

**IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF TEXAS
HOUSTON DIVISION**

PILOT ENERGY SOLUTIONS, LLC,

and

**PILOT INTELLECTUAL
PROPERTY, LLC,**

Plaintiffs,

V.

**CHEVRON U.S.A. INC., dba
CHEVRON NORTH AMERICA
EXPLORATION AND
PRODUCTION COMPANY,**

and

SCOUT ENERGY MANAGEMENT, LLC,

Defendants.

CIVIL ACTION NO. 4:23-cv-02505-

JURY TRIAL DEMANDED

**PLAINTIFFS PILOT ENERGY SOLUTIONS, LLC AND
PILOT INTELLECTUAL PROPERTY, LLC'S
ORIGINAL COMPLAINT**

Plaintiffs Pilot Energy Solutions, LLC (“Pilot Energy Solutions” or “Pilot”) and Pilot Intellectual Property, LLC (“PIP”) file this Original Complaint against Defendants Chevron U.S.A. Inc., dba Chevron North America Exploration and Production Company (“Chevron”) and Scout Energy Management, LLC (“Scout Energy”) (collectively “Defendants”).

I. INTRODUCTION

1. This proceeding is a patent infringement action brought by Plaintiffs Pilot Energy Solutions and PIP against Defendants Chevron and Scout Energy for infringement of Pilot/PIP's United States Patent No. 8,505,332 ("the '332 Patent").

2. Plaintiff Pilot Energy Solutions also asserts Texas common law causes of actions for fraudulent (or at least negligent) misrepresentations against Defendant Chevron, for its misrepresentations about the processes used in its Mabee gas plant near Midland, Texas.

II. PARTIES

3. Plaintiffs Pilot Energy Solutions and PIP are Texas limited liability companies, each with its principal place of business in Houston, Texas.

4. Defendant Chevron is a Pennsylvania corporation, which identifies its principal place of business as San Ramon, California.

5. Defendant Chevron has registered and is authorized to transact business in the State of Texas, and may be served with process by serving its registered agent for service, Prentice-Hall Corporation System, at 211 E. 7th Street, Suite 620, Austin, Texas 78701-3218.

6. Defendant Scout Energy is a Texas limited liability company with its principal place of business in Dallas, Texas.

7. Defendant Scout has registered and is authorized to transact business in the State of Texas, and may be served with process by serving its registered agent for service, Jon C. Piot, at 13800 Montfort Drive, Suite 100, Dallas, TX 75240.

III. JURISDICTION AND VENUE

8. This action states claims arising under the patent laws of the United States, 35 U.S.C. § 271. Plaintiffs Pilot Energy Solutions and PIP assert a cause of action for infringement of the ‘332 Patent. This Court has original and exclusive subject matter jurisdiction over these claims under 28 U.S.C. §§ 1331 and 1338(a). This Court has supplemental jurisdiction over the related state law fraud and negligent misrepresentation claims under 28 U.S.C. § 1367.

9. This Court has personal jurisdiction over Defendants Chevron and Scout Energy because each has designated a registered agent for service of process in Texas. This Court also has personal jurisdiction over Defendants Chevron and Scout Energy because each is doing business in Texas, and because each is committing torts including patent infringement, which are the subject of this action, in Texas.

10. Venue is proper in this Court under 28 U.S.C. §§ 1391(b), (c), and 1400(b) because the corporate Defendant Chevron resides in this judicial district, a substantial part of the events or omissions giving rise to Plaintiffs’ claims occurred in this judicial district, and because the Defendant Chevron conducts business within this judicial district.

11. Defendant Chevron resides in this judicial district, under 28 U.S.C. § 1391(c)(2), because Chevron does business in this judicial district including operations in Houston with over 6,000 employees in downtown Houston. 28 U.S.C. § 1391(c)(2) (“[A]n entity . . . shall be deemed to reside, if a defendant, in any judicial district in which such defendant is subject to the court’s personal jurisdiction with respect to the civil action in question”).

12. Furthermore, venue is proper in this Court under 28 U.S.C. § 1391(d) because Defendants Chevron and Scout Energy are subject to personal jurisdiction in this judicial district. 28 U.S.C. § 1391(d) (“[I]n a State which has more than one judicial district and in which a

defendant that is a corporation is subject to personal jurisdiction at the time an action is commenced, such corporation shall be deemed to reside in any district in that State within which its contacts would be sufficient to subject it to personal jurisdiction if that district were a separate State.”).

IV. BACKGROUND

Pilot Energy Solutions and PIP

13. Plaintiff Pilot Energy Solutions is a full-service technology and gas processing company, specializing in high CO₂ and unconventional gas streams, for natural gas liquid (“NGL”) and CO₂ recovery. Pilot Energy Solutions offers a full suite of gas processing technologies to address a range of flow rates and compositions. Pilot Energy Solutions specializes in evaluating unusual, unconventional, low volume, or stranded (wet) gas, and developing unique, cost-effective processing technologies.

14. Plaintiff PIP is a subsidiary of Pilot Energy Solutions that owns and administers certain intellectual property assets of the Pilot Energy group of companies.

15. Pilot Energy Solutions is based in Houston, Texas, and currently operates four NGL recovery plants in North America utilizing its proprietary technology. Pilot Energy Solutions’ proprietary technology is protected by a portfolio of over twenty United States patents, including the ‘332 Patent asserted in this case.

16. The technology at issue in this case is Pilot Energy Solutions’ patented CO₂Flex[®] process for recovering NGLs from high-CO₂ natural gas streams. Pilot Energy Solutions submitted a proposal for a project in which Pilot proposed to build and operate a gas processing facility at Chevron’s Mabee gas plant near Midland, Texas. Rather than accepting Pilot Energy

Solutions' proposal, Chevron rejected the proposal, contracted with another company to build the gas processing facility, and then operated the facility utilizing Pilot's patented process.

Chevron

17. Defendant Chevron is a multinational energy company with its global headquarters in San Ramon, California. Chevron operated the infringing gas processing facility in its Mabee gas plant near Midland, Texas until its sale of the Mabee gas plant to Scout Energy Management in November 2021.

Scout Energy

18. Scout Energy Partners is a private investment firm, which acquired the Mabee gas plant from Chevron in November 2021. Its affiliate Defendant Scout Energy Management, LLC operates the Mabee gas plant, including the infringing gas processing facility.

History of Chevron's Concealed Infringement of Pilot/PIP's '332 Patent

19. In August 2007 Pilot Energy Solutions and Chevron began discussions about processing the recycle CO₂ gas at Chevron's Mabee gas plant near Midland, Texas (the "Mabee Plant"), for NGL extraction, using Pilot technology. During these discussions Pilot and Chevron executed a Confidentiality Agreement in 2008, and again in 2009. Subsequently, Pilot shared drawings, process simulations, heat and material balances, preliminary cost estimates, and made multiple visits to the Mabee Plant site.

20. During 2007-2008 Pilot personnel attended several meetings with Chevron personnel regarding the proposed project. In November 2007, and again in April 2008, Pilot made formal proposals to build a plant, at its sole cost, to third-party process the CO₂ recycle gas at the

Mabee Plant recompression station. Chevron's continuing evaluation of the Pilot proposals included a field trip to Pilot's plant in Wyoming, to allow Chevron personnel to further evaluate Pilot's proprietary process and speak to the operations staff.

21. During this period there were a number of meetings with Chevron to discuss the possibility of using Pilot's technology at Chevron's Reinecke field, also near Midland, Texas. All discussions were suspended until July 2009, when Chevron contacted Pilot and asked for an updated evaluation based on the most current flow and composition data for the Mabee Plant. Pilot promptly provided this information to Chevron. Other than addressing a few additional technical questions about the Mabee Plant proposal, there were no additional discussions until May 2010 when Pilot received an email from Chevron, asserting that Chevron had a "two year plan" and that no final decision would be made on the Mabee Plant until 2012.

22. In August 2010 Pilot received a follow-up email from Chevron asserting that Chevron was still evaluating Pilot's technology and its processing proposal for the Mabee Plant. In response Pilot offered to explore the possibility of alternative deal structures including a third-party arrangement or a joint venture with Chevron for the Mabee Plant. Pilot did not receive a response from Chevron.

23. In January 2012, Pilot learned through several industry contacts familiar with Pilot's technology, that Chevron was building the Mabee Plant and that it appeared the Plant was going to use Pilot's technology. Pilot contacted Chevron to discuss the situation, remind Chevron that Pilot had previously disclosed its proprietary process under a confidentiality agreement, and inquire as to whether Chevron may be using that technology at the Mabee Plant. Chevron said they would check into the matter.

24. Pilot and Chevron had further discussions in February 2012, in which Pilot reiterated its concerns that Chevron may be incorporating Pilot's proprietary (then patent-pending) technology in the Mabee Plant. Chevron (including Allen Hein) asserted that the Mabee Plant they were building was identical to their Rangely, Colorado plant, using Chevron's own technology from that plant.

25. Pilot requested a meeting with Chevron to discuss Pilot's then-pending patent application, and to review Chevron's Mabee Plant drawings. Chevron did not agree to the proposed meeting, and Pilot heard nothing further from Chevron on the matter over the next several months.

26. After continuing to hear information leading Pilot to believe that Chevron was using Pilot's technology at the Mabee Plant, Pilot looked up the Mabee Plant's air permit application at the Texas Commission for Environmental Quality ("TCEQ") to review the plant design. In November 2012, Pilot was able to find and review the air permit application, which was consistent with what Pilot had been hearing. Attached as Exhibit P-2 is the Chevron Mabee Plant Air Permit Application (November 5, 2012)

27. Pilot's '332 Patent issued on August 13, 2013. Two days later, on August 15, 2013, Pilot sent a letter to Chevron, detailing this history of Pilot's proposals for the Mabee Plant, notifying Chevron of the issuance of the patent, and confirming that the patent covers the technology disclosed to Chevron in Pilot's proposals for the Mabee Plant. (*See* Ex. P-3, Notice Letter from Pilot Energy Solutions to Chevron (August 15, 2013).) Pilot requested a meeting with Chevron to review the '332 Patent and compare it to the technology used by Chevron at the Mabee Plant. Notably, Pilot told Chevron that "we will be happy to drop the matter" if it is determined that Chevron is not using Pilot's technology.

28. Chevron did not agree to the proposed meeting, but did respond with an August 29, 2013 letter from Chevron's legal department. In the letter, Chevron stated that they had reviewed Pilot's '332 Patent, along with "the processes used by Chevron for conditioning and recycling CO₂ gas at the Mabee Plant," and confirmed that "Chevron does not infringe any of the claims of the '332 Patent."

29. Chevron attached to the letter a copy of its U.S. Patent No. 4,753,666 ("Pastor"), further perpetuating Chevron's assertions the Mabee Plant was built identical to their Rangely, Colorado plant using Chevron's own technology. Attached as Exhibit P-5 is Chevron's Pastor patent, which states that the process described and claimed in the Pastor patent was used in Chevron's Rangely, Colorado plant. (*See* Ex. P-1, 6:14-19 ("To further illustrate [the advantages of this invention], various reservoir simulations were performed ... in a petroleum reservoir in Rangely, Colo.").)

30. Chevron concluded the letter by stating that they therefore "consider this matter to be closed." (Ex. P-4, Response Letter from Chevron to Pilot Energy Solutions (August 29, 2013).) As Pilot had committed to in its August 15, 2013 letter, Pilot dropped the matter, relying on Chevron's confirmation that they had reviewed the matter and determined that Chevron was not using Pilot's technology in the Mabee Plant.

31. After years of relying on Chevron's assertions that its Mabee Plant was built using Chevron's own proprietary technology from its Rangely, Colorado plant, as described in Chevron's Pastor patent, rather than Pilot's now patented technology provided to Chevron in Pilot's initial proposals for the Mabee Plant, Pilot discovered new information in 2022, leading Pilot to the conclusion that Chevron had been misrepresenting its processes being used in the Mabee Plant.

32. In July of 2022, Pilot discovered a paper on the Internet that described the technology being used in Chevron's Mabee Plant. Attached as Exhibit P-6 is the paper entitled "Hydrate Formation in Chevron Mabee Unit for NGL Recovery and CO2 Purification for EOR." The paper states that it was "Submitted to Gas Processors Association 2017." Included among the authors is a Chevron Process Engineer.

33. The paper opens by describing Chevron's Rangely, Colorado plant as "designed based on" Chevron's Pastor patent, and then states that Chevron built its Mabee Plant as "a similar facility" designed "based on the success of the Rangely plant's operation." (*See* Ex. P-1, Abstract.) Despite continuing to perpetuate Chevron's assertions that its Chevron Mabee Plant uses its own proprietary processes described in the Pastor patent, the details regarding the processes as described in this 2017 paper have led Pilot to conclude that Chevron's Mabee plant uses Pilot's patented technology claimed in its '332 Patent, and as provided to Chevron in Pilot's proposals for building the Mabee Plant.

34. The Chevron Mabee Plant is not a public facility and members of the public are not able to view the processes used within the Plant. From the time of Chevron's misrepresentations regarding the processes that were actually used in the Mabee Plant, until the time of Pilot's July 2022 discovery of the Hydrate Formation paper, details sufficient to contradict Chevron's misrepresentations were not available to Pilot. Prior to its discovery of the Hydrate Formation paper, Pilot could not have acquired knowledge in the exercise of reasonable care sufficient to lead to the discovery of Chevron's misrepresentations.

**V.
CLAIMS FOR RELIEF**

**COUNT I
PATENT INFRINGEMENT**

35. Plaintiffs Pilot Energy Solutions and PIP incorporate by reference the allegations of each and every one of the preceding paragraphs as though fully set forth herein.

36. Prior to July 1, 2021, Plaintiff Pilot Energy Solutions was the owner of all right, title, and interest in and to the ‘332 Patent, issued August 13, 2013, entitled “Natural Gas Liquid Recovery Process.” A true copy of the ‘332 Patent is attached to this Complaint as Exhibit P-1. Pilot Energy Solutions continues to own the right to sue and recover damages for any infringement of the ‘332 Patent occurring before July 1, 2021.

37. By assignment from Plaintiff Pilot Energy Solutions, Plaintiff PIP now owns all right, title, and interest in and to the ‘332 Patent, including the right to sue and recover damages for any infringement of the ‘332 Patent occurring on or after July 1, 2021.

38. Defendants Chevron and Scout Energy have infringed, and Scout Energy continues to infringe, the ‘332 Patent by performing the methods recited in one or more of the claims of the ‘332 Patent. *See* 28 U.S.C. § 271(a).

39. For example, as set forth in detail in the Claim Chart attached as Exhibit P-7 for exemplary Claim 1, Defendants Chevron and Scout Energy have infringed, and Defendant Scout Energy continues to infringe, at least Claim 1 of the ‘332 Patent.

40. These acts of infringement are irreparably harming and causing damage to Plaintiffs, and will continue to do so unless and until restrained by this Court.

41. Defendants’ acts of infringement are willful because Defendants deliberately continued their infringing conduct after having received notice of Plaintiffs’ ‘332 Patent.

42. Plaintiffs assert that this is an exceptional case such that the Defendants should be required to pay Plaintiffs' reasonable attorney fees in accordance with 35 U.S.C. § 285.

COUNT II
TEXAS COMMON LAW FRAUDULENT
(OR AT LEAST NEGLIGENT) MISREPRESENTATIONS

43. Plaintiffs Pilot Energy Solutions and PIP incorporate by reference the allegations of each and every one of the preceding paragraphs as though fully set forth herein.

44. Chevron's representations described above regarding the processes that is used in its Mabee Plant were false. The processes used in the Mabee Plant include Pilot's patented technology that was provided to Chevron in Pilot's proposals for building the Plant, not Chevron's own proprietary technology described in Chevron's Pastor patent and used in Chevron's Rangely, Colorado facility, as represented by Chevron.

45. Chevron acted knowingly and recklessly in making those false representations. Furthermore, in making these false representations Chevron intended to induce Pilot to not pursue its claims for patent infringement. Pilot justifiably relied on Chevron's representations, causing injury to Pilot including limiting the time period for recovering damages under federal law for patent infringement committed by Chevron.

46. In the alternative, Chevron committed at least negligent misrepresentations, by not exercising reasonable care or competence in communicating with Pilot regarding the processes used in the Mabee Plant.

47. To the extent that Pilot may be barred under 35 U.S. Code § 286 from recovering damages for patent infringement committed by Chevron more than six years prior to the filing of this Complaint, or any other bar to recovery based on a delay in filing suit while relying on Chevron's misrepresentations regarding the processes used in the Mabee Plant, those damages that

otherwise would have been recoverable as patent infringement damages should be recoverable as an award of actual damages for Chevron's fraudulent (or at least negligent) misrepresentation under Texas common law.

48. Plaintiff Pilot Energy Solutions is entitled to an award of actual damages, exemplary damages, and costs of the action, together with prejudgment and post-judgment interest.

VII. JURY DEMAND

49. Plaintiffs hereby demand a trial by jury of any and all issues triable of right by a jury pursuant to Rule 38 of the Federal Rules of Civil Procedure.

PRAYER

Plaintiffs Pilot Energy Solutions and PIP request a judgment from this Court including the following:

- a. a finding that Defendants infringe Plaintiffs' '332 Patent;
- b. an order preliminarily and permanently enjoining Defendants, and all those in active concert or participation with them, from infringing the '332 Patent, in accordance with 35 U.S.C. § 283;
- c. an order awarding damages, interest, and costs to Plaintiffs and against Defendants for Defendants' infringement of the '332 Patent, pursuant to 35 U.S.C. § 284;
- d. a finding that Defendants' infringement of Plaintiffs' '332 Patent is willful;
- e. an order awarding trebled damages to Plaintiffs and against Defendants for Defendants' willful infringement of the '332 Patent, pursuant to 35 U.S.C. § 284;

f. a finding that this case is exceptional, and ordering Defendant to pay Plaintiffs' reasonable attorney fees in accordance with 35 U.S.C. § 285;

g. a finding that Defendant Chevron is liable for Texas common law fraudulent (or at least negligent) misrepresentation, and that Plaintiff Pilot Energy Solutions incurred resulting damages;

h. an award of Plaintiff Pilot Energy Solution's damages and exemplary damages arising out of Defendants' acts of fraudulent (or at least negligent) misrepresentation;

i. an award of interest, including pre-judgment and post-judgment interest on the foregoing sums;

j. an Order directing the Defendants and their agents, employees, servants, attorneys, successors, and assigns, and all others in privity or acting in concert therewith, to file with this Court, and serve upon Plaintiffs' counsel within thirty (30) days after entry of such judgment, a written report under oath, setting forth in detail the manner and form in which they have complied with such judgment; and

k. an order awarding Plaintiffs all such other and further relief as is available, at law or in equity, that this Court deems just, equitable, and proper under the circumstances.

Respectfully submitted this 7th day of July, 2023,

s/ Charles J. Rogers

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**EXHIBITS TO
PLAINTIFFS PILOT ENERGY SOLUTIONS
AND PILOT INTELLECTUAL PROPERTY'S
ORIGINAL COMPLAINT**

- P-1 United States Patent No. 8,505,332 (“the ‘332 Patent”).
- P-2 Chevron Mabee Plant Air Permit Application – Texas Commission for Environmental Quality (“TCEQ”) (November 5, 2012).
- P-3 Notice Letter from Pilot Energy Solutions to Chevron (August 15, 2013).
- P-4 Response Letter from Chevron to Pilot Energy Solutions (August 29, 2013).
- P-5 United States Patent No. 4,753,666 (“Pastor”).
- P-6 Hydrate Formation in Chevron Mabee Unit for NGL Recovery and CO2 Purification for EOR (Submitted to Gas Processors Association 2017).
- P-7 Claim Chart (‘332 Patent Claim 1).

Exhibit P-1

United States Patent No. 8,505,332
 (“the ‘332 Patent”)



US008505332B1

(12) **United States Patent**
Prim

(10) **Patent No.:** **US 8,505,332 B1**
(45) **Date of Patent:** **Aug. 13, 2013**

(54) **NATURAL GAS LIQUID RECOVERY PROCESS**

(75) Inventor: **Eric Prim**, Midland, TX (US)

(73) Assignee: **Pilot Energy Solutions, LLC**, Houston, TX (US)

(*) Notice: Subject to any disclaimer, the term of this patent is extended or adjusted under 35 U.S.C. 154(b) by 1489 days.

(21) Appl. No.: **12/122,336**

(22) Filed: **May 16, 2008**

4,529,411 A *	7/1985	Goddin et al.	95/51
4,563,202 A	1/1986	Yao et al.	
4,595,404 A	6/1986	Ozero et al.	
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4,762,543 A	8/1988	Pantermuehl et al.	
4,765,407 A	8/1988	Yuvancic	
5,019,279 A	5/1991	Haines et al.	
5,411,721 A	5/1995	Doshi et al.	
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6,505,683 B2	1/2003	Minkinen et al.	
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6,915,662 B2	7/2005	Wilkinson et al.	
2003/0161780 A1 *	8/2003	Howard et al.	423/437.1
2008/0156035 A1 *	7/2008	Aspelund et al.	62/606
2011/0197629 A1 *	8/2011	Prim et al.	62/618

* cited by examiner

Related U.S. Application Data

(60) Provisional application No. 60/938,726, filed on May 18, 2007.

(51) **Int. Cl.**
F25J 3/00 (2006.01)
C07C 7/00 (2006.01)
C07C 7/10 (2006.01)
C07C 7/144 (2006.01)

(52) **U.S. Cl.**
USPC **62/618**; 62/620; 62/928; 585/802;
585/818; 585/833

(58) **Field of Classification Search**
USPC 62/617, 618, 620, 622; 585/818,
585/802, 833, 837
See application file for complete search history.

(56) **References Cited**

U.S. PATENT DOCUMENTS

4,136,738 A	1/1979	Haynes, Jr. et al.
4,374,657 A	2/1983	Schendel et al.
4,441,900 A	4/1984	Swallow
4,451,275 A	5/1984	Vines et al.

Primary Examiner — Frantz Jules

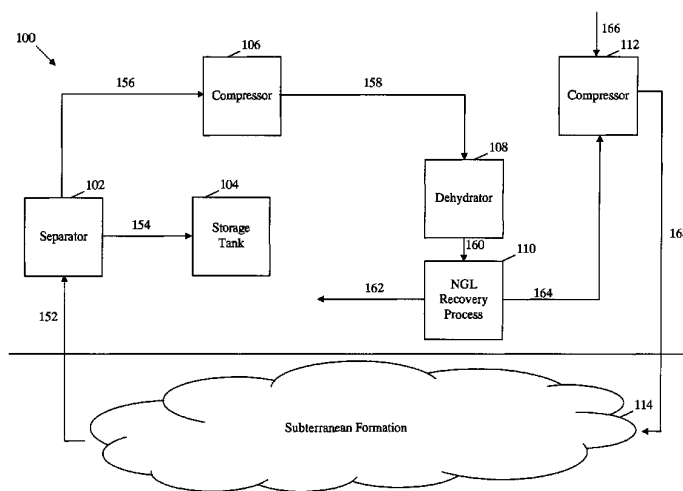
Assistant Examiner — Keith Raymond

(74) *Attorney, Agent, or Firm* — Conley Rose, P.C.; Grant Rodolph; Nicholas K. Beaulieu

(57) **ABSTRACT**

A method comprising receiving a hydrocarbon feed stream, separating the hydrocarbon feed stream into a heavy hydrocarbon rich stream and a carbon dioxide recycle stream, separating the carbon dioxide recycle stream into a natural gas liquids (NGL) rich stream and a purified carbon dioxide recycle stream, and injecting the purified carbon dioxide recycle stream into a subterranean formation. Included is a method comprising selecting a first recovery rate for a NGL recovery process, estimating the economics of the NGL recovery process based on the first recovery rate, selecting a second recovery rate that is different from the first recovery rate, estimating the economics of the NGL recovery process based on the second recovery rate, and selecting the first recovery rate for the NGL recovery process when the estimate based on the first recovery rate is more desirable than the estimate based on the second recovery rate.

26 Claims, 4 Drawing Sheets



U.S. Patent

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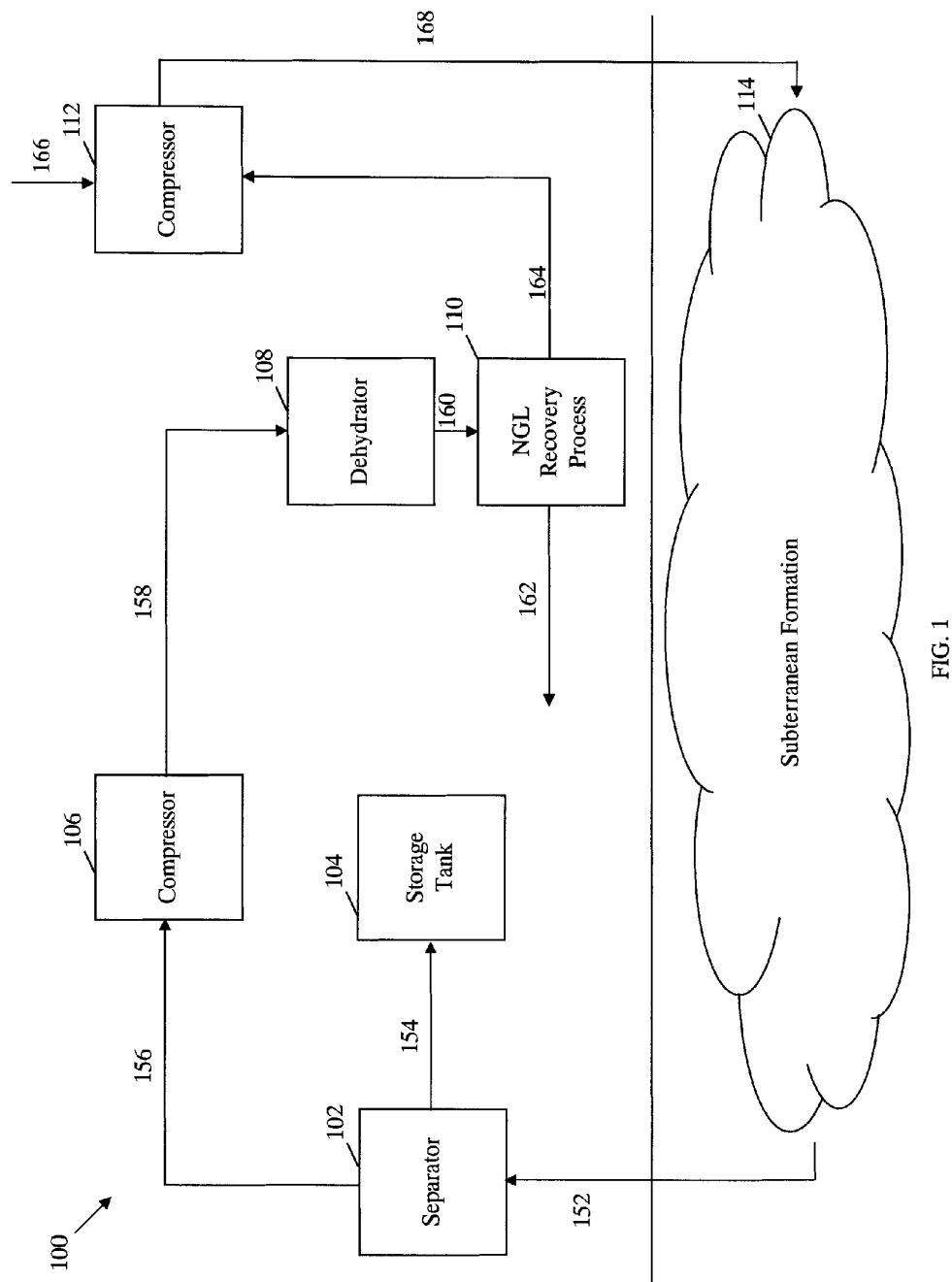


