performance testing to achieve COD.

CC Facility Testing

Prior to COD, the Consortium was required to demonstrate that the CC Facility and BOP facilities met minimum capability and performance requirements. A facility capability demonstration tests demonstrated that the CC Facility achieved stable, reliable and safe operation over its entire designed operating range from start-up, load ramping, shutdown, and emergency shutdown scenarios. In order to accomplish this, the Consortium performed the following tests from December 15, 2016 to December 23, 2016:

- Emergency Shutdown - Emergency plant shutdown logic was simulated with the CC Facility off-line using the control system to verify final status of trip logic after the Emergency Stop (E-Stop) push button is pressed. An actual emergency shutdown test of the CC Facility was performed to support a CO_2 compressor inspection prior to the performance test period. The emergency shutdown test demonstrated that the CC Facility will shut down safely without mechanical or electrical damage to its equipment and piping systems and verified that appropriate equipment fail-safe conditions are established.
- Plant start-up and shutdown - The demonstration of start-up and shutdown was successfully conducted in accordance with the instructions/operation manual.
- 50% Load Operation - 50% turndown operation was established and held for a prescribed period at stable load to ensure that the flue gas flow rate, CO_2 production flow rate and CO_2 composition in CO_2 product can be maintained within the required ranges.
- Full load operation - Full load operation was established and held for a prescribed period at stable load to ensure that the flue gas flow rate and CO_2 production flow rate can be maintained within the required ranges.
- Ramp up and down (from 50% load to full load, from full load to 50% load) - The operating load of the CC Facility was successfully adjusted from 50% stable load operation to full load stable operation and to verify the MHIA specified ramp rate limits for the CC Facility.

A performance demonstration test was conducted from December 26, 2016 to December 29, 2016 to demonstrate that the CC Facility can achieve the original design parameters. During this test, the CC Facility, Cogen Facility, and BOP facilities were operated at a stable 100% load point for a continuous prescribed period. The test results met all minimum performance requirements including (a) CO_2 production capacity, (b) CO_2 product quality, (c) permit limits, and (d) utilities (for example, electrical power consumption, steam consumption, and make-up water to the cooling water).

As described above, the process consumes some KS-1 during operation. As a result, the KS-1 consumption rate is monitored, and make-up quantities are tested to ensure no cross-contamination when mixed into the process. There are two key tests tied to KS-1: (a) a consumption test to confirm that KS-1 consumption does not exceed design expectations and (b) testing of all KS-1 deliveries to ensure they meet the required quality specifications. The KS-1 solvent is tested prior to delivery using an independent third-party testing company and again upon delivery to ensure there was no cross contamination during shipping. This test is designed to ensure the KS-1 meets required specifications set forth in a baseline infrared spectroscopic analysis (fingerprint of the chemical).

To confirm that consumption rates of KS-1 does not exceed the original design parameters, a consumption calculation procedure and time period was jointly developed and agreed upon by MHIA and Petra Nova and interim calculations were done at the end of each reclaiming cycle. The KS-1 consumption calculation procedure required: (a) the collection and analysis of samples from various locations in the CCS process and (b) the collection of DCS data on process and storage tank levels, both to determine KS-1 Solvent volume and concentration. KS-1 make-up quantities added to the CCS process during a reclaiming cycle is accounted for in the calculation along with corrections for CCS load and flue gas CO_2 concentration. Any lost KS-1 (i.e., thru leaks) is estimated and a standard amount of consumed KS-1 is assumed for each start-up and shut-down cycle. The results were within the expected consumption rate.

CC Facility Enhancements

During the construction process, there were several items identified and deployed to improve the safety, operations, and maintenance of the Project:

- CO_2 Monitoring – During the Phase 1 HAZOP, it was not fully concluded how CO_2 leak detection would be specifically managed around the site including the number, type (continuous area monitors, leak detection, personal portable monitors), and location (all areas, near high pressure, etc.) of such devices. Upon further examination during Phase 2, the Project deployed a CO_2 detection system around the high-pressure area with additional gas detectors at the control room as an enhancement.
- CTG Control Logic Changes – The original design of the cogeneration controls and steam header pressure controls were not optimized to follow the CCS operation and the expected electrical dispatch requirements of ERCOT. During Phase 2, it became apparent that modifications to the steam header pressure control and combustion turbine dispatch process were needed to provide for smooth facility start-up and ramping. These modifications required control logic changes to allow for this flexibility.
- Absorber Elevator – Upon better understanding of how maintenance activities would be performed at various levels in the absorber column, it was determined that this would best be handled using a permanent elevator. The elevator installed for construction purposes remained as a permanent fixture.
- Access Walkways/Platforms/Ramps – Site walk downs envisioning how operational “rounds” would be conducted caused Petra Nova to install additional access stairways and ramps throughout the site. Most notably is a stairway between the absorber column and the heat exchanger upper level which would have otherwise required someone to climb down from the one side to get to the other side.
- Area Site Improvements – Some impacts such as the tearing up of roads from re-routed truck traffic around the construction site as well as some improvements to existing facilities were addressed.

- Backup Power – There is a single source power feed into the Project, and if there is a 138kV outage or the line needs to be taken out, the entire Project would lose power. Since power had to be brought in from another location to perform construction activities, Petra Nova elected to modify and upgrade this system to provide an alternative backfeed in the event of an outage on the primary feed. Petra Nova utilized a great deal of the construction power system so that the modifications were minor when compared to installing a completely new system.

- Miscellaneous – There were other miscellaneous changes made such as various technical studies, additional instrumentation, additional pipe routing and metering for discharge streams, access/entry points, but these were less significant in terms of costs or impact to the overall Project.

In addition to these enhancements, there were design changes and/or enhancements due to the discovery of design deficiencies during commissioning that weren't anticipated during the FEED study HAZOP efforts. The most significant are summarized here:

- FRP Ductwork Design Changes/Drains – The WAP Unit 8 takeoff design was not fully developed during the FEED phase. Various design refinements both on the FRP design itself, its interconnection into WAP Unit 8, and drain configuration were made.

- CO_2 Bypass and Interconnection into the Pipeline – The valve configuration and piping interconnection into the Pipeline wasn't sufficiently defined in the FEED phase. The valve at the outlet of the CO_2 compressor wasn't designed to handle the pressure drop upon initial fill of the Pipeline (i.e., it was not designed to accommodate delivery of CO_2 when the TCV pipeline is at pressures lower than 150 psig). A smaller diameter bypass line and control valve was designed and installed to handle the pressure drop when pipeline pressure conditions prevent the use of the original primary control valve.

- Transformer Firewall – The location of the demin water building was shifted slightly to stay off the existing gas line feeding the CTG. This shift pushed the building close to the CTG generator step-up transformer resulting in a firewall being built between it and the building.

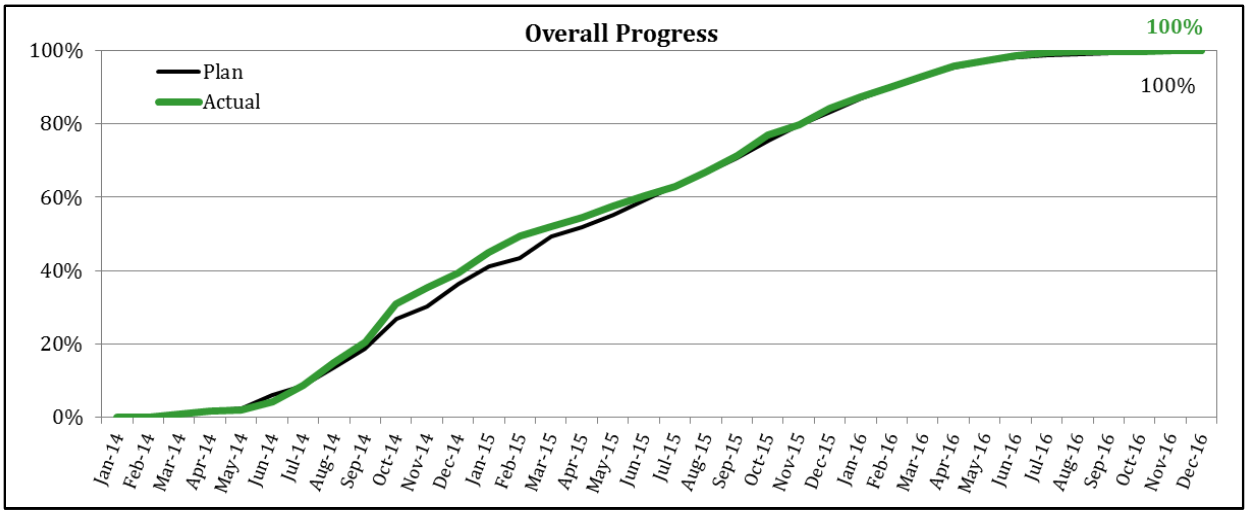
- CEMS Modifications – The plan was to reuse the existing CEMS installed on the CTG in peaking configuration; however, additional modifications and measurements were necessary to support installation of the inlet bleed heat (IBH) system and the NO_X measurement approach (differential method) that were not originally planned.

- Petra Nova to TCV Pipeline Interconnection Expansion Loop – During early CO_2 deliveries and operation of the TCV pipeline, inspections revealed pipe expansion at both ends of the approximate 1,800-foot section of pipeline that connects the Petra Nova CO_2 compressor discharge to the TCV pipeline at the WAP metering station. A study was commissioned with a third-party engineer, which concluded that design pipeline stresses were being exceeded under normal operating conditions due to the magnitude of the expansion. The third-party engineer designed an expansion loop, which was installed at the metering station end of the interconnection.

Other, less significant, items included dealing with a few existing but undocumented underground utilities, repairs to deficient facilities and other customary scope changes routinely experienced on brownfield retrofits. All changes and improvements were absorbed by the Project budget and schedule.

Manhours/Construction Progress

At the peak of construction, TIC had 323 construction employees on-site (January 2016) and over a million manhours were worked. Safety was a major focus with regularly scheduled safety meetings and periodic safety stand-downs. This focus resulted in a Recordable Incident Rate of <1 and a zero Lost Time Incident Rate. Additionally, a zero Environmental Reportable Incident Rate was achieved. The following graph shows the actual progress for EPC activity.



Non-Construction Phase 2 Activity

During Phase 2, in addition to the EPC activity, several additional project activities were being conducted to support the management and operation of Petra Nova, most notably corporate matters, permitting, and execution of commercial agreements.

Permitting – A range of permitting activities involving air, waste handling, and waste discharge were performed during Phase 2. The key activities are described as follows:

- Air Permit (Cogen Facility) - Title V and New Source Review (NSR) permit were obtained from TCEQ for the Cogen Facility. Prior to converting the peaking facility to the Cogen Facility, a Title V permit existed for the peaking facility that was abandoned when the new permit was obtained. The new Title V permit for the Cogen Facility was issued in June 2014 and includes the Cogen Facility and balance of the plant except the absorber stack. As discussed above, since the Project is in the HGB non-attainment areas, emission credits were needed for permitting, and necessary credits were obtained and surrendered to the TCEQ. The NSR permit for the Cogen Facility was also obtained which included Leak Detection and Repair (LDAR) regulations to monitor fugitive VOC leaks from facility equipment. The permitting process also included a CO_2 netting demonstration to avoid the Prevention of Significant Deterioration (PSD) permitting process. The CO_2 emissions from the Cogen Facility was demonstrated to be below the 75,000 tons per year trigger.
- Air Permit (Absorber Stack) - The absorber stack was permitted as a part of the WAP Unit 8

facility NSR permit and Title V permit. The WAP Unit 8 permit was modified to include the absorber stack, and the total emissions for this unit included the sum of emissions from both from the WAP Unit 8 stack and absorber stack as a dual stack permit. CEMS is installed on the WAP Unit 8 stack, absorber stack and the inlet to the duct work to calculate and monitor emissions from the dual stack configuration. This configuration was approved by the EPA, and periodic emission reports are submitted to the EPA and TCEQ. All initial compliance demonstration tests were performed at the Cogen Facility, absorber stack, and the WAP Unit 8 stack to demonstrate the emissions limits listed in the permit representations.

- LDAR – as required by the TCEQ, the fugitive VOCs are required to be monitored and reported under the LDAR program. LDAR VOC emissions are tracked periodically by a contractor to measure the fugitive VOC emissions from the tagged 2,393 LDAR emission points. Initially these points were monitored on a quarterly basis and then moved to a semi-annual frequency as there were no notable leaks detected.
- Texas Pollutant Discharge Elimination System (TPDES) – a total of four waste streams were permitted under the Petra Nova TPDES Permit: (a) discharge from the plant drains oil-water separator, (b) discharge from the waste water treatment system (including quencher blow down, RO reject, scrubber wastewater, sludge thickener overflow), (c) blow down from the cooling tower, (d) storm waters, and (e) the final discharge to Smithers Lake collecting of the all these listed waste streams.
- Hazardous Waste Permit/Registration **–** issued by TCEQ, this permit covers the storage, handling, and disposal of hazardous waste. Petra Nova waste streams including sludge, reclaimer and pre-coat waste, oily rags, and other waste items have been characterized as non-hazardous waste.
- As required under the TPDES Permit, the following pollution prevention plans are in place: (a) Storm Water Pollution Prevention Plan (SWPPP), (b) Pollution Prevention (P2) Plan, and (c) Spill Prevention Control and Countermeasures (SPCC) Plan.

Corporate Matters – During Phase 2, under the Petra Nova Parish Holdings LLC partnership agreement, the management structure of Petra Nova was determined. Both NRG and JX seconded employees into the Project to provide leadership, asset management, financing, debt compliance, environmental, legal, and contract management services. Petra Nova also entered into corporate services contracts with NRG for corporate support services and with JX for technical services related to Petra Nova’s ownership share of TCV.