FIG. 1

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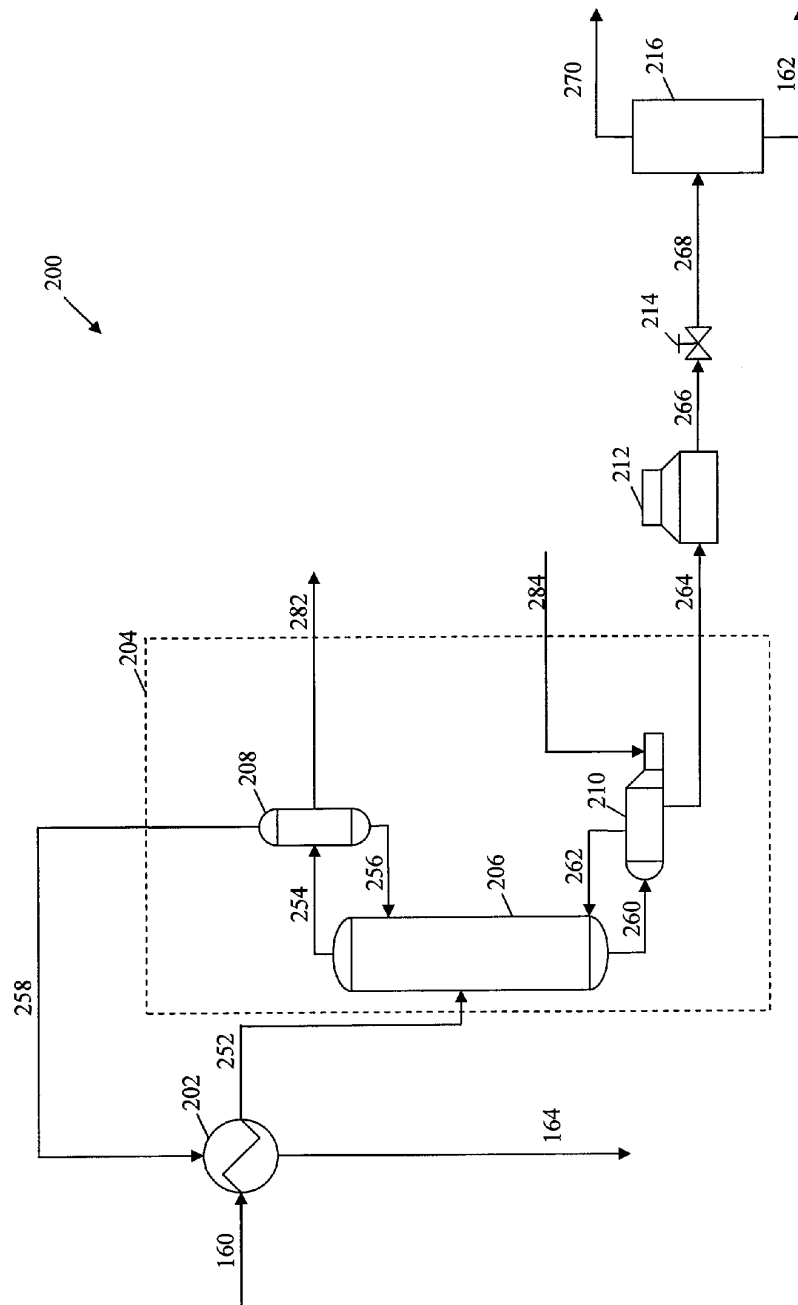


FIG. 2

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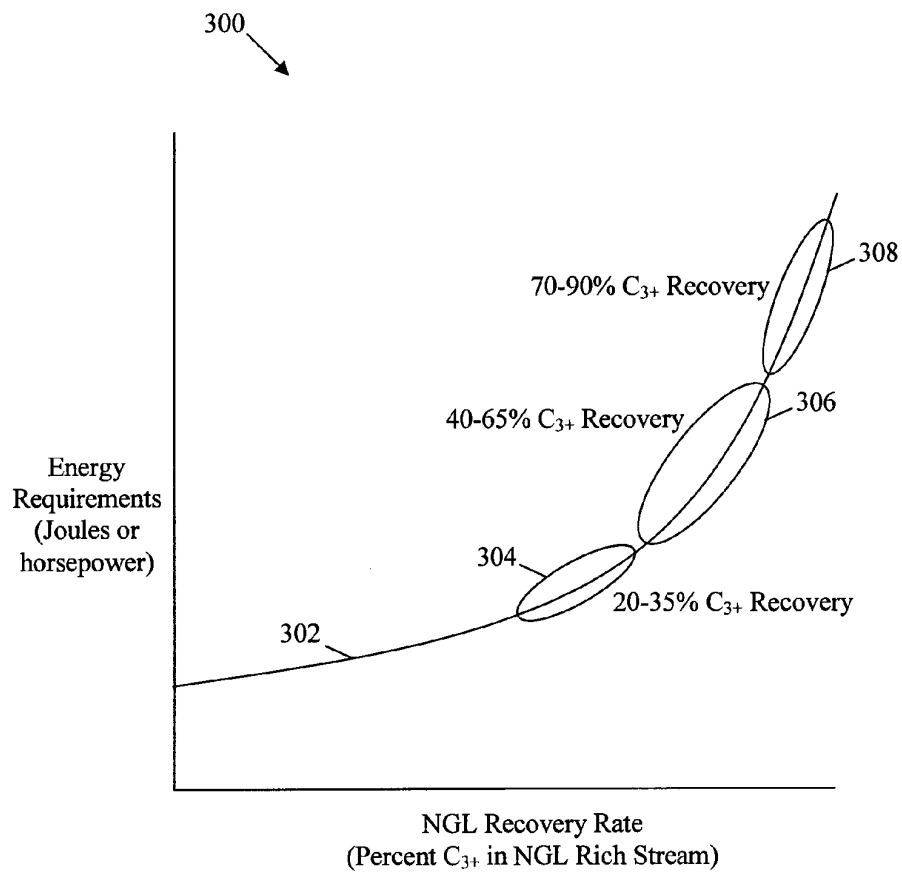


FIG. 3

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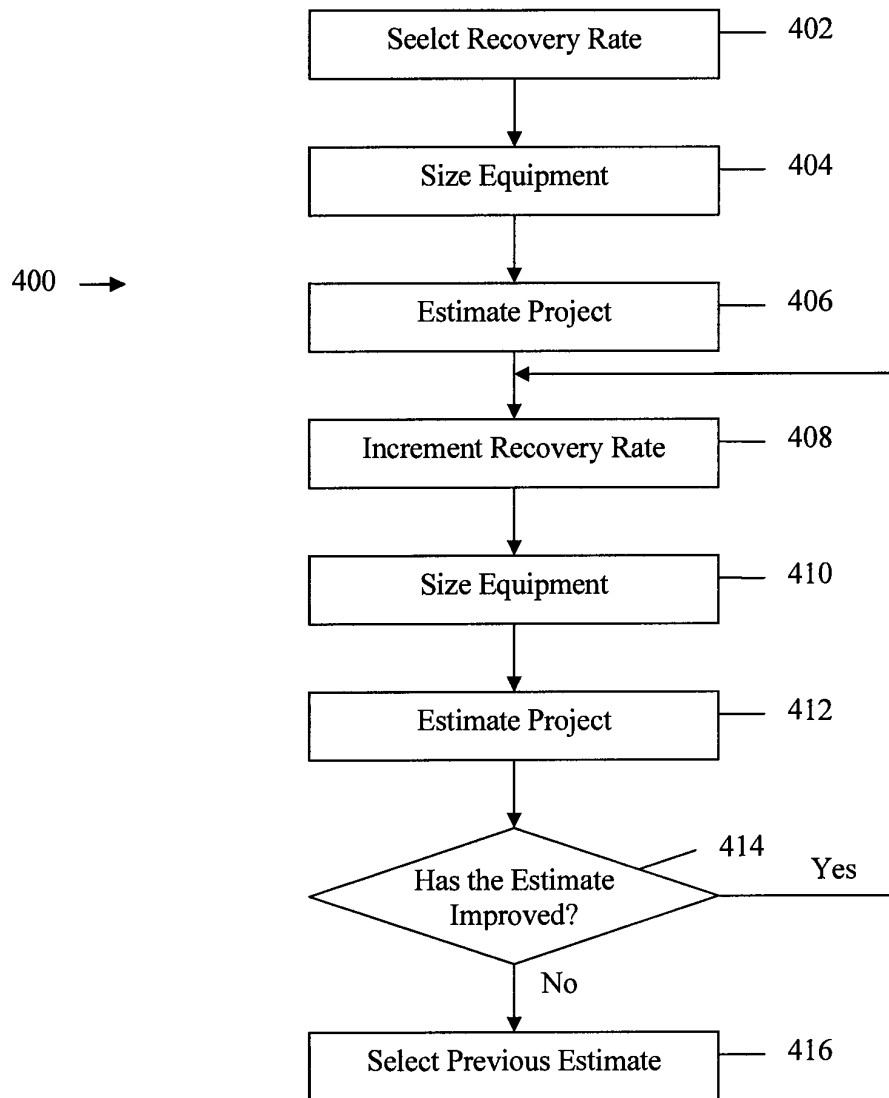


FIG. 4

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NATURAL GAS LIQUID RECOVERY PROCESS

CROSS-REFERENCE TO RELATED APPLICATIONS

The present application claims priority to U.S. Provisional Patent Application Ser. No. 60/938,726, filed May 18, 2007 by Eric Prim, and entitled "NGL Recovery Process," which is incorporated herein by reference as if reproduced in their entirety.

STATEMENT REGARDING FEDERALLY SPONSORED RESEARCH OR DEVELOPMENT

Not applicable.

REFERENCE TO A MICROFICHE APPENDIX

Not applicable.

BACKGROUND

Carbon dioxide (CO₂) is a naturally occurring substance in most hydrocarbon subterranean formations. Carbon dioxide may also be used for recovering or extracting oil and hydrocarbons from subterranean formations. One carbon dioxide based recovery process involves injecting carbon dioxide into an injection well, and recovering heavy hydrocarbons and perhaps some of the carbon dioxide from at least one recovery well. Carbon dioxide reinjection process may also produce natural gas liquids (NGLs).

SUMMARY

In one aspect, the disclosure includes a method comprising receiving a hydrocarbon feed stream, separating the hydrocarbon feed stream into a heavy hydrocarbon rich stream and a carbon dioxide recycle stream, separating the carbon dioxide recycle stream into a NGL rich stream and a purified carbon dioxide recycle stream, and injecting the purified carbon dioxide recycle stream into a subterranean formation.

In another aspect, the disclosure includes a plurality of process equipment configured to implement a method comprising receiving a recycle stream comprising at least one C₃₊ hydrocarbon and a gas selected from the group consisting of carbon dioxide, nitrogen, air, and water, and separating the recycle stream into a NGL rich stream and a purified recycle stream, wherein the NGL rich stream comprises less than about 70 percent of the C₃₊ hydrocarbons from the recycle stream.

In a third aspect, the disclosure includes a method comprising selecting a first recovery rate for a NGL recovery process, estimating the economics of the NGL recovery process based on the first recovery rate, selecting a second recovery rate that is different from the first recovery rate, estimating the economics of the NGL recovery process based on the second recovery rate, and selecting the first recovery rate for the NGL recovery process when the estimate based on the first recovery rate is more desirable than the estimate based on the second recovery rate.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. 1 is a process flow diagram for an embodiment of a carbon dioxide reinjection process.

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FIG. 2 is a schematic diagram of an embodiment of a NGL recovery process.

FIG. 3 is a chart depicting an embodiment of the relationship between the NGL recovery rate and the energy requirement.

FIG. 4 is a flowchart of an embodiment of a NGL recovery optimization method.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENTS

It should be understood at the outset that although an illustrative implementation of one or more embodiments are provided below, the disclosed systems and/or methods may be implemented using any number of techniques, whether currently known or in existence. The disclosure should in no way be limited to the illustrative implementations, drawings, and techniques illustrated below, including the exemplary designs and implementations illustrated and described herein, but may be modified within the scope of the appended claims along with their full scope of equivalents.

Disclosed herein is a NGL recovery process that may be implemented as part of a carbon dioxide reinjection process to recover NGLs from a carbon dioxide recycle stream. When implementing a carbon dioxide reinjection process, the carbon dioxide is typically injected downhole into an injection well and a stream comprising hydrocarbons and carbon dioxide is generally recovered from a recovery well. The carbon dioxide may be separated from the heavy hydrocarbons and then recycled downhole, e.g. in the reinjection well. In some cases, the carbon dioxide recycle stream may comprise some NGLs, which may be recovered prior to injecting the carbon dioxide recycle stream downhole. The NGL recovery process may be optimized by weighing the NGL recovery rate against the amount of energy expended on NGL recovery.

FIG. 1 illustrates an embodiment of a carbon dioxide reinjection process 100. The carbon dioxide reinjection process 100 may receive hydrocarbons and carbon dioxide from a subterranean formation 114, separate heavy hydrocarbons and some of the NGLs from the carbon dioxide, and inject the carbon dioxide downhole. As shown in FIG. 1, additional process steps may be included in the carbon dioxide reinjection process, such as compressing the carbon dioxide, dehydrating the carbon dioxide, and/or adding additional carbon dioxide to the carbon dioxide recycle stream. The specific steps in the carbon dioxide reinjection process 100 are explained in further detail below.

The carbon dioxide reinjection process 100 may receive a hydrocarbon feed stream 152 from a subterranean formation 114. The hydrocarbon feed stream 152 may be obtained from at least one recovery well as indicated by the upward arrow in FIG. 1, but may also be obtained from other types of wells. In addition, the hydrocarbon feed stream 152 may be obtained from the subterranean formation 114 using any suitable method. For example, if a suitable pressure differential exists between the subterranean formation 114 and the surface, the hydrocarbon feed stream 152 may flow to the surface via the pressure differential. Alternatively, surface and/or downhole pumps may be used to draw the hydrocarbon feed stream 152 from the subterranean formation 114 to the surface.

Although the composition of the hydrocarbon feed stream 152 will vary from one location to another, the hydrocarbon feed stream 152 may comprise carbon dioxide, methane, ethane, NGLs, heavy hydrocarbons, hydrogen sulfide (H₂S), helium, nitrogen, water, or combinations thereof. The term "hydrocarbon" may refer to any compound comprising, consisting essentially of, or consisting of carbon and hydrogen

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atoms. The term “natural gas” may refer to any hydrocarbon that may exist in a gas phase under atmospheric or downhole conditions, and includes methane and ethane, but may also include diminishing amounts of C₃-C₈ hydrocarbons. The term “natural gas liquids” or NGLs may refer to natural gases that may be liquefied without refrigeration, and may include C₃-C₈ hydrocarbons. Both natural gas and NGL are terms known in the art and are used herein as such. In contrast, the term “heavy hydrocarbons” may refer to any hydrocarbon that may exist in a liquid phase under atmospheric or downhole conditions, and generally includes liquid crude oil, which may comprise C₉₊ hydrocarbons, branched hydrocarbons, aromatic hydrocarbons, and combinations thereof.

The hydrocarbon feed stream **152** may enter a separator **102**. The separator **102** may be any process equipment suitable for separating at least one inlet stream into a plurality of effluent streams having different compositions, states, temperatures, and/or pressures. For example, the separator **102** may be a column having trays, packing, or some other type of complex internal structure. Examples of such columns include scrubbers, strippers, absorbers, adsorbers, packed columns, and distillation columns having valve, sieve, or other types of trays. Such columns may employ weirs, downspouts, internal baffles, temperature control elements, and/or pressure control elements. Such columns may also employ some combination of reflux condensers and/or reboilers, including intermediate stage condensers and reboilers. Alternatively, the separator **102** may be a phase separator, which is a vessel that separates an inlet stream into a substantially vapor stream and a substantially liquid stream, such as a knock-out drum, flash drum, reboiler, condenser, or other heat exchanger. Such vessels may also have some internal baffles, temperature control elements, and/or pressure control elements, but generally lack any trays or other type of complex internal structure commonly found in columns. The separator **102** may also be any other type of separator, such as a membrane separator. In a specific embodiment, the separator **102** is a knockout drum. Finally, the separator **102** may be any combination of the aforementioned separators **102** arranged in series, in parallel, or combinations thereof.

The separator **102** may produce a heavy hydrocarbon stream **154** and a carbon dioxide recycle stream **156**. The heavy hydrocarbon stream **154** may comprise most of the heavy hydrocarbons from the hydrocarbon feed stream **152**. In embodiments, the heavy hydrocarbon stream **154** may comprise at least about 90 percent, at least about 95 percent, at least about 99 percent, or substantially all of the heavy hydrocarbons from the hydrocarbon feed stream **152**. The heavy hydrocarbon stream **154** may be sent to a pipeline for transportation or a storage tank **104**, where it is stored until transported to another location or further processed. In contrast, the carbon dioxide recycle stream **156** may comprise most of the carbon dioxide from the hydrocarbon feed stream **152**. In embodiments, the carbon dioxide recycle stream **156** may comprise at least about 90 percent, at least about 95 percent, at least about 99 percent, or substantially all of the carbon dioxide from the hydrocarbon feed stream **152**. Similarly, the carbon dioxide recycle stream **156** may comprise at least about 80 percent, at least about 90 percent, at least about 95 percent, or substantially all of the natural gas from the hydrocarbon feed stream **152**. All of the percentages referred to herein are molar percentages until otherwise specified.

The carbon dioxide recycle stream **156** may enter a compressor **106**. The compressor **106** may be any process equipment suitable for increasing the pressure, temperature, and/or density of an inlet stream. The compressor **106** may be configured to compress a substantially vapor phase inlet stream,

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a substantially liquid phase inlet stream, or combinations thereof. As such, the term “compressor” may include both compressors and pumps, which may be driven by electrical, mechanical, hydraulic, or pneumatic means. Specific examples of suitable compressors **106** include centrifugal, axial, positive displacement, turbine, rotary, and reciprocating compressors and pumps. In a specific embodiment, the compressor **106** is a turbine compressor. Finally, the compressor **106** may be any combination of the aforementioned compressors **106** arranged in series, in parallel, or combinations thereof.

The compressor **106** may produce a compressed carbon dioxide recycle stream **158**. The compressed carbon dioxide recycle stream **158** may contain the same composition as the carbon dioxide recycle stream **156**, but at a higher energy level. The additional energy in the compressed carbon dioxide recycle stream **158** may be obtained from energy added to the compressor **106**, e.g. the electrical, mechanical, hydraulic, or pneumatic energy. In embodiments, difference in energy levels between the compressed carbon dioxide recycle stream **158** and the carbon dioxide recycle stream **156** is at least about 50 percent, at least about 65 percent, or at least about 80 percent of the energy added to the compressor **106**.

The compressed carbon dioxide recycle stream **158** may enter a dehydrator **108**. The dehydrator **108** may remove some or substantially all of the water from the compressed carbon dioxide recycle stream **158**. The dehydrator **108** may be any suitable dehydrator, such as a condenser, an absorber, or an adsorber. Specific examples of suitable dehydrators **108** include refrigerators, molecular sieves, liquid desiccants such as glycol, solid desiccants such as silica gel or calcium chloride, and combinations thereof. The dehydrator **108** may also be any combination of the aforementioned dehydrators **108** arranged in series, in parallel, or combinations thereof. In a specific embodiment, the dehydrator **108** is a glycol unit. Any water accumulated within or exiting from the dehydrator **108** may be stored, used for other processes, or discarded.

The dehydrator **108** may produce a dehydrated carbon dioxide recycle stream **160**. The dehydrated carbon dioxide recycle stream **160** may contain little water, e.g. liquid water or water vapor. In embodiments, the dehydrated carbon dioxide recycle stream **160** may comprise no more than about 5 percent, no more than about 3 percent, no more than about 1 percent, or be substantially free of water.

The dehydrated carbon dioxide recycle stream **160** may enter a NGL recovery process **110**. The NGL recovery process **110** may separate the dehydrated carbon dioxide recycle stream **160** into a NGL rich stream **162** and a purified carbon dioxide recycle stream **164**. The NGL rich stream **162** may only comprise a portion of the total NGLs from the dehydrated carbon dioxide recycle stream **160**. For example, the NGL rich stream **162** may comprise less than about 70 percent, from about 10 percent to about 50 percent, or from about 20 percent to about 35 percent of the NGLs from the dehydrated carbon dioxide recycle stream **160**. By taking a less aggressive cut of the NGLs and/or disregarding the recovery of methane, ethane, and optionally propane from the dehydrated carbon dioxide recycle stream **160**, the NGL recovery process **110** may produce a relatively high quality NGL rich stream **162** with relatively little process equipment or energy. A specific example of a suitable NGL recovery process **110** is shown in FIG. 2 and described in further detail below.

As mentioned above, the NGL recovery process **110** may produce a relatively high-quality NGL rich stream **162**. Specifically, while the NGL recovery process **110** recovers only a portion, e.g., about 20 to about 35 percent, of the NGLs in the dehydrated carbon dioxide recycle stream **160**, the result-

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ing NGL rich stream 162 is relatively lean with respect to methane, ethane, and acid gases. For example, the NGL rich stream 162 may comprise most of the butane and heavier components from the dehydrated carbon dioxide recycle stream 160. For example, the NGL rich stream 162 may comprise at least about 90 percent, at least about 95 percent, at least about 99 percent, or substantially all of the C_{4+} from the dehydrated carbon dioxide recycle stream 160. In embodiments, the NGL rich stream 162 may comprise no more than about 10 percent, no more than about 5 percent, no more than about 1 percent, or be substantially free of ethane. Similarly, the NGL rich stream 162 may comprise no more than about 5 percent, no more than about 3 percent, no more than about 1 percent, or be substantially free of methane. Moreover, the NGL rich stream 162 may comprise no more than about 5 percent, no more than about 3 percent, no more than about 1 percent, or be substantially free of acid gases, such as carbon dioxide or hydrogen sulfide. It will be realized that the composition of the NGL rich stream 162 may be dependent on the dehydrated carbon dioxide recycle stream 160 composition. The examples provided below show the composition of the NGL rich stream 162 for three different dehydrated carbon dioxide recycle stream 160 compositions. The NGL rich stream 162 may be sent to a pipeline for transportation or a storage tank, where it is stored until transported to another location or further processed.

As mentioned above, the NGL recovery process 110 may produce a purified carbon dioxide recycle stream 164. The purified carbon dioxide recycle stream 164 may comprise most of the carbon dioxide from the dehydrated carbon dioxide recycle stream 160, as well as some other components such as methane, ethane, propane, butane, nitrogen, and hydrogen sulfide. In embodiments, the purified carbon dioxide recycle stream 164 may comprise at least about 90 percent, at least about 95 percent, at least about 99 percent, or substantially all of the carbon dioxide from the dehydrated carbon dioxide recycle stream 160. In addition, the purified carbon dioxide recycle stream 164 may comprise at least about 90 percent, at least about 95 percent, at least about 99 percent, or substantially all of the methane from the dehydrated carbon dioxide recycle stream 160. As such, the purified carbon dioxide recycle stream 164 may comprise at least about 65 percent, at least about 80 percent, at least about 90 percent, or at least about 95 percent carbon dioxide. In embodiments, the purified carbon dioxide recycle stream 164 may comprise no more than about 10 percent, no more than about 5 percent, no more than about 1 percent, or be substantially free of C_{3+} . Similarly, the purified carbon dioxide recycle stream 164 may comprise no more than about 20 percent, no more than about 10 percent, no more than about 5 percent, or be substantially free of C_{2+} .

The purified carbon dioxide recycle stream 164 may enter a compressor 112. The compressor 112 may comprise one or more compressors, such as the compressor 106 described above. In a specific embodiment, the compressor 112 is a turbine compressor. The compressor 112 may compress the purified carbon dioxide recycle stream 164, thereby producing a carbon dioxide injection stream 168. The carbon dioxide injection stream 168 may contain the same composition as the purified carbon dioxide recycle stream 164, but at a higher energy level. The additional energy in the carbon dioxide injection stream 168 may be obtained from energy added to the compressor 112, e.g. the electrical, mechanical, hydraulic, or pneumatic energy. In embodiments, difference in energy levels between the carbon dioxide injection stream 168 and the purified carbon dioxide recycle stream 164 is at

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least about 50 percent, at least about 65 percent, or at least about 80 percent of the energy added to the compressor 112.

In some embodiments, a makeup stream 166 may be combined with either the purified carbon dioxide recycle stream 164 or the carbon dioxide injection stream 168. Specifically, as the carbon dioxide reinjection process 100 is operated, carbon dioxide and other compounds will be lost, e.g. by replacing the hydrocarbons in the subterranean formation 114, by leakage into inaccessible parts of the subterranean formation 114, and/or to other causes. Alternatively, it may be desirable to increase the amount of carbon dioxide and other compounds injected downhole. As such, the makeup stream 166 may be combined with either the purified carbon dioxide recycle stream 164 and/or the carbon dioxide injection stream 168, for example in the compressor 112. Alternatively or additionally, the makeup stream 166 may be combined with the carbon dioxide recycle stream 156, the compressed carbon dioxide recycle stream 158, the dehydrated carbon dioxide recycle stream 160, or combinations thereof. The makeup stream 166 may comprise carbon dioxide, nitrogen, methane, ethane, air, water, or any other suitable compound. In an embodiment, the makeup stream 166 comprises at least 75 percent, at least 85 percent, or at least 95 percent carbon dioxide, nitrogen, methane, air, water, or combinations thereof.

FIG. 2 illustrates an embodiment of a NGL recovery process 200. The NGL recovery process 200 may recover some of the NGLs from a carbon dioxide recycle stream described above. For example, the NGL recovery process 200 may be implemented as part of the carbon dioxide reinjection process 100, e.g. by separating the dehydrated carbon dioxide recycle stream 160 into a NGL rich stream 162 and a purified carbon dioxide recycle stream 164.

The NGL recovery process 200 may begin by cooling the dehydrated carbon dioxide recycle stream 160 in a heat exchanger 202. The heat exchanger 202 may be any equipment suitable for heating or cooling one stream using another stream. Generally, the heat exchanger 202 is a relatively simple device that allows heat to be exchanged between two fluids without the fluids directly contacting each other. Examples of suitable heat exchangers 202 include shell and tube heat exchangers, double pipe heat exchangers, plate fin heat exchangers, bayonet heat exchangers, reboilers, condensers, evaporators, and air coolers. In the case of air coolers, one of the fluids is atmospheric air, which may be forced over tubes or coils using one or more fans. In a specific embodiment, the heat exchanger 202 is a shell and tube heat exchanger.

As shown in FIG. 2, the dehydrated carbon dioxide recycle stream 160 may be cooled using the cooled, purified carbon dioxide recycle stream 258. Specifically, the dehydrated carbon dioxide recycle stream 160 is cooled to produce the cooled carbon dioxide recycle stream 252, and the cooled, purified carbon dioxide recycle stream 258 is heated to produce the purified carbon dioxide recycle stream 164. The efficiency of the heat exchange process depends on several factors, including the heat exchanger design, the temperature, composition, and flowrate of the hot and cold streams, and/or the amount of thermal energy lost in the heat exchange process. In embodiments, the difference in energy levels between the dehydrated carbon dioxide recycle stream 160 and the cooled carbon dioxide recycle stream 252 is at least about 60 percent, at least about 70 percent, at least about 80, or at least about 90 percent of the difference in energy levels between the cooled, purified carbon dioxide recycle stream 258 and the purified carbon dioxide recycle stream 164.

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The cooled carbon dioxide recycle stream **252** then enters a NGL stabilizer **204**. The NGL stabilizer **204** may comprise a separator **206**, a condenser **208**, and a reboiler **210**. The separator **206** may be similar to any of the separators described herein, such as separator **102**. In a specific embodiment, the separator **206** is a distillation column. The condenser **208** may receive an overhead **254** from the separator **206** and produce the cooled, purified carbon dioxide recycle stream **258** and a reflux stream **256**, which is returned to the separator **206**. The condenser **208** may be similar to any of the heat exchangers described herein, such as heat exchanger **202**. In a specific embodiment, the condenser **208** is a shell and tube, kettle type condenser coupled to a refrigeration process, and contains a reflux accumulator. As such, the condenser **208** may remove some energy **282** from the reflux stream **256** and cooled, purified carbon dioxide recycle stream **258**, typically by refrigeration. The cooled, purified carbon dioxide recycle stream **258** is substantially similar in composition to the purified carbon dioxide recycle stream **164** described above. Similarly, the reboiler **210** may receive a bottoms stream **260** from the separator **206** and produce a sour NGL rich stream **264** and a boil-up stream **262**, which is returned to the separator **206**. The reboiler **210** may be like any of the heat exchangers described herein, such as heat exchanger **202**. In a specific embodiment, the reboiler **210** is a shell and tube heat exchanger coupled to a hot oil heater. As such, the reboiler **210** adds some energy **284** to the boil-up stream **262** and the sour NGL rich stream **264**, typically by heating. The sour NGL rich stream **264** may be substantially similar in composition to the NGL rich stream **162**, with the exception that the sour NGL rich stream **264** has some additional acid gases, e.g. acid gases **270** described below.

The sour NGL rich stream **264** may then be cooled in another heat exchanger **212**. The heat exchanger **212** may be like any of the heat exchangers described herein, such as heat exchanger **202**. For example, the heat exchanger **212** may be an air cooler as described above. A cooled, sour NGL rich stream **266** exits the heat exchanger **212** and enters a throttling valve **214**. The throttling valve **214** may be an actual valve such as a gate valve, globe valve, angle valve, ball valve, butterfly valve, needle valve, or any other suitable valve, or may be a restriction in the piping such as an orifice or a pipe coil, bend, or size reduction. The throttling valve **214** may reduce the pressure, temperature, or both of the cooled, sour NGL rich stream **266** and produce a low-pressure sour NGL rich stream **268**. The cooled, sour NGL rich stream **266** and the low-pressure sour NGL rich stream **268** have substantially the same composition as the sour NGL rich stream **264**, albeit with lower energy levels.

The low-pressure sour NGL rich stream **268** may then be sweetened in a separator **216**. The separator **216** may be similar to any of the separators described herein, such as separator **102**. In an embodiment, the separator **216** may be one or more packed columns that use a sweetening process to remove acid gases from the low-pressure sour NGL rich stream **268**. Suitable sweetening processes include amine solutions, physical solvents such as SELEXOL or RECTISOL, mixed amine solution and physical solvents, potassium carbonate solutions, direct oxidation, absorption, adsorption using, e.g., molecular sieves, or membrane filtration. The separator **216** may produce the NGL rich stream **162** described above. In addition, any acid gases **270** accumulated within or exiting from the separator **216** may be stored, used for other processes, or suitably disposed of. Finally, while FIGS. 1 and 2 are described in the context of carbon dioxide reinjection, it will be appreciated that the concepts described

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herein can be applied to other reinjection processes, for example those using nitrogen, air, or water.

FIG. 3 illustrates an embodiment of a chart **300** depicting the relationship between the NGL recovery rate and the energy expended to recover NGLs in the NGL recovery process. The NGL recovery rate may be a percentage recovery, and may represent the amount of C_{3+} in the carbon dioxide recycle stream that is recovered in the NGL rich stream. The energy requirement may be measured in joules (J) or in horsepower (hp), and may represent the energy required to generate the condenser energy and reboiler energy described above. If additional compressors are needed at any point in the carbon dioxide reinjection process than would be required in an otherwise similar carbon dioxide reinjection process that lacks the NGL recovery process, then the energy required to operate such compressors may be included in the energy requirement shown in FIG. 3.

As shown by curve **302**, the energy requirements may increase about exponentially as the NGLs are recovered at higher rates. In other words, substantially higher energy may be required to recover the NGLs at incrementally higher rates. For example, recovering a first amount **304** of from about 20 percent to about 35 percent of C_{3+} may require substantially less energy than recovering a second amount **306** of from about 40 percent to about 65 percent of C_{3+} . Moreover, recovering the second amount **306** of from about 40 percent to about 65 percent of C_{3+} may require substantially less energy than recovering a third amount **308** of from about 70 percent to about 90 percent of C_{3+} . Such significant reduction in energy requirements may be advantageous in terms of process feasibility and cost, where relatively small decreases in NGL recovery rates may require significantly less energy and process equipment, yielding significantly better process economics. Although the exact relationship of the curve **302** may depend on numerous factors especially the price of C_{3+} , in an embodiment the economics of the NGL recovery process when the NGL recovery rate is in the second amount **306** may be better than the economics of the NGL recovery process when the NGL recovery rate is in the third amount **308**. Similarly, the economics of the NGL recovery process when the NGL recovery rate is in the first amount **304** may be significantly better than the economics of the NGL recovery process when the NGL recovery rate is in the second amount **306**. Such a relationship is counterintuitive considering that in many other processes, the process economics generally improve with increased recovery rates.

FIG. 4 illustrates an embodiment of a NGL recovery optimization method **400**. The NGL recovery optimization method **400** may be used to determine an improved or optimal project estimate for implementing the NGL recovery process and recovering NGLs at a suitable rate. As such, the NGL recovery process may be configured using appropriate equipment design based on the NGL recovery rate. Specifically, the NGL recovery optimization method **400** may design or configure the equipment size, quantity, or both based on an initial NGL recovery rate and required energy, and hence estimate the project feasibility and cost. The method **400** may upgrade or improve the project estimate by iteratively incrementing the initial NGL recovery rate, re-estimating the project, and comparing the two estimates.

At block **402**, the method **400** may select an initial NGL recovery rate. The initial NGL recovery rate may be relatively small, such as no more than about 20 percent recovery, no more than about 10 percent recovery, no more than about 5 percent recovery, or no more than about 1 percent recovery. Choosing the initial NGL recovery rate at a small percentage

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of the total NGL amount may result in a relatively low project estimate that may be increased gradually to reach improved estimates.

The method 400 may then proceed to block 404, where the project equipment size may be determined based on the initial NGL recovery rate. Specifically, the size of the equipment described in the NGL recovery process and any additional compressors as described above may be determined. In addition, the pressure and temperature ratings and material compositions of such equipment may be determined at block 404, if desired.

The method 400 may then proceed to block 406, where the project may be estimated. Project estimation may comprise an economic evaluation of the NGL recovery process, and may include the cost of obtaining, fabricating, and/or field constructing the equipment sized in block 404. In addition, project estimation may include the cost of operating and maintaining the NGL process, as well as the revenue generated by the sale or use of the products obtained by implementing the NGL process. As such, the project estimate may comprise the total project benefits (including production, sales, etc.) minus the total project capital and operating costs (including cost, equipment, etc.). In some embodiments, the project estimate may be based on an existing carbon dioxide reinjection plant that lacks the NGL recovery process.

The method 400 may then proceed to block 408, where the recovery rate is incremented. The NGL recovery rate may be incremented by a relatively small percentage, for example no more than about 10 percent, not more than about 5 percent, or no more than about 1 percent. The method 400 may then proceed to block 410, which is substantially similar to block 404. The method 400 may then proceed to block 412, which is substantially similar to block 406.

The method 400 may then proceed to block 414, where the method 400 may determine whether the project estimate has improved. For instance, the method 400 may compare the project estimate from block 412 with the previous project estimate (either block 406 or the previous iteration of block 412) and determine whether the revised estimate is more economically desirable. The method 400 may return to block 408 when the condition at block 414 is met. Otherwise, the method 400 may proceed to block 416.

At block 416, the method 400 may choose the previous project estimate as the final estimate. For example, the method 400 may select the previous NGL recovery rate (either block 406 or the previous iteration of block 412) instead of the estimate obtained at block 412. In some embodiments, the desired or optimum recovery rate selected at block 416 may represent a range of desirable or optimum points, as opposed to a single point. Accordingly, the method 400 may select the equipment sizing corresponding to the selected NGL recovery rate. The selected project estimate and sizing may then be used for the NGL recovery process. Of course, it will be appreciated that the method 400 may be revised to include a decremented, top-down estimation approach as opposed to an incremented, bottom-up estimation approach.

The method 400 may have several advantages over other project estimation methods. For example, process equipment of a specific size may be selected, and the corresponding recovery rate determined. Alternatively, a required recovery rate may be selected, and the equipment sized to achieve the recovery rate. However, it has been discovered that such approaches are inflexible and often yields suboptimal process economics. For example, relatively high NGL recovery rates will not lead to an improvement in process economics, e.g. because of the exponential increase in energy consumption.

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In contrast, the method 400 provides a flexible approach to determining a desirable or optimal project estimate.

In an embodiment, the equipment size may be configured to allow for variations in recovery rates to accommodate changes in economic conditions, such as C_{3+} or energy pricing. Specifically, the equipment described herein can be sized above or below the desired or optimum amount to allow the processes described herein to operate at recovery rates slightly greater than or slightly less than the desirable or optimum point obtained in method 400. As the process parameters and the energy requirements may be closely related, the ability of the process to continue to successfully operate under differing conditions may be reflected by constrained changes in the energy requirements of the process. When operating in the first amount 304 or the second amount 306 on the curve 302 in FIG. 3, significant increases or decreases in NGL recovery rate may be obtained with little change in the energy requirements. Such is not the case when operating in the third amount 308 on the curve 302 in FIG. 3, where significant increases or decreases in energy requirements yield only incremental changes in NGL recovery rate.

EXAMPLES

In one example, a process simulation was performed using the NGL recovery process 200 shown in FIG. 2. The simulation was performed using the Hyprotech Ltd. HYSYS Process v2.1.1 (Build 3198) software package. The NGL recovery process 200 separated the dehydrated carbon dioxide recycle stream 160 into the purified carbon dioxide recycle stream 164, the NGL rich stream 162, and the acid gas stream 270. The specified values are indicated by an asterisk (*). The physical properties are provided in degrees Fahrenheit (F), pounds per square inch gauge (psig), million standard cubic feet per day (MMSCFD), pounds per hour (lb/hr), U.S. gallons per minute (USGPM), and British thermal units per hour (Btu/hr). The material streams, their compositions, and the associated energy streams produced by the simulation are provided in tables 1, 2, and 3 below, respectively.

TABLE 1A

Material Streams			
Name	Dehydrated CO ₂ Recycle Stream 160	Cooled CO ₂ Recycle Stream 252	Cooled, Purified CO ₂ Recycle Stream 258
Vapor Fraction	0.9838	0.9392	1.0000
Temperature (F.)	104.0*	45.00*	4.011
Pressure (psig)	340.0*	335.0	330.0
Molar Flow (MMSCFD)	17.00*	17.00	15.88
Mass Flow (lb/hr)	8.049e+04	8.049e+04	7.254e+04
Liquid Volume Flow (USGPM)	218.1	218.1	192.3
Heat Flow (Btu/hr)	-2.639e+08	-2.658e+08	-2.577e+08

TABLE 1B

Material Streams			
Name	Purified CO ₂ Recycle Stream 164	Sour NGL Rich Stream 264	Cooled Sour NGL Rich Stream 266
Vapor Fraction	1.0000	0.00000	0.0000
Temperature (F.)	97.39	202.6	120.0*
Pressure (psig)	325.0	340.0	635.3*
Molar Flow (MMSCFD)	15.88	1.119	1.119

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TABLE 1B-continued

Material Streams				
Name		Purified CO ₂ Recycle Stream 164	Sour NGL Rich Stream 264	Cooled Sour NGL Rich Stream 266
Mass Flow	(lb/hr)	7.254e+04	7947	7947
Liquid Volume Flow	(USGPM)	192.3	25.84	25.84
Heat Flow	(Btu/hr)	-2.558e+08	-8.443e+06	-8.862e+06

TABLE 1C

Material Streams				
Name		Low-Pressure Sour NGL Rich Stream 268		
			Acid Gas Stream 270	NGL Rich Stream 162
Vapor Fraction		0.0000	1.0000	0.0000
Temperature (F.)		120.9	100.0*	111.8
Pressure (psig)		200.3*	5.304*	185.3*
Molar Flow (MMSCFD)		1.119	0.1030	1.016
Mass Flow (lb/hr)		7947	446.4	7501
Liquid Volume Flow (USGPM)		25.84	1.100	24.74
Heat Flow (Btu/hr)		-8.862e+06	-1.083e+06	-7.779e+06

TABLE 2A

Stream Compositions				
Name		Dehydrated CO ₂ Recycle Stream 160	Cooled CO ₂ Recycle Stream 252	Cooled, Purified CO ₂ Recycle Stream 258
Comp Mole Frac (H ₂ S)		0.0333*	0.0333	0.0327
Comp Mole Frac (Nitrogen)		0.0054*	0.0054	0.0058
Comp Mole Frac (CO ₂)		0.7842*	0.7842	0.8359
Comp Mole Frac (Methane)		0.0521*	0.0521	0.0558
Comp Mole Frac (Ethane)		0.0343*	0.0343	0.0348
Comp Mole Frac (Propane)		0.0406*	0.0406	0.0313
Comp Mole Frac (i-Butane)		0.0072*	0.0072	0.0022
Comp Mole Frac (n-Butane)		0.0171*	0.0171	0.0015
Comp Mole Frac (i-Pentane)		0.0058*	0.0058	0.0000
Comp Mole Frac (n-Pentane)		0.0057*	0.0057	0.0000
Comp Mole Frac (n-Hexane)		0.0070*	0.0070	0.0000
Comp Mole Frac (n-Octane)		0.0071*	0.0071	0.0000
Comp Mole Frac (H ₂ O)		0.0000*	0.0000	0.0000

TABLE 2B

Stream Compositions				
Name		Purified CO ₂ Recycle Stream 164	Sour NGL Rich Stream 264	Cooled Sour NGL Rich Stream 266
Comp Mole Frac (H ₂ S)		0.0327	0.0421	0.0421
Comp Mole Frac (Nitrogen)		0.0058	0.0000	0.0000
Comp Mole Frac (CO ₂)		0.8359	0.0500	0.0500
Comp Mole Frac (Methane)		0.0558	0.0000	0.0000
Comp Mole Frac (Ethane)		0.0348	0.0281	0.0281
Comp Mole Frac (Propane)		0.0313	0.1728	0.1728
Comp Mole Frac (i-Butane)		0.0022	0.0789	0.0789
Comp Mole Frac (n-Butane)		0.0015	0.2388	0.2388
Comp Mole Frac (i-Pentane)		0.0000	0.0887	0.0887
Comp Mole Frac (n-Pentane)		0.0000	0.0866	0.0866
Comp Mole Frac (n-Hexane)		0.0000	0.1063	0.1063

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TABLE 2B-continued

Stream Compositions				
Name		Purified CO ₂ Recycle Stream 164	Sour NGL Rich Stream 264	Cooled Sour NGL Rich Stream 266
Comp Mole Frac (n-Octane)		0.0000	0.1077	0.1077
Comp Mole Frac (H ₂ O)		0.0000	0.0000	0.0000

TABLE 2C

Stream Compositions				
Name		Low-Pressure Sour NGL Rich Stream 268		
			Acid Gas Stream 270	NGL Rich Stream 162
Comp Mole Frac (H ₂ S)		0.0421	0.4568	0.0000
Comp Mole Frac (Nitrogen)		0.0000	0.0000	0.0000
Comp Mole Frac (CO ₂)		0.0500	0.5432	0.0000
Comp Mole Frac (Methane)		0.0000	0.0000	0.0000
Comp Mole Frac (Ethane)		0.0281	0.0000	0.0309
Comp Mole Frac (Propane)		0.1728	0.0000	0.1903
Comp Mole Frac (i-Butane)		0.0789	0.0000	0.0869
Comp Mole Frac (n-Butane)		0.2388	0.0000	0.2630
Comp Mole Frac (i-Pentane)		0.0887	0.0000	0.0977
Comp Mole Frac (n-Pentane)		0.0866	0.0000	0.0954
Comp Mole Frac (n-Hexane)		0.1063	0.0000	0.1171
Comp Mole Frac (n-Octane)		0.1077	0.0000	0.1186
Comp Mole Frac (H ₂ O)		0.0000	0.0000	0.0000

TABLE 3

Energy Streams		
Name		Heat Flow (Btu/hr)
Condenser Q Energy Stream 282		1.469e+06
Reboiler Q Energy Stream 284		1.152e+06

In another example, the process simulation was repeated using a different dehydrated carbon dioxide recycle stream 160. The material streams, their compositions, and the associated energy streams produced by the simulation are provided in tables 4, 5, and 6 below, respectively.

TABLE 4A

Material Streams				
Name		Dehydrated CO ₂ Recycle Stream 160	Cooled CO ₂ Recycle Stream 252	Cooled, Purified CO ₂ Recycle Stream 258
Vapor Fraction		0.9874	0.9286	1.0000
Temperature (F)		104.0*	60.00*	22.77
Pressure (psig)		685.3*	680.3	590.0
Molar Flow (MMSCFD)		20.00*	20.00	18.86
Mass Flow (lb/hr)		8.535e+04	8.535e+04	7.780e+04
Liquid Volume Flow (USGPM)		258.0	258.0	232.2
Heat Flow (Btu/hr)		-2.741e+08	-2.760e+08	-2.683e+08

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TABLE 4B

Material Streams			
Name	Purified CO ₂ Recycle Stream 164	Sour NGL Rich Stream 264	Cooled Sour NGL Rich Stream 266
Vapor Fraction	1.0000	0.00000	0.0000
Temperature (F)	87.48	290.7	120.0*
Pressure (psig)	585.0	600.0	635.3*
Molar Flow (MMSCFD)	18.86	1.139	1.139
Mass Flow (lb/hr)	7.780e+04	7552	7552
Liquid Volume Flow (USGPM)	232.2	25.83	25.83
Heat Flow (Btu/hr)	-2.663e+08	-7.411e+06	-8.371e+06

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TABLE 4C

Material Streams			
Name	Low-Pressure Sour NGL Rich Stream 268	Acid Gas Stream 270	NGL Rich Stream 162
Vapor Fraction	0.0000	1.0000	0.0000
Temperature (F)	120.5	100.0*	118.6
Pressure (psig)	200.3*	5.304*	185.3*
Molar Flow (MMSCFD)	1.139	0.02943	1.110
Mass Flow (lb/hr)	7552	141.2	7411
Liquid Volume Flow (USGPM)	25.83	0.3421	25.49
Heat Flow (Btu/hr)	-8.371e+06	-5.301e+05	-7.841e+06

TABLE 5A

Stream Compositions			
Name	Dehydrated CO ₂ Recycle Stream 160	Cooled CO ₂ Recycle Stream 252	Cooled, Purified CO ₂ Recycle Stream 258
Comp Mole Frac (H ₂ S)	0.0004*	0.0004	0.0004
Comp Mole Frac (Nitrogen)	0.0153*	0.0153	0.0162
Comp Mole Frac (CO ₂)	0.6592*	0.6592	0.6975
Comp Mole Frac (Methane)	0.1813*	0.1813	0.1922
Comp Mole Frac (Ethane)	0.0620*	0.0620	0.0620
Comp Mole Frac (Propane)	0.0411*	0.0411	0.0275
Comp Mole Frac (i-Butane)	0.0064*	0.0064	0.0017
Comp Mole Frac (n-Butane)	0.0179*	0.0179	0.0024
Comp Mole Frac (i-Pentane)	0.0040*	0.0040	0.0000
Comp Mole Frac (n-Pentane)	0.0049*	0.0049	0.0000
Comp Mole Frac (n-Hexane)	0.0030*	0.0030	0.0000
Comp Mole Frac (n-Octane)	0.0045*	0.0045	0.0000
Comp Mole Frac (H ₂ O)	0.0000*	0.0000	0.0000

TABLE 5B

Stream Compositions			
Name	Purified CO ₂ Recycle Stream 164	Sour NGL Rich Stream 264	Cooled Sour NGL Rich Stream 266
Comp Mole Frac (H ₂ S)	0.0004	0.0008	0.0008
Comp Mole Frac (Nitrogen)	0.0162	0.0000	0.0000
Comp Mole Frac (CO ₂)	0.6975	0.0250	0.0250
Comp Mole Frac (Methane)	0.1922	0.0000	0.0000
Comp Mole Frac (Ethane)	0.0620	0.0613	0.0613
Comp Mole Frac (Propane)	0.0275	0.2670	0.2670
Comp Mole Frac (i-Butane)	0.0017	0.0836	0.0836
Comp Mole Frac (n-Butane)	0.0024	0.2751	0.2751
Comp Mole Frac (i-Pentane)	0.0000	0.0697	0.0697

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TABLE 5B-continued

Stream Compositions			
Name	Purified CO ₂ Recycle Stream 164	Sour NGL Rich Stream 264	Cooled Sour NGL Rich Stream 266
Comp Mole Frac (n-Pentane)	0.0000	0.0858	0.0858
Comp Mole Frac (n-Hexane)	0.0000	0.0527	0.0527
Comp Mole Frac (n-Octane)	0.0000	0.0790	0.0790
Comp Mole Frac (H ₂ O)	0.0000	0.0000	0.0000

TABLE 5C

Stream Compositions			
Name	Low-Pressure Sour NGL Rich Stream 268	Acid Gas Stream 270	NGL Rich Stream 162
Comp Mole Frac (H ₂ S)	0.0008	0.0315	0.0000
Comp Mole Frac (Nitrogen)	0.0000	0.0000	0.0000
Comp Mole Frac (CO ₂)	0.0250	0.9685	0.0000
Comp Mole Frac (Methane)	0.0000	0.0000	0.0000
Comp Mole Frac (Ethane)	0.0613	0.0000	0.0629
Comp Mole Frac (Propane)	0.2670	0.0000	0.2740
Comp Mole Frac (i-Butane)	0.0836	0.0000	0.0858
Comp Mole Frac (n-Butane)	0.2751	0.0000	0.2824
Comp Mole Frac (i-Pentane)	0.0697	0.0000	0.0716
Comp Mole Frac (n-Pentane)	0.0858	0.0000	0.0881
Comp Mole Frac (n-Hexane)	0.0527	0.0000	0.0541
Comp Mole Frac (n-Octane)	0.0790	0.0000	0.0811
Comp Mole Frac (H ₂ O)	0.0000	0.0000	0.0000

TABLE 6

Energy Streams	
Name	Heat Flow (Btu/hr)
Condenser Q Energy Stream 282	1.884e+06
Reboiler Q Energy Stream 284	2.211e+06

In a third example, the process simulation was repeated using a different dehydrated carbon dioxide recycle stream 160. The material streams, their compositions, and the associated energy streams produced by the simulation are provided in tables 7, 8, and 9 below, respectively.

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TABLE 7A

Material Streams			
Name	Dehydrated CO ₂ Recycle Stream 160	Cooled CO ₂ Recycle Stream 252	Cooled, Purified CO ₂ Recycle Stream 258
Vapor Fraction	1.0000	0.9988	1.0000
Temperature (F)	104.0*	30.00*	4.617
Pressure (psig)	340.0*	335.0	330.0
Molar Flow (MMSCFD)	17.00*	17.00	16.82
Mass Flow (lb/hr)	8.083e+04	8.083e+04	7.968e+04
Liquid Volume Flow (USGPM)	203.4	203.4	199.5
Heat Flow (Btu/hr)	-3.016e+08	-3.032e+08	-3.025e+08

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TABLE 7B

Material Streams			
Name	Purified CO ₂ Recycle Stream 164	Sour NGL Rich Stream 264	Cooled Sour NGL Rich Stream 266
Vapor Fraction	1.0000	0.00000	0.0000
Temperature (F)	76.45	199.4	120.0*
Pressure (psig)	325.0	340.0	635.3*
Molar Flow (MMSCFD)	16.82	0.1763	0.1763
Mass Flow (lb/hr)	7.968e+04	1153	1153
Liquid Volume Flow (USGPM)	199.5	3.894	3.894
Heat Flow (Btu/hr)	-3.009e+08	-1.278e+06	-1.340e+06

TABLE 7C

Material Streams			
Name	Low-Pressure Sour NGL Rich Stream 268	Acid Gas Stream 270	NGL Rich Stream 162
Vapor Fraction	0.0000	1.0000	0.0000
Temperature (F)	120.4	100.0*	115.4
Pressure (psig)	200.3*	5.304*	185.3*
Molar Flow (MMSCFD)	0.1763	0.01048	0.1659
Mass Flow (lb/hr)	1153	48.82	1105
Liquid Volume Flow (USGPM)	3.894	0.1188	3.776
Heat Flow (Btu/hr)	-1.340e+06	-1.653e+05	-1.175e+06

TABLE 8A

Stream Compositions			
Name	Dehydrated CO ₂ Recycle Stream 160	Cooled CO ₂ Recycle Stream 252	Cooled, Purified CO ₂ Recycle Stream 258
Comp Mole Frac (H ₂ S)	0.0031*	0.0031	0.0030
Comp Mole Frac (Nitrogen)	0.0008*	0.0008	0.0008
Comp Mole Frac (CO ₂)	0.9400*	0.9400	0.9493
Comp Mole Frac (Methane)	0.0219*	0.0219	0.0222
Comp Mole Frac (Ethane)	0.0156*	0.0156	0.0157
Comp Mole Frac (Propane)	0.0116*	0.0116	0.0088
Comp Mole Frac (i-Butane)	0.0015*	0.0015	0.0002
Comp Mole Frac (n-Butane)	0.0031*	0.0031	0.0001
Comp Mole Frac (i-Pentane)	0.0007*	0.0007	0.0000
Comp Mole Frac (n-Pentane)	0.0006*	0.0006	0.0000
Comp Mole Frac (n-Hexane)	0.0005*	0.0005	0.0000

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TABLE 8A-continued

Stream Compositions			
Name	Dehydrated CO ₂ Recycle Stream 160	Cooled CO ₂ Recycle Stream 252	Cooled, Purified CO ₂ Recycle Stream 258
Comp Mole Frac (n-Octane)	0.0006*	0.0006	0.0000
Comp Mole Frac (H ₂ O)	0.0000*	0.0000	0.0000

TABLE 8B

Stream Compositions			
Name	Purified CO ₂ Recycle Stream 164	Sour NGL Rich Stream 264	Cooled Sour NGL Rich Stream 266
Comp Mole Frac (H ₂ S)	0.0030	0.0094	0.0094
Comp Mole Frac (Nitrogen)	0.0008	0.0000	0.0000
Comp Mole Frac (CO ₂)	0.9493	0.0500	0.0500
Comp Mole Frac (Methane)	0.0222	0.0000	0.0000
Comp Mole Frac (Ethane)	0.0157	0.0000	0.0000
Comp Mole Frac (Propane)	0.0088	0.2794	0.2794
Comp Mole Frac (i-Butane)	0.0002	0.1265	0.1265
Comp Mole Frac (n-Butane)	0.0001	0.2985	0.2985
Comp Mole Frac (i-Pentane)	0.0000	0.0713	0.0713
Comp Mole Frac (n-Pentane)	0.0000	0.0617	0.0617
Comp Mole Frac (n-Hexane)	0.0000	0.0482	0.0482
Comp Mole Frac (n-Octane)	0.0000	0.0550	0.0550
Comp Mole Frac (H ₂ O)	0.0000	0.0000	0.0000

TABLE 8C

Stream Compositions			
Name	Low-Pressure Sour NGL Rich Stream 268	Acid Gas Stream 270	NGL Rich Stream 162
Comp Mole Frac (H ₂ S)	0.0094	0.1584	0.0000
Comp Mole Frac (Nitrogen)	0.0000	0.0000	0.0000
Comp Mole Frac (CO ₂)	0.0500	0.8416	0.0000
Comp Mole Frac (Methane)	0.0000	0.0000	0.0000
Comp Mole Frac (Ethane)	0.0000	0.0000	0.0000
Comp Mole Frac (Propane)	0.2794	0.0000	0.2970
Comp Mole Frac (i-Butane)	0.1265	0.0000	0.1345
Comp Mole Frac (n-Butane)	0.2985	0.0000	0.3174
Comp Mole Frac (i-Pentane)	0.0713	0.0000	0.0758
Comp Mole Frac (n-Pentane)	0.0617	0.0000	0.0656
Comp Mole Frac (n-Hexane)	0.0482	0.0000	0.0512
Comp Mole Frac (n-Octane)	0.0550	0.0000	0.0584
Comp Mole Frac (H ₂ O)	0.0000	0.0000	0.0000

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TABLE 9

Energy Streams	
Name	Heat Flow (Btu/hr)
Condenser Q Energy Stream 282	6.236e+06
Reboiler Q Energy Stream 284	5.666e+06

While preferred embodiments of the invention have been shown and described, modifications thereof can be made by one skilled in the art without departing from the spirit and teachings of the invention. The embodiments described herein are exemplary only, and are not intended to be limiting. Many variations and modifications of the invention disclosed herein are possible and are within the scope of the invention. Specifically, while the process is described in terms of a continuous process, it is contemplated that the process can be implemented as a batch process. In addition, where numerical ranges or limitations are expressly stated, such express ranges or limitations should be understood to include iterative ranges or limitations of like magnitude falling within the expressly stated ranges or limitations (e.g., from about 1 to about 10 includes, 2, 3, 4, etc.; greater than 0.10 includes 0.11, 0.12, 0.13, etc.). Use of the term "optionally" with respect to any element of a claim is intended to mean that the subject element is required, or alternatively, is not required. Both alternatives are intended to be within the scope of the claim. Use of broader terms such as comprises, includes, having, etc. should be understood to provide support for narrower terms such as consisting of, consisting essentially of, comprised substantially of, etc. Moreover, the percentages described herein may be mole fraction, weight fraction, or volumetric fraction.

Accordingly, the scope of protection is not limited by the description set out above but is only limited by the claims that follow, that scope including all equivalents of the subject matter of the claims. Each and every claim is incorporated into the specification as an embodiment of the present invention. Thus, the claims are a further description and are an addition to the preferred embodiments of the present invention. The discussion of a reference in the herein is not an admission that it is prior art to the present invention, especially any reference that may have a publication date after the priority date of this application. The disclosures of all patents, patent applications, and publications cited herein are hereby incorporated by reference, to the extent that they provide exemplary, procedural, or other details supplementary to those set forth herein.