Commercial Contracts – During Phase 1 and 2, numerous commercial agreements were executed covering important services to the Project. The key agreements addressed:

- Provision of flue gas from the host coal unit (including maintenance/availability plans for the host coal unit)
- Construction management agreement with NRG to manage construction activities
- Operating and maintenance services from NRG for both the CC and Cogen Facilities
- Site services agreements with NRG to provide for common services (already in place to support WAP) for both facilities – includes items such as site security, maintenance of grounds, warehouse services, and raw and service water

- An agreement with the NRG dispatch group to handle the daily interface with the ERCOT ISO for delivery of excess power from the Cogen Facility
- Gas supply agreement with a third-party gas supplier
- A supply agreement for the purchase of KS-1, the proprietary solvent used at Petra Nova
- Provision of a rental treatment equipment to characterize and treat waste streams
- CO_2 supply agreement between Petra Nova and TCV (and related transportation agreement with TCV Pipeline)

Petra Nova purchased two 4.6-acre tracts from NRG Texas Power LLC – one for the BOP facilities (includes waste water treatment, raw water clarifier, demineralization facilities, the Cogen Facility, and the Petra Nova office) and one for the CCS equipment (including the cooling tower and control room). Additionally, Petra Nova and NRG Texas entered into easement agreements to allow for (a) the construction of utilities between the two facility tracts (including both overhead and underground facilities such as the steam and condensate lines, cooling and demin water, waste water treatment lines, and power and fiber optic lines), (b) the flue gas duct between the host coal unit and the CCS battery limits, (c) a power transmission line from the Cogen Facility to the Petra Nova switchyard, (d) interconnections with plant infrastructure (e.g., fire water, service water, raw water, and ammonia), (e) drainage easements, and (f) general reciprocal ingress and egress rights across each other's property.

Lessons Learned

At the conclusion of Phase 2, participants from Petra Nova and the Consortium held a working session to document "lessons learned" with a goal to identify good work practices, innovative approaches, negative experiences, contractor performance, deviations from what was planned versus what was performed, unexpected events encountered, and other lessons learned from both owner and contractor perspectives, all with the intent to improve processes and minimize risk for future projects. Areas of discussion focused on included project development, contracting strategy, project planning, procurement, safety, construction, QA/QC, start-up, and initial operations. The table below is a summary of key observations:

Description	Lesson Learned
Safety	
Program Structure	Petra Nova benefited from hiring a contractor with a robust safety process; specific site safety plan; adequate staffing, corporate support, upfront planning, orientations, and field observations.
Use of CVIS (Craft Voice in Safety) Program	Constructor's practice of using a craft only safety committee to communicate upstream to project management on safety items – ensures all craft has a voice in safety program
Supervisor Alignment Meetings	Enabled management to assess the buy-in from front line supervision to the safety process.

Description	Lesson Learned
Use of Outside Consultants	Third party review can identify and point out deficiencies that are overlooked by site management.
Work Plan Reviews	Open invitations for participation extended to contractor and owners management and personnel to broaden involvement.
Hard Hat Designation	Different color for hard hats makes foremen more visible/identifiable in the field.
Communication Plan on Overhead Hazards	Increased safety awareness and minimized exposure of personnel to overhead dropped object hazards. Everyone on the site knew about these hazards through signage, reviews and stand downs.
Report Everything Mindset	Provided early detection of unsafe trends which were dealt with in a timely manner.
Use of Temporary Decking	Good decision to use on Process Pipe Rack - facilitated productivity and safety by mitigating overhead hazards related to dropped objects. The wood decking had to be removed and disposed of at completion. Option would have been to install permanent grating.
Reporting of Near Misses	Investigating all "near misses" facilitated an early response and focus on potential safety lapses/trends and mitigated the possibility of major accidents.
Management Involvement	Ongoing interaction with crews during real time safety observations and feedback discussions conveys and reinforces to craftsmen that management is engaged and an integral part of the safety culture.
Off-site Safety	Safety program was extended to include off-site activity – specifically safe driving practices to reach project site.
CO_2 Hazard Safety Program	A site-specific CO_2 Hazard Safety Program was not studied during the development phase of the project. A study was performed to quantify the risks which led to the development and implementation of a CO_2 hazard plan and training prior to commissioning. The plan also included the installation of monitoring and warning equipment.
Environmental	
Spill Reporting	Every spill (e.g., equipment oil, hydraulic fluid, etc.) was reported no matter the size - provided trend data and facilitated improvements in prevention and response planning.
Site Oversight	Constructor kept an environmental manager onsite resulting in improved communication with Petra Nova environmental team and ensured focus on project environmental standards and construction permits.
Wildlife Management Plan	The project lost productivity due to migratory bird nest on a critical lift crane. Having rehab license in place early in the project schedule would minimize wildlife impacts.

Description	Lesson Learned
Review of Containment Requirements	Review of containment requirements on chemical storage and equipment leads to better planning for containment of spills and minimizes area impacts and clean-up costs.
Contingency Planning	Ensure a multilayer response and communication plan is in place to handle emergencies during holidays, week-ends and off hours to prevent escalation of unplanned situations.
Waste Disposal Permit Discharge Restrictions	Having an upfront plan for waste disposal for all chemicals, KS-1, demin and process water, chemical flushes, etc. leads to better contractor understanding and planning for prevention, containment, collection, and disposal.
Recycle Program	Integrate a recycle program into the overall environmental project program up-front.
Sustainability Program	The Sustainability Program focused on areas where cost savings could be realized, which included: (a) solid waste, recyclables, scrap metal, and concrete, (b) wood reuse and recycling, (c) switchable and low energy lighting, (d) equipment wash water recycling, (e) electric carts, and (f) paper use reduction.
Development	
Major Equipment Selection	First-of-a-kind scale up uncovered design issues during start-up and operation with certain equipment. The lesson learned is to better understand where manufacturers are pushing their equipment envelope (size, performance, temperatures, pressures, environment, materials, etc.) and either select a more proven vendor (if one exists), or drill into the vendors plan to address, and/or contract for more robust performance guarantees or warranties.
Process Scale-up Validation	The validation process relied upon MHIA's technical understanding and experience obtained from the smaller scale Plant Barry project. An area that could have been better understood was the process chemistry changes over time and impacts from solvent degradation. The scaled-up Project was validated during demonstration testing. The testing was performed at new and clean conditions; hence, it was unknown if enough design margin exists to mitigate impacts from performance degradation over the period between maintenance outages.
Integration into Existing Plant Systems	The project team worked closely with the Plant on leveraging shared services and facilities where excess capacity/availability existed, and while technically feasible and reasonable, some permitting/regulatory nuances prevented the Project from integrating into certain systems that the Project had previously planned on (and was technically acceptable). Expanding plant integration evaluations beyond technical feasibility assessment to fully understand broader reaching permitting, commercial,

Description	Lesson Learned
	regulatory and other implications can help prevent unexpected late-changes to work scope and schedule.
Interface WA Parish	The project team developed a comprehensive tie-point list into interfacing Plant systems but given the high number of interfaces between Petra Nova and plant infrastructure, it was concluded that more up-front communication and sharing of design documents and development of appropriate agreements can help coordinate integration planning.
Development of Staffing Plan	The team built the original staffing plan based on feedback from MHIA in conjunction with NRG Plant Operations. Staffing for the standalone CCS may have been planned sufficiently, but when integrated with all the extended BOP facilities (water treatment, Cogen, etc.) and PNPH pipeline obligations, initial staffing levels developed by the project team ended up being insufficient. A more careful end-to-end assessment of all the O&M obligations beyond CCS would have improved upfront planning.
Start-up Manpower Requirements	Process start-up (S/U) and shutdown (S/D) was not well understood by the Owner's so automation vs. manpower was not optimized. A better understanding of S/U and S/D would have led to a more efficient procedure, manpower, and likely some process automation.
Schedule of Values versus Milestones	Development of a detailed schedule of values minimized potential disputes when processing monthly invoices.
FEED Studies	Multiple FEED studies had a significant positive impact on defining project engineering scope and was the key factor contributing to ~1% in change orders on the project.
Work Scope Definition	FEED studies and up-front engineering scope development work resulted in a good scope definition to support the open book process and to minimize change orders.
HAZOP	The HAZOP process design, review, and validation was useful in vetting and validating the process design. The activity could have been better facilitated, but the thorough review of the process design provided a necessary venue for joint validation and understanding and consensus on the process design.
Plant Layout	The Barry Plant layout served as a useful reference for the scale-up and layout developed for Petra Nova. Further optimization of the Petra Nova layout (for example, moving the cooling tower from the BOP site to the CCS site) provided cost reduction opportunities.
Equipment Standardization	Potential opportunities to reduce maintenance costs may have been missed by not standardizing certain equipment to reduce the need for excess spare parts (e.g., pumps parts, cooling water heat exchanger plate packs).

Description	Lesson Learned
Planning	
Design Review	Committing time for 3D model walks and design reviews contributed to improved planning and execution and ensuring constructability. Examples of design enhancements or verifications included: (a) the addition of a dump condenser to handle excess steam during CCS start-ups and part load operation, (b) decision to fabricate the absorber and quencher towers on-site (even with the learning curve), and (c) decision to take a modular approach to completing the compressor and process filter (which minimized and simplified the field erection scope).
Permanent versus Temporary Decking	The use of temporary decking in certain areas over permanent decking should have taken into consideration future maintenance access as it would have justified installing permanent decking in areas later found to be deficient or posing a safety risk.
FRP Duct Design Engineering Interface	The design of the FRP interconnection with WAP should have been integrated into the EPC Consortium. Issues with communication, coordination, and execution could have been minimized or eliminated if work was properly transferred from the original design firm to the EPC contractor scope. A late design change was also needed to properly provide power to operate the shut-off dampers at WAP.
Execution of Overseas Procurement Orders	Concerns over overseas suppliers of equipment and timely execution of orders did not manifest into critical path schedule impacts. The contractor managed its suppliers exceptionally well and when issues came up, they were addressed and resolved promptly.
Project Team Selection	The project team selection was a significant factor in the project success in achieving its goals. The project teams representing each organization were made up of individuals bringing the right safety culture, attitudes, and experience to the integrated team which facilitated communication, problem solving without finger pointing, and execution at a high-performance level.
Scheduling and Reporting	Seven P6 schedules were generated and maintained during project execution - all ultimately being fed into a master schedule for overall project tracking. The EPC contract should stipulate that a single master schedule is required for the project.
Document Controls	Assignment of constructability oversight needs to be done early in the project. MHIA was assigned this role and was responsible for establishing and maintaining one centralized document control center. This facilitated successful project planning and execution.
Owner Issues Log (OIL)	A centralized tracking and processing of issues provided a transparent and visible means of documenting issues in one location, assigning stake holders, tracking them to resolution, and providing a historical account of the issue. The process expedited the timely resolution of issues.

Description	Lesson Learned
Permitting	
Permit Matrix	Development of a permit matrix served as a weekly focal point for status updates, communication, and execution of permitting activities. The document served as a useful tool for managing the process internally and with project contractors which supported the permitting process.
Contractor Support	Integrating Contractors into the permitting process facilitated timely execution of project permits.
Corporate Environmental Support	A lack of coordination with the NRG corporate environmental team resulted in a late discovery of an omission in the air permit application which resulted in added pressure to get the required elements in place.
Dispersion Modeling	Air modeling feedback on design refinements was coordinated through the Owner which made the process inefficient. Putting the proper confidentiality agreements in place between trusted consultants with clear and effective communication protocols (to include Owner) can help alleviate such bottlenecks, sharing of information, and confusion.
Vetting Subcontractors	The Constructor reported that the Owner's preferred CEMS contractor was difficult to work with and impacted the CEMS schedule. An investigation revealed that the CEMS contractor work load impacted its ability to deliver on schedule. Better vetting of contractors' ability to deliver and identifying alternate CEMS contractors could have mitigated this issue.
Engineering	
Regenerator - Hydro Testing	Original specifications required hydro-testing of the regenerator vessel. It was determined prior to pressure testing that it could not be hydro-tested, and an exception was issued by the fabricator requesting approval to perform a pneumatic test. The EPC did not contain provisions for pneumatic testing, so Petra Nova had to evaluate the procedure and risks. Future EPC specifications should delineate the acceptability of pneumatic testing to facilitate timely project execution.
Compressor Engineering Design Issues	Design issues were discovered and resolved during shop testing. The Engineering Team responded promptly to the challenges, resolved the issues, and tested them before shipping. Discovery of design issues in the factory proved to be a critical element that facilitated resolution and mitigated any impact on the project schedule.
Pipe Rack Structure - Expansion Issue	A pipe rack structure expansion issue was identified sometime after erection was completed. The Project Team initiated a Root Cause Analysis (RCA) and promptly identified the cause which led to MHIA design modifications. The process worked well and resulted in a timely resolution of the issue, but expansion should have been addressed in earlier stages.