What is claimed is:

1. A method comprising:

receiving a hydrocarbon feed stream, wherein the hydrocarbon feed stream comprises carbon dioxide, natural gas liquid (NGL), heavy hydrocarbons, and acid gas, wherein the NGL comprises C_3 - C_8 hydrocarbons, and wherein the heavy hydrocarbons comprise C_{9+} hydrocarbons;

separating the hydrocarbon feed stream into a heavy hydrocarbon rich stream and a carbon dioxide recycle stream, wherein the heavy hydrocarbon rich stream comprises the C_{9+} hydrocarbons, and wherein the carbon dioxide recycle stream comprises the carbon dioxide, the C_3 - C_8 hydrocarbons, and the acid gas;

separating the carbon dioxide recycle stream into a sour NGL rich stream and a purified carbon dioxide recycle stream, wherein the sour NGL rich stream comprises the

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C_3 - C_8 hydrocarbons and the acid gas, and wherein the purified carbon dioxide recycle stream comprises the carbon dioxide; and

separating the sour NGL rich stream into a sweet NGL rich stream and an acid gas stream, wherein the sweet NGL rich stream comprises the C_3 - C_8 hydrocarbons, and wherein the acid gas stream comprises the acid gas, wherein the carbon dioxide is not removed from the hydrocarbon feed stream and is not removed from the carbon dioxide recycle stream prior to separating the carbon dioxide recycle stream into the sour NGL rich stream and the purified carbon dioxide recycle stream, and wherein the hydrocarbon feed stream, the carbon dioxide recycle stream, and the sour NGL rich stream are not subjected to cryogenic conditions, membranes, and carbon dioxide recovery solvents between being received and being separated into the heavy hydrocarbon rich stream, the purified carbon dioxide recycle stream, the sweet NGL rich stream, and the acid gas stream.

2. The method of claim 1, further comprising:

compressing the carbon dioxide recycle stream prior to separating the carbon dioxide recycle stream;

dehydrating at least part of the carbon dioxide recycle stream using a dehydration solvent prior to separating the carbon dioxide recycle stream;

combining a carbon dioxide makeup stream external to the method with the purified carbon dioxide recycle stream; and

injecting the combined carbon dioxide makeup stream and the purified carbon dioxide recycle stream into a subterranean formation.

3. The method of claim 1, further comprising cooling the carbon dioxide recycle stream with the purified carbon dioxide recycle stream.

4. The method of claim 3, wherein the sweet NGL rich stream comprises no more than 1 molar percent methane, no more than 1 molar percent ethane, and no more than 1 molar percent acid gases.

5. The method of claim 1, wherein the sweet NGL rich stream comprises from 20 molar percent to 40 molar percent of the C_{3+} hydrocarbons from the carbon dioxide recycle stream, and wherein the purified carbon dioxide recycle stream comprises at least 94 molar percent of the carbon dioxide, at least 94 molar percent of the methane, and at least 93 molar percent of the ethane from the carbon dioxide recycle stream.

6. The method of claim 1, wherein separating the carbon dioxide recycle stream into the sour NGL rich stream and the purified carbon dioxide recycle stream comprises:

refluxing part of the purified carbon dioxide recycle stream;

reboiling part of the sour NGL rich stream; and

cooling and throttling the sour NGL rich stream.

7. The method of claim 6, wherein the sour NGL rich stream comprises no more than 5 molar percent carbon dioxide, no more than 1 molar percent methane, and no more than 5 molar percent ethane, and wherein the sweet NGL rich stream is substantially free of carbon dioxide.

8. The method of claim 1, further comprising:

compressing the carbon dioxide recycle stream prior to separating the carbon dioxide recycle stream;

dehydrating at least part of the carbon dioxide recycle stream using molecular sieves prior to separating the carbon dioxide recycle stream;

combining a carbon dioxide makeup stream external to the method with the purified carbon dioxide recycle stream; and

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injecting the combined carbon dioxide makeup stream and the purified carbon dioxide recycle stream into a subterranean formation.

9. A method comprising:

receiving a hydrocarbon feed stream comprising at least one C_{3+} hydrocarbon, at least one C_{9+} hydrocarbon, acid gas, and a gas selected from the group consisting of carbon dioxide, nitrogen, air, and water;

separating the hydrocarbon feed stream into a heavy hydrocarbon rich stream and a recycle stream, wherein the heavy hydrocarbon rich stream comprises most of the C_{9+} hydrocarbon in the hydrocarbon feed stream, wherein the recycle stream comprises most of the C_{3+} hydrocarbon and most of the acid gas in the hydrocarbon feed stream, and wherein the acid gas is selected from the group consisting of carbon dioxide, nitrogen, air, and water;

separating the recycle stream into a sour natural gas liquid (NGL) rich stream and a purified recycle stream, wherein the sour NGL rich stream comprises some of the C_{3+} hydrocarbon and some of the acid gas in the recycle stream, and wherein the purified recycle stream comprises most of the C_{3+} hydrocarbon and most of the acid gas in the recycle stream; and

separating the sour NGL rich stream into a sweet NGL rich stream and an acid gas stream, wherein the sweet NGL rich stream comprises substantially all of the C_{3+} hydrocarbon in the sour NGL rich stream, and wherein the acid gas stream comprises substantially all of the acid gas in the sour NGL rich stream,

wherein the hydrocarbon feed stream, the recycle stream, and the sour NGL rich stream are not subjected to cryogenic conditions, membranes, and carbon dioxide recovery solvents between being received and being separated into the heavy hydrocarbon rich stream, the sweet NGL rich stream, the purified recycle stream, and the acid gas stream, and

wherein carbon dioxide, nitrogen, and air are not removed from the hydrocarbon feed stream and are not removed from the recycle stream prior to separating the recycle stream into the sour NGL rich stream and the purified recycle stream.

10. The method of claim 9, wherein the sweet NGL rich stream comprises at least 90 molar percent C_{3+} hydrocarbons, wherein the sweet NGL rich stream comprises from 20 molar percent to 40 molar percent of the C_{3+} hydrocarbons from the recycle stream, and wherein the purified recycle stream comprises at least 94 molar percent of the carbon dioxide, at least 94 molar percent of the methane, and at least 93 molar percent of the ethane from the recycle stream.

11. The method of claim 10, wherein the sweet NGL rich stream comprises no more than 5 molar percent ethane and no more than 1 molar percent methane, and wherein the purified recycle stream comprises no more than 10 molar percent C_{2+} .

12. The method of claim 9, wherein separating the recycle stream into the sour NGL rich stream and the purified recycle stream comprises:

refluxing part of the purified recycle stream; reboiling part of the sour NGL rich stream; and cooling and throttling the sour NGL rich stream.

13. The method of claim 12, further comprising:

cooling the sour NGL rich stream; expanding the sour NGL rich stream; and cooling the recycle stream using the purified recycle stream.

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14. The method of claim 13, further comprising:

compressing the recycle stream prior to separating the recycle stream; and

dehydrating at least part of the recycle stream using a dehydration solvent after separating the hydrocarbon feed stream and prior to separating the recycle stream.

15. The method of claim 13, wherein the sour NGL rich stream comprises no more than 5 molar percent carbon dioxide, no more than 1 molar percent methane, and no more than 5 molar percent ethane, and wherein the sweet NGL rich stream is substantially free of carbon dioxide.

16. The method of claim 13, further comprising:

compressing the recycle stream prior to separating the recycle stream; and

dehydrating at least part of the recycle stream using molecular sieves after separating the hydrocarbon feed stream and prior to separating the recycle stream.

17. The method of claim 14, wherein the heavy hydrocarbon rich stream comprises at least 90 molar percent of the C_{9+} hydrocarbons in the hydrocarbon feed stream, wherein the recycle stream comprises at least 90 molar percent of the carbon dioxide in the hydrocarbon feed stream, wherein the sweet NGL rich stream comprises at least 60 molar percent of the C_{4+} hydrocarbons in the recycle stream, and wherein the purified recycle stream comprises at least 90 molar percent of the carbon dioxide and at least 90 molar percent of the methane in the recycle stream.

18. The method of claim 14, further comprising combining a carbon dioxide makeup stream from a source external to the method with the purified recycle stream and subsequently injecting the combined carbon dioxide makeup stream and the purified recycle stream into a subterranean formation.

19. A method comprising:

receiving a hydrocarbon feed stream, wherein the hydrocarbon feed stream comprises carbon dioxide, natural gas liquid (NGL), and heavy hydrocarbons, wherein the NGL comprises C_3 - C_8 hydrocarbons, and wherein the heavy hydrocarbons comprise C_{9+} hydrocarbons;

separating the hydrocarbon feed stream into a heavy hydrocarbon rich stream and a carbon dioxide recycle stream, wherein the heavy hydrocarbon rich stream comprises most of the C_{9+} hydrocarbons in the hydrocarbon feed stream, and wherein the carbon dioxide recycle stream comprises most of the carbon dioxide and most of the C_3 - C_8 hydrocarbons in the hydrocarbon feed stream;

separating the carbon dioxide recycle stream into a sour NGL rich stream and a purified carbon dioxide recycle stream, wherein the sour NGL rich stream comprises some of the C_3 - C_8 hydrocarbons in the carbon dioxide recycle stream, and wherein the purified carbon dioxide recycle stream comprises most of the carbon dioxide in the carbon dioxide recycle stream;

separating the sour NGL rich stream into a sweet NGL rich stream and a carbon dioxide rich stream, wherein the sweet NGL rich stream comprises the substantially all of the C_3 - C_8 hydrocarbons in the source NGL rich stream, and wherein the carbon dioxide rich stream comprises substantially all of the carbon dioxide in the sour NGL rich stream;

combining a carbon dioxide makeup stream from a source external to the method with the purified carbon dioxide recycle stream; and

subsequently injecting the combined carbon dioxide makeup stream and the purified carbon dioxide recycle stream into a subterranean formation,

wherein the carbon dioxide is not removed from the hydrocarbon feed stream and is not removed from the carbon dioxide recycle stream prior to separating the carbon

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dioxide recycle stream into the sour NGL rich stream and the purified carbon dioxide recycle stream, and wherein the hydrocarbon feed stream, the carbon dioxide recycle stream, and the sour NGL rich stream are not subjected to cryogenic conditions, membranes, and carbon dioxide recovery solvents between being received and being separated into the heavy hydrocarbon rich stream, the purified carbon dioxide recycle stream, the sweet NGL rich stream, and the carbon dioxide rich stream.

20. The method of claim 19, further comprising: compressing the carbon dioxide recycle stream prior to separating the carbon dioxide recycle stream; dehydrating at least part of the carbon dioxide recycle stream using a dehydration solvent after separating the hydrocarbon feed stream and prior to separating the carbon dioxide recycle stream; and cooling the carbon dioxide recycle stream with the purified carbon dioxide recycle stream.

21. The method of claim 20, further comprising: cooling the sour NGL rich stream; expanding the sour NGL rich stream; and cooling the carbon dioxide recycle stream using the purified carbon dioxide recycle stream.

22. The method of claim 19, wherein the heavy hydrocarbon rich stream comprises at least 90 molar percent of the C_{9+} hydrocarbons in the hydrocarbon feed stream, wherein the carbon dioxide recycle stream comprises at least 90 molar percent of the carbon dioxide in the hydrocarbon feed stream, wherein the sweet NGL rich stream comprises at least 60 molar percent of the C_{4+} hydrocarbons in the carbon dioxide recycle stream, wherein the sweet NGL rich stream comprises no more than 5 molar percent ethane and no more than 1 molar percent methane, wherein the purified carbon dioxide recycle stream comprises at least 90 molar percent of the

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carbon dioxide and at least 90 molar percent of the methane from the carbon dioxide recycle stream, and wherein the purified carbon dioxide recycle stream comprises no more than 10 molar percent C_{2+} .

23. The method of claim 19, wherein separating the carbon dioxide recycle stream into the sour NGL rich stream and the purified carbon dioxide recycle stream comprises:

refluxing part of the purified carbon dioxide recycle stream;

reboiling part of the sour NGL rich stream; and cooling and throttling the sour NGL rich stream.

24. The method of claim 23, wherein the sour NGL rich stream comprises no more than 5 molar percent carbon dioxide, no more than 1 molar percent methane, and no more than 5 molar percent ethane, and wherein the sweet NGL rich stream is substantially free of carbon dioxide.

25. The method of claim 19, wherein the sweet NGL rich stream comprises at least 90 molar percent C_{3+} hydrocarbons, wherein the sweet NGL rich stream comprises from 20 molar percent to 40 molar percent of the C_{3+} hydrocarbons from the recycle stream, and wherein the purified carbon dioxide recycle stream comprises at least 94 molar percent of the carbon dioxide, at least 94 molar percent of the methane, and at least 93 molar percent of the ethane from the carbon dioxide recycle stream.

26. The method of claim 19, further comprising:

compressing the carbon dioxide recycle stream prior to separating the carbon dioxide recycle stream;

dehydrating at least part of the carbon dioxide recycle stream using molecular sieves after separating the hydrocarbon feed stream and prior to separating the carbon dioxide recycle stream; and

cooling the carbon dioxide recycle stream with the purified carbon dioxide recycle stream.

* * * * *

Exhibit P-2

**Chevron Mabee Plant
Air Permit Application
Texas Commission for Environmental Quality
("TCEQ")
(November 5, 2012)**

Bryan W. Shaw, Ph.D., *Chairman*
 Carlos Rubinstein, *Commissioner*
 Toby Baker, *Commissioner*
 Zak Covar, *Executive Director*



Air Permit
[Signature]

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
Protecting Texas by Reducing and Preventing Pollution

November 5, 2012

MR PETER J BOTES
 AIR ADVISOR
 CHEVRON USA INC
 15 SMITH RD
 MIDLAND TX 79705-5423

FILE COPY

Standard Permit Registration Number: 80221 Renewal Date: November 3, 2016
 Location: N on FM 1788 from FM 158 go 8 Mi and turn E at
 Chevron-Texaco Mabee sign follow lease rd to plant
 City/County: Midland, Andrews County
 Project Description/Unit: Add NGL Recovery Plant to the Mabee CO₂ Recycle
 Facility
 Regulated Entity Number: RN102535796
 Customer Reference Number: CN600132484
 New or Existing Site: Existing
 Affected Permit (if applicable): None
 Standard Permit Type: Oil and Gas Production Facilities (effective 9/4/00)

Chevron USA, Inc. has registered the emissions associated with the addition of a NGL recovery plant to the existing Mabee CO₂ Recycle Facility under the standard permit listed above as authorized by the Commissioners pursuant to Title 30 Texas Administrative Code § 116.602 (30 TAC § 116.602). Emissions are listed on the attached table. For rule information see www.tceq.texas.gov/permitting/air/nav/standard.html.

No planned MSS emissions have been represented or reviewed for this registration and none will be authorized.

The company is also reminded that these facilities may be subject to and must comply with other state and federal air quality requirements. In addition, under the applicability section for all Standard Permits, § 116.610(a)(2) states that "Construction or operation of the project must be commenced prior to the effective date of a revision to this subchapter."

If you have questions, please contact Ms. Donna Wurst at (512) 239-5258. This action is taken under authority delegated by the Executive Director of the TCEQ.

Sincerely,

[Signature]

Anne M. Inman, P.E., Manager
 Rule Registrations Section
 Air Permits Division
 Texas Commission on Environmental Quality

cc: Air Section Manager, Region 7 – Midland



**TECHNICAL REVIEW: STANDARD PERMIT FOR
INSTALLATION AND/OR MODIFICATION OF OIL AND GAS FACILITIES**

Permit No.:	80221	Company Name:	Chevron USA, Inc.,	APD Reviewer:	Ms. Donna Wurst
Project No.:	184091	Site/Area Name:	Add NGL Recovery Plant to the Mabee Ranch CO2 Plant	SP No.:	6002 - 116.620 (effective 9/4/00)

GENERAL INFORMATION			
Regulated Entity No.:	RN102535796	Project Type:	Standard Permit Application
Customer Reference No.:	CN600132484	Date Received by TCEQ:	October 12, 2012
Account No.:	AB-0111-T	Date Received by Reviewer:	October 30, 2012
City/County:	Midland, Andrews County	Physical Location:	n on fm 1788 from fm 158 drive 8 mi and turn e at chevron-texaco mabee sign follow lease rd to plant

CONTACT INFORMATION					
Responsible Official/Primary Contact Name and Title:	Mr. Peter J Botes Air Advisor	Phone No.:	(432) 687-7297	Email:	botespi@chevron.com
		Fax No.:	(866) 719-6224		
Technical Contact/Consultant Name and Title:	Mr. Russell Morris Air HES Specialist	Phone No.:	(432) 687-7491	Email:	Russell.morris@chevron.co
		Fax No.:	(866) 719-6224		m

GENERAL RULES CHECK	YES	NO	COMMENTS
Is confidential information included in the application?		X	
Are there associated NSR or Title V permits at the site?		X	There are no permits for this site and no pending permits for this operation. The site is represented as being below major source thresholds and will not require a Title V Operating Permit.
Is the application for renewal of an existing standard permit?		X	

DESCRIBE OVERALL PROCESS AT THE SITE
Chevron USA, Inc. owns and operates the Mabee CO2 Recycle Facility. - This is an existing facility that dehydrates and compresses gas from Chevron's Mabee Ranch tertiary oil recovery project. - The facility is authorized by Standard Permit Registration No. 80221.

DESCRIBE PROJECT AND INVOLVED PROCESS
The purpose of this submittal is to add a NGL Recovery Plant to the facility. The only changes to previously reported emissions, due to the addition of the NGL Recovery Plant, are the addition of a 3 MMBtu/hr hot oil heater, the addition of a 0.25 MMBtu/hr CO2 stripper heater, and increased fugitives from propane refrigeration, NGL's, an additional electric compressor, and the Sulfa-Treat tower. Incoming gas is routed through a knock-out drum to remove liquids before the gas is compressed. The liquids are sent to the water/condensate tank and then to field batteries for disposal. After compression, the gas is routed to the glycol dehydration unit. The dehydration gas is recompressed and sent to the Mabee Ranch Field for reinjection. Rich CO2 gas from the existing second stage compressors will be cooled, dehydrated via the existing TEG unit, and fed to a fractionation tower. The fractionation tower reboiler and condenser duty will be supplied by a hot oil furnace and propane refrigeration unit. The tower bottoms product NGL undergoes COS hydrolysis, air cooling, water separation, SulfaTreat, and storage before being pumped to the West Texas LPG Pipeline. H2S removed by the Sulfa-treat tower produces solid waste sulfur cakes. The addition of one 500 HP electric compressor along with current electric compression and will be used. A flare is used to burn purge gas from the compressor, inlet gas during planned maintenance on the recycle gas compressors, emissions from the water/condensate tank, and for emergency upsets. All existing emissions except for process fugitives are the same as previously represented. New emissions are from the hot oil heater and the CO2 stripper heater. Increased fugitives are from propane refrigeration, NGL's, an additional electric compressor, and the Sulfa-Treat tower. Existing Emissions Flare (EPN 3-1) During normal operation, the flare burns gases generated from the continuous purging of the compressor seals with 100% nitrogen and emissions from the water/condensate tank. Calculations are based on a conservative gas analysis from the flare scrubber. The purge gas flow rate is 75 MCFD and the flow rate from each of the three pilots is 0.83 SCFM. Pilot gas is sweet natural gas. The flow rates for the water/condensate tank were rounded up from emission rates calculated by the program E&P TANK. The flare is also used for maintenance and emission events. No startup, shutdown or maintenance emissions are included in this application. NOx and CO emissions were calculated using factors from the TCEQ's Technical Guidance Package for Flares and Vapor Oxidizers, dated October 2000. The flare is a non-assisted flare using fuel with heat content between 900 and 1000 Btu/scf. The higher of the NO and CO flare emission factors for low and high Btu fuels were used to calculate emissions. H2S and VOC emission rates were based on 98% destruction efficiency. However, a conservative 100% conversion of H2S to SO2 was assumed to calculate SO2 emission rates, which are based on 2.5 mol% H2S in the purge gas and 1.5 mol% H2S in the maintenance gas. All of the sulfur in the gas was assumed to be H2S. To conservatively calculate HAP emissions based on the Flare Scrubber Gas analysis, all C6 compounds were treated as n-hexane and as benzene, and all C7+ compounds were treated as ethylbenzene, toluene and xylenes.

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§116.610. Applicability.

- (a) Under the TCAA, §382.051, a project which meets the requirements for a standard permit listed in this subchapter or issued by the commission is hereby entitled to the standard permit, provided the following conditions listed in this section are met. For the purposes of this subchapter, project means the construction or modification of a facility or a group of facilities submitted under the same registration.
- (1) Any project that results in a net increase in emissions of air contaminants from the project other than carbon dioxide, water, nitrogen, methane, ethane, hydrogen, oxygen, or those for which a national ambient air quality standard has been established must meet the emission limitations of §106.261 of this title (relating to Facilities (Emission Limitations)), unless otherwise specified by a particular standard permit.

Chevron U.S.A. Inc.

All air contaminants meet the emission limitations of §106.261 or §106.262. The following compounds are emitted at rates no higher than 6 lb/hr and 10 tons/yr, which meet the emission limitations of §106.261(a)(2): butane, carbon monoxide, oxides of nitrogen and propane.

The following chemicals are emitted at rates no higher than 1.0 lb/hr and have L values greater than 200 mg/m³, and so meet the requirements of §106.261(a)(3): pentanes, hexanes, heptanes+, ethylbenzene, and xylene. Triethylene glycol is not listed or referenced in Table 262, and the emission rate is less than 1.0 lb/hr.

The remaining compounds: n-hexane, benzene, toluene, PM, and hydrogen sulfide meet the emission limitations of §106.262(a)(2). These compounds are not emitted at rates greater than 5 tons/yr and 6 lb/hr or a quantity greater than E lb/hr where E=L/K. The nearest off-plant receptor is located at a distance of greater than 3000 feet, so a value of 8 is used for K. See the Emission Rate Summary for speciated emission rates and L/K calculations.

- (2) Construction or operation of the project must be commenced prior to the effective date of a revision to this subchapter under which the project would no longer meet the requirements for a standard permit.

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- (b) Any project that constitutes a new major stationary source or major modification as defined in §116.12 of this title (relating to Nonattainment and Prevention of Significant Deterioration Review Definitions) is subject to the requirements of §116.110 of this title (relating to Applicability) rather than this subchapter.

Chevron U.S.A. Inc.

The emissions from the facility do not constitute a new major source or major modification under the FCAA, Part C or Part D.

- (c) Persons may not circumvent by artificial limitations the requirements of §116.110 of this title.

Chevron U.S.A. Inc.

No artificial limitations are employed to circumvent permit requirements.

- (d) Any project involving a proposed affected source (as defined in §116.15(1) of this title (relating to Section 112(g) Definitions)) shall comply with all applicable requirements under Subchapter E of this chapter (relating to Hazardous Air Pollutants: Regulations Governing Constructed or Reconstructed Major Sources (FCAA, §112(g), 40 CFR Part 63)). Affected sources subject to Subchapter E of this chapter may use a standard permit under this subchapter only if the terms and conditions of the specific standard permit meet the requirements of Subchapter E of this chapter.

Chevron U.S.A. Inc.

The facility is not an affected source as defined in §116.15(1).

§116.611. Registration to Use a Standard Permit.

- (a) If required, registration to use a standard permit shall be sent by certified mail, return receipt requested, or hand delivered to the executive director, the appropriate commission regional office, and any local air pollution program with jurisdiction, before a standard permit can be used. The registration must be submitted on the required form and must document compliance with the requirements of this section, including, but not limited to:
- (1) the basis of emission estimates;
 - (2) quantification of all emission increases and decreases associated with the project being registered;
 - (3) sufficient information as may be necessary to demonstrate that the project will comply with §116.610(b) of this title (relating to Applicability);

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§116.614. Standard Permit Fees.

Any person who registers to use a standard permit or an amended standard permit, or to renew a registration to use a standard permit shall remit, at the time of registration, a flat fee of \$900 for each standard permit being registered, unless otherwise specified in a particular standard permit. No fee is required if a registration is automatically renewed by the commission. All standard permit fees will be remitted in the form of a check, certified check, electronic funds transfer, or money order made payable to the Texas Commission on Environmental Quality (TCEQ) and delivered with the permit registration to the TCEQ, P.O. Box 13088, MC 214, Austin, Texas 78711-3087. No fees will be refunded.

Chevron U.S.A. Inc.

The permit fee of \$900 has been paid on line.

§116.615. General Conditions.

The following general conditions are applicable to holders of standard permits, but will not necessarily be specifically stated within the standard permit document.

- (1) **Protection of public health and welfare.** The emissions from the facility, including dockside vessel emissions, must comply with all applicable rules and regulations of the commission adopted under Texas Health and Safety Code, Chapter 382, and with the intent of the Texas Clean Air Act (TCAA), including protection of health and property of the public.

Chevron U.S.A. Inc.

The emissions from the facility will comply with all applicable rules and regulations of the commission adopted under the Texas Health and Safety Code, Chapter 382, and with the intent of the TCAA, including protection of health and property of the public.

- (2) **Standard permit representations.** All representations with regard to construction plans, operating procedures, and maximum emission rates in any registration for a standard permit become conditions upon which the facility or changes thereto, must be constructed and operated. It is unlawful for any person to vary from such representations if the change will affect that person's right to claim a standard permit under this section. Any change in condition such that a person is no longer eligible to claim a standard permit under this section requires proper authorization under §116.110 of this title (relating to Applicability). If the facility remains eligible for a standard permit, the owner or operator of the facility shall notify the executive director of any change in conditions which will result in a change in the method of control of emissions, a change in the character of the emissions, or an increase in the discharge of the various emissions as compared to the representations in the original registration or any previous notification of a change in representations. Notice of changes in

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- (D) A particular standard permit may modify start-up notification requirements.**

Chevron U.S.A. Inc.

The operation of the facility has commenced.

- (6) Sampling requirements.** If sampling of stacks or process vents is required, the standard permit holder shall contact the commission's appropriate regional office and any other air pollution control agency having jurisdiction prior to sampling to obtain the proper data forms and procedures. All sampling and testing procedures must be approved by the executive director and coordinated with the regional representatives of the commission. The standard permit holder is also responsible for providing sampling facilities and conducting the sampling operations or contracting with an independent sampling consultant.

Chevron U.S.A. Inc.

There are no sampling requirements for the facility.

- (7) Equivalency of methods.** The standard permit holder shall demonstrate or otherwise justify the equivalency of emission control methods, sampling or other emission testing methods, and monitoring methods proposed as alternatives to methods indicated in the conditions of the standard permit. Alternative methods must be applied for in writing and must be reviewed and approved by the executive director prior to their use in fulfilling any requirements of the standard permit.

Chevron U.S.A. Inc.

Chevron U.S.A. Inc. does not plan to use alternative methods.

- (8) Recordkeeping.** A copy of the standard permit along with information and data sufficient to demonstrate applicability of and compliance with the standard permit shall be maintained in a file at the plant site and made available at the request of representatives of the executive director, the United States Environmental Protection Agency, or any air pollution control agency having jurisdiction. For facilities that normally operate unattended, this information shall be maintained at the nearest staffed location within Texas specified by the standard permit holder in the standard permit registration. This information must include, but is not limited to, production records and operating hours. Additional recordkeeping requirements may be specified in the conditions of the standard permit. Information and data sufficient to demonstrate applicability of and compliance with the standard permit must be retained for at least two years following the date that the

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a condition of the permit, the determination of whether the distance, setback, or buffer is satisfied shall be made on the basis of conditions existing at the earlier of:

- (A) the date new construction, expansion, or modification of a facility begins; or**
- (B) the date any application or notice of intent is first filed with the commission to obtain approval for the construction or operation of the facility.**

Chevron U.S.A. Inc.

Chevron U.S.A. Inc. acknowledges this provision.

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- (5) Total Volatile Organic Compound (VOC) emissions from a natural gas glycol dehydration unit shall not exceed ten tons per year (tpy) unless the vapors are collected and controlled in accordance with subsection (b)(2) of this section.**

Chevron U.S.A. Inc.

The vapors from the glycol dehydration unit will be controlled by routing the emissions to the compressor suction for reinjection. This exceeds the requirements of subsection (b)(2) of this section.

- (6) Any combustion unit (excluding flares, internal combustion engines, or natural gas turbines), with a design maximum heat input greater than 40 million British thermal units (Btu) per hour (using lower heating values) shall not emit more than 0.06 pounds of nitrogen oxides per million Btu.**

Chevron U.S.A. Inc.

There are no combustion units with a design maximum heat input greater than 40 million Btu/hr authorized in the standard permit.

- (7) No facility which is less than 500 feet from the nearest off-plant receptor shall be allowed to emit uncontrolled VOC process fugitive emissions equal to or greater than ten tpy, but less than 25 tpy, unless the equipment is inspected and repaired according to subsection (c)(1) of this section.**

Chevron U.S.A. Inc.

Does not apply. The nearest off-plant receptor is greater than 500 feet away. Uncontrolled VOC process fugitive emissions are less than 25 tpy.

- (8) No facility which is 500 feet or more from the nearest off-plant receptor shall be allowed to emit uncontrolled VOC process fugitive emissions equal to or greater than 25 tpy unless the equipment is inspected and repaired according to subsection (c)(1) of this section.**

Chevron U.S.A. Inc.

Does not apply. The nearest off-plant receptor is greater than 500 feet away. Uncontrolled VOC process fugitive emissions are less than 25 tpy.

- (9) No facility which is less than 500 feet from the nearest off-plant receptor shall be allowed to emit uncontrolled VOC process fugitive emissions equal to or greater than 25 tpy unless the equipment is inspected and repaired according to subsection (c)(2) of this section.**

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and regulations promulgated thereunder, and with Subchapter C of this chapter (relating to Hazardous Air Pollutants: Regulations Governing Constructed or Reconstructed Major Sources (FCAA, §112(g), 40 CFR Part 63)) are being met. The oil and gas facility shall be required to meet the requirements of Subchapter B of this chapter (relating to New Source Review Permits) instead of this subchapter if a PSD or nonattainment permit or a review under Subchapter C of this chapter is required.

Chevron U.S.A. Inc.

There are no PSD, nonattainment, or MACT regulations applicable to the facility.

- (14) Documentation shall be submitted to demonstrate compliance with applicable New Source Performance Standards (NSPS, 40 CFR Part 60).**

Chevron U.S.A. Inc.

The storage tanks and fugitives are the only sources with potentially applicable NSPS requirements. The storage tanks are not subject to NSPS Kb since they store condensate prior to custody transfer, and the design storage capacity is less than 1,589.874 m³. The site fugitives are subject to NSPS OOOO. Appropriate documentation will be submitted.

- (15) Documentation shall be submitted to demonstrate compliance with applicable National Emission Standards for Hazardous Air Pollution (NESHAP, 40 CFR Part 61).**

Chevron U.S.A. Inc.

There are no NESHAP subparts applicable to the site.

- (16) Documentation shall be submitted to demonstrate compliance with applicable maximum achievable control technology standards as listed under 40 CFR Part 63, promulgated by the EPA under FCAA, §112 or as listed in Chapter 113, Subchapter C of this title (relating to National Emissions Standards for Hazardous Air Pollutants for Source Categories (FCAA §112, 40 CFR Part 63)).**

Chevron U.S.A. Inc.

There are no MACT subparts applicable to the site. The site is an area source of HAP in which the glycol dehy unit has no emissions because it is hard piped back to the front end of the plant, so there are no MACT HH standards.

- (17) New and increased emissions shall not cause or contribute to a violation of any National Ambient Air Quality Standard or regulation property line standards as specified in Chapters 111, 112, and 113 of this title (relating to**

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- (B) Mechanical shoe or liquid-mounted primary seals shall include a rim-mounted secondary seal on all external floating roofs tanks. Vapor-mounted primary seals will not be accepted.
- (C) All floating roof tanks shall comply with the requirements under §115.112(a)(2)(A) - (F) of this title (relating to Control Requirements).
- (D) In lieu of a floating roof, tank emissions may be routed to:
 - (i) a destruction device such that a minimum VOC destruction efficiency of 98% is achieved; or
 - (ii) a vapor recovery system such that a minimum VOC recovery efficiency of 95% is achieved.
- (E) Independent of the permits by rule listed in this paragraph, if the emissions from any fixed roof tank exceed ten tpy of VOC or ten tpy of sulfur compounds, the tank emissions shall be routed to a destruction device, vapor recovery unit, or equivalent method of control that meets the requirements listed in subparagraph (D) of this paragraph.

Chevron U.S.A. Inc.

The storage tanks at the site area are all less than 25,000-gallon capacity, so this requirement does not apply.

- (2) The VOC emissions from a natural gas glycol dehydration unit shall be controlled as follows.
 - (A) If total uncontrolled VOC emissions are equal to or greater than ten tpy, but less than 50 tpy, a minimum of 80% by weight minimum control efficiency shall be achieved by either operating a condenser and a separator (or flash tank), vapor recovery unit, destruction device, or equivalent control device.
 - (B) If total uncontrolled VOC emissions are equal to or greater than 50 tpy, a minimum of:
 - (i) 98% by weight minimum destruction efficiency shall be achieved by a destruction device or equivalent; or
 - (ii) 95% by weight minimum control efficiency shall be achieved by a vapor recovery system or equivalent.

Chevron U.S.A. Inc.

The glycol dehydration unit still vent is routed through two Vapor Recovery Units and the vapors are sent to the compressor suction for reinjection. The only emissions associated with this vent are fugitive piping emissions.

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quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Flanges in VOC service shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

- (F) Each open-ended valve or line in VOC service, other than a valve or line used for safety relief, shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.
- (G) Accessible valves in VOC service shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. For valves equipped with rupture discs, a pressure gauge shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity, but no later than the next process shutdown. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc or venting to a control device are exempt from monitoring.
- (H) Dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system, submerged pumps, or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic driven pumps) are exempt from monitoring.
- (I) All other pump and compressor seals emitting VOC shall be monitored with an approved gas analyzer at least quarterly.
- (J) After completion of the required quarterly inspections for a period of at least two years, the operator of the oil and gas facility may request in writing to the Office of Permitting, Remediation, and Registration that the monitoring schedule be revised based on the percent of valves leaking. The percent of valves leaking shall be determined by dividing the sum of valves leaking during current monitoring and valves for which repair has been delayed by the total number of valves subject to the requirements.

This request shall include all data that has been developed to justify the following modifications in the monitoring schedule.

- (i) After two consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0%, an owner or operator may begin to skip one of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

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developed to justify the following modifications in the monitoring schedule.

- (i) After two consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0%, an owner or operator may begin to skip one of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.
- (ii) After five consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0%, an owner or operator may begin to skip three of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.
- (K) A directed maintenance program shall be used and consist of the repair and maintenance of VOC fugitive emission components assisted simultaneously by the use of an approved gas analyzer such that a minimum concentration of leaking VOC is obtained for each component being maintained. Replaced components shall be remonitored within 30 days of being placed back into VOC service.

Chevron U.S.A. Inc.

This section does not apply because Sections (a)(9) and (a)(10) do not apply to this standard permit. The facility process fugitives are controlled according to NSPS OOOO. Uncontrolled VOC process fugitives are less than 40 tons per year and the facility is greater than 500 feet from the nearest off-plant receptor.

- (3) For owners and operators who are subject to the applicable parts of subsection (a)(11) of this section, auditory and visual checks for SO₂ and H₂S leaks within the operating area shall be made every day. Immediately, but no later than eight hours upon detection of a leak, operating personnel shall take the following actions:
 - (A) isolate the leak; and
 - (B) commence repair or replacement of the leaking component; or
 - (C) use a leak collection/containment system to prevent the leak until repair or replacement can be made if immediate repair is not possible.

Chevron U.S.A. Inc.

Chevron U.S.A. Inc. will make auditory and visual checks for SO₂ and H₂S leaks within the operating area every day. Repairs will be made according to (c)(3) above.

- (d) Approved test methods.

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- (2) The results of the VOC leak detection and repair requirements shall be made available to the executive director or any air pollution control agency having jurisdiction upon request. Records, for all components, shall include:**

- (A) appropriate dates;**
- (B) test methods;**
- (C) instrument readings;**
- (D) repair results; and**
- (E) corrective actions. Records of flange inspections are not required unless a leak is detected.**

Chevron U.S.A. Inc.

Results of the VOC leak detection and repair requirements will be made available to the executive director or any air pollution control agency having jurisdiction upon request.

- (3) Records for repairs and replacements made due to inspections of H₂S and SO₂ components shall be maintained.**

Chevron U.S.A. Inc.

These records shall be maintained.

- (4) Records shall be kept for each production, processing, and pipeline tank battery or for each storage tank if not located at a tank battery, on a monthly basis, as follows:**
- (A) tank battery identification or storage tank identification, if not located at a tank battery;**
 - (B) compound stored;**
 - (C) monthly throughput in barrels/month; and**
 - (D) cumulative annual throughput, barrels/year.**

Chevron U.S.A. Inc.

These records shall be maintained.

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Project No.:	184091	Site/Area Name:	Add NGL Recovery Plant to the Mabree Ranch CO2 Plant	SP No.:	6002 - 116.620 (effective 9/4/00)

SPECIATED EMISSIONS RATE SUMMARY*

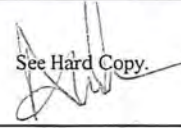
Component	Authorized using emission limitations of:	Emissions (lb/hr)	L Value (mg/m ³)	Allowable (lb/hr) (L/K or Max)	Is Hourly Total < Allowable?	Emissions (tons/yr)
Propane	106.261(a)(2)	0.10	NA	6.00	Yes	0.45
Butanes	106.261(a)(2)	0.09	NA	6.00	Yes	0.43
Pentanes	106.261(a)(3)	0.08	350	1.00	Yes	0.32
Hexanes	106.261(a)(3)	0.05	1760	1.00	Yes	0.25
Heptanes plus	106.261(a)(3)	0.25	350	1.00	Yes	1.07
n-Hexane	106.262(a)(2)	0.06	176	6.00	Yes	0.24
Benzene	106.262(a)(2)	0.053	3	0.33	Yes	0.26
Toluene	106.262(a)(2)	0.25	188	6.00	Yes	1.08
Ethylbenzene	106.261(a)(3)	0.25	434	1.00	Yes	1.07
Xylene	106.261(a)(3)	0.24	434	1.00	Yes	1.07
Hydrogen sulfide	106.262(a)(2)	0.16	10	1.25	Yes	0.72
Triethylene Glycol	106.261(a)(3)	0.014	NA	1.00	Yes	0.028
Carbon Monoxide	106.261(a)(2)	0.37	NA	6.00	Yes	3.83
Nitrogen Oxides	106.261(a)(2)	0.64	NA	6.00	Yes	2.78
Particulate Matter	106.262(a)(2)	0.040	10	1.25	Yes	0.18

* Emission increases are denoted by bold and italicized text.

K value = 8 for 3000 ft

MAXIMUM EMISSION RATES TABLE (MERT)

EPN / Emission Source	VOC		NOx		CO		PM ₁₀ / PM _{2.5}		SO ₂		H ₂ S		HAPs (in VOC total)	
	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy
3-1: Flare (Purge Operation)	0.52	2.27	0.11	0.47	0.43	1.89	<0.01	<0.01	14.00	61.30	0.14	0.62	0.76	3.30
2-1: Open Drain Tank	0.10	0.10												
4-3: Glycol Storage Tank	0.01	0.01												
4-1: Glycol Reboiler	0.01	0.04	0.17	0.76	0.15	0.64	0.01	0.06	0.03	0.11				
FE-001: Process Fugitives	0.33	1.29									0.02	0.10	0.09	0.40
HTR-1: Hot Oil Heater	0.02	0.08	0.33	1.43	0.27	1.20	0.03	0.11	0.05	0.21				
HTR-2: CO2 Stripper Heater	<0.01	0.01	0.03	0.12	0.02	0.10	<0.01	0.01	<0.01	0.02				
TOTAL EMISSIONS (TPY):		3.80		2.78		3.83		0.18		61.64		0.72		3.70
MAXIMUM OPERATING SCHEDULE:	Hours/Day		24		Days/Week		7		Weeks/Year		52		Hours/Year	
													8760	

	TECHNICAL REVIEWER	PEER REVIEWER	FINAL REVIEWER
SIGNATURE:			
PRINTED NAME:	Ms. Donna Wurst		
DATE:	November 5, 2012		

BASIS OF PROJECT POINTS	POINTS
Base Points: O&G SP 6002	2.50
Project Complexity Description and Points: completed in <15 days	1.00
Technical Reviewer Project Points Assessment:	3.5
Final Reviewer Project Points Confirmation:	

CHEVRON U.S.A. INC.
MABEE CO₂ RECYCLE FACILITY
REVISION TO STANDARD PERMIT REGISTRATION NO. 80221

OCTOBER 2012

ATTACHMENT V.B

PROCESS DESCRIPTION AND FLOW DIAGRAM

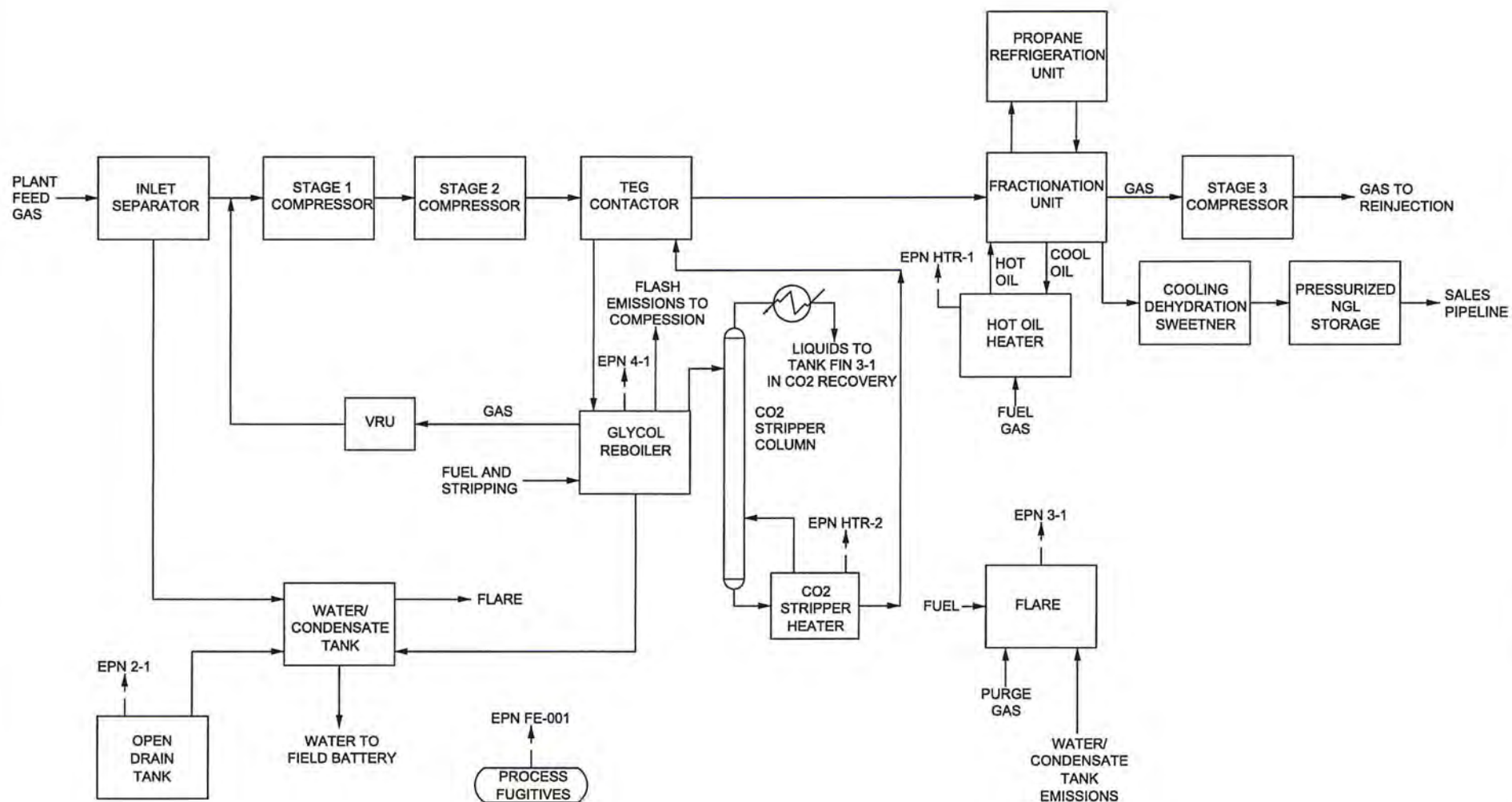
Mabee CO₂ Recycle Facility is an existing facility that dehydrates and compresses gas from Chevron's Mabee Ranch tertiary oil recovery project. The facility is authorized by Standard Permit Registration No. 80221. The purpose of this submittal is to add a NGL Recovery Plant to the facility. The only changes to previously reported emissions, due to the addition of the NGL Recovery Plant, are the addition of a 3 MMBtu/hr hot oil heater, the addition of a 0.25 MMBtu/hr CO₂ stripper heater, and increased fugitives from propane refrigeration, NGL's, an additional electric compressor, and the Sulfa-Treat tower.

Incoming gas is routed through a knock-out drum to remove liquids before the gas is compressed. The liquids are sent to the water/condensate tank and then to field batteries for disposal. After compression, the gas is routed to the glycol dehydration unit. The dehydration gas is recompressed and sent to the Mabee Ranch Field for reinjection.

Rich CO₂ gas from the existing second stage compressors will be cooled, dehydrated via the existing TEG unit, and fed to a fractionation tower. The fractionation tower reboiler and condenser duty will be supplied by a hot oil furnace and propane refrigeration unit. The tower bottoms product NGL undergoes COS hydrolysis, air cooling, water separation, SulfaTreat, and storage before being pumped to the West Texas LPG Pipeline. H₂S removed by the Sulfa-treat tower produces solid waste sulfur cakes. The addition of one 500 HP electric compressor along with current electric compression and will be used.

A flare is used to burn purge gas from the compressor, inlet gas during planned maintenance on the recycle gas compressors, emissions from the water/condensate tank, and for emergency upsets.

MABEE RANCH CO2 RECYCLE FACILITY PROCESS FLOW DIAGRAM

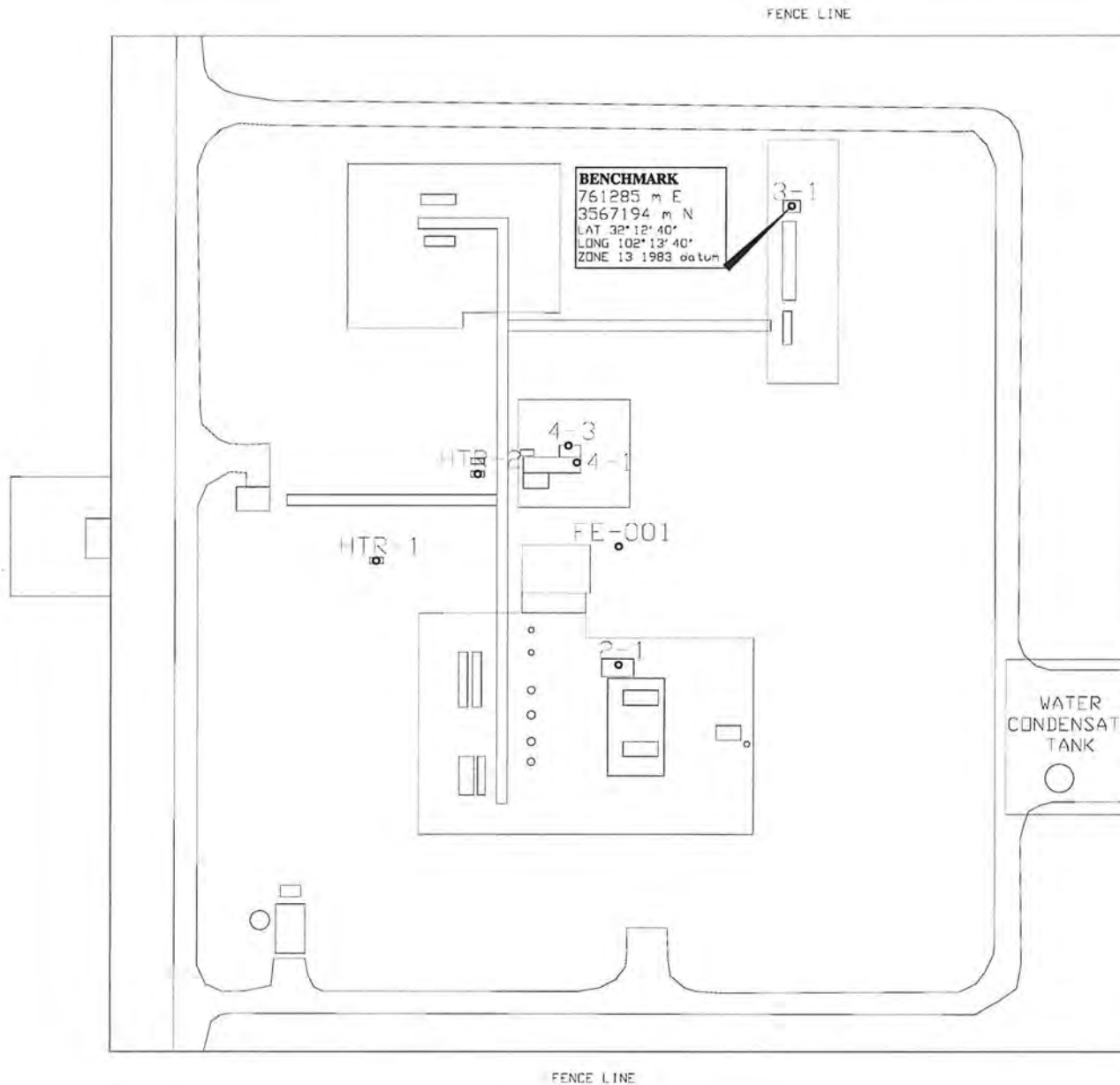
**WALD** ENVIRONMENTAL

CHEVRON U.S.A. INC.

MABEE RANCH CO2 RECYCLE FACILITY PROCESS FLOW DIAGRAM

Screen ID	Start Date	End Date	Chart Name	Run No.
DWW	5/24/06	9/25/12	FLOW	6

H:\CLIENTS\CHEVRON EP\CTX8698\ACAD		
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Emission Point Number	Name	Location Easting, Northing (meters)
2-1	OPEN DRAIN TANK	761244, 3567085
3-1	FLARE	761285, 3567194
4-1	GLYCOL REBOTTLE	761234, 3567133
4-3	GLYCOL STORAGE TANK	761232, 3567137
FE-001	PROCESS FUGITIVES	761244, 3567113
HTR-1	HOT OIL HEATER	761186, 3567110
HTR-2	CO2 STRIPPER HEATER	761211, 3567130



WAID ENVIRONMENTAL

CHEVRON U.S.A. INC.

MABEE RANCH CO2 RECYCLE FACILITY

Drawn By	Start Date	Rev. Date	Drawn Name	Rev. No.
DWW	5/24/06	9/14/12	PL018698	4

H:\CLIENTS\CHEVRON-TEX\CTX8698\ACAD

Exhibit P-3
Notice Letter
from Pilot Energy Solutions to Chevron
(August 15, 2013)



August 15, 2013

Mr. Tyler Hahn,
Chevron North America Exploration and Production Company
1400 Smith
Houston, Tx. 77002

RE: Mabee Plant and U.S. Patent No. 8,505,332

Dear Mr. Hahn:

I am writing to outline the chronology of meetings and conversations with various Chevron representatives about our concerns that Chevron might be incorporating Pilot Energy Solutions LLC's proprietary technology in its Mabee plant.

In August 2007 Pilot Energy Solutions and Chevron began discussions about processing the recycle CO₂ gas at Mabee for NGL extraction, using Pilot technology (the "Mabee Plant"). During these discussions Pilot and Chevron executed a Confidentiality Agreement in 2008, and again in 2009. Subsequently, Pilot shared drawings, process simulations, heat and material balances, preliminary cost estimates, and made multiple visits to the Mabee Plant site. During 2007-2008 we attended several meetings with Chevron personnel, including Matthew Passmore, Julie Huff, Stan Shitaku, and Alan Hein. In November 2007 and again in April 2008, Pilot made formal proposals to build a plant, at its sole cost, to third-party process the CO₂ recycle gas at the Mabee recompression station. Chevron's continuing evaluation of the Pilot proposals included a field trip to our plant in Wyoming in Chevron's corporate plane, to allow Chevron personnel to further evaluate our proprietary process and speak to the operations staff. During this period there were also a number of meetings with Chevron to discuss the possibility of using Pilot's technology at Chevron's Reinecke field. All discussions were suspended until July 2009, when Aubrey Arms, (Facilities Engineer, CO₂ team), contacted Pilot. Ms. Arms asked Pilot for an updated evaluation, based on the most current flow and composition data for the Mabee facility. Pilot promptly provided this information to Ms. Arms. Other than addressing a few additional technical questions about the Mabee Plant proposal, we had no additional discussions until May 2010 when we received an email from Ms. Arms telling us that Chevron had a "two year plan" and that no final decision would be made on the Mabee Plant until 2012. In August 2010 we received a follow-up email from Ms. Arms letting us know that Chevron was still evaluating Pilot's technology and its processing proposal for the Mabee Plant. In response we offered to explore the possibility of alternative deal structures including a third party arrangement or a joint venture with Chevron for the Mabee Plant. We did not receive a response from either Chevron or Ms. Arms.

In January 2012, Pilot learned through several industry contacts, familiar with our technology, that Chevron was building the Mabee Plant and that it appeared the Plant was going to use

Pilot's technology. This information prompted us to look up the Mabee Plant's air permit application at the TCEQ (Texas Commission for Environmental Quality) to review the plant design. Based on this information, I contacted Rick Sweeney, then Manager of the Midland office. I suggested to Mr. Sweeney that because of the turnover in Chevron's Houston office they might not be aware that Pilot had previously disclosed its proprietary process under a confidentiality agreement and that Chevron may be using that technology at the Mabee Plant. Mr. Sweeney asked me a few questions about the technology and said he would check into the matter. We did not hear back from Mr. Sweeney.

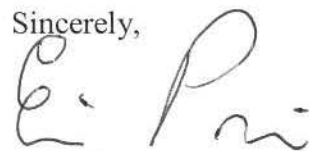
Naomi Baker, Pilot's Director of Operations and Engineering, received a call from Allen Hein on February 14, 2012. During the call Ms. Baker reiterated Pilot's concern that Chevron may have used Pilot's proprietary, patent pending technology at its Mabee Plant. Mr. Hein asked what protected technology Pilot believed Chevron was using. Ms. Baker did not have a copy of the patent application at the time of the call and she could not give specifics. She did however, remind Mr. Hein that he was involved in several of the meetings where the technology was discussed, and also participated in the field trip to Wyoming which toured the operating plant employing the technology. Ms. Baker suggested Pilot and Chevron sit down together and discuss Pilot's patent application and go over Chevron's Mabee Plant drawings. We have not heard from Chevron.

In meetings with Chevron, we had disclosed that the process in question was patent pending and was covered under our confidentiality agreements. On August 13, 2013 U.S. Patent No. 8,505,332 ("the '332 Patent") was issued from the United States Patent and Trademark Office to Pilot. The '332 Patent covers the technology disclosed to Chevron in Pilot's proposals for the Mabee Plant.

Pilot would like to schedule a meeting to go over the '332 Patent and compare it to the technology used by Chevron at the Mabee Plant. If it is determined Chevron is not using Pilot's technology, we will be happy to drop the matter.

We would like to schedule the suggested meeting within the next few days. Please feel free to call me at my office (281.260.4081) or cell phone (713.715.8785) to discuss a meeting time and location.

Sincerely,



Eric Prim
President
Pilot Energy Solutions



Exhibit P-4
Response Letter
from Chevron to Pilot Energy Solutions
(August 29, 2013)



Maurice E. Teixeira
Senior Counsel

Law Department
Chevron Services Company
1400 Smith, 5th Floor
Houston, TX 77002
Tel 713 372 9070
mtgl@chevron.com

August 29, 2013

Pilot Energy Solutions LLC
Attn: Mr. Eric Prim
333 N. Sam Houston Pkwy, Suite 600
Houston, Texas 77060

Re: Mabee Plant and U.S. Patent No. 8,505,332

Dear Mr. Prim:

We are in receipt of your letter dated August 15, 2013 with regards to the above-referenced matter to Chevron North America Exploration and Production Company, a division of Chevron U.S.A. Inc. ("Chevron").

Chevron takes any allegation of infringement of intellectual property seriously. It is our policy to avoid infringement of the valid intellectual property rights of others.

We reviewed U.S. Patent No. 8,505,332 (the "332 Patent") and the processes used by Chevron for conditioning and recycling CO₂ gas at the Mabee Plant. Chevron does not infringe any of the claims of the 332 Patent. As such we consider this matter to be closed.

Please direct any future communications regarding this matter to me.

Yours truly,

A handwritten signature in blue ink, appearing to read "Maurice Teixeira".

Maurice Teixeira
Senior Counsel

Exhibit P-5
United States
Patent No. 4,753,666
("Pastor")

United States Patent [19]

Pastor et al.