Description	Lesson Learned
Use of 3D Model	A CCS 3D model was built early in the process and was updated as drawings were issued and/or updated. The model reviews were effective in identifying design issues and resolving them quickly. The model could have been better used by Operations personnel for training.
Design Margin	It was discovered that healthy design margins were intentionally included to help ensure the Project achieves its commercial guarantees on a first of a scale project. More open discussions among team members explicitly balancing design margins and output guarantees may have helped to optimize both objectives.
CO_2 Piping Design – Start-up Bypass	A start-up bypass line was necessary for low downstream pressure start-up conditions. Like other start-up scenarios discussed in other sections, this was missed in early design reviews. More emphasis on start-up of systems under various scenarios was needed. (bypass, automation, manpower, dump condenser).
Project Construction	
Control of Design Drawing Revisions	The contractor drawing revision control process was determined to be the root cause for a misinterpretation in the fabrication shop that led to a potential design deficiency in the absorber foundation. (A detailed analysis of the as-built foundation showed sufficient margin to meet required strength specifications.)
Skilled Task Assessment	Welding requirements for the absorber and quencher fabrication were beyond initial expectations and planning – ultimately requiring a night shift to be added. More up-front planning on work detail, specifications, and skilled labor would have improved productivity and execution.
Engineering Review Complacency	A fabrication error on a common BOP piece of equipment was missed when the fabricator and inspection teams were complacent and missed the error during final inspection. A thorough shop inspection should have been performed to verify fabrication matches OEM design drawings even with the low risk assessment of commonly used equipment.
Phase Array Welding	Once phase array welding was fully implemented, it provided for increased productivity.
Track Welding	Once implemented, track welding proved to be effective in improving productivity - this process should have been more widely applied to the fabrication of vessels.
Hydro and Pneumatic Testing Review Packages	Contractor provided excellent review packages for review and approval for hydro-testing which carried over to the development of pneumatic testing procedures for Owner approval.
QA/QC - Processes and Procedures	Contractor had excellent documented processes and procedures in place which included area/system turnovers, a smart sheet tracking process,

Description	Lesson Learned
	and a construction work list tracking mechanism (pre-punch list). Project productivity and execution was improved.
Construction Support from Engineering Leads	Contractors decision to place engineering leads in the field to perform regular project walk downs was effective in identifying issues early and resolving them in a timely manner by collaborating with office engineers through regular daily communications.
Project Start-Up and Commissioning	
Planning - Five Step Process	The contractor's commissioning team implemented a five-step planning and execution process which involved all stake holders. The process steps included: (1) verification of equipment mechanical completion and testing, (2) systems testing, (3) dry commissioning, (4) wet commissioning, and (5) training and safety (integrated into the overall process from start to finish). Planning was effective, complete, and clearly communicated which had a positive impact on productivity and execution.
Team Make-Up	The Project Team was integrated with key members from all stake holders. The roles and rules of engagement and cooperation were well defined and agreed upon before project execution began. Daily meetings facilitated timely communication, identification of problems, resolution of issues, productivity, and execution.
MOC Program	A Management of Change (MOC) program was implemented with a well-defined process, this provided a reliable detailed record of all project changes (to drawings, as-builts, procedures, control logic, etc.). One lapse was the use of temporary relay settings to facilitate start-up and commissioning; however, the settings were not documented under the MOC program.
Work Areas - Identification of Control Areas	The startup and commissioning team implemented a visible means of identifying project components that were undergoing commissioning activity by using purple rope and tags – this was very effective.
Operations Transition	
Delivery of Project Documentation	The contractor document turnover process was well defined in the EPC contract leading to proper execution and turnover of document revisions.
Spare Part Documentation	The requirements on the Consortium to provide spare part specifications was not sufficient to satisfy the NRG inventory management system requirements resulting in an excessive amount of manpower spent on obtaining missing part specifications.
Spare Part Management	The project team should have included a dedicated member from NRG's procurement group to manage spare part deliveries. Allocating the work

Description	Lesson Learned
	among different team members was not efficient as it lacked coordination.
Warranty & Punchlist Program	The project team made a commitment early in the project to effectively manage and execute on warranty and punch list items with a focus on action and timely turnaround. The contractor's smart sheet program was a key in facilitating the process. Priorities and disputes were quickly elevated to proper levels of authority.

Phase 3: Demonstration and Monitoring

Phase 3 is a three-year demonstration period commencing with the operation of the CC Facility; this period was from January 2017 through December 2019. At the beginning of Phase 3, the CC Facility was released into full operation for sustained use and operations and maintenance support. The specific objective of Phase 3 under the CA was to operate the CC Facility and report on its operating performance along with the CO_2 monitoring activity at West Ranch to ensure that the transported CO_2 to West Ranch is sequestered in a secure geological storage facility.

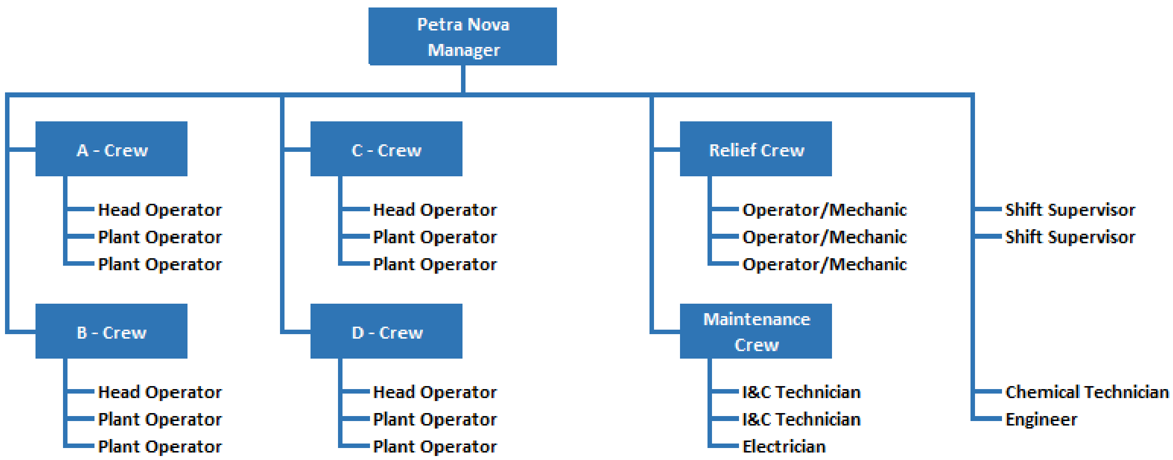
Key elements of project tracking included:

- CCS/BOP – Performance of the CCS/BOP as it relates to overall CO_2 capture rates, energy consumption, chemical consumption, and issues such as disruptions or outages. Additional information includes optimization work (mechanically, chemically, or procedurally), key operating and maintenance issues, and selected costs aspects.
- CO_2 Monitoring – A MVA Plan was developed and administered by the Bureau of Economic Geology to ensure that the CO_2 is sequestered in a secure geological storage facility, a program exists to monitor any leaks of CO_2, and a mass balance program is established to quantify any released CO_2 (see summary of monitoring activity below).

The project management and overall operations approach for the Project were administered according to NRG's operational policies, procedures, and controls, which were developed over time consistent with best industry practices. First and foremost is a commitment to safety, which is a core value with the goal of zero injuries at the Project. To achieve this goal, the team focused on accident prevention. They apply NRG's safety standard as broadly as possible and apply it to all managers, supervisors, staff, contractors, and visitors. During Phase 3, the Project experienced only one lost time safety event, demonstrating our commitment to safety.

Staffing

Petra Nova Plant Operations personnel are responsible for operating processes and equipment in a safe, clean, and effective manner to ensure the capture of high-quality CO_2 while meeting all regulatory compliance requirements. Petra Nova entered into Operation and Maintenance Agreements with NRG Texas LLC to provide a dedicated team, sourced from the NRG Operations group, to be trained to operate the Cogen and CC Facilities. The Organization Chart on the following page shows the disciplines included in the 23-member Operations Team dedicated to the Project.



Notes:

1) All Operators perform minor maintenance
2) Shift Supervisors work day shift only 5 days per week
3) Maintenance activities will be suplemented from WAP maintenance staff as necessary, and billed to PN
4) Other O&M activities (environmental, warehouse, etc.) will be performed by WAP staff and billed to PN

Twelve Operators are on a rotating shift schedule. They consist of four crews of three members each, working two 12-hour shifts to provide 24/7 coverage. The three member teams have a head operator in the control room with the other two members making rounds in the CCS and BOP portions of the Project. Supporting these crews are two shift supervisors that rotate through a day shift schedule five days per week.

In addition to the shift work, there is a three-member maintenance team comprised of two Instrumentation and Control Technicians and one Electrician (all working standard business hours) with supplemental maintenance support pulled in from the host coal plant (WAP), as needed. There is a Plant Manager, a chemical technician, an engineer, and a three-member relief crew to cover operators and maintenance staff. WAP provides support services (primarily maintenance, environmental and administrative support services) on an as-needed basis. These support services are anticipated to include between three to five full-time equivalent employees (FTEs) on an annual basis depending on operational needs.

The Operations Team manages the day-to-day activity required to keep the Project operating in a safe, reliable, and environmentally responsible manner. The Operations Team, working in coordination with Asset Management, is continuously challenged to look for ways to lower operating costs, reduce downtime, and improve plant reliability while maintaining full compliance with all safety and environmental regulations. A comprehensive preventative maintenance program is critical to preventing unscheduled shutdowns and unnecessary maintenance. As expected with any first-of-a-kind facility (especially the scale of the Project) combined with Houston's summer ambient conditions, the Operations Team faced numerous challenges during the Demonstration Period, many of which are detailed later in this section of the report.

In additional to operating the CC and Cogen Facilities, Petra Nova's operators are also responsible for maintaining communications with (a) WAP plant operations (to track status of WAP Unit 8), (b) Harvest Pipeline (the contract operator of the TCV Pipeline, who maintains a 24x7 control room), (c) operators of West Ranch, who also maintains a 24x7 control room), and (d) NRG Commercial Operations (to coordinate scheduling excess MWs from the CTG being delivered to the ERCOT market).

The primary role of the chemist is to monitor BOP water and steam chemistry, CCS process chemistry, outfall discharge chemistry, flue gas analysis, and testing of captured CO_2 to ensure that it meets pipeline specifications. These activities are critical to ensure that Petra Nova is in compliance with (a) environmental permits and (b) project operating procedures. The chemist also performs reclaimer sampling and analysis and waste characterization for off-site waste disposal as well as manages chemical inventories required to maintain water, steam, and process chemistry. Monitoring consists of regular sampling and analysis. Another key activity is analysis of solvent samples from nine different locations in the CCS process to determine (a) timing to start a reclaiming cycle and (b) when fresh solvent make-up volumes need to be added.

The chemist performs the analysis in a dedicated on-site lab furnished with specialized equipment designed to analyze samples containing KS-1. For sample analysis that isn't performed on-site, the chemist oversees analysis performed by third party labs. Other chemist activity includes: maintaining lab equipment, maintaining bulk chemical inventory for the CC and Cogen Facilities, and facilitating pre- and post-regulatory inspections. Given the uniqueness of the CC Facility chemistry requiring specialized training, it is difficult for the WAP chemistry group to provide full back-up support. At times during Phase 3, Petra Nova had to contract with MHIA to provide a back-up chemist. The Project is considering adding additional chemist support to the team.

The dedicated Engineer plays a critical role in working with Operations to address the technical challenges of Petra Nova, most notably the issues experienced with a first-of-a-kind facility. Other key activities include: (a) working with the technology provider on warranty items, technical issues, and proposed changes to operating protocol, (b) developing specifications for capital and expense projects and depending on the nature of the project, managing third party contractors, (c) collaborating with various departments to maintain mechanical, electrical, and I&C integrity of CCS programs and processes, and (d) generally performing all engineering related needs of the Project, for example, monitoring equipment performance and evaluating any proposed enhancements. The engineer supports (a) Asset Management on reporting obligations and development and validation of CCS operating decision models and (b) the Project chemist in assessing sample analysis results and trends. Throughout Phase 3, there has been a significant amount of interface between the plant engineer and OEMs to address RCAs and other technical aspects of the facility.

Operations

Operations staff has an extensive background in power plant and auxiliary systems operation and maintenance. Training of the team involved classroom and field instruction as well as field participation in system walk downs, inspections, checkouts, and turnover of facility systems to the commissioning team. Training continued during initial start-up and commissioning as the team shadowed and performed activities alongside MHIA's operating personnel. The chemist shadowed the MHI lab technician on sample collection rounds and during sample analysis in the lab. To supplement desk operator training, Petra Nova purchased a training simulator that simulates CC Facility operation under various operating conditions. Some operating scenarios and related challenges are discussed below:

Initial Start-up (when pipeline pressure is below 150 psig) – A 4-inch startup bypass line was designed and installed during commissioning when it was discovered the pressure drop across the existing 12-inch control valve when the pipeline pressure is at 0 psig would result in gas temperatures dropping below recommended limits for the pipeline protective coating. MHIA designed the bypass system to be used when start-up will require delivery of CO_2 when pipeline pressure is less than 150 psig. Once pipeline pressure reaches 150 psig or higher, the bypass is closed, and the 12-inch control valve is opened to continue and complete the pipeline fill.

Startup (Cold/Cold Standby) – Cold start-ups can take 12 to 18 hours to reach full load. The field operators perform a variety of manual activities as directed by the desk operator. Initial start-up activity (e.g., start-up of water and waste water treatment system, DH system, process circulation) are done using purchased power, hence prior to starting the CTG. Once the Cogen Facility is at base-load, the remaining systems are started. The flue gas dampers are opened, and the flue gas blower is started. Once CO_2 capture is started and stabilized, the compressor is started and CO_2 delivery to the pipeline commences.

Startup (Hot/Hot Standby) – Hot start-ups can take from 2 hours to 9.5 hours to reach full load depending on which of three operating modes the CC Facility is in prior to the start-up:

- Recycle Mode – In recycle mode, the CC Facility is not delivering compressed CO_2 to the pipeline but is operating at 50% load with the CO_2 compressor and flue gas blower remaining in service and compressed CO_2 is routed to and vented at the top of the absorber. This operating mode allows for deliveries to the pipeline to start within 2 hours, so this mode is used when outages on the pipeline or at West Ranch are short in duration.

- Catch & Release Mode – In catch and release mode, the CC Facility is operating at 50% load with the flue gas blower remaining in service, but the CO_2 compressor is out-of-service. This operating mode allows for deliveries to the pipeline to start within 4 hours when outages on the pipeline or at the oilfield are short in duration.

- Solvent Circulation Mode – This operating mode allows the CTG to be taken off-line while operating the CC Facility at minimum power consumption without experiencing a full shut-down. In this mode, the flue gas blower and CO_2 compressor are off-line. This operating mode allows for a 9.5-hour return to service.

Facility Shutdown – A full shutdown of the CCS and BOP facilities can take up to 10 hours. The sequence of shutdown activities is in reverse order of the start-up sequence.

Normal Operations – The CO_2 production target under normal operations is 5,200 short tons per day, which is the 100% design load point. The control room operator manages CCS load changes by changing the target CO_2 production set point in the control system. Automatic control functions maintain stable control while the desk operator monitors systems and introduces control corrections in response to trends, alarms, and upset conditions. The desk operator also directs field operators to perform specific activities as required, for example adjusting valve settings. The CC Facility is designed to operate between 50 and 100% CO_2 production load points. The facility controls are normally in automatic mode in this load range and ramping of the unit is directed with the desk operator changing the load set point. The control system automatically responds and directs the necessary control actions required to obtain the desired set point. Although the ramping capability has been used, the system functions best at 100%.

During off-peak hours, the host coal unit will turn down to minimum load points impacting both CO_2 concentration in the flue gas and flue gas flow. The host coal unit must maintain a minimum flue gas flow to maintain stack buoyancy and stability while retaining reliable CEM performance. Considering the optimal operating mode for the CC Facility regarding flue gas flow and CO_2 concentration, a higher minimum load for the host unit to support operating the CC Facility at 100% was established. Below this level, the CCS must reduce its load proportionally with the host unit to mitigate the risk of stack flow instability.

Establishing the minimum load point for CCS operations also has financial ramifications for Petra Nova – most notably, when ERCOT wholesale power prices do not cover the host coal unit's marginal costs of operation, there is a financial disincentive for the host unit to remain above its minimum load point. Petra Nova must evaluate several factors when low load operations occur including: (a) impact on CO_2 production (and potential impact on oilfield operations), (b) impact on CC Facility operating costs, and (c) impact on Cogen Facility operating costs. Although the CC Facility has the ability to operate between 50% and 100% load, a low-load operating point was established at 70% load. Below this load point, maintaining stable operation became difficult due to the limitation on CTG turn-down (for example, handling excess steam), not any issues with the CC Facility. Petra Nova continues to evaluate improvements and upgrades that will improve controllability and reliability during expended operation below this load point.

Outage Planning & Management

Outage planning starts several months before the outage date. Once a list of projects is identified, Petra Nova operations personnel will collaborate with NRG support groups (Technical Support, Contractor Services, Project Planning, Procurement) and OEMs. For each task, the following activities are performed:

- Task scope, schedule sequence, and duration is developed
- Labor requirements are determined
- Equipment, material, and tool requirements are determined
- Information, specifications, safety precautions and permit requirements are determined
- Safety hazards and obstacles that could impact the work progress are identified as follows:
    - The complexity of the lock-out-tag-out (LOTO) process
    - Permits for line breaks, confined space, excavation, air and water discharges
    - Barricade requirements and impact on normal traffic patterns
    - Equipment weight and height limitations in the work area

An overall schedule is developed to confirm if the work can be performed in the timeframe allotted. Labor resources are procured (as noted above, Petra Nova has limited manpower dedicated to support maintenance outages and as a result will use support from NRG, OEMs, and third party contractors). The final schedule is used to manage the day-to-day execution of work and more importantly, communicate work expectations to supervisors and workers while monitoring the work progress. During an outage, daily schedule updates are communicated to the management and the work force to facilitate on-time completion of the outage.

CC Facility Maintenance Practices

The CCS maintenance program includes planned, preventive, predictive and corrective (repair) maintenance. Planned major maintenance on the CCS is aligned with the major outage schedule of the host coal unit to the extent possible. Preventive maintenance, which consists of a series of time-based maintenance requirements, is utilized on equipment as prescribed in the O&M manuals. Predictive maintenance activities include trending and monitoring all key CCS process and equipment operating parameters that are available in the control system. These parameters include temperature, pressure, power use, vibration, flow, and response to control demands. The control system also employs smart transmitters which allow Instrument Technicians to monitor and test the health of these devices online. The predictive maintenance program is supplemented with independent periodic vibration and motor current measurements on all rotating equipment (fans and pumps). Infrared technology is employed to supplement temperature monitoring on motors and is also used to detect and monitor hot spots on the transition duct from the CTG exhaust to the HRSG. The data collected by the predictive maintenance program feeds into the outage planning program so that required resources can be planned and scheduled to complete the scope of defined work for a planned outage.

Increased levels of degradation products and HSS in the solvent are indicators of corrosion. Reclaiming provides the primary means to remove or control the level of these constituents from the process. Detecting and monitoring corrosion and scaling is an ongoing learning experience. Differential pressure across defined sections/levels of the quencher, absorber, and regenerator serve as predictive indicators for the presence of scaling, corrosion, and increased solvent viscosity due to increasing levels of degradation product (which only applies to the absorber and regenerator). The quencher, absorber, and regenerator require internal visual inspections during minor and major inspection outages to determine if corrosion and/or scaling is occurring. During Phase 3, cleaning of the quencher bottom was required to remove sludge and the flue gas blower had required cleanings to remove scaling. Both the sludge and scaling were the result of carry-over from the wet SO_2 scrubber from the host coal unit. An inspection and cleaning, as necessary, of the quencher, absorber, and regenerator are planned for 2020, but predictive data does not suggest that any significant corrosion or scaling is currently present.

During Phase 3, the Operations Team developed maintenance plans as experience was gained from operating the equipment. This experience will continue to play a key role as maintenance cycles are proved over the next several years. One example is the maintenance of plate and frame heat exchangers. The Project has 17 plate and frame heat exchangers, eight of which are called "process heat exchangers" and nine are "cooling water heater exchangers." For process heat exchangers, one is a single-point-of-failure for which a back-up unit was procured. The remaining process heat exchangers have the same plate size and gasket design, so a single spare gasketed plate pack was procured to support servicing these units. Multiple spare plate packs are also being purchased for the cooling water heat exchangers that are critical to maintain 100% production. Standardizing the heat exchanger design for the cooling water heat exchangers could have potentially reduced ongoing maintenance costs.

Project Performance/Lessons Learned

As with any first-of-a-kind facility, issues were experienced with the CC Facility during the initial periods of operations. Valuable insight was gained by the technology provider to address these issues for the next generation carbon capture facility. Additionally, CC Facility availability is also impacted by connected upstream and downstream systems including outages of the host coal unit, the Cogen Facility, the CO_2 pipeline, or the inability of West Ranch to receive CO_2. The table on the following page summarizes the outages during Phase 3.

Outage by Component (Total Phase 3)

	2017			2018			2019		
	Total	Full (Days)	Partial (FDEs)	Total	Full (Days)	Partial (FDEs)	Total	Full (Days)	Partial (FDEs)
CC Facility	41	23	18	34	19	15	29	17	12
Cogen Facility	67	57	10	1	1	0	20	14	6
WAP Unit 8	13	8	5	30	28	2	17	12	5
CO_2 Pipeline	0	0	0	0	0	0	0	0	0
West Ranch	6	0	6	30	13	17	6	4	2
Weather	14	13	1	5	2	3	2	2	0
Planned Outage	0	0	0	52	52	0	0	0	0
Totals	**141**	**101**	**40**	**152**	**115**	**37**	**74**	**49**	**25**

Notes:

1. Except for the Cogen Facility, issues with BOP equipment is included in the CC Facility values.
2. Totals are shown for total day outages plus partial day outages (in full day equivalents, FDE). To calculate full day equivalents, daily de-rates were converted to hours (using a daily target of 5,265 tons per day), summed for the year, and divided by 24. For example, if CO_2 capture rate on a given day was 4,739 tons (or 90% of 5,265 tons) it would equate to 2.4 hours of outage time. If this occurred for 10 days, it would equal 24 hours or 1 full day equivalent.

Each year is discussed in further detail below; excluding the planned outage in 2018, outage performance has improved year over year. The timing of the planned outage in 2018 was driven by the regularly scheduled interval of the host coal unit; however, the timing was ideal for the planned work to address the intercooler issue discussed below. Additionally, Petra Nova performed additional work on both the CC and Cogen Facilities during this outage, thus the outage is not allocated to one specific component. Overall, the CC Facility (and BOP equipment) accounted for 28% of the outage days. The Cogen Facility followed with 24% and WAP Unit 8 was 16%. Finally, although short outages on the CO_2 Pipeline did impact CO_2 production, it accounted for less than 1% of the total outage time. The discussion below addresses the key drivers for the outages by year.

2017

Combined, the CC and Cogen Facilities accounted for 108 equivalent full days of outages, which is 77% of total outage time for 2017. Almost half of the outage days for the CC Facility were de-rates, warranty fixes, and other minor items. The discussion below addresses the causes of key outages.

Although not contributing to a significant number of outage days, a key issue in 2017 concerned some of the plate and frame heat exchangers, one being a single-point-of-failure. These HEs generally process either cool lean (without CO_2) or heat rich (with CO_2) KS-1 and began experiencing leaks. The original OEM performed various design upgrades to address concerns over plate expansion and shifting gaskets. Modifications to the start-up procedure to minimize both temperature and pressure impacts on the units did not eliminate the leaks.

Ultimately, a plan was put in place to replace these HEs with units using a different manufacturer. Many of the replacement heat exchangers also developed leaks. The reason for the leaks was determined to be the cold-set properties of the gasket. Upon the recommendation from the OEM, a program to replace the gaskets was initiated and was still in progress at the end of Phase 3. The upgraded plate packs appear to have mitigated the leaking issue; however, the replacement heat exchangers have higher pinch temperatures than the units they replaced, reducing some of the cooling margin in the system. (Pinch temperature is the difference between the hot outlet temperature and the cold inlet temperature, a measure of how well heat is being taken out of the hot fluid.)

The Flue Gas Blower developed a vibration issue from a build-up of scrubber carryover. Flue gas from the host coal unit is scrubbed by a wet limestone FGD scrubber to remove SO_2 from the flue gas. The CC Facility flue gas duct tie-in point is downstream of the FGDs and the take-off is from the bottom of the breach duct which runs from the host coal unit FGD outlet to the base of the flue gas stack. The bottom tie-in configuration was chosen over a side tie-in configuration because CFD modeling of duct flow showed the bottom tie-in configuration does not create low velocity and recirculation zones as does the side tie-in configuration. During the CFD modeling, solids carry-over and drop out of solids from the saturated flue gas and slurry flowing along the bottom of the duct from the outlet of the FGDs was identified as a concern. A low-profile diversion wall was installed around the tie-in opening to mitigate slurry carry-over and solids buildup in the Petra Nova tie-in duct. Three collection drains were also installed on the FRP duct.

Operating history has revealed the solids and slurry carryover from the FGD to be higher than anticipated. The drains in the FRP duct tend to become plugged from heavy slurry/solids carryover requiring a program of regular inspections and cleaning to mitigate the amount of slurry that reaches the quencher. The impact of solids and slurry carryover on CCS operation initially resulted in scaling on FRP duct instrumentation and on the flue gas blower. Flue gas instrumentation requires weekly cleaning to maintain operational reliability. The flue gas blower developed a hard calcium-based scale over a 12 to 18-month operating time which introduced an imbalance with increasing vibration levels. In 2017, a vibration required a cleaning of the blower, which also showed up again in 2019. Impacts on the quencher and CCS process chemistry are not evident, but Petra Nova is performing an ongoing study through monitoring and sample analysis which is showing that calcium and calcium-based compound levels are increasing in the trim FGD blow down and solvent. As discussed above, signs of scaling may be showing up in the quencher cooling section leading to the plan for an inspection during the 2020 planned outage.

The Cogen Facility experienced excess vibration in the CTG exhaust to HRSG transition duct resulting in loosened liner panels and failing insulation. Ultimately, a duct exterior stiffener upgrade was installed. In addition, repairs to the interior liner panels and floor liner were made which included the installation of additional insulation pins and new insulation. Blanket insulation will be used to repair/replace the batt insulation in problem areas in the future, as needed. Gas control valve failures resulted in the CTG lube oil system being drained, cleaned, and filled with an upgraded quality of lube oil. In April 2017, the first of several CTG exhaust frame blower motor failures occurred. Investigation determined that with the CTG originally designed for service overseas, the exhaust frame blower assembly mounting location was moved from the normal ground mounted configuration to a frame mounted configuration and the motor orientation changed from horizontal to vertical; however, the upper radial bearing design was not changed to an angular contact bearing design to accommodate the vertical loading introduced when the motor orientation was changed. A full replacement exhaust frame blower assembly with the upgraded motor bearing design will be installed during an early 2020 planned outage.

2018

Combined, the CC and Cogen Facilities accounted for 35 equivalent full days of outages (excluding the planned outage) or 87 FDEs (including the planned outage), which is 23% or 57% of total outage time for 2018, respectively. The discussion below addresses the causes of key outages.