[11] **Patent Number:** 4,753,666[45] **Date of Patent:** Jun. 28, 1988[54] **DISTILLATIVE PROCESSING OF CO₂ AND HYDROCARBONS FOR ENHANCED OIL RECOVERY**4,547,209 10/1985 Netzer 62/17
4,563,202 1/1986 Yoa et al. 62/20[75] **Inventors:** Gerald R. Pastor, Englewood; Janet F. Peters, Littleton; Wayne K. Larsen, Aurora; Al C. Iakovakis, Englewood, all of Colo.[73] **Assignee:** Chevron Research Company, San Francisco, Calif.[21] **Appl. No.:** 889,975[22] **Filed:** Jul. 24, 1986[51] **Int. Cl.⁴** F25J 3/02[52] **U.S. Cl.** 62/24; 62/37; 62/54[58] **Field of Search** 62/9, 11, 23, 24, 27, 62/28, 54, 37[56] **References Cited****U.S. PATENT DOCUMENTS**

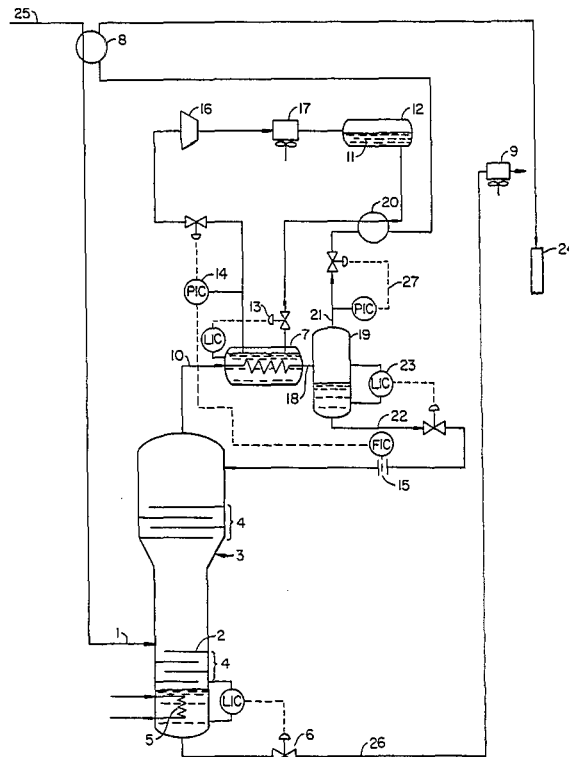
3,983,711	10/1976	Soloman	62/28
4,185,978	1/1980	McGalliard et al.	62/23
4,235,613	11/1980	Castoe	62/24
4,293,322	10/1981	Ryan et al.	62/17
4,318,723	3/1982	Holmes et al.	62/20
4,350,511	9/1982	Holmes et al.	62/17
4,383,841	5/1983	Ryan et al.	62/17
4,383,842	5/1983	Obrien	62/20
4,417,449	11/1983	Hogarty et al.	62/22
4,428,759	1/1984	Ryan et al.	62/17
4,441,900	4/1984	Swallow	62/23
4,444,576	4/1984	Ryan et al.	62/20

OTHER PUBLICATIONS

P. J. Persico et al., "Separation of CO₂ EOR Associated Gas", Gas Conditioning Conference Mar. 5-7 1984.
 "Texas EOR Project Proposed", Oil & Gas Journal (7/22/85).
 B. C. Price, "Looking at CO₂ Recovery in Enhanced Oil Recovery Projects", Oil & Gas Journal (12/24/84).
 J. E. Johnson et al.; "Gas Processing Needs for EOR", Hydrocarbon Processing (10/1985).

Primary Examiner—Ronald C. Capossela*Attorney, Agent, or Firm*—S. R. LaPaglia; E. J. Keeling; V. A. Norviel[57] **ABSTRACT**

A method of treating CO₂ rich gas for injection into a petroleum reservoir is described. CO₂ rich gas containing methane, nitrogen, ethane, propane, butanes, and heavier components is distilled such that substantially all of the heavier components are produced as a bottoms product and substantially all of the CO₂, ethane, and propane are produced as an overhead vapor. The presence of ethane and propane in the overhead vapors overcomes the effect of nitrogen and methane on minimum miscibility pressure in the reservoir, and the problems created by CO₂ freezing and the CO₂/ethane azeotrope are avoided, furthermore, a readily marketable liquid product is produced.

15 Claims, 2 Drawing Sheets

U.S. Patent

Jun. 28, 1988

Sheet 1 of 2

4,753,666

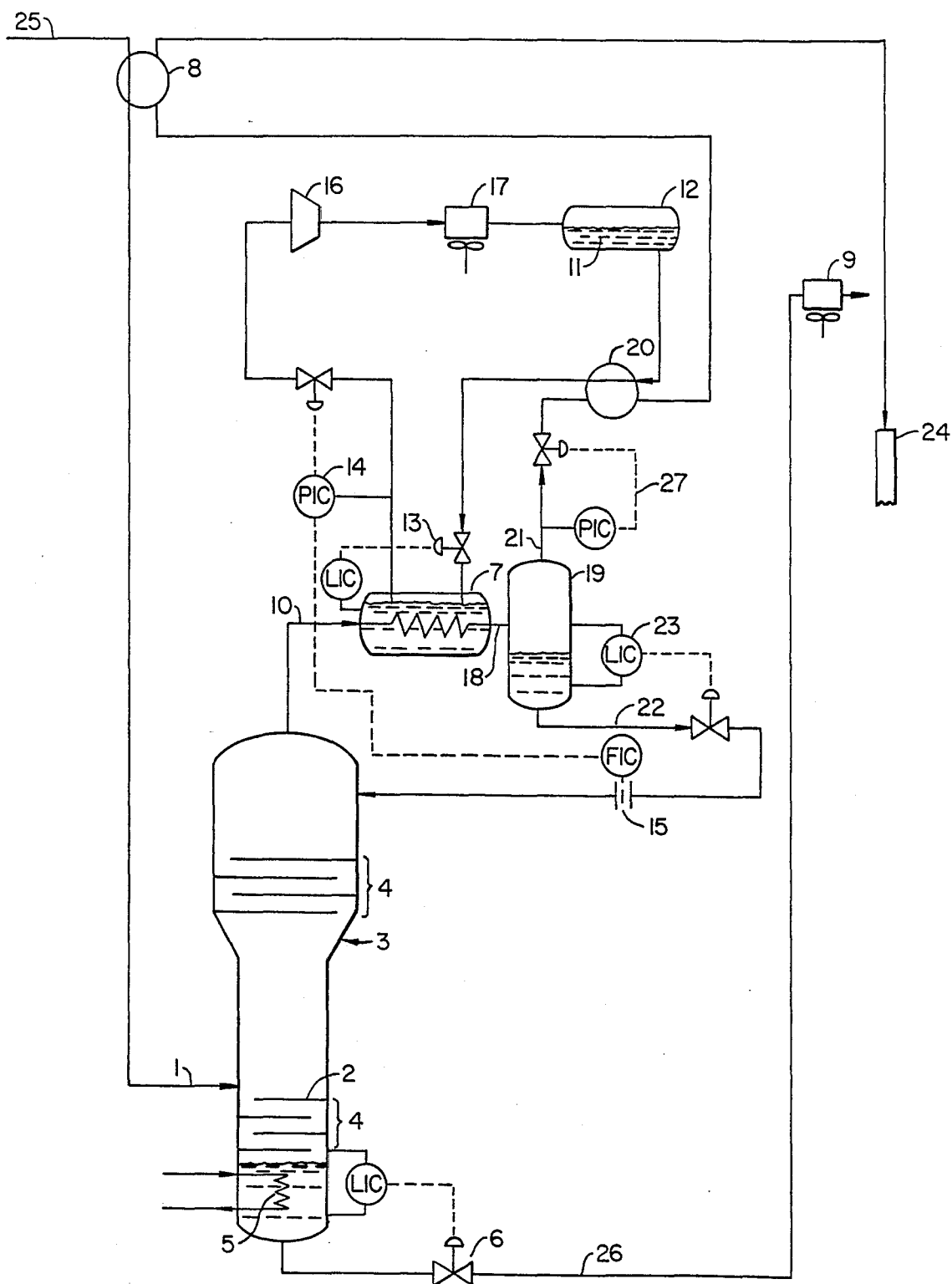


FIG. 1.

U.S. Patent

Jun. 28, 1988

Sheet 2 of 2

4,753,666

FIG. 2.

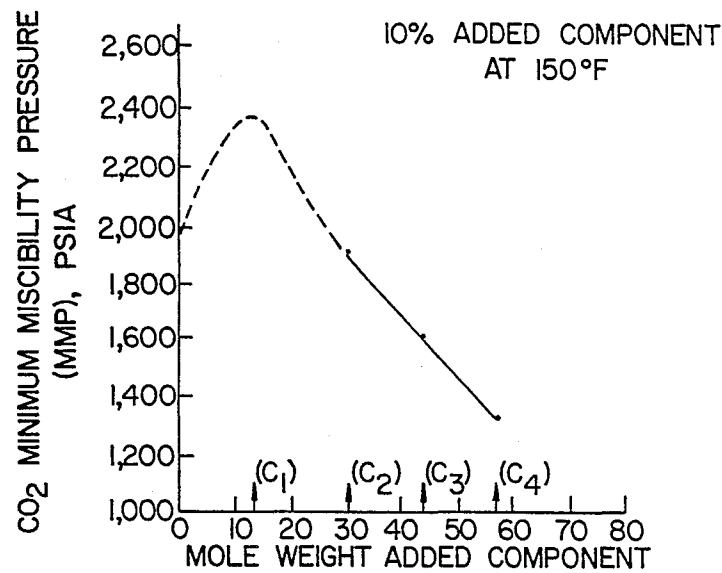


FIG. 3.

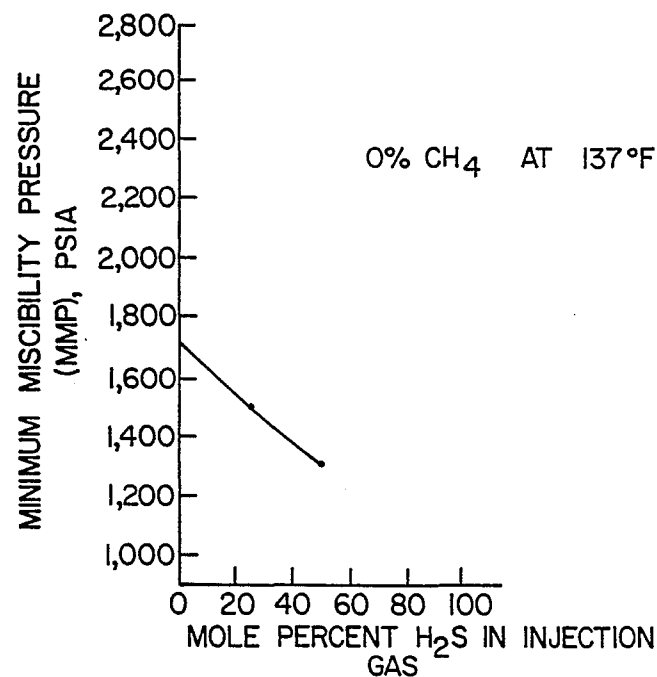
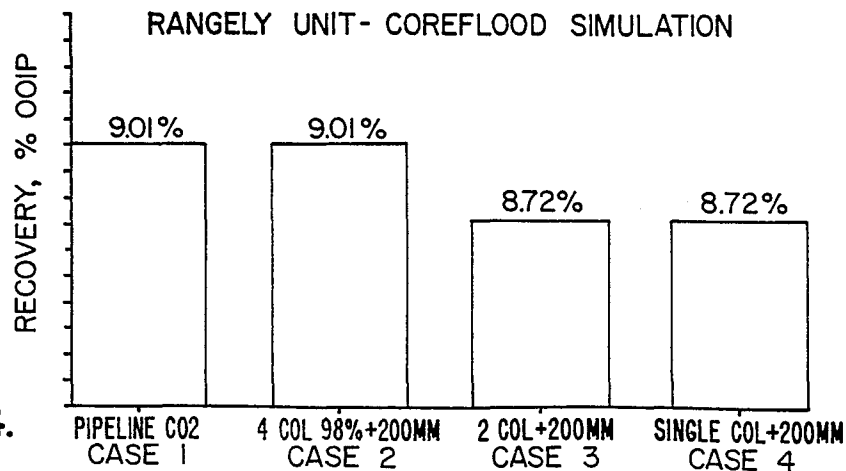


FIG. 4.



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DISTILLATIVE PROCESSING OF CO₂ AND HYDROCARBONS FOR ENHANCED OIL RECOVERY

FIELD OF THE INVENTION

This invention relates generally to an improved method for enhanced oil recovery. More specifically the invention provides an improved method for treating CO₂ rich gas streams for injection into oil-bearing formations.

BACKGROUND OF THE INVENTION

It is well known that only a small fraction of the original oil in place in a petroleum reservoir can be recovered with so called "primary" and "secondary" production methods. Various "tertiary" methods of increasing the recovery of oil contained in oil-bearing rocks have been devised. Among these tertiary recovery techniques is the method of injecting a miscible compound into the reservoir. The most common miscible compound used is carbon dioxide (CO₂).

In the initial stages of a CO₂ flood, CO₂ gas is commonly purchased from a large CO₂ distribution pipeline. The price of gas purchased from these pipelines is presently in the range of \$1.00 to \$1.50 per thousand standard cubic feet (MSCF).

After injecting CO₂ into the reservoir for a period of time, associated gas production will contain increasingly high percentages of CO₂ due to breakthrough of the injected CO₂ gas. It is often economical to recycle this gas into the petroleum reservoir. However, this recycled gas commonly has several undesirable components contained in it and it must be processed before reinjection. The primary constituents that must be considered in processing of this gas are methane (CH₄) and nitrogen (N₂) because these gases will dramatically reduce the miscibility of the injected gas. Other components that should be considered are heavier hydrocarbons (because of both their economic value as separate products and because of their ability to offset the miscibility problems created by CH₄ and N₂), H₂S (because of safety concerns and sales specifications), and water (because of hydrate problems).

Extensive efforts have been devoted to developing an economical method for treating these gas streams and a large number of process schemes have been devised.

Chemical solvents (such as amines) have been considered for removal of CO₂ from the hydrocarbon components. Use of these solvents becomes impractical in gas streams containing high concentrations of CO₂ because of the large energy demand of amine reboilers and other equipment. Further, the CO₂ is saturated with water in amine plants and this can create hydrate and corrosion problems downstream.

Distillation of CO₂ from methane has also been considered. The relative volatility of methane and CO₂ is very high and this distillation is in theory quite easy. However, the process must operate at relatively high pressure and low temperature and, therefore, the possibility of a solid carbon dioxide phase coexisting with vapor/liquid CO₂/CH₄ mixture is high. Solutions to this problem have been proposed in U.S. Pat. Nos. 4,318,723, 4,293,322 et al. in which an additive (generally natural gasoline recycled from elsewhere in the plant) is introduced into the feed. This prevents CO₂ freezing and also aids in breaking an ethane/CO₂ azeotrope. These processes have several inherent disadvantages, however.

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Initially, these processes are extremely expensive from both a capital and operating perspective since it is necessary to provide multiple distillation columns and massive refrigeration capacity to cool the entire inlet gas stream to -40° F. or colder. For example, in the example labeled "Table II" in U.S. Pat. No. 4,318,723, the feed temperature is reduced to -65° F. This also results in the need to use exotic materials of construction for the process equipment.

Further, the process produces sour, high vapor pressure liquid streams that must be subjected to additional processing before sale. Further, the ultimate value of the liquid products is offset by the need to purchase additional CO₂ as a result of the lost gas volume, i.e., there is significant shrinkage associated with the process.

Simpler techniques for treating hydrocarbon rich CO₂ streams have also been proposed in broad conceptual terms. For example, in "Looking at CO₂ Recovery in Enhanced-Oil-Recovery Projects," *Oil and Gas Journal*, Dec. 24, 1984, the authors show a "Straight Refrigeration" process for separating hydrocarbons from CO₂. However, this process also has several inherent disadvantages. Initially, as with the processes described in the above-mentioned patents, the inlet gas stream must be cooled to -40° F. or colder for recovery of C₃+, requiring extremely high refrigeration capacity. Further, the liquid stream produced by this process would require further treatment before sale since it will have a high vapor pressure (approximately 40 psia RVP) as well as unacceptable CO₂ and H₂S concentrations. Finally, a large portion of the C₄+ would go overhead and be unnecessarily wasted since no rectification section is provided on the column.

In summary, it is desirable to create a process that recognizes the ability of ethane, propane and butane to overcome the negative effects of nitrogen and methane on the miscibility of CO₂ injection gas. It is further desirable to create a process that produces both acceptable CO₂ injection gas and saleable liquid products. It is further desirable to create a process that treats CO₂ injection gas in an economical manner from both a capital investment and operating expense perspective. It is further desirable to create a process that does not require elaborate processing to overcome the CO₂/C₂H₆ azeotrope or to avoid CO₂ solid formation. It is further desirable to create a process which minimizes the shrinkage of the CO₂ injection gas.

BRIEF SUMMARY OF THE INVENTION

Accordingly, the present invention provides a method and apparatus for treating hydrocarbon rich CO₂ gas streams for injection into oil-bearing formations in an effective and economical manner. A hydrocarbon rich CO₂ gas stream is compressed to approximately 350 psia. The gas enters a multi-tray distillation column at an intermediate tray. Overhead vapor from the column is cooled in an overhead condenser to approximately -20° to 0° F. with propane refrigerant to produce a two-phase stream. The two-phase stream is separated into a liquid and a vapor (product) stream in a reflux drum. Vapor from the reflux drum is further compressed for injection into an oil-bearing formation. Liquid from the reflux drum is returned to the top tray of the column as reflux.

A reboiler on the bottom of the column maintains the bottom temperature at approximately 360° F. An NGL

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bottoms product consisting of a large fraction of the C_4+ in the inlet stream is removed from the column, cooled, and sold.

Most of the C_2 and C_3 and a significant fraction of the C_4 go overhead with the CO_2 injection gas. By leaving the C_2 , C_3 , and a portion of the C_4 (mostly isobutane) in the CO_2 , the negative effects of C_1 on the miscibility of the CO_2 injection gas are overcome. The recovery of C_3/C_4 can be monitored to control the miscibility of the CO_2 injection gas and optimize the economical operation of the plant.

H_2S is concentrated in the overhead gas. H_2S is known to enhance the miscibility of injection gas. Furthermore, H_2S would have to be removed from a liquid product requiring expensive processing equipment.

The process produces a CO_2 gas stream with a relatively low minimum miscibility pressure with a minimum capital investment since only one distillation column, and only a fraction of the refrigeration capacity needed in other processes is necessary. The use of exotic materials of construction is also minimized because of the higher plant operating temperature and lower operating pressures. Further, since the distillation split takes place at the temperatures and pressures necessary to make a split at the C_4 level, the CO_2/C_2 azeotrope and CO_2 solid formation are not problems. Shrinkage is also minimized because most of the C_1 to C_3 remains in the CO_2 gas product.

DESCRIPTION OF THE DRAWINGS

FIG. 1 is a schematic flow diagram showing the distillative apparatus for carrying out the invention described herein. (PIC=Pressure Indicating Controller, FIC=Flow Indicating Controller, and LIC=Level Indicating Controller.)

FIG. 2 is a graph showing minimum miscibility pressure versus the molecular weight of an added component for a selected crude oil.

FIG. 3 is a graph showing the minimum miscibility pressure versus mole percent H_2S for injection gas.

FIG. 4 is a bar graph showing the percentage of original oil in place recovered using the present invention and various prior art devices.

DETAILED DESCRIPTION OF THE INVENTION

The present invention provides a method for economically treating hydrocarbon rich CO_2 gas for injection into an oil-bearing formation utilizing the steps of introducing a feed stream into distillation equipment. The feed stream may contain a mixture of carbon dioxide, methane, ethane, propane, butanes, and heavier hydrocarbons. The feed stream is distilled in the distillation equipment to produce an overhead stream and a bottoms stream. The overhead stream contains substantially all of the carbon dioxide, methane, ethane and propane, and the bottoms stream contains substantially all of said heavier hydrocarbons. The overhead stream is then injected into a hydrocarbon bearing formation.

Referring to FIG. 1, in the preferred embodiment of the invention, a CO_2 gas stream 25 containing a substantial percentage of hydrocarbons and potentially containing hydrogen sulfide, nitrogen, mercaptans and other trace components is cross-exchanged in heat exchanger 8 with the column overhead product 21 and flows onto the feed tray 2 of a distillation column 3 containing a plurality of vapor/liquid contacting devices 4 such as bubble cap trays, sieve trays or packing.

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In the preferred embodiment of the invention, the feed 1 enters the column at approximately 350 psia and 90° F. Other temperatures and pressures may be chosen. For example, lower feed temperatures may be desirable in some cases. 90° F. is chosen as being easy to achieve with an air cooler that may be located upstream of the process and feed/product heat exchanger 8.

In the preferred embodiment, the rectification portion of the column 3 is a larger diameter than the stripping section, as shown in FIG. 1. This feature is desirable because large vapor loadings will be present in the upper portion of the column.

The bottom portion of the column is equipped with a reboiler 5 that supplies heat to the column via hot oil or steam. The reboiler is equipped with temperature control equipment that maintains the temperature of the bottoms at approximately 360° F. in the preferred embodiment. The bottom of the column is also equipped with level control equipment 6 which maintains the liquid level at a point above the reboiler but sufficiently below the first tray. The bottoms product 26 flows from the bottom of the column to a bottoms air cooler 9 to be cooled to approximately ambient temperature for sale or blending with crude oil.

The overhead vapors 10 flow to an overhead condenser 7 which cools and partially condenses the overhead vapors. In the preferred embodiment, propane is used as a refrigerant. Other refrigerants could be used, as would be readily obvious to one skilled in the art (for example, ammonia). Liquid propane 11 is supplied from a propane surge drum 12. A level control system 13 maintains the level of propane above tubes in the overhead condenser. The pressure in the overhead condenser is maintained with a pressure control system 14 which, in the preferred embodiment, has its pressure set-point determined by a reflux flow measuring device 15. This control system enables the operator to maintain a fixed quantity of reflux to the column.

Propane vapors from the overhead condenser are compressed in a compressor 16, condensed in a propane condenser 17, and returned to the propane surge drum 12. A propane subcooler 20 may also be desirable to increase the energy efficiency of the process.

The two-phase mixture 18 flowing from the overhead condenser is separated in a reflux drum 19. The two-phase mixture is separated into an overhead product stream 21 and a reflux stream 22. A level control system 23 maintains a constant amount of liquid in the reflux drum, and is opened to allow liquid to flow into the column.

The pressure at which the distillation equipment operates is controlled by pressure control equipment 27. The product vapor stream flows from the reflux drum to the propane/overhead subcooler 20 and then to the overhead/feed heat exchanger 8. The overhead product stream is further compressed in a compressor (not shown) and sent to injection wells 24.

To illustrate the operation of the above described process, the program PROCESS™ (Simulation Sciences Inc., Version 1.01, 1985) was used to simulate the operation of the process on a typical CO_2 /hydrocarbon gas stream. The results of the simulation are illustrated in Table I:

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TABLE I

Summary of PROCESS™ Simulation of the Present Invention on a Typical CO ₂ /Hydrocarbon Stream			
No. of Ideal Trays in Column	20		
Feed Point Tray	7		
Gas Feed Rate	110 MMSCF		
Reflux Drum Pressure	350 psia		
Column Differential Pressure	5 psia		
Condenser Duty	17 MM BTU/Hour		
Reboiler Duty	8 MM BTU/Hour		
Reflux Temperature	1.2° F.		
Bottoms Temperature	360° F.		

	Stream Name		
	Feed	Overhead Product	Bottoms Product
Rate	110 MMSCF	107 MMSCF	2620 BPD
H ₂ S (ppmv)	500	514	—
	Mole Percent		
N ₂	3.4	3.5	—
CO ₂	83.9	86.3	—
C ₁	6.6	6.9	—
C ₂	1.4	1.4	—
C ₃	1.1	1.1	0.02
iC ₄	0.5	0.4	3.1
nC ₄	0.7	0.3	16.7
iC ₅	0.4	0.001	16.0
nC ₅	0.6	—	23.3
C ₆	0.6	—	24.4
C ₇₊	0.4	—	16.4

As can be seen, operation of the process in the above-described manner results in a separation in which essentially all of the propane and ethane go into the overhead stream while most of the butane and essentially all of the pentane and heavier components are present in the bottoms stream.

Although the invention has been illustrated with regard to the above example, a range of operating pressures and temperatures might be selected to make the above described separation. The optimum range of the major process variables are described in Table II:

TABLE II

Optimum Process Variables	
Column Pressure	150 to 400 psia
Overhead Condenser Temperature	—40 to 20° F.
Reboiler Temperature	225 to 400° F.
Reflux Ratio	0.21 to 0.30
Number of Trays	22 to 40
Number of Trays above Feed Point	10 to 20
Number of Trays Below Feed Point	15 to 25

An important advantage of the above described process is that the negative effects of methane and nitrogen on the miscibility of the injection gas are largely overcome with the presence of ethane, propane and butane, and the process does not require elaborate process steps to avoid CO₂ freezing and/or to overcome the CO₂/Ethane azeotrope.

FIGS. 2 and 3 (adapted from "Miscible Displacement", F. I. Stalkup, Society of Petroleum Engineers of AIME, 1983, pages 141 and 140, respectively), and 4 generally illustrate the effect of distilling the CO₂ injection gas in the described method. FIG. 2 shows the effect of various alkyl hydrocarbons on CO₂ miscibility at 150° F. when 10% of the alkyl hydrocarbon is added to CO₂. As shown in FIG. 2, methane has a negative effect, i.e. the miscibility pressure is increased. By contrast, the presence of ethane, propane and butane is a positive one, i.e. the minimum miscibility pressure is decreased below that of pure CO₂. Similarly, the pres-

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ence of H₂S is positive, as illustrated in FIG. 3. As the percentage of H₂S in the gas increases, the minimum miscibility pressure decreases, regardless of the concentration of methane present.

The present invention takes full advantage of these effects. Unlike prior art processes, methane is left in the overhead gas, thereby overcoming the many problems associated with methane/CO₂ distillation discussed above. To offset the effect of methane or minimum miscibility pressure, H₂S, ethane, propane, and a portion of the butane remain in the overhead gas. Further, an easily saleable liquid product is produced.

To further illustrate this advantage, various reservoir simulations were performed to determine the effect of various process schemes on the ultimate recovery of oil in a petroleum reservoir in Rangely, Colo., using a miscible flood reservoir simulation program of the type familiar to one skilled in the art. The program was run assuming the following:

Case 1 It was assumed that "pipeline quality" (99.3%) CO₂ was purchased and used exclusively for injection. Produced gas would be flared or otherwise disposed of in this case.

Case 2 It was assumed that a "Four Column Ryan-Holmes Plant" similar to that described in FIG. 13 of "Looking at CO₂ Recovery in Enhanced Oil Recovery Projects" was used to treat produced gas and that the CO₂ product from this plant was injected along with 200 MMSCF of pipeline quality gas.

Case 3 It was assumed that a "Two Column Ryan-Holmes Plant" similar to that described in FIG. 12 of "Looking at CO₂ Recovery in Enhanced Oil Recovery Projects" was used to treat produced gas and that the CO₂ product from this plant was injected along with 200 MMSCF of pipeline quality gas.

Case 4 It was assumed that a 1 column plant as described in the present invention was used to treat produced gas and that the CO₂ product from this plant was injected along with 200 MMSCF of pipeline quality gas.

The results of those reservoir simulations are shown in FIG. 4. As would be expected in Case 1, the pure pipeline quality gas recovers the greatest percentage of the original oil in place. The elaborate 4 column Ryan-Holmes plant in Case 2 achieves essentially the same results as Case 1 since the gas is processed to almost pipeline quality.

It is seen in Case 4 that the simpler 1 column plant described in the present invention achieves essentially the same results as the more complex 2 column Ryan-Holmes plant used in Case 3. However, the present invention has the advantages of having a lower capital cost lower refrigeration requirements, and lower overall operating costs. Similarly, the plant described in Case 4, while achieving a lower percentage recovery of original oil in place than Case 2, would have dramatically lower capital and operating costs than the 4-Column Ryan-Holmes plant used in Case 2. These lower costs could (in many situations) result in better overall economics.

It is intended that the above description be illustrative and not restrictive. Variations on the above process will be readily apparent to those skilled in the art. The scope of the invention should, therefore be limited not to the above description but by the appended claims.

What is claimed is:

4,753,666

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1. A method for treating hydrocarbon rich CO₂ gas for injection into an oil-bearing formation comprising the steps of:

- (a) introducing a feed stream into distillation equipment, said feed stream comprising a mixture of carbon dioxide, methane, ethane, propane, butanes, and heavier hydrocarbons;
- (b) distilling said feed stream with said distillation equipment to produce an overhead stream and a bottoms stream, said overhead stream containing substantially all of said carbon dioxide, methane, ethane and propane, and said bottoms stream containing substantially all of said heavier hydrocarbons; and
- (c) injecting said overhead stream into a hydrocarbon bearing formation.

2. A method for treating a gas stream, containing carbon dioxide, methane, ethane, propane, butane, and heavier hydrocarbons for reinjection into an oil-bearing formation comprising the steps of:

- (a) introducing the gas stream into a distillation column at a feed tray, said distillation column containing a plurality of vapor/liquid contacting devices, said feed tray below a rectification section and above a stripping section;
- (b) operating said distillation column to produce an overhead stream containing substantially all of said carbon dioxide, methane, ethane and propane, and a bottoms stream containing substantially all of said heavier hydrocarbons, and;
- (c) injecting said overhead stream into an oil-bearing formation.