Plate and frame heat exchanger issues seen in 2018 were a continuation of the issues discussed above. A failure of the CO_2 compressor motor exciter cable was a one-time event, and once replacement parts were secured, it was repaired and there has not been any reoccurring issues.

The raw water clarifier caused two issues in 2018: (a) mixer issues due to a bearing misalignment causing gearbox failures (a bearing mounting design modification was implemented and a replacement gearbox with upgraded load rating specifications to handle the service duty was installed) and (b) clarifier sludge rake also due to a drive assembly bearing failure (an inspection revealed it had failed from lack of grease and presence of foreign material, an enhanced bearing grease injection system was installed and a bearing housing was installed to mitigate the intrusion of foreign material into the bearing seals).

Each of the first four stages of the CO_2 compressor are equipped with intercoolers (shell and tube heat exchangers) with the compressor dehydration system providing CO_2 drying between the 4^{th} and 5^{th} stages. Early in Phase 3, heat transfer performance issues were detected in the CCS reflux system plate and frame heat exchanger. During an inspection, scaling was found in the heat exchanger, the reflux system piping, and intercooler drains. An investigation revealed that the CO_2 compressor intercoolers were fabricated with materials not conducive to the environment. The parties developed a plan to replace the required intercooler components during the 2018 planned outage.

Prior to the intercooler component replacement, MHIA proposed and Petra Nova agreed to implement an interim plan to mitigate ongoing scaling which included the rerouting of a compressor drain to the reclaimer combined with continuous reclaiming operations to collect and concentrate the corrosion to keep it out of the reflux system. MHIA also designed and installed a backup filtering system which was used to filter the compressor drain flow during reclaimer waste transfer operations. These measures were effective and remained in place until the outage. The intercooler work scope during the outage included a combination of replacement of the tube bundles in certain units and a complete replacement of the remaining intercoolers. The scope of work also included flushing and cleaning the reflux and dehydration systems, and an inspection of the reclaimer. The reclaimer inspection revealed the presence of a waste material in the bottom of the reclaimer and scale coating on the tubes. The reclaimer tube bundle was removed and cleaned but the tube scaling could not be fully removed.

Following the outage, as cooling water temperatures increased with ambient temperatures, it became clear that the performance of the replacement intercoolers did not achieve the performance levels of the original units. The replacement intercoolers could not match the original performance due to space restrictions around and under the compressor. The result was higher discharge temperatures from the intercoolers resulting in the concern of a potential impact on the dehydration system operation. Discussions with the OEM confirmed that the dehydration system could operate reliably with the higher inlet temperatures but recommended upgrades including the addition of a Stahl column, which are being planned for 2020. During 2018 and 2019 summer operation, no detectible dehydration system performance loss was observed.

The 2018 planned outage focused on two key areas: CO_2 compressor major inspection and the intercooler replacement discussed above. Additional outage work included: (a) the ongoing replacement of heat exchangers with the new units, (b) completing open warranty work, and (c) general preventative and routine maintenance on both the CC and Cogen Facilities.

To support GSU inspections (which requires isolating the GSU from the 138kV transmission circuit resulting in a total facility power blackout), a back-up power feed from an existing 35kV distribution circuit was installed to provide power to essential CC Facility and cogeneration equipment (i.e., control systems, battery systems, lighting, HVAC, and critical pumps). This back-up power will be needed whenever the GSU or substation equipment is removed from service for maintenance, as was required during this outage to support the GSU inspection by Petra Nova and transmission breaker testing by the local transmission and distribution company.

During the 2018 outage, Petra Nova discovered that the 1st stage scroll casing flow diffuser in the CO_2 compressor suffered leading-edge failures most of the diffuser vanes. An RCA revealed that flow induced resonance caused the damage on the leading edges. A new design was completed, and a replacement diffuser was fabricated and delivered for future installation. The original diffuser was repaired and reinstalled with an expected minor loss in 1st stage performance. No issues were found in the other diffusers.

2019

Combined, the CCS and Cogen Facilities accounted for 48 equivalent full days of outages, which is 66% of total outage time for 2019. Overall 2019 resulted in a significant improvement in CO_2 capture rates. The key issue on the CC Facility, as discussed in the 2017 section above, was scrubber carryover resulting in an extended outage for the mechanical cleaning of the flue gas blower fan blades. During Phase 3, Petra Nova has experienced several issues with the HRSG steam drum, temporary repairs were made per OEM instructions until permanent upgrades can be done based on the OEM's final set of recommendations.

Although not leading to outages or having a significant impact on CO_2 capture rates, two issues resulted in activity in 2019: (a) tube corrosion in the reclaimer and (b) performance degradation in certain stages of the CO_2 compressor. As reported in the intercooler section above, the reclaimer was used to remove corrosion by products from the CCS process until the intercoolers were replaced during the Spring 2018 outage. No detectable signs of corrosion were found during the inspection and cleaning of the reclaimer, but scaling was discovered on the tubes. Efforts to remove the scaling were not totally successful and the reclaimer was returned to normal service. During a CC Facility start-up in late January 2019, an internal process solvent leak was detected in the steam condensate system on the condensate discharge side of the reclaimer. An investigation of the tube bundle revealed that several tubes were damaged from corrosion. An RCA to determine the cause of the tube corrosion was initiated and was still in progress at the end of Phase 3. Several different root causes were identified for evaluation. Although the RCA is ongoing, to ensure the availability of the reclaimer, a replacement tube bundle is being secured based on an updated tube configuration and upgraded tube material.

The compressor operated without any measurable performance loss until mid-summer 2019 when a slight drop in performance was detected in the operating data. The OEM suggested fouling in one of the stages might be occurring. Petra Nova completed a compressor power use evaluation and determined that the power use was on a small, but steady rate of increase since early 2019. In September, the OEM informed Petra Nova that operating data is indicating performance loss in two additional stages. A reason for the performance degradation is not readily known until an inspection can be done – which is scheduled for 2020.

Other Operation Observations – CC Facility

The viability of the KM-CDR Process® was demonstrated at the 25 MWe (500 TPD) facility installed at Southern Company's Plant Barry near Mobile, Alabama. The scale-up design of the Petra Nova 240 MWe CC Facility was based, in part, on operating and technical data obtained from the Barry Project. As discussed above, the Project completed performance and emissions testing on December 29, 2016. The testing results confirmed that the technical parameters and design basis for the process scale-up were accurate. All performance guarantees were achieved, and the facility demonstrated additional operating margin that was not anticipated.

Throughout Phase 3, Petra Nova continued to demonstrate that the technology worked at commercial scale. When operating at 100%, the facility was generally able to maintain the targeted CO_2 capture rate. However, the combination of the scale-up, Houston's summer ambient conditions, the premature replacement of key cooling components (i.e., the CO_2 compressor intercoolers and eight process plate and frame heat exchangers discussed above) resulted in the loss of excess margin in the cooling system stressing the ability to maintain 100% capture, especially during periods when the host coal unit ramps during off-peak hours.

Absorber and regenerator temperatures, CO_2 concentration in the flue gas, flue gas flow, and solvent concentration are key parameters that contribute to CO_2 capture operations. When solvent concentration and absorber and regenerator temperatures are in their optimum ranges, CO_2

concentration becomes the critical parameter that dictates CO_2 capture rate. When the CO_2 concentration in the host unit flue gas falls below design levels, the CC Facility controls automatically compensate by pulling more flue gas from the host unit for increased mass flow through the absorber and/or increasing steam flow into the regenerator reboilers to increase CO_2 release rate in the regenerator. When the CO_2 concentration falls far enough below the design limits (seen during Q4 2019), capture rate drops. This occurs because a maximum design flow limit on the flue gas blower prevents it from pulling additional flue gas to compensate, and the maximum design steam flow limits on the reboilers prevent additional steam flow to compensate. The CC Facility automatic controls will adjust CO_2 capture downward or upward in response to changing loaded on the host unit and corresponding changes in the host unit flue gas CO_2 concentration. The host unit flue gas CO_2 concentration drops as the host unit load is reduced. Typically, when the host unit CO_2 concentrations are at design levels, the CC Facility can maintain 100% load with the host unit operating at 50% load.

As discussed earlier, there are numerous plate and frame heat exchangers throughout the Project. All units have shown some level of performance degradation (i.e., pinch temperatures being higher than design). For the process heat exchangers, performance loss was seen with the change-out of the units to a different plate and gasket design. The remaining units are in cooling applications utilizing cooling water as the cold side fluid. Pieces of cooling tower fill have been found in the cooling water system and in the inlet piping on several of these heat exchangers (cooling tower fill is a medium used in cooling towers to increase the surface area of the tower)**.** The presence of fill indicates that insufficient screening/filtering was done during cooling water system start-up and commissioning. Most likely, fill is present in the cooling water system heat exchangers and contributing to the loss of heat transfer performance. The fill will be removed during the planned maintenance activity on these heat exchangers. Other potential contributors to lower performance is fouling (scaling on the plate surfaces) and cooling water flow. The units will be checked for scaling during maintenance cycles on the units. Cooling water flow values were evaluated during summer conditions in 2019 and while the new intercoolers have impacted flow volumes, the cooling water system did not impact CO_2 production during the summer.

When designing the Project, decisions were made on where to build in redundancy and where to accept single-points-of-failure. Available capital prohibited redundancy in major components such as the CO_2 compressor and flue gas blower. Ultimately, the design of the BOP and CC Facilities incorporated a philosophy that minimized system redundancy while maintaining the ability to achieve high levels of reliability, availability, and maintainability (RAM). Consultants were hired to perform a RAM Analysis to independently evaluate the technical, process reliability, and spare parts provisioning risks associated with the Project in order to increase confidence in the Project's design and operational philosophy. The consultants concluded that it is extremely unlikely that the Project will fail to operate. Furthermore, it was deemed likely that the Project will meet or exceed the minimum guaranteed CO_2 capture rate after an initial "shake-out" period. The analysis showed that the Project's expected mean capacity factor can achieve 85% levels with a well-planned maintenance program and by having strategic spare parts and equipment available to minimize time to return to service.

The table below shows CO_2 capture rates for Phase 3. As shown and as discussed throughout this report, capture for the first two years fell well below expectations; however, the issues experienced were largely the extension of the integrated system that would likely not have been avoided with additional localized system redundancies. Through Phase 3, CO_2 capture levels continue to be unaffected by redundancy issues as predicted in the RAM report.

CCS CO_2 CAPTURE METRICS			
YEAR	PLANNED CO_2 CAPTURE (SHORT TONS)	ACTUAL CO_2 CAPTURE (SHORT TONS)	PERCENT OUTPUT VS. PLAN OF 85%
2017	1,635,919	1,180,594	72%
2018	1,392,300	1,122,050	81%
2019	1,613,300	1,529,174	95%

One area of redundancy is the application of triple redundant instrumentation on all critical control loops to ensure highly reliable feedback, control, and interlock response. Recently, Operations determined that some less critical process applications with single transmitters would benefit if double or triple redundant transmitters were applied. One such area is the three regenerator bed differential pressure measurements. The single transmitters in this application have been erratic and maintenance intensive. Additional areas where transmitters would improve monitoring include the inlet and outlet pressures and temperatures on heat exchangers. Automation of rich and lean process pump start-up discharge valves was not considered in the original design. During Phase 3, it was determined that during start-up these manual valves must be slowly throttled to minimize start-up pressure impacts on the process plate and frame heat exchangers to mitigate risk of leaks. Automation of these valves would eliminate the need to have field operators perform this function and free them up to attend to other responsibilities in the startup sequence.

Other Operation Observations – Balance of Plant

The cooling water facilities include an intake structure sourcing water from Smithers Lake, a raw water clarifier that removes total suspended solids (TSS) from lake water using limestone and soda ash, a six-cell forced cooled evaporation cooling tower, and the necessary piping and pumps. Cooling water is pumped through several (a) plate and frame and (b) shell and tube heat exchangers to provide cooling to (a) the flue gas in the quencher, (b) the CO_2 in the first five stages of the CO_2 compressor, and (c) the CO_2 prior to being injected in the pipeline. As discussed above, Operations experienced several unexpected issues with the raw water clarifier (mixer bearing, gearbox, and rake bearing) and cooling tower fill carryover.

Demin water production begins with well water supplied from WAP site wells. The water is stored in a well water tank in the BOP water treatment area. The water is pumped from the well water tank and treated using multi-media filters, reverse osmosis filters, and demineralizing media beds. Demin water uses include: (a) CCS solvent dilution, (b) HRSG steam/water cycle make-up and steam condensate tank supplemental cooling, and (c) seal water supply for several vertical shaft pump applications including the HRSG quencher blowdown pumps, circulating water priming pump, and the Trim FGD blowdown pump. Initially, the seals for these pumps were being supplied with process water; however, reoccurring bearing failures resulted in the OEM to change its seal water design specifications to require use of demin water. Demin water is also used to flush the reclaimer after a reclaiming cycle is completed and to flush process heat exchangers prior to performing inspections and maintenance.

Petra Nova contracted for the installation and rental of (a) a temporary phys-chem system to treat the quencher caustic scrubber waste stream and RO reject and (b) a temporary condensate polishing system to treat the quencher cooling section condensate return. The intent was to collect samples and data over an extended operating period to characterize chemistry parameters and better define design parameters for a permanent system. The characterization process verified the quencher cooling section condensate return met quality standards allowing the waste stream to be returned directly to the cooling water system. This led to a TPDES permit amendment being approved by the TCEQ and removal of the condensate polishing system.