3. A method for treating hydrocarbon-rich CO₂ gas containing carbon dioxide, methane, ethane, propane, butane, and heavier hydrocarbons for injection into an oil-bearing formation in an economical manner comprising the steps of:

- (a) introducing said hydrocarbon-rich gas stream into a multi-tray distillation column at an intermediate tray;
- (b) cooling an overhead vapor from said distillation column in a partial condenser to produce a two-phase stream;
- (c) separating said two-phase stream in a reflux drum to produce a reflux stream and a product stream;
- (d) introducing said reflux stream onto a top tray of said distillation column;
- (e) reboiling said distillation column with a reboiler;
- (f) injecting said product stream into a hydrocarbon-bearing formation; and
- (g) said steps of introducing said gas stream into a distillation column, chilling, separating, introduc-

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ing said reflux stream onto a top tray of said distillation column, and reboiling carried out under conditions which most of said methane, ethane, and propane are contained in said product stream.

4. The method of claim 2 wherein said step of operating said distillation column further comprises the step of cooling an overhead stream in a partial condenser.

5. The method of claim 2 wherein said step of operating said distillation column further comprises the step of reboiling a bottoms stream in a reboiler.

6. The method of claim 1 wherein said distillation equipment further comprises a distillation column, a condenser, and a reboiler.

7. The method of claim 2, 3 or 6 wherein said distillation column operates in a range of pressures from 150 to 400 psia.

8. The method of claim 3, 4 or 6 wherein said condenser operates in the temperature range from -40° F. to 20° F.

9. The method of claim 3, 4 or 6 wherein said reboiler operates in the temperature range from 225° F. to 400° F.

10. The method of claim 3, 4 or 6 wherein said condenser is cooled with a propane refrigerant.

11. The method of claim 3, 4 or 6 wherein said condenser is cooled with an ammonia refrigerant.

12. The method of claim 10 further comprising the step of setting a pressure of said propane refrigerant based on a reflux flow rate.

13. The method of claim 12 further comprising the step of warming said overhead gas with said propane.

14. The method of claim 13 further comprising the step of cooling said feed stream with said overhead stream.

15. A method for treating hydrocarbon-rich CO₂ gas for injection into an oil-bearing formation consisting essentially of the steps of:

- (a) introducing a feed stream into distillation equipment, said feed stream comprising a mixture of carbon dioxide, methane, ethane, propane, butanes, and heavier hydrocarbons;
- (b) distilling said feed stream with said distillation equipment to produce an overhead stream and a bottoms stream, said overhead stream containing substantially all of said carbon dioxide, methane, ethane and propane, and said bottoms stream containing substantially all of said heavier hydrocarbons; and
- (c) injecting said overhead stream into a hydrocarbon-bearing formation.

* * * * *

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Exhibit P-6
Hydrate Formation
in Chevron Mabee Unit
for NGL Recovery and
CO₂ Purification for EOR
(Submitted to Gas Processors
Association 2017)

Hydrate Formation in Chevron Mabee Unit for NGL Recovery and CO₂ Purification for EOR

Abstract

In the early 1990's, Chevron installed a new process to recover natural gas liquids (NGLs) from recycled CO₂ in their Rangely Weber Sand Unit. The facility was designed based on a patent issued in June of 1988 (U.S. Patent # 4,753,666). The process, as claimed in the patent, used a refluxed distillation tower to produce an overhead stream virtually free of n-butane and heavier components and a bottoms stream containing the majority of the heavier components. Based on the success of the Rangely plant's operation, a similar facility was designed and fabricated by Dickson Process Systems and installed in Chevron's Mabee field near Midland, Texas.

When the Mabee plant faced some unique challenges in the NGL Recovery unit, Chevron contacted Dickson Process Systems, Bryan Research & Engineering (BR&E), and Sulzer Chemtech USA to help troubleshoot the process to operate as designed. The Mabee NGL Recovery unit is a distillation column with a partial condenser and a reboiler. The condenser, operating between 4-15 °F, experienced what were described as "reflux events", where liquid level would rapidly buildup in the reflux accumulator.

While troubleshooting, it was found that hydrates formed in the top section of the column, restricting the liquid from continuing down to the next tray. The resulting buildup of liquid not only prevented reflux from entering the column, but also flooded the trays and quickly overwhelmed the top section of the column. This paper describes the process used to identify and address the formation of hydrates in the top section of the distillation column and the use of process simulation modelling combined with plant data to improve plant operability.

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Introduction

In 2013, an NGL recovery unit designed and fabricated by Dickson Process was added onto the existing compressor station in Chevron's Mabee field outside of Andrews, TX. This unit was installed between 2nd and 3rd stage compression following the existing triethylene glycol (TEG) dehydrator. The NGL recovery unit was designed based on a feed gas water content of 3 lbs/MMscf in accordance to Chevron's US Patent 4,753,666 [1]. TEG dehydration units routinely remove water to levels below 7 lb/MMscf in the dry gas. If stripping gas is utilized, the water content of 3 lbs/MMscf can be achieved [2]. In this system, NGLs are extracted using a reflux column to produce an overhead stream free of n-butane and heavier components and a bottoms stream containing the heavier components.

The distillation column is a 26-tray tower equipped with a partial condenser and reboiler, as shown in Figure 1. A pressure differential transmitter spans from tray 1 through tray 26. Temperature transmitters are equipped at the column overhead, column inlet located at tray 15, tray 23, and column bottoms. Propane is used as the refrigerant in the partial condenser. The reflux accumulator level is maintained through the use of continuously operating pumps along with a level control valve feeding the reflux back into the column and a flow control valve recycling reflux back to the accumulator.

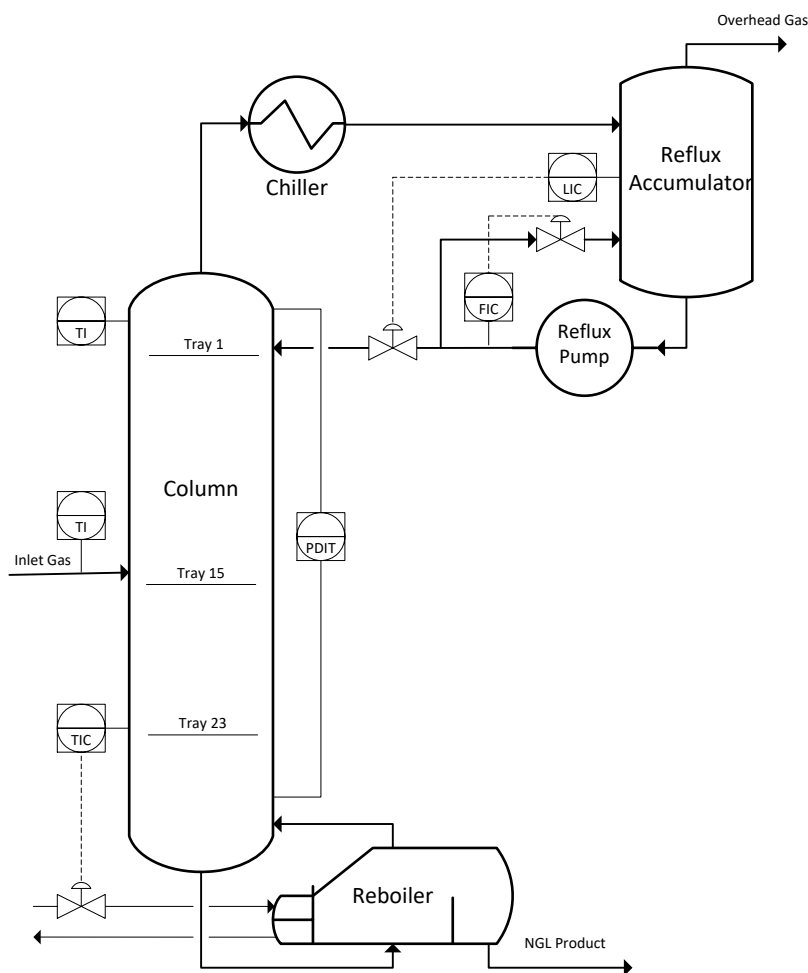


Figure 1: Process Flow Diagram of Distillation Column and Reflux

After deployment, the distillation tower experienced what plant operations coined as “reflux events.” During these events, the reflux level in the reflux accumulator would suddenly rise at a rapid rate. The level would remain high and overwhelm the tower reflux system. Corrective action involved warming up the chiller outlet temperature to stop liquid generation until the reflux accumulator level fell within the normal operating range. This pattern is shown in Figure 2. These corrective measures disrupted the temperature profile across the column, reduced NGL production, increased H₂S content in the NGL product, and required continuous involvement from plant operators.

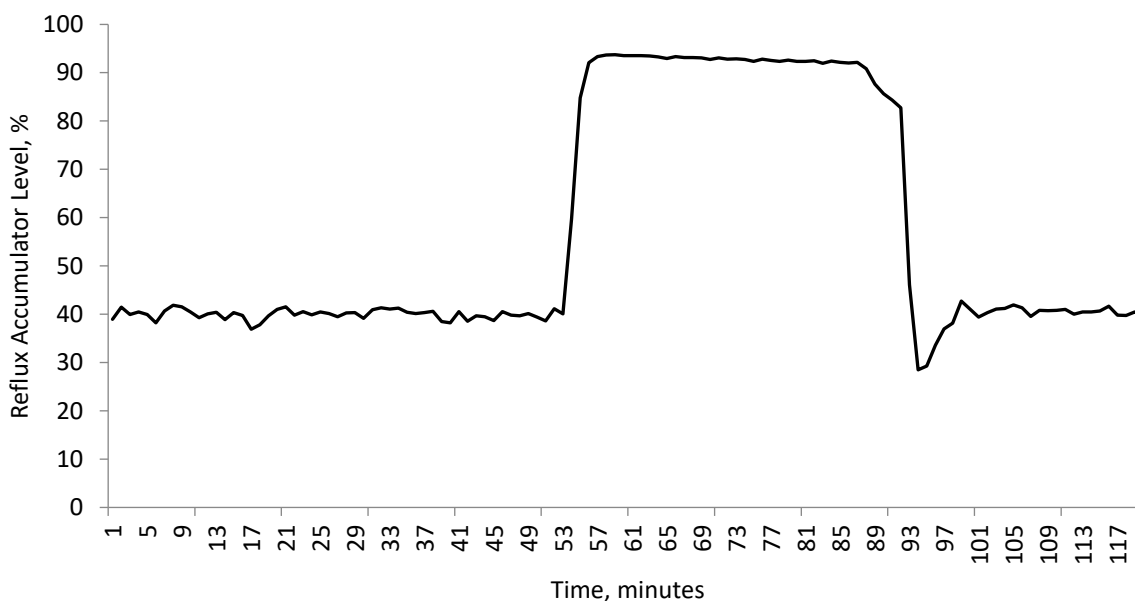


Figure 2: Example of Reflux Accumulator Level Versus Time During a Reflux Event

While this solution maintained operability in the short-term, a long-term solution was desired. Therefore, a team consisting of engineers from Chevron, Dickson Process Systems, Bryan Research & Engineering, Inc., and Sulzer Chemtech USA, Inc. was assembled to quality check and troubleshoot the process to ensure the facility operated as designed. With Sulzer Chemtech’s assistance, column hydraulics were ruled out as the source of the reflux events.

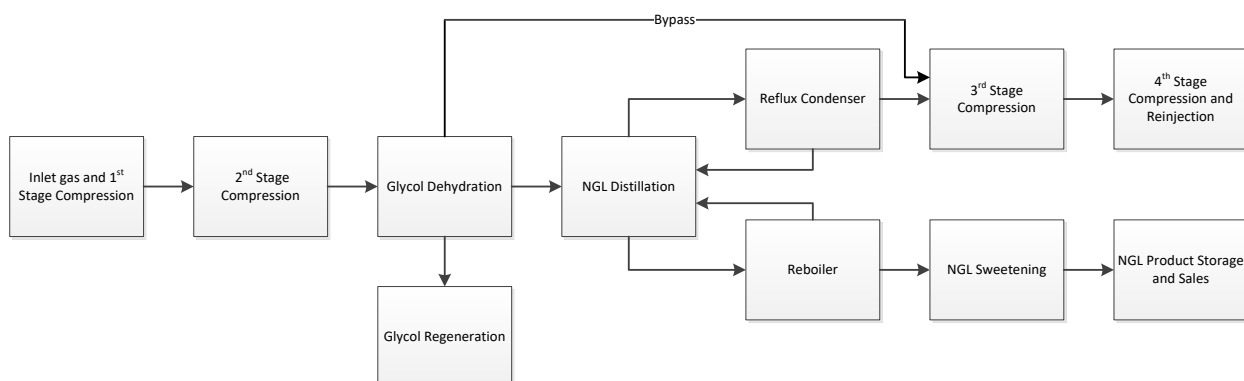
Identifying the Cause of Rapid Liquid Buildup in the Reflux Accumulator

The first step was to develop a process simulation of the distillation column to model the process conditions and study the possible causes of the reflux events. The NGL extraction model was developed in ProMax® [3] based on data collected from the field. The composition results from the simulator agreed with the data well, as shown in Table 1.

Table 1: Model Validation of Plant Data

	Field	Model
Condenser Temp, F	5.7	5.7
Reboiler Temp, F	260	260
NGL Composition, mol %		
Propane	6.02	5.48
i-Butane	17.11	16.75
n-Butane	41.78	38.39
i-Pentane	14.57	14.20
n-Pentane	9.50	8.96
Hexane +	10.84	10.96

To thoroughly diagnose the abnormal conditions, the team reviewed the operations upstream of the NGL Recovery Unit. As shown by Figure 3, upstream of the distillation tower, glycol dehydration removes water from the process gas in preparation for NGL extraction. If water exceeds certain thresholds in the NGL recovery column, the water can become trapped in the tower trays, leading to blockages and, if conditions allow, hydrate formation.

**Figure 3: Mabee Gas Plant Block Flow Diagram**

Initially, it was thought that the reflux events were not a result of hydrate formation or trapped water as field instrumentation indicated very low water content in the feed gas. When modeled with an inlet feed water content below 3 lbs/MMscf, the process simulation model predicted no hydrate formation in the NGL recovery column. Additionally, the pressure differential transmitter across the tower spanned 0 to 1 psi across the tower trays, offering little insight as to the tray loading both leading up to and during the events. Figure 4 illustrates data collected in the facility where reflux events were observed despite data indicating moisture content to the tower well below the design requirement of 3 lb/MMscf.

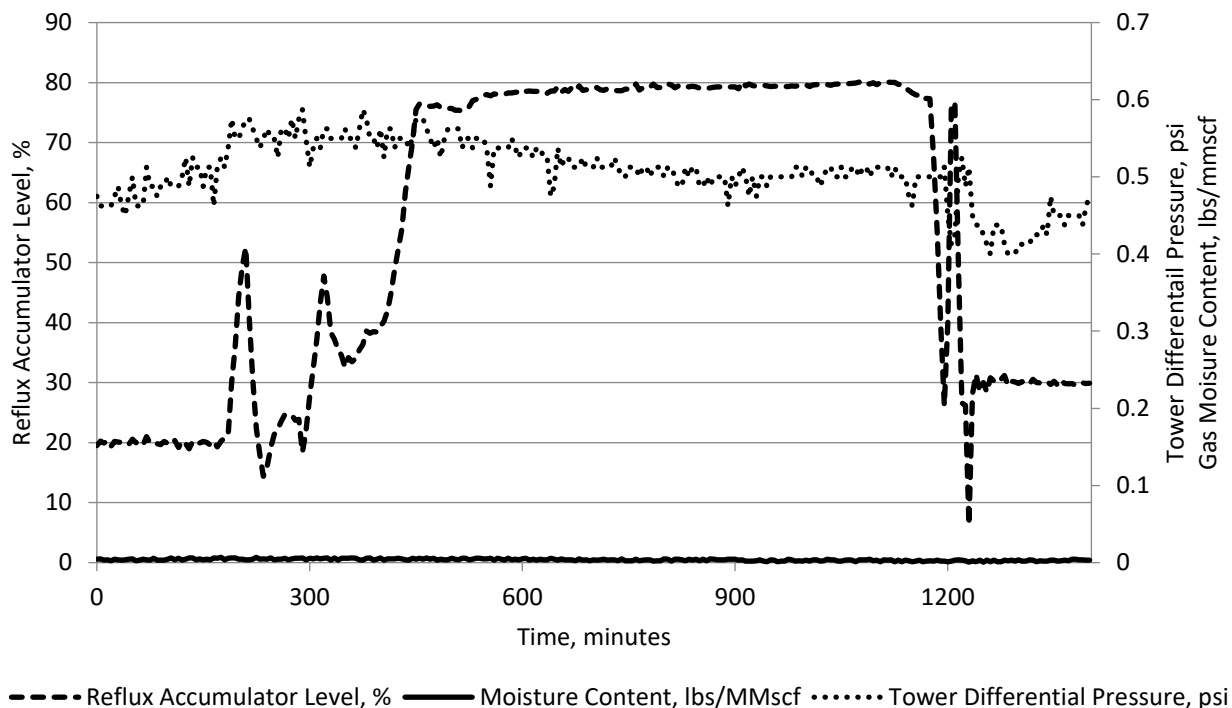


Figure 4: A Typical Reflux Event as Shown Through Reflux Accumulator Level, Inlet Moisture Content, and Tower Differential Pressure

In the interest of creating a model of the entire plant to evaluate upstream effects on this process, a model of the dehydration unit was added with current operating data and integrated with the NGL recovery model. Once the team modeled the upstream TEG dehydration unit, the predicted water content at the inlet of the NGL recovery unit was noticeably higher than what instrumentation indicated.

As designed by Dickson Process Systems, the NGL recovery unit required a dried feed gas with a water content of no more than 3 lbs/MMscf. When modeled at the operating conditions, a gas water content of 9 lbs/MMscf was predicted. The plant engineers manually measured the moisture content in the inlet feed to the NGL recovery column using Draeger tubes and a hand-held automatic dew point hygrometer, both of which confirmed the higher water content predicted by the model. The in-line water content analyzer was found to be miscalibrated, which explained why it was difficult to identify the cause of the reflux events. In the interest of collecting the most accurate data moving forward, the in-line moisture analyzer was recalibrated and currently delivers reasonable values.

The updated model of the NGL recovery unit showed significant hydrate formation in the rectifying section of the column, which led to a belief that hydrates or trapped water blocked the liquid return from the reflux accumulator to the column. The pressure differential transmitter was recalibrated, rescaled, and converted to report values in inches of water to identify these blockages. Prior to the modifications to the pressure differential transmitter, Figure 4 shows that there was no indication of a flooding within the tower. Recalibration of the instruments helps identify these issues through rises in column differential pressure.

Accurately modeling the entire plant provided a very good reality check and proved to be a useful tool for troubleshooting the integrated facility. Chevron was able to quickly identify the cause of the reflux events and immediately moved to resolve it.

The Solution

Improvements to the operation of the existing facility were required to be fully aligned with pre-deployment expectations for the performance of the integrated NGL recovery unit. The team focused on reducing water content to the NGL recovery unit through process optimization. The dehydration system, in place before the addition of the NGL recovery unit, uses triethylene glycol as a solvent to physically absorb water. The water rich glycol is then regenerated and returned to the contactor to start the process all over again as shown in Figure 5.

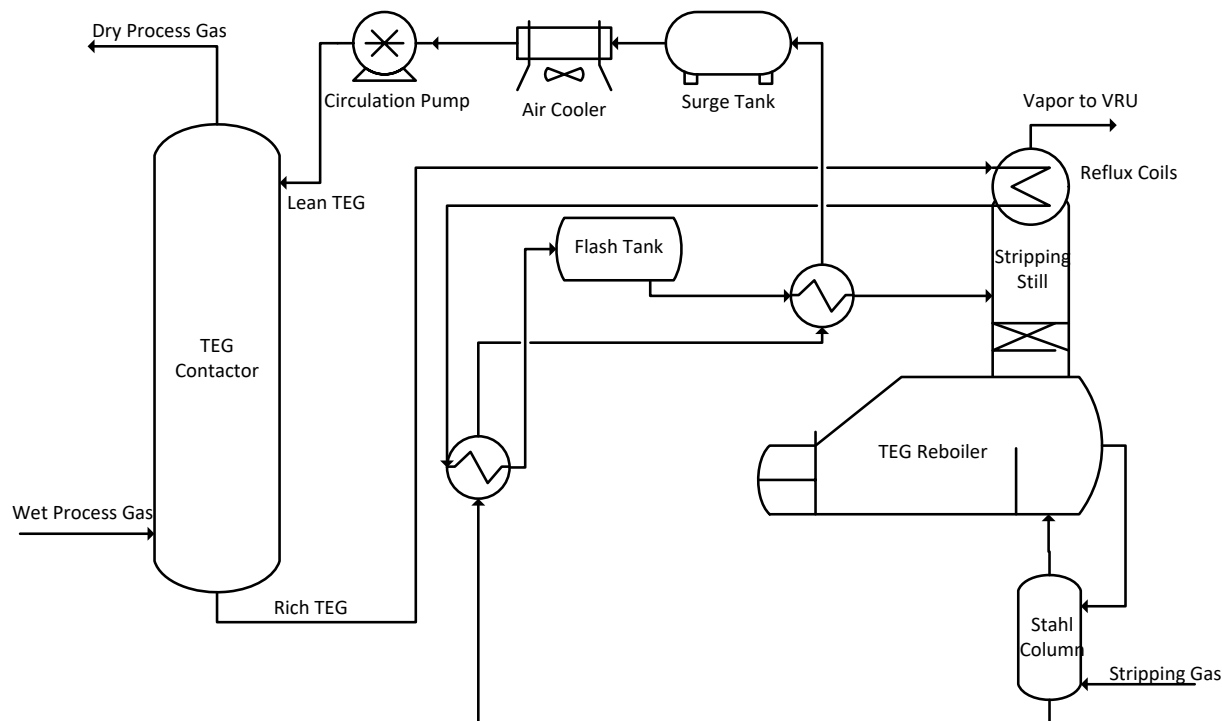


Figure 5: Process Flow Diagram for Gas Dehydration and Glycol Regeneration

The solvent circulation rate, reboiler temperature, stripping gas flowrate and process gas inlet temperature were all considered during optimization. At the time of troubleshooting, the reboiler temperature was 375 °F while circulating 25 sgpm of TEG without stripping gas.

The circulation rate was modeled and evaluated, as shown in Figure 6. Roughly one pound per minute of water was required to be removed, indicating about three gallons per minute of glycol needed to be contacted with the gas [2].

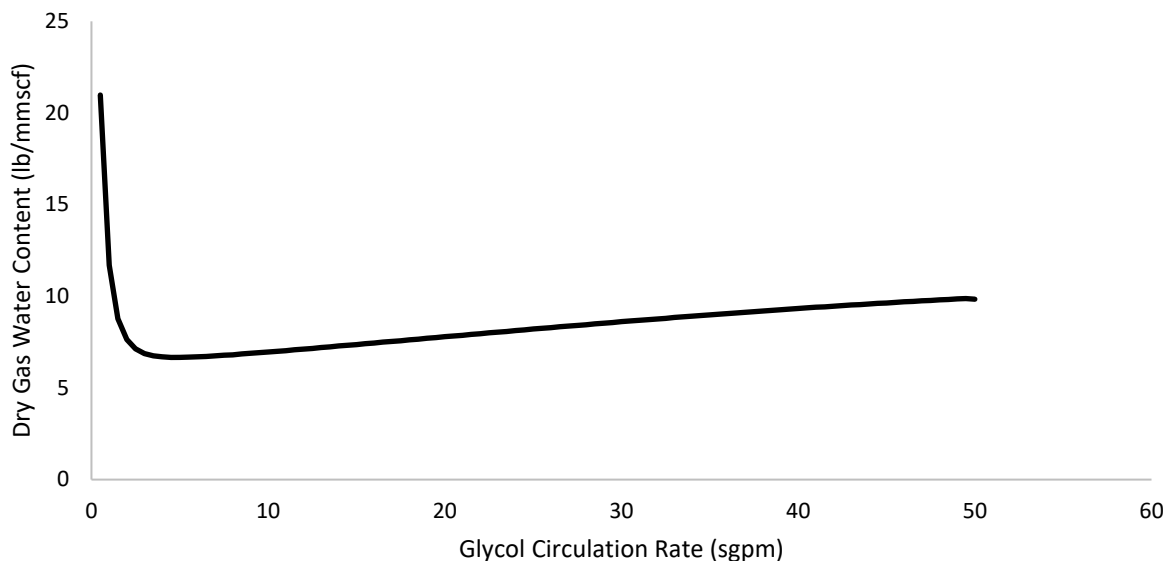


Figure 6: TEG Circulation Effect on Dry Gas Water Content Without Stripping Gas

The trend may counter previously held understandings that more glycol circulation results in a dryer gas, but is easily explained when looking at the temperature effect the solvent circulation has on the dry gas. The lean TEG will have a higher temperature than the wet gas. Typically, the lean TEG temperature effect on the dry gas temperature is negligible due to the significantly lower flowrate when compared to the high flowrate of the gas, as it is common to maintain a 3:1 ratio of glycol being circulated to water being removed. The Mabey plant was operating at about 25 gallons of glycol per pound of water being removed. If the lean glycol flowrate is increased, it increases the temperature of the column, which shifts the water equilibrium point in the gas. A warmer gas holds more water [2]. At low flowrates of TEG, the temperature effect is insignificant. Having knowledge of this trend prevents the temptation to circulate more TEG. Keeping the circulation rate low ensures the gas stays as cool as possible through the contactor.

While the optimum TEG circulation rate was found to be near 3 sgpm, pump constraints prevented the TEG rate from being less than 12 sgpm. Therefore, the TEG circulation rate was reduced from 25 sgpm to 12 sgpm. Optimizing the circulation rate in and of itself would not reduce the dry gas water content to hydrate free levels in the NGL recovery unit. The addition of stripping gas was needed to accomplish this goal. At a constant glycol circulation rate of 12 sgpm, the dry gas water content was studied at various reboiler temperatures and stripping gas rates in Figure 7.

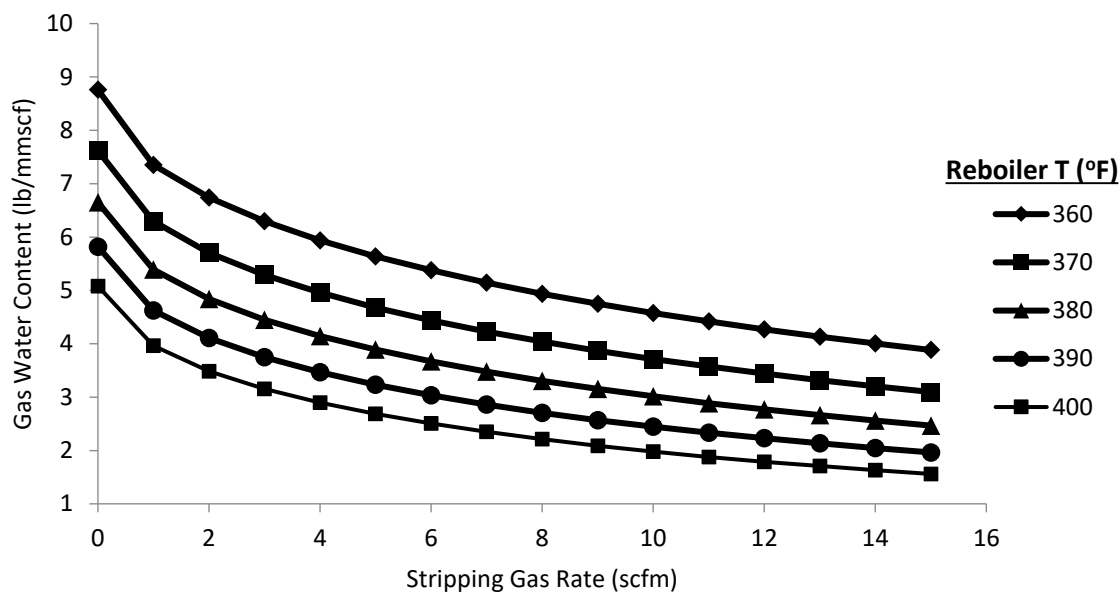


Figure 7: The Effect of Stripping Gas and Reboiler Temperature on Dry Gas Water Content

With no stripping gas to the dehydration unit, Figure 7 shows that even a reboiler temperature of 400 °F is not sufficient to reduce feed gas moisture content below 3 lbs/MMscf [4]. As glycol is known to degrade at temperatures higher than 400 °F, it is necessary to introduce some stripping gas to the system in order to achieve the desired water content [4]. Since multiple combinations of reboiler temperature and stripping gas rate can achieve the desired result, operational costs can be calculated and compared across the probable cases to determine the most cost effective solution. In this case, the reboiler temperature and stripping gas rate were increased to 390 F and 6 scfm, respectively, in order to achieve a moisture content averaging around 3 lbs/MMscf to the tower.