Characterization of the quencher caustic scrubber waste stream was completed in 2018, and an economic evaluation on a permanent waste water system was done. The evaluation showed that the best option for the Project was to extend the existing rental agreement calling for modest system upgrades (enlarging the system from 90 GPM to 150 GPM). The upgrades to the system were in progress at the end of Phase 3 and should be completed by February 2020. The planned upgrades include: (a) increasing the flow capacity from 90 GPM to 150 GPM, (b) addition of a weir tank for removing suspended solids, (c) adding a weir tank bypass to facilitate on-line sludge removal, (d) additional multi-media filter bed to improve capacity, (e) adding discharge TSS analyzer and bypass with automatic controls, and (f) improving cold weather protection and spill containment.

Environmental

As discussed above, the Cogen Facility was permitted by the EPA and the TCEQ under the Title V and NSR programs and the CC Facility absorber stack was permitted as a modification to the WAP Unit 8 NSR permit. These permits cover all conditions under which the Cogen Facility and CC Facility can operate which includes emissions limits for criteria pollutants such as NOx, CO, VOC, NH_3, and PM (particulate matter). These pollutants are monitored continuously using CEMS. CEMS are installed on the Cogen Facility stack (located on the HRSG), absorber stack and at the inlet of the flue gas duct bringing flue gas from the host unit. Since the absorber stack is permitted under a dual stack configuration with the WAP Unit 8 stack, all emissions from the absorber and WAP Unit 8 are reported to the EPA together.

The Cogen Facility stack flow rate for NOx, CO, O_2, and NH_3 is monitored on a continuous basis while other pollutants are calculated to demonstrate compliance with emission limits. CEMS monitors and alarms are configured in the control room to monitor emissions. Every year, emissions Relative Accuracy Test Audits (RATA) and flow RATA are performed to confirm accuracy of the CEMS and flow monitoring systems. When the Cogen Facility permit was initially issued, conductivity and total dissolved solids (TDS) were measured on the cooling tower to establish a factor to calculate the baseline cooling tower TDS standard. After the curve was established, cooling tower TDS is calculated to ensure compliance with the permit. Opacity from emission sources at the Cogen Facility is also monitored on a monthly and quarterly basis.

Initial compliance through demonstration testing was performed on both the Cogen Facility stack and CC Facility absorber stack in 2016. This testing was performed to demonstrate that stacks met the vendor guarantee emission limits (which were incorporated in the permits). For the absorber stack, tests were performed for VOC and ammonia which included testing emissions at the absorber stack and the inlet duct and at the WAP Unit 8 stack. For the Cogen Facility stack, tests were performed for NOx, SO_2, PM, VOC and NH_3. The test results are shown in the metric tables below; all emissions limits and guarantees were met during the testing. Final reports with test results and methodologies used for the testing were submitted to the TCEQ.

Since the WAP Unit 8 stack and the absorber stack is subject to Mercury and Air Toxic Standards (MATS) regulations, quarterly MATS testing was also performed on both stacks until the 2nd quarter of 2019 (since these stacks qualified as low emitters after testing for each quarter for three years, no subsequent testing is required).

Per permit compliance obligations, periodic compliance reports are submitted to the EPA and TCEQ to demonstrate compliance with permit condition and emission limits. The TCEQ also conducts on-site and desktop audits of the Title V permit and NSR permits. In 2018, after a TCEQ on-site audit, Petra Nova received a Notice of Violation for self-reported deviations. Petra Nova had identified these deviations and self-reported to the TCEQ in 2017. All corrective actions were already completed when the NOV was issued.

Fugitive VOCs are monitored through the LDAR program. Initially, a walk-through of the CC Facility was conducted to identify and tag all LDAR VOC components which includes piping joints, flanges, and drain values. After the initial assessment, more LDAR components were identified and added as modifications were made to the plant. During an internal audit, it was identified that all open-ended lines needed caps or secondary valves to properly seal each line. This led to additional LDAR monitoring point as these additional caps/valves were added. In total, there are 2,393 LDAR components that were identified, tagged and monitored. In compliance with regulations, these tagged components were initially monitored for fugitive VOC emissions on a quarterly basis. In 2019, Petra Nova was permitted to reduce LDAR monitoring frequency to semi-annually given that emissions were not above the permitted threshold.

Petra Nova greenhouse gas (GHG) emissions are reported to the EPA under the mandatory GHG reporting program. Under the GHG program, Petra Nova reports emissions for the Cogen Facility and as a supplier of CO_2. These GHG emissions are reported on an annual basis and are included as part of WAP's GHG reporting program. Since Petra Nova is not an operator of the West Ranch oil field, the amount of CO_2 injected is reported to the EPA by Hilcorp as operator of the oil field.

The Title V air permit for the Cogen Facility expired in June 2019 and a renewal application was submitted within the required time period in 2018. As of the end of 2019, the application and draft permit are undergoing a 30-day public comment period. The renewed permit is expected to be issued in early 2020. In 2017, additional "permit-by-rule" notifications were made to the TCEQ to include additional oil water separators. In 2018, due to the addition of LDAR points, the NSR permit representations were submitted and approved by the TCEQ to increase fugitive LDAR VOC emission limits and the number of LDAR points. All changes made to the NSR permits were incorporated into the latest Title V renewal application.

The TPDES wastewater permit was issued by the TCEQ to regulate the wastewater discharged into Smithers Lake located on WAP property. The permit regulates all Project water discharges through a single outfall (external outfall) to the lake (all wastewater from the Project drains and internal outfalls are co-mingled and discharged through this external outfall). The wastewater streams that discharge through this outfall include (a) treated process wastewater, (b) cooling tower blowdown, (c) plant drain wastewater, and (d) all storm waters. The Project's storm water is managed as a part of WAP's stormwater plan and all storm drains are maintained in accordance with the plan. There are daily flow limits that are monitored at the external outfall and Petra Nova is in compliance with this permit limit. There are three additional internal outfalls that are also monitored. The first is for the absorber blowdown, wastewater treatment system discharge, and the sludge thickener overflow. The volume of flow, TSS, and oil and grease are monitored at this outfall. The second internal outfall is for the cooling tower blowdown. The volume of flow and free available chlorine are monitored at this outfall. The third internal outfall is for all plant drains and stormwater discharges. The volume of flow, TSS, and oil and grease are also monitored at this outfall.

During the initial permitting process, four samples were collected (one sample per week) to perform a complete analysis on all regulated constituents, such as VOCs, metals, PBBs, and mercury. The results of those tests were submitted to the TCEQ for review. If any pollutant exceeded the water quality limits for the water basin, permit limits would have been incorporated into the TPDES permit. Since none of those results were above any water quality standards, none of those parameters were added to the permit limits. Currently, weekly water samples are collected and analyzed at the outfalls to ensure permit compliance. During Phase 3, there were no permit limit exceedances. All sampling data is submitted to the TCEQ on a quarterly basis.

The initial Petra Nova waste water permit expired in June 2019, and a renewal application was submitted to the TCEQ in 2018. As part of the renewal application process, four samples were collected (one per week) and analyzed for all regulated parameters; no issues were noted. During the renewal process, the application and draft permit underwent a 30-day public comment period, and no comments were received resulting in the new permit being issued in 2019.

A hazardous waste registration permit and EPA ID number was obtained for the facility to ship all hazardous waste generated during operation. Initially the facility was registered as a large quantity generator. In 2017, after waste streams generated were tested and determined to be non-hazardous, the registration was changed to small quantity generator. All the waste generated has been profiled, categorized, and shipped off property. Key waste streams include laboratory waste, reclaimer waste, pre-coat filter waste, clarifier sludge waste and DH system blowdown waste.

As reported above, the Petra Nova pipeline lateral that crosses the plant boundary and connects to the TCV meter station crosses a public access road and as a result, the 0.32-mile lateral is regulated by the Texas Railroad Commission (TXRRC) and PHMSA. Under PHMSA and TXRRC regulations, the pipeline is a US Department of Transportation (DOT) regulated pipeline operating under a T-4 operating permit. Per TXRRC regulations, Petra Nova uses DOT trained employees or DOT approved contractors to operate or maintain the pipeline. Petra Nova also maintains necessary plans and procedures including an O&M Manual, Drug and Alcohol Plan, and Operators Qualification Procedures. To comply with the TXRRC and PHMSA regulations, Petra Nova also participates in the public awareness program by attending public meetings and sending out pipeline safety instructions to the neighboring public. The TXRRC also conducts periodic audits on all the programs. During a recent audit, Petra Nova received an NOV for not calibrating an overpressure valve. Petra Nova corrected the finding by calibrating the valve and added it to the maintenance task list.

Operating Metrics

CCS PERFORMANCE METRICS (AT 100% LOAD)		
ITEM	**AT COMMERCIAL OPERATION DATE**	**PHASE 3 RESULTS (3-YEAR AVG)**
CO_2 Capture Efficiency	93%	90.2%
CO_2 Production (STON/HR)	222.6	222.5
CO_2 Purity	99.24%	> 99%
Steam Consumption (STON/HR)	243	255
Power Consumption	34,851 kW	34,903 kW
Compressor Discharge Pressure	1,905 psig (MIN)	1,806 psig (NORM)
Compressor Discharge Temperature	96 DEG F	< 120 DEG F
Make-up Water to Cooling Tower	1,328 GPM	1,350 GPM

ABSORBER EMISSIONS METRICS (AT 100% LOAD)		
ITEM	**PERMIT LIMITS**	**PHASE 3 RESULTS (3-YEAR AVG)**
Volatile Organic Compounds (VOC)	24.53 TPY	2.84 TPY
Ammonia (NH_3)	1.35 TPY	0.318 TPY

CCS/COGEN WATER USE (Acre-Feet)				
ITEM	**2017**	**2018**	**2019**	**3-Year Avg**
Raw Water (primarily used for cooling)	1,303	1,312	1,681	1,432
Well Water (used to make demin water)	85	94	98	92

VI. MVA Program

The Gulf Coast Carbon Center at the BEG, in close coordination with the Project team, designed and conducted a monitoring program to document retention of fluids in the subsurface during CO_2 injection for enhanced oil recovery at West Ranch. The monitoring program included a baseline period prior to CO_2 injection and was subsequently conducted for 3 years during injection of more than 3.5 million metric tons of CO_2. The monitoring program was designed to meet DOE requirements set forth in their CCPI. It was not specifically designed to meet any other monitoring, accounting, testing or reporting goals; however, it is based on the same principles of several other evolving monitoring programs and is intended to be sufficient to meet needs to document retention of CO_2 in the subsurface in many applications.

Seven work elements/tasks were conducted: 1) fluid-flow modeling, 2) mass-balance accounting, 3) pressure monitoring, 4) geophysical logging, 5) fluid sampling and analysis, 6) characterization of USDW, and 7) vadose-zone definition.

Task 1: Fluid Flow Modeling

Fluid flow modeling is the major predictive tool that determines the capacity of the subsurface to accept CO_2. Fluid flow models are used to model the spatial extent of the CO_2 plume in the subsurface, which demonstrates that under given assumptions and operational strategies, CO_2 is remaining within the targeted area.

Fluid flow models and analytical models are used to assess well leakage scenarios to understand the impact of CO_2 leakage volume and location on AZMI pressure response. Plugged and abandoned wells, especially older ones with less information on completion, plugging and abandonment, are considered the only substantive risk for vertical CO_2 migration from the storage reservoir toward the overlying formations at West Ranch.

Fluid flow modeling starts by building static reservoir models. The tops and bases of target sandstones and major seals are defined with well logs. Static reservoir models were constructed in Petrel software based on rock properties interpreted from Spontaneous Potential and Gamma-Ray logs and to a limited extent core sample studies at West Ranch. Rock properties (permeability, porosity, rock (facies type), fluid saturations, etc.) were assigned based on available data through literature review, historical field measurements, and data provided by the operating company. This allowed the BEG to populate the static reservoir model with appropriate rock type, porosity, and permeability distributions.

Numerical simulation models were constructed of the initial injection zone, the Frio 98-A sandstone and the second injection zone, Frio 41-A. Two AZMI of Toney sandstones (below Anahuac regional seal) and 80-A sandstones (above Anahuac regional seal) were characterized for above zone pressure monitoring conducted in Task 3. The BEG used the static geologic model (as described before) as well as fluid properties (fluid compositions and pressure, volume, temperature (PVT) data) from the field to develop a dynamic numerical model to history match the production and pressure data of the field and to simulate the current and future activities in the field. The numerical model was developed using a compositional simulator. In compositional simulations, three phases (water, oil and gas) with multiple components were defined. Relative permeability data, available through literature survey and the operating company, was used as input in multiphase fluid flow simulations. Thermodynamic properties of the specific fluids in this field were tuned and modeled in a nodal analysis software.

In close collaboration with the operating company, we received well locations and their corresponding injection and production volumes on a monthly basis. This information was integrated into the numerical model to perform dynamic reservoir simulations. Compiled monthly injection and production data for the wells, perforated in the 98-A zone, indicates that there has been a significant increase in the number of WAG (water alternating gas) wells as well as oil production during field operations.

The fluid flow simulation starts when CO_2 injection into the 98-A was started in December 2016. The 98-A pressure response to water and CO_2 injection was then used to further validate the models. History matching of the model continued throughout the 3-year demonstration period by matching the cumulative oil and gas production data and bottom hole pressure of the in-zone monitoring wells. The BEG tuned the model by studying the effect of different parameters on the simulation results. These parameters were chosen based on their uncertainty that is associated with their measurements. To perform the history match, the BEG relied on the uncertainty of the original oil in place in the field, oil and gas relative permeability, and the porosity-permeability distribution of the formation. Several simulations were performed to find the best combination of parameters that produce the most realistic matches between the simulation results and collected field data. The BEG has history matched the model with the field injection-production-pressure history and believe that the model is reasonably useful for designing future development strategies for the operation in the field and forecasting the location of the CO_2 plume.

In late 2018, the operating company decided to divert some of the CO_2 volumes from 98-A sandstone to flood the 41-A sandstone within the same reservoir complex at West Ranch. The 41-A sandstone formation is above the 98-A reservoir and below the regional Anahuac shale. A numerical mode was used to run field scale dynamic reservoir simulations to evaluate the CO_2 distribution in the 41-A sandstone. For the numerical simulation, PVT models and relative permeability curves, provided by the operating company, were used for history matching of the production and injection operations in the 41-A sandstone until end of September 2019. The 98-A and 41-A sandstone numerical simulations were able to achieve a reasonable match between the numerical models and collected field data.

The simulation results indicate that the pressure elevation in the injection zone was managed by the operation and did not exceed 3,000 psi. Based on the extended numerical simulation models (which are history matched to the field data), when patterns are fully flooded the average gas saturation reached around 52%.

The BEG modeled a hypothetical leakage of CO_2 from 98-A to 80-A/Noble monitoring zone. Fluid flow models of vertical fluid leakage were used to estimate the impact on the pressure observed in the 80-A zone. In order to study the potential leakage, the BEG first gathered and analyzed the pressure data from five monitoring wells that are perforated in this AZMI zone. The team developed a reliable simulation approach to investigate the connection between the two layers in any potential fluid migration and pressure disturbance caused by this fluid movement. Then the team forwarded modeled leakage scenarios to determine the well spacing over the plume area needed to detect potential leakage. Numerical models were set to detect 2 psi change in pressure in AZMI wells six months after the start of the simulated leak. Based on numerical simulations in the 80-A zone, to detect a pressure change (in at least one of the five monitoring wells), the leakage rate from 98-A zone should be higher than 5,000 Mscf/day. This leakage rate required to show a 2-PSI pressure change is significantly reduced if we consider the entire 3-year monitoring period.

In general, our fluid flow modeling shows that the targeted formations have the capacity to accept the injected CO_2 volumes and that the CO_2 will not migrate out of the structural trap, providing permanent retention. In addition, based on our numerical models no major leakage into 80-A zone was detected.

Task 2: Mass-Balance Accounting

A fundamental part of the monitoring program designed for West Ranch is the accurate mass accounting of the fluids injected, withdrawn, recycled and lost during the enhanced oil recovery operation. The importance of this task is inherent in the need to provide a full accounting for the mass of captured CO_2 stored in the subsurface at West Ranch.

Under this task, the BEG developed a carbon mass accounting protocol that estimates CO_2 storage mass by subtracting CO_2 surface and subsurface losses to the captured CO_2 mass injected into the oil reservoir. The total mass of CO_2 injected (captured from WAP plus recycled) was measured with a flow meter located at the capture plant and a flow meter upstream of the recycle gas compressor. Recycle gas was corrected by a composition measurement at the metered location so that only CO_2 is accounted for and produced reservoir gases are excluded.

The mass of CO_2 lost from surface equipment includes vapored gas releases, blowdown releases, maintenance releases, troubleshooting releases, flare releases, venting and unusual events such as pipeline and well releases. The mass of CO_2 lost in the subsurface (i.e., CO_2 migration outside of the subsurface storage complex) is measured by the MVA program.

Mass accounting activities started in March 2017 when production operations from wells in the initial 7 patterns (7 WAG injection wells and 14 production wells) became stable and after finalizing the production commissioning process at the first of two Central Processing Facilities (CPF).

Captured CO_2 at the WAP is compressed and transported to West Ranch via the CO_2 pipeline. Transported CO_2 volume is measured a) by the custody transfer meter located at the inlet of the pipeline at Petra Nova, and b) the meter located at the outlet of the pipeline in West Ranch. Both of a) and b) are reported to the operating company and Petra Nova daily and sent to the BEG monthly. Supplied CO_2 from the WAP is combined with field recycle CO_2 at the injection header located in the CPF, delivered to the test (manifold) sites and subsequently to individual WAG injection wells for injection into the oil reservoir.

Injected CO_2 is mixed with reservoir fluid in the oil reservoir and produced back through production wells. Produced fluid from the individual production wells is gathered at the test site then transferred to CPF by high/mid/low pressure production lines, based on pressure. After liquid separation (water and oil) in the high/mid/low pressure water knock-out/flush drums and separators, produced gas (CO_2 and reservoir hydrocarbon gas) is transferred to flash/recycle gas compressors (FGC/RGC). Gas with mid/high pressure is directly transferred to the RGC. Gas with low pressure is compressed by the FGC then transferred to the RGC. The volume of produced gas (CO_2 and reservoir hydrocarbon gas) is measured at the inlet of RGC by a volumetric flow meter. Then produced gas is compressed and combined with captured CO_2 from WAP for reinjection into the oil reservoir.

The operating company measured the mole fraction of produced gas at the inlet of the RGC every month starting from March 2017. The daily volume (volume converted to standard condition: 14.65 psia, 60° F) and the mole fraction of the produced gas was reported to Petra Nova, monthly, which was forwarded to the BEG. Secondly, maintenance of surface equipment was tracked, and an assumed volume of CO_2 was deemed to be lost based on maintenance frequency. Lastly, any unexpected loss of CO_2 due to any equipment failure was estimated by the BEG and included in the final mass balance results.

Under the MVA Plan, a total of 3,609,924 short tons were sequestered using the mass balance accounting approach. Since the mass balance accounting did not start until March of 2017 allowing for the full commissioning of surface facilities at West Ranch, the amount of CO_2 sequestered during Phase 3 is understated. For proper comparison, during the same period subject to mass balance accounting, the CC Facility captured 3,651,244 short tons of CO_2. After adjusting for mol% and other adjustments made by the BEG, a net capture value of 3,643,146 short tons of CO_2 was calculated for the mass balance accounting period resulting in surface losses of 33,222 short tons at West Ranch (primarily as the result of maintaining surface equipment). This resulted in 99.08% of the captured CO_2 being sequestered meeting the DOE target of sequestering 99% of the CO_2 captured.

Task 3: Pressure Monitoring

Measurement of pressure at reservoir depth is another critical parameter in the monitoring program. The expectations of the monitoring program are somewhat different than those of conventional field management. In this monitoring plan, the BEG emphasized pressure surveillance as the principle tool to both validate fluid flow models and to document that fluid is not migrating into shallower horizons. Pressure monitoring in the injection zone is used to calibrate the fluid flow models.

Task 3 is important because pressure monitoring of the injection zone allows us to: 1) monitor the pressure in the injection zone to avoid over-pressuring the injection zone, 2) monitor migration of CO_2 in the injection zone, and 3) allow the comparison in pressure change between injection zone and above-zone monitoring intervals to identify vertical migration of fluids. Successful pressure monitoring gives confidence that injection zones are not over-pressurized, and the CO_2 is retained in the project boundaries.

Starting January 2016, ten above zone monitoring wells have been continuously collecting pressure data in West Ranch. In addition, two in-zone monitoring wells were also collecting continuous pressure data since June 2016 through mid-2018. CO_2 injection in West Ranch started in December 2016, and pressure data prior to this date provides several months of baseline data for pressure monitoring. Two in-zone wells (WRA-479 and WRA-601) perforated in 98-A sand to directly measure the pressure changes inside the injection zone provided necessary data for fluid flow model calibration. These wells were collecting data until mid-2018. Five above zone monitoring wells (WRA-007, WRA-127, WRA-399, WRA-522 and WRA-602) were perforated in the Toney sand and collect continuous data until end of 2019. Four above zone monitoring wells (WRA-489, WRA-075, WRA-415, and WRA-520) were perforated in 80-A sand and collect continuous data until end of 2019. In addition, one monitoring wells in Nobel sand (WRA-455) is also collecting pressure data until end 2019. These ten wells were workovers of existing wells and were selected based on location in order to cover the planned flood area.

Regarding the two bottom-hole pressure and temperature gauges that were installed in the 98-A sandstone, gauges were connected via wireline to surface readouts that collect high-frequency data via phone or satellite uplink to a central location (supervisory control and data acquisition (SCADA) or some other automated data collection system). These two in-zone monitoring wells are located outside of the initial seven patterns of the CO_2 flood and were designed to provide (1) additional assurance that the area of elevated pressure and potential migration of the CO_2 is within expected ranges, and (2) calibration for the reservoir pressure models that allow a quantitative assessment of the connectivity between the reservoir and the AZMI.

Significant amounts of fluid flow could occur through flawed well completions without creating a detectable anomaly in the injection zone. Pressure monitoring above the injection zone is a more effective leakage detection approach. This monitoring design allows surveillance of small pressure changes in AZMI that document hydrologic isolation from injection zone.

Monitoring pressure above the injection zone is recommended in several storage monitoring protocols. Above-zone pressure techniques have been used successfully to document storage in gas storage reservoirs and tested at several other pilot storage sites. Successful monitoring above the injection zone is dependent on selection of a suitable AZMI. Suitability criteria are (1) a permeable zone into which any fluid migrating out of the injection zone would migrate and (2) hydrologic characteristics that would allow the detection of the pressure signal from fluid migration. Updated geologic characterization of the monitoring zone and modeling may be needed to evaluate the suitability of available strata and the placement, completion, and operation of monitoring wells. Non-site-specific criteria for selection of an AZMI include lateral continuity over as much of the plume area of possible. Pressure signals will be stronger in thinner rather than in thicker intervals. Pressure signals will be stronger in the sedimentary section closer to the injection zone. The potential for geo-mechanical interference and for single phase (brine only) matrix flow across minor confining zone should be considered in AZMI selection.

At West Ranch, several uncertainties were evaluated prior to selection of the optimal AZMI. The pressure profile in West Ranch shows that several zones are over-pressured or under-pressured as compared to hydrostatic pressure. This could be a response to past or current water disposal and production. The current pressure distribution provides high-value information about the hydrologic properties and lateral continuity of the prospective AZMI. Understanding temporal and spatial pressure distribution is essential to the selection of an effective AZMI, because pressure recovery can mimic a leakage trend. Prior to final design of the AZMI monitoring strategy, a clear understanding of the operational conditions planned for the EOR flood is essential.

The uppermost regionally extensive sandstone below the base of fresh water, Miocene 80-A was selected as the main AZMI with four monitoring wells. In the center of the field where the 80-A sandstone was poorly developed, the underlying Noble sandstone was perforated by one monitoring well. The pressure was stable and slightly decreasing during the project period, documenting that the zone is hydrologically isolated from the underlying injection zone.

A second zone below Anahuac regional shale was also selected for pressure monitoring, and five monitoring wells equipped with pressure gauges were installed. A deeper AZMI gauge installation in the Toney proved to be very noisy because the zone was kept in production, causing pressure decrease in most gauges. One gauge also underwent a pressure increase which could be a signal of fluid communication between the Toney and the 98-A. Headspace gas was collected as part of Task 5, but no CO_2 was detected in this monitoring well showing that no CO_2 had reached the perforated zone of this well. The Toney is below the regional Anahuac seal and within the zone to be considered for future flooding. This detection has no implication for CO_2 retention and it does demonstrate the validity of the pressure monitoring method.

Task 4: Geophysical Logging

The goal of this task was to assess the extent to which CO_2 is occupying pore volumes as EOR progresses. Pulsed neutron logs (Schlumberger's Reservoir Saturation Tools, RST) collected prior to injection served as a baseline. When the same log is repeated after the CO_2 flood has progressed, changes in the log curves can be inverted to estimate how much pore space has been occupied by CO_2. This fluid saturation data can then be used as part of fluid-flow model calibration to confirm no change in saturation in zones outside the intended injection zone. Repeat RST were collected in six wells in the flood area. The raw logs were depth corrected using gamma-ray curves to register the repeat logs; however, environmental corrections were not successful, limiting the usefulness of the logs. The uncorrected offset makes it problematic to accurately identify and qualify reservoir zones in which CO_2 has swept. Wireline logging with pulsed neutron tools run though tubing is another technique that has been used to validate fluid flow models. However, the history match methods selected for this study focused on matching fluid injection, produced fluids, and pressure response; detailed matching of fluid saturations at individual wells was not part of the calibration. The team therefore did not attempt to complete the environmental correction needed to use the time-lapse pulsed neutron logs collected.

Task 5: Fluid Sampling and Analysis

The goal of Task 5 in phase three of the West Ranch CO_2 monitoring project was to characterize: (a) the geochemistry of transported CO_2 off the pipeline, (b) the brine in the injection zone and AZMIs, and (c) the gasses accumulated in the head space of monitoring wells. An opportunistic strategy was employed in collecting samples. Formation brine was collected at the separator facility during normal oilfield operations and from over-pressured monitoring wells that produced brine at the well head without additional pumping. In one case, a well was sampled during swabbing. In cases where over-pressured monitoring wells produced gas without brine, a head space gas sample was taken.

The geochemical characterization of formation brine, headspace gas, and captured CO_2 is required to produce geochemical models that predict the change in groundwater chemistry due to a theoretical leak of CO_2, formation brine or thermogenic hydrocarbons, and is a needed complement to pressure monitoring for follow-up of any adverse signal. AZMI brine samples were collected from six wells and gas samples were collected from nine wells during Phase 3. Analyses of brine and gas samples collected prior to the start of CO_2 injection in December 2016 were used to establish pre-injection chemistry baseline.

Task 6: Characterization of Underground Sources of Drinking Water (USDW)

The goal of Task 6 was to monitor groundwater chemistry at predetermined monitoring wells and screen these wells for changes in chemistry related to unintended releases from the deep subsurface related to injection of CO_2. Injection of CO_2 for EOR may adversely affect overlying USDW in several ways. Increased formation pressure caused by CO_2 injection may cause upward migration of formation brines resulting in groundwater salinization. Upward migration of supercritical CO_2 and subsequent change into gas-phase CO_2 may migrate into USDW causing groundwater acidification and drive dissolution reactions of aquifer minerals. Existing groundwater chemistry was used to produce models to predict changes in groundwater chemistry resulting from leakage of CO_2, brine or thermogenic hydrocarbons into USDW. Migration of CO_2 gas may cause less soluble dissolved gasses to exsolve and produce mobile gas phases that migrate upward into USDW. This mechanism may increase thermogenic methane, ethane, propane, etc. concentrations in groundwater. Several groundwater collection trips were made prior to the December 2016 start of CO_2 injection. These analyses established pre-CO_2 injection baseline used to monitor for changes in groundwater chemistry caused by potential CO_2 leaks after the start of CO_2 injection.

A reactive transport model was made to assess the feasibility of detecting a leak of CO_2 from the top of the 80A into overlying groundwater via changes in groundwater chemistry. A 16,093 meter (11-mile) by 17,703 meter (12-mile) and 948 meter (0.6 mile) deep, 14-layer model, with West Ranch centered, was constructed. Shallow subsurface wells obtained from the TXRRC were used to assign layer thickness. A CO_2 hypothetical leakage rate of 340 and 315 tons/year were modelled to assess the potential impact on groundwater chemistry. Previous work suggested that a leakage signal, if one were to occur, would be spatially small and easily missed even with a dense monitoring network and this was confirmed though site-specific modeling.

A knowledge of local groundwater chemistry is important in producing geochemical models that will predict changes in groundwater chemistry that result from a hypothetical CO_2 leak. These geochemical models can be used to attribute the cause of changes in groundwater chemistry associated with allegations of damage to USDW protecting stakeholders and increasing public acceptance. Monitoring wells selected in Phase 2, were periodically monitored prior to for baselining and during Phase 3. Two main aquifers were targeted. Four wells were chosen in the Evangeline aquifer, depth >300m below surface, and 7 wells in the Chicot aquifer, depth <70 m below surface. Groundwater salinity is variable between wells and there is little temporal variability in groundwater chemistry. Variable salinity is seen in two wells but the increase in salinity started prior to the injection of CO_2 and appears to be unrelated to injection of CO_2. No change in groundwater chemistry consistent with a direct leak of captured CO_2 into groundwater was observed.

Shallow borehole geophysical logging using apparent electrical conductivity and natural gamma-ray activity was performed on 5 polyvinyl chloride (PVC) cased wells. All wells show intervals with high conductivity vs. gamma ray activity suggests intervals of high salinity groundwater. These logs were collected prior to CO_2 injection and therefore the identified high salinity groundwater was not related to CO_2 injection.

The source of dissolved hydrocarbons in groundwater can be determined by comparing the carbon isotopic composition of methane to the ratio of methane to ethane and propane. Deep sourced thermogenic methane and shallow biologically produced methane have distinct methane to ethane plus propane ratios and methane C isotopic compositions. Upward migration of injected CO_2 may cause migration of deep thermogenic hydrocarbons that may be detected in USDW. Many monitoring wells have high dissolved methane concentrations, but this is naturally occurring biogenic methane. Methane mixing models between a typical West Ranch groundwater and thermogenic methane collected from deep monitoring wells were produced. The result of this effort did not indicate any concern with observed near surface thermogenic methane being a result of CO_2 injection. Thermogenic-biogenic methane mixing trends shows the validity in the model.

Reactive transport models were made that simulated a CO_2 leak near the top of the 80A formation at a depth of 841m. Upward migration of a plume produced by leaking 315 tons of CO_2/year produced an upward migration from 841m to 750m after 40 years. Adding simulated pumping from the Evangeline aquifer did not affect the migration of the simulated plume. Reactive transport modelling results show no impact to USDW outside the West Ranch lease under simulated conditions.

Task 7: Vadose-Zone Definition

The goal of Task 7 was to characterize the composition of soil gasses at West Ranch and to develop models that would predict changes to soil gas compositions by unintentional migration of CO_2 or thermogenic gases into the vadose zone from deep CO_2 injection zones. Approximately fifteen sites corresponding to existing water wells (for location purposes) were identified for field evaluation in December 2015. Preliminary field sampling and on-site analysis of soil gases was accomplished at twelve sites near water wells at West Ranch to determine the suitability of soil gas sampling as a method to be implemented at the site. The vadose zone was found to be substantial and the decision was made to proceed with soil gas monitoring. Analysis of the soil gas data collected during the reconnaissance trip was used to choose locations for installation of semi-permanent soil gas sampling chambers.

Task 7 is important because vadose zone monitoring programs, a historically used method for CO_s leak detection, provide assurance to the public and stakeholders that monitoring for potential CO_2 leaks is occurring. Previous work suggests that small leaks would be very hard to identify and that if CO_2 is captured from a coal-fired power plant it would be chemically indistinguishable from naturally occurring CO_2. Analysis of naturally occurring soil gases, including concentrations and isotopic compositions of CO_2, can be used to characterize soil gas variability and produce models that predict changes to soil gas compositions should a leak occur. These models can be used to attribute the cause of soil gas anomalies should allegations of leakage occur.

Semi-permanent soil gas sampling stations were installed at five locations at West Ranch. A Geoprobe rig was used to drill 2-inch diameter boreholes to depths up to 22 feet. Sampling stations were located near water wells. At each sampling station, two sampling ports were installed at different depths within each borehole for a total of ten sampling ports. Sampling ports consist of 6-inch vapor implant mesh screens connected to 1/8-inch stainless steel tubing, sealed at the top with Swagelok gas-tight fittings. At each sampling interval, screens were set in 10 inches of quartz sand and isolated with bentonite clay. A PVC protector pipe was installed over the sampling tubes and capped and labeled to protect the gas sampling wells from environmental damage.

A total of five soil gas sampling trips were accomplished over the course of the study in July and October 2016 and January, April and August 2017. During the sampling, gas was collected in gas bags and subsequently analyzed for CO_2, O_2, N_2, and CH_4 in the laboratory at the University of Texas BEG on an SRI 8610 gas chromatograph and/or at an outside lab. Samples analyzed at the outside lab also included He, H_2, CO, and higher hydrocarbons (C_2-C_6+). The results were analyzed and reported using a process-based analysis (Romanak et al., 2012; Romanak et al., 2013) which is an emerging method of environmental monitoring and source attribution for shallow soil anomalies. The approach uses the relationships among coexisting soil gases to identify CO_2 concentrations that represent anomalies and then uses radiocarbon (^{14}C) and stable carbon isotope ($\delta^{13}C$) to further assess any identified anomalies.

In addition to analyzing for the major soil gases (CO_2, O_2, N_2, and CH_4), the BEG also performed carbon isotopic analyses on select soil gas samples collected in April and August 2017 to augment our understanding of the geochemical system if any changes are perceived during the project. This information provided additional characterization of the system to help distinguish any changes that are natural from those that may result from leakage.

Over the monitoring period, CO_2 ranged from near-atmospheric values of 0.07% to 17.43%, O_2 ranged from atmospheric values of 21% to 0.42%, and N_2 ranged from 73.72% to 93.11%. No significant methane was found. Process-based ratio analysis indicated a few samples hovering to the right of the respiration line having a slight indication of a signal. One sample had a relatively high N_2/O_2 ratio signaling vigorous respiration and dissolution of CO_2, which is known to occur in some natural systems. Compositional and isotopic data was acquired for the select soil gas samples which hovered slightly to the right of the respiration line. Soil gas data for ^{14}C range from 106.7 to 60.1 percent modern carbon (pmc). $\delta^{13}C$ for soil gas samples ranged from -17.9 to -22.68 per mil. Most of the soil gas samples have a natural signal with ^{14}C greater than 100 pmc. Field-wide there is no indication of leakage from the storage formation and this signal appears to represent a very localized and small-scale potential anomaly that may be due to an older organic carbon source being utilized by microbes for respiration. The results showed that the samples are consistent with a modelled mixing trend between a CO_2 soil gas source of a $\delta^{13}C$ between -20 and -21 per mil and atmosphere (assumed concentration of 400 ppm with a $\delta^{13}C$ isotopic signature of -7.5). Thus, the $\delta^{13}C$ data for soil gases sampled at West Ranch supply additional evidence for normal and natural processes at West Ranch.

References:

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VII. Conclusion

There are several factors that led to the success of the Petra Nova Project – for example, in order to deploy a first-of-a-kind project, Petra Nova needed to unlock the complex value chain and develop a commercial structure that aligns sources of CO_2 with EOR field interests. This required otherwise dissimilar industries (power and O&G), with differing strategic business models, to come together to structure, plan and execute this endeavor. Furthermore, attracting risk-sharing sponsors to large, complex, capital-intensive, first-of-a-kind advanced energy projects such as this was extremely difficult. It required an international public-private multi-stakeholder arrangement.

Next, selecting a proven technology with commercial guarantees and proper planning was critical to its success. The Texas Gulf Coast provided for an ideal location for CCUS given the availability of oilfields conducive for a CO_2 flood and existing pipeline corridors for further co-location of CO_2 pipelines. However, being in the Gulf Coast also provided key challenges, most notably, the scale-up of certain Project equipment needed to meet the cooling needs in Texas' ambient summer conditions.

Petra Nova's project execution was first-class as (a) a dedicated team of technical professionals proactively addressed environmental study management, permitting, licensing, Grant application and administration, commercial contracts, financing structure, and other development-related activities and (b) an experienced team of professionals with a history of managing large projects at NRG were assigned to manage the engineering, procurement, and construction activity. The selection of the EPC contractor was critical and the decision to have the technology provider and construction company form the Consortium under the single EPC contract improved communication and the timely resolution of key issues. An all-hands "lessons learned" exercise also identified areas for improvement for future projects. A dedicated Operations team was assembled and trained – however, the selection of Operations management should have been done earlier in the process to better understand how design and engineering decisions may impact future operations and management activity.

Lastly, stakeholders were aligned in creating a first-of-a-kind project. These stakeholders included Petra Nova's owners, the technology provider, the construction contractor, the oilfield operator (and ownership partner with Petra Nova of the oilfield), Project lenders, and the Department of Energy – all of which played a critical role to ensure that Petra Nova was completed on time and on budget.

VIII. Publications

NRG Energy took a more conservative approach to public relations during the development, construction and commencement of operations of the Project than other carbon capture facilities. We submitted a press release when we applied for the DOE award in 2009 (https://www.businesswire.com/news/home/20090901005439/en/NRG-Energy-Files-Clean-Coal-Power-Initiative) and a release in 2010 when we received the DOE award (https://www.businesswire.com/news/home/20100309006898/en/Department-Energy-Selects-NRG-Post-Combustion-Carbon-Capture). These two press releases generated limited trade and local coverage.

After these two releases, we decided to be only reactive through further development until we were able to announce the commencement of construction in 2014 (https://www.businesswire.com/news/home/20140715005632/en/Worlds-Largest-Post-Combustion-Carbon-Capture-Enhanced-Oil-Recovery) and hold a groundbreaking ceremony (https://www.businesswire.com/news/home/20140905005840/en/Industries-Government-Celebrate-Ground-Breaking-Petra-Nova) which generated significant international, national, local and trade interest including the Wall Street Journal (https://www.wsj.com/articles/co2-project-electricity-firm-to-tap-greenhouse-gas-for-oil-drilling-1405450726), Reuters, NPR, Bloomberg and locally with the Dallas Morning News, Houston Chronicle and Houston Business Journal.

After the ground breaking, we once again were primarily reactive until we could announce commencement of operations on schedule and on budget at the end of 2016 (https://www.businesswire.com/news/home/20170109006496/en/NRG-Energy-JX-Nippon-Complete-World%E2%80%99s-Largest) and hold a "valve-turning" ceremony (https://www.businesswire.com/news/home/20170413006016/en/Secretary-Energy-Rick-Perry-Governor-Texas-Greg). Both the commencement of operations and the ceremony generated extensive coverage including a prominent placement in the New York Times (https://www.nytimes.com/2017/01/02/science/donald-trump-carbon-capture-clean-coal.html), Washington Post (https://www.washingtonpost.com/news/energy-environment/wp/2017/01/10/americas-first-clean-coal-plant-is-now-operational-and-another-is-on-the-way/) and many other publications.

This also positioned Petra Nova to be Power Magazine plant of the year for 2017 (https://www.powermag.com/capturing-carbon-and-seizing-innovation-petra-nova-is-powers-plant-of-the-year/). After the coverage of commence of operations, NRG returned to a more reactive posture focused on the success of the technology but the economic challenges of carbon capture.

On the web, Petra Nova developed a web page with numerous resources for journalists. This web page is now a case study (https://www.nrg.com/case-studies/petra-nova.html).

In addition to this activity, representatives of Petra Nova presented the status of the project in numerous conferences - primarily those hosted by the DOE, carbon capture industry groups, clean coal symposiums. Most of these presentations were in the United States; however, a limited number of presentations were done internationally. Finally, the Project has hosted an extensive number of domestic and international visitors for tours of the facilities. These groups have included visitors from industry, congressional/legislative, education, and special interests. There were no patents developed by Petra Nova during this project; all patents are owned by MHIA regarding the carbon capture technology or by the OEM for other components. MHIA has licensed Petra Nova to use the technology.