Finally, the inlet gas temperature was evaluated against the dry gas water content in Figure 8.

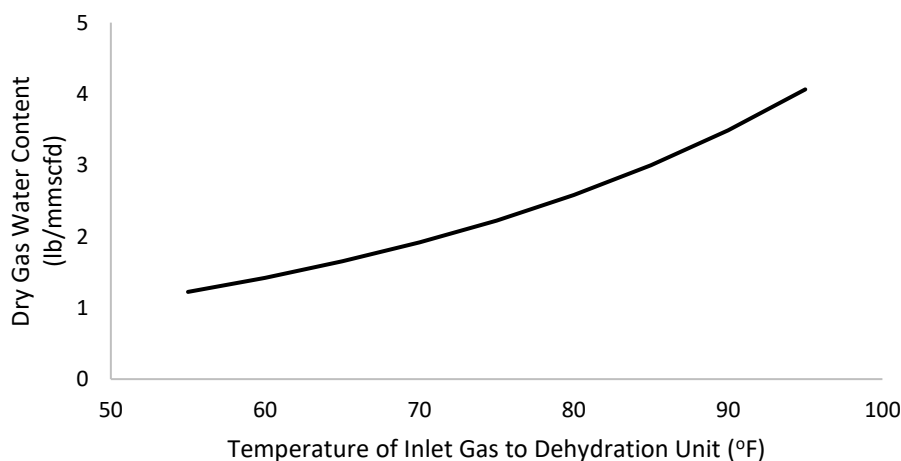


Figure 8: Effect of Inlet Temperature on the Dry Gas Water Content for 390 °F Reboiler and 6 scfm Stripping Gas

As expected, the trend shows lower dry gas water content at lower inlet gas temperatures [2]. By reducing the inlet gas temperature, the dry gas water content could be reduced well below the design limit. Based on the optimization study, the dehydration plant operating conditions were changed to the conditions summarized in Table 2.

Table 2: Summary of Changes Made to the Dehydration Unit

	Previous	Present Day
Inlet Gas Temperature (°F)	85	60
Glycol Circulation Rate (sgpm)	25	12
Reboiler Temperature (°F)	375	390
Stripping Gas (scfm)	0	6
Dry Gas Water Content (lb/mmascf)	9	1.5

Once the changes were made in the plant, new data was collected which showed close agreement with the predictions from the simulator.

Distillation Tower Operations

While operating the dehydration unit at its optimum is important, operators need to know what temperature to operate the NGL distillation tower in order to mitigate the risk of hydrate formation. Figure 9 was created to give clear recommendations for operation of the tower temperatures at various inlet water contents. Although the margin is thin, Figure 9 shows operational flexibility.

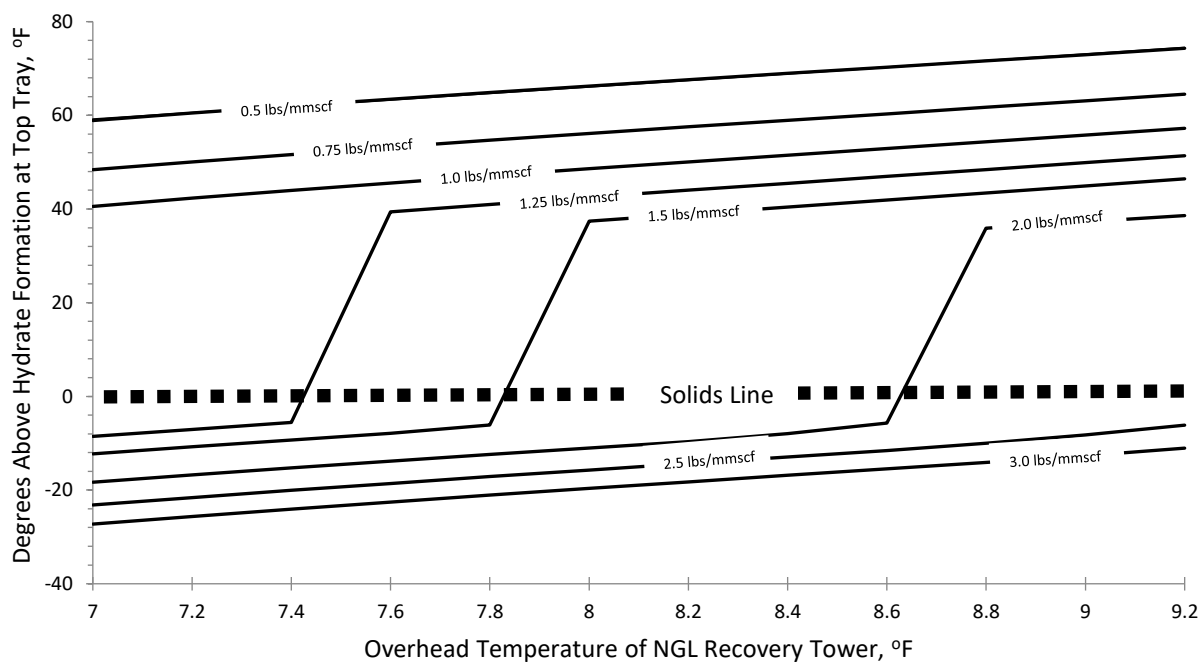


Figure 9: Operator Reference Guide to Avoid Hydrate Formation at Various Inlet Water Contents

With reduced reflux events bringing on smoother operations and better understanding of tower internals, the team then identified an opportunity to improve the top tower controls to more directly control the reflux accumulator level while achieving NGL product to the desired specification.

Conclusions

The water content of the inlet gas to the incorporated NGL recovery unit greatly affected the expected operational reliability of the rectifying section. Once the pressure differential and moisture analyzer transmitters were rescaled to report accurate values, the team identified the need to optimize the existing TEG regeneration unit to meet the design feed conditions. An operator reference guide was created to monitor the NGL recovery tower condenser temperature to avoid hydrate risk, resulting in more reliable operations and a reduction the operational demands of the unit.

In order to take the appropriate steps to troubleshoot process issues, instrumentation should be functioning reliably and reporting accurate data to properly identify the issues. Process models like ProMax® are valuable tools in identifying instrumentation reliability and opportunities for improvement. Process models can be used to validate data being received from the plant and identify the most effective operating parameters for process optimization. And finally, involving the right team of people in troubleshooting efforts can accelerate solutions.

An accurate model was essential to making meaningful decisions about operating the NGL recovery and glycol dehydration units. Since the optimization effort, the Mabee Gas Plant is operating reliably and reflux events of this nature are rarely observed.

Works Cited

- [1] G. R. Pastor, J. F. Peters, W. K. Larsen and A. C. Iakovakis. United States of America Patent 4,753,666, 1988.
- [2] Gas Processors Suppliers Association, Engineering Data Book, Tulsa, 1998.
- [3] Bryan Research & Engineering, Inc., "ProMax 4.0," Bryan, 2016.
- [4] A. L. Kohl and R. Nielsen, Gas Purification, Gulf Professional Publishing, 1997.

Exhibit P-7
Claim Chart
(‘332 Patent Claim 1)

U.S. Patent No. 8,505,332
Representative Claim 1

Claim 1	Mabee Air Permit Application (Ex. P-2, Chevron Mabee Plant Air Permit Application (Nov 5, 2012) (“Air Permit”))	Mabee Hydrate Formation Paper (Ex. P-6, Hydrate Formation in Chevron Mabee Unit) (“Hydrate Formation Paper”))
1. A method comprising: receiving a hydrocarbon feed stream, wherein the hydrocarbon feed stream comprises carbon dioxide, natural gas liquid (NGL), heavy hydrocarbons, and acid gas, wherein the NGL comprises C₃-C₈ hydrocarbons, and wherein the heavy hydrocarbons comprise C₉₊ hydrocarbons;	The “INLET SEPARATOR” receives “PLANT FEED GAS.” (Air Permit Fig. 1 of 2, Mabee Ranch CO₂ Recycle Facility Process Flow Diagram (hereinafter “Process Flow Diagram”). The Process Flow Diagram in the Air Permit shows the inlet stream in the stages of the process after most of the heavy hydrocarbons have been removed from the plant feed gas. (Process Flow Diagram)	Figure 3 in the Hydrate Formation paper shows the inlet stream in the stages of the process after most of the heavy hydrocarbons have been removed from the plant feed gas. (Hydrate Formation Paper Fig. 3, Mabee Gas Plant Block Flow Diagram) (hereinafter “Block Flow Diagram”). The Abstract on page 1 of the Hydrate Formation paper states that the Chevron Mabee Unit is similar to the Chevron Rangely Weber Sand Unit that is designed based on U.S. Patent 4,753,666 (“Pastor”). The Pastor patent describes injecting carbon dioxide into a hydrocarbon bearing formation to recover oil (e.g., C₉₊ hydrocarbons). (Pastor 1:14-22 and 3:47-59)

		The Pastor patent states that the feed includes N₂, CO₂, C₁, C₂, C₃, iC₄, nC₄, nC₅, C₆, and C₇₊ (e.g., carbon dioxide and C₁-C₇₊ hydrocarbons). (Pastor, Table 1) The Hydrate Formation paper shows that the NGL Composition includes propane, i-butane, n-butane, i-pentane, n-pentane, and hexane plus (e.g., C₃-C₆₊). (“Table 1: Model Validation of Plant Data” on page 4) The Hydrate Formation paper states that: “These corrective measures disrupted the temperature profile across the column, reduced NGL production, increased H₂S content in the NGL product, and required continuous involvement from plant operators” (Page 3). H₂S is an acid gas, so “increased H₂S content in the NGL product” shows that the feed stream includes acid gas. The Hydrate Formation paper includes an “NGL Sweetening” block. “NGL Sweetening” is used to remove acid gas (Block Flow Diagram). This shows that the feed stream includes acid gas.
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separating the hydrocarbon feed stream into a heavy hydrocarbon rich stream and a carbon dioxide recycle stream, wherein the heavy hydrocarbon rich stream comprises the C₉₊ hydrocarbons, and wherein the carbon dioxide recycle stream comprises the carbon dioxide, the C₃-C₈ hydrocarbons, and the acid gas;	As stated above, The Process Flow Diagram in the Air Permit shows the inlet stream in the stages of the process after most of the heavy hydrocarbons have been removed from the plant feed gas. (Process Flow Diagram)	As stated above, Figure 3 in the Hydrate Formation paper shows the inlet stream in the stages of the process after most of the heavy hydrocarbons have been removed from the plant feed gas. (Block Flow Diagram)
separating the carbon dioxide recycle stream into a sour NGL rich stream and a purified carbon dioxide recycle stream, wherein the sour NGL rich stream comprises the C₃-C₈ hydrocarbons and the acid gas, and wherein the purified carbon dioxide recycle stream comprises the carbon dioxide; and	The “FRACTIONATION UNIT” separates the stream from the “TEG CONTACTOR” (the carbon dioxide recycle stream) into a “GAS” stream that is sent to the “STAGE 3 COMPRESSOR” and then to “REINJECTION” (the purified carbon dioxide recycle stream), and a stream that is sent to a “COOLING DEHYDRATION SWEETENER” (the sour NGL rich stream). (Process Flow Diagram)	The “NGL Distillation” separates the stream from the “Glycol Dehydration” (the carbon dioxide recycle stream) into a purified carbon dioxide stream that is sent to “3rd Stage Compression” through a “Reflux Condenser” and then to “Reinjection,” and a sour NGL rich stream that is sent to “NGL Sweetening” through a “Reboiler.” (Block Flow Diagram) The Hydrate Formation paper shows that the NGL Composition includes propane, i-butane, n-butane, i-pentane, n-pentane, and hexane plus (e.g., C₃-C₆₊) (“Table 1: Model Validation of Plant Data” on page 4). The Hydrate Formation paper states that: “These corrective measures disrupted the temperature profile across the column, reduced NGL production, increased H₂S

		content in the NGL product, and required continuous involvement from plant operators” (Page 3). H₂S is an acid gas, so “increased H₂S content in the NGL product” shows that the sour NGL rich stream includes acid gas. The Hydrate Formation paper includes an “NGL Sweetening” block. “NGL Sweetening” is used to remove acid gas (Block Flow Diagram). This shows that the sour NGL rich stream includes acid gas.
separating the sour NGL rich stream into a sweet NGL rich stream and an acid gas stream, wherein the sweet NGL rich stream comprises the C₃-C₈ hydrocarbons, and wherein the acid gas stream comprises the acid gas,	The “COOLING DEHYDRATION SWEETENER” receives the stream from the “FRACTIONATION UNIT” (the sour NGL rich stream) and produces a stream that is sent to “PRESSURIZED NGL STORAGE” and then to the “SALES PIPELINE” (the sweet NGL rich stream). The sweetening process performed by the “COOLING DEHYDRATION SWEETENER” separates the sour NGL rich stream into the sweet NGL rich stream and an acid gas stream. (Process Flow Diagram)	The “NGL Sweetening” receives the sour NGL rich stream from the “Reboiler” and produces a stream that is sent to “NGL Product Storage and Sales” (the sweet NGL rich stream). The sweetening process performed by the “NGL Sweetening” separates the sour NGL rich stream into the sweet NGL rich stream and an acid gas stream. (Block Flow Diagram). The Hydrate Formation paper shows that the NGL Composition includes propane, i-butane, n-butane, i-pentane, n-pentane, and hexane plus (e.g., C₃-C₆₊). (“Table 1: Model Validation of Plant Data” on page 4).

		The Hydrate Formation paper states that: “These corrective measures disrupted the temperature profile across the column, reduced NGL production, increased H ₂ S content in the NGL product, and required continuous involvement from plant operators” (Page 3). H ₂ S is an acid gas, so “increased H ₂ S content in the NGL product” shows that the acid gas stream includes acid gas.
wherein the carbon dioxide is not removed from the hydrocarbon feed stream and is not removed from the carbon dioxide recycle stream prior to separating the carbon dioxide recycle stream into the sour NGL rich stream and the purified carbon dioxide recycle stream, and	No carbon dioxide removal is performed between “PLANT FEED GAS” being received at “INLET SEPARATOR” and the stream being fed to “FRACTIONATION UNIT.” (Process Flow Diagram)	No carbon dioxide removal is performed between “Inlet gas and 1 st Stage Compression” and “NGL Distillation.” (Block Flow Diagram)
wherein the hydrocarbon feed stream, the carbon dioxide recycle stream, and the sour NGL rich stream are not subjected to cryogenic conditions, membranes, and carbon dioxide recovery solvents between being received and being separated into the heavy hydrocarbon rich stream, the purified carbon dioxide recycle stream, the sweet NGL rich stream, and the acid gas stream.	There are no cryogenic conditions, membranes, or carbon dioxide recovery solvents in the process. “TEG CONTACTOR” is for dehydrating the stream and not for carbon dioxide recovery. (Process Flow Diagram)	There are no cryogenic conditions, membranes, or carbon dioxide recovery solvents in the process. “Glycol Dehydration” is for dehydrating the stream and not for carbon dioxide recovery. (Block Flow Diagram)

**EXHIBITS TO
PLAINTIFFS PILOT ENERGY SOLUTIONS
AND PILOT INTELLECTUAL PROPERTY'S
ORIGINAL COMPLAINT**

- P-1 United States Patent No. 8,505,332 (“the ‘332 Patent”).
- P-2 Chevron Mabee Plant Air Permit Application – Texas Commission for Environmental Quality (“TCEQ”) (November 5, 2012).
- P-3 Notice Letter from Pilot Energy Solutions to Chevron (August 15, 2013).
- P-4 Response Letter from Chevron to Pilot Energy Solutions (August 29, 2013).
- P-5 United States Patent No. 4,753,666 (“Pastor”).
- P-6 Hydrate Formation in Chevron Mabee Unit for NGL Recovery and CO2 Purification for EOR (Submitted to Gas Processors Association 2017).
- P-7 Claim Chart (‘332 Patent Claim 1).

Exhibit P-1

United States Patent No. 8,505,332
 (“the ‘332 Patent”)



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(12) **United States Patent
Prim**

(10) **Patent No.:** **US 8,505,332 B1**
(45) **Date of Patent:** **Aug. 13, 2013**

(54) **NATURAL GAS LIQUID RECOVERY
PROCESS**

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TX (US)

(*) Notice: Subject to any disclaimer, the term of this
patent is extended or adjusted under 35
U.S.C. 154(b) by 1489 days.

(21) Appl. No.: **12/122,336**

(22) Filed: **May 16, 2008**

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Related U.S. Application Data

(60) Provisional application No. 60/938,726, filed on May
18, 2007.

(51) **Int. Cl.**
F25J 3/00 (2006.01)
C07C 7/00 (2006.01)
C07C 7/10 (2006.01)
C07C 7/144 (2006.01)

(52) **U.S. Cl.**
USPC **62/618**; 62/620; 62/928; 585/802;
585/818; 585/833

(58) **Field of Classification Search**
USPC 62/617, 618, 620, 622; 585/818,
585/802, 833, 837
See application file for complete search history.

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Primary Examiner — Frantz Jules

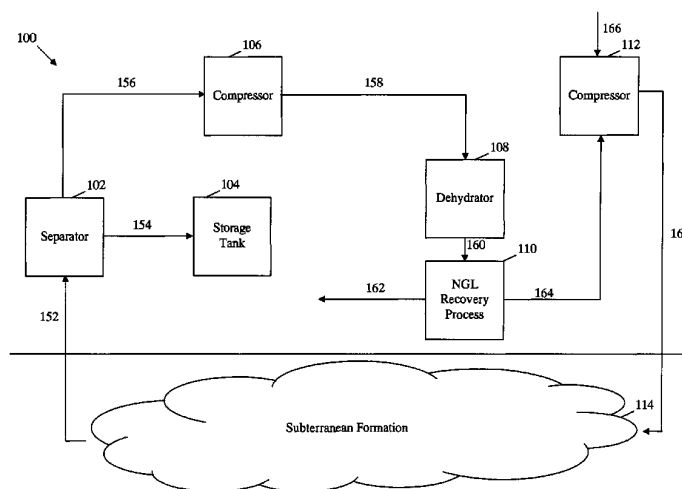
Assistant Examiner — Keith Raymond

(74) *Attorney, Agent, or Firm* — Conley Rose, P.C.; Grant
Rodolph; Nicholas K. Beaulieu

(57) **ABSTRACT**

A method comprising receiving a hydrocarbon feed stream, separating the hydrocarbon feed stream into a heavy hydrocarbon rich stream and a carbon dioxide recycle stream, separating the carbon dioxide recycle stream into a natural gas liquids (NGL) rich stream and a purified carbon dioxide recycle stream, and injecting the purified carbon dioxide recycle stream into a subterranean formation. Included is a method comprising selecting a first recovery rate for a NGL recovery process, estimating the economics of the NGL recovery process based on the first recovery rate, selecting a second recovery rate that is different from the first recovery rate, estimating the economics of the NGL recovery process based on the second recovery rate, and selecting the first recovery rate for the NGL recovery process when the estimate based on the first recovery rate is more desirable than the estimate based on the second recovery rate.

26 Claims, 4 Drawing Sheets

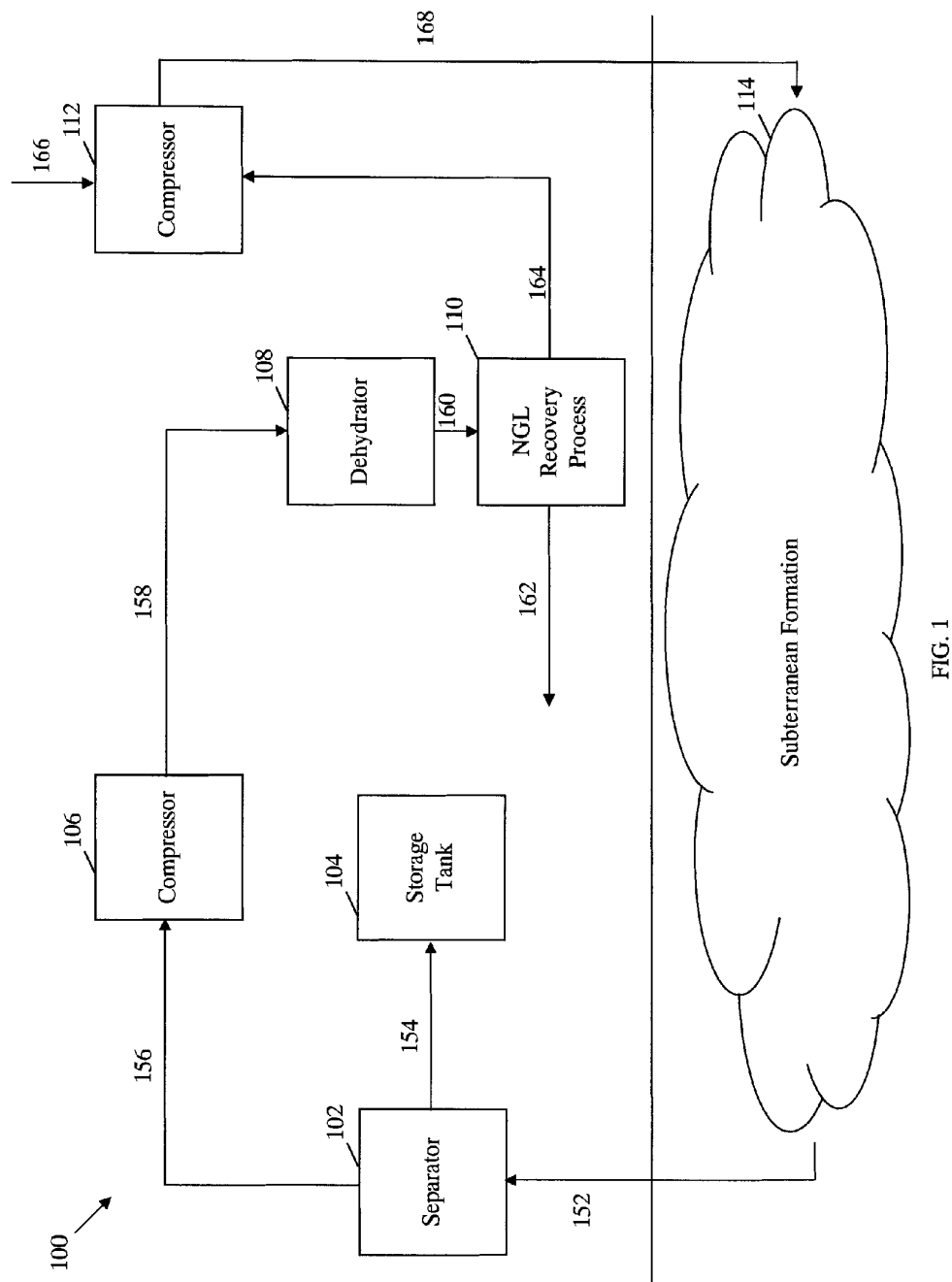


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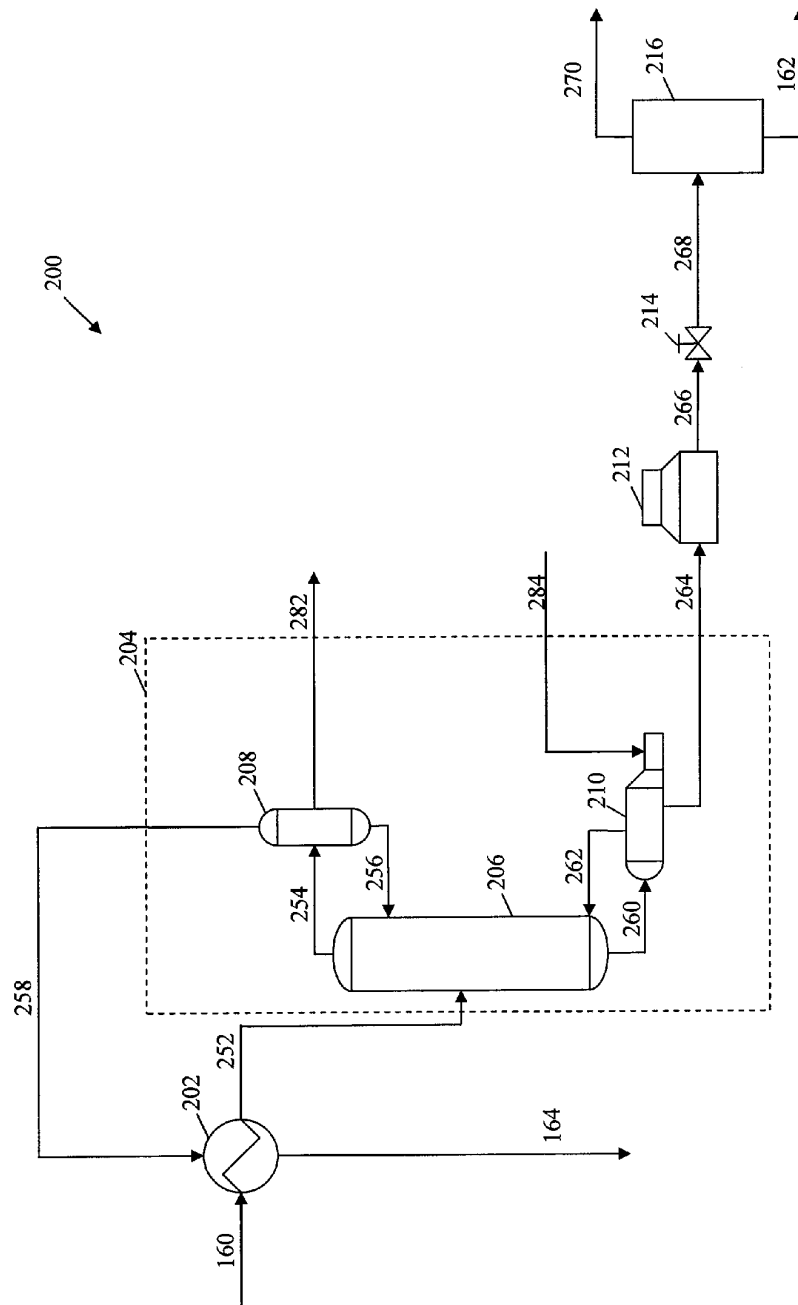


FIG. 2

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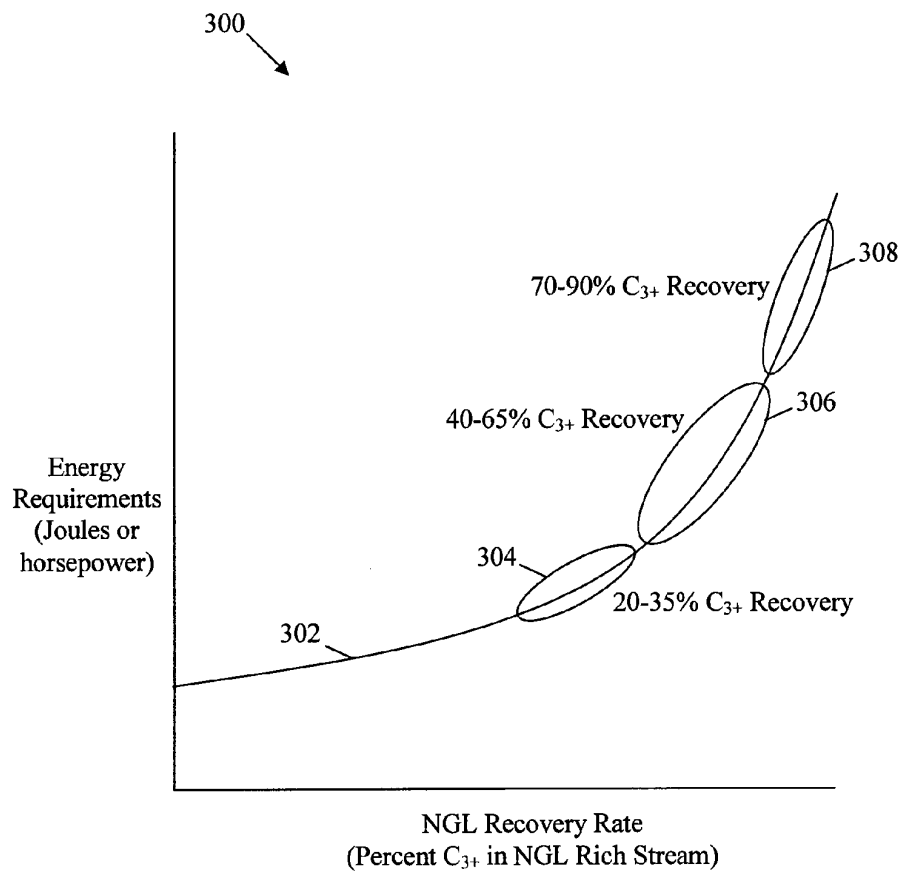


FIG. 3

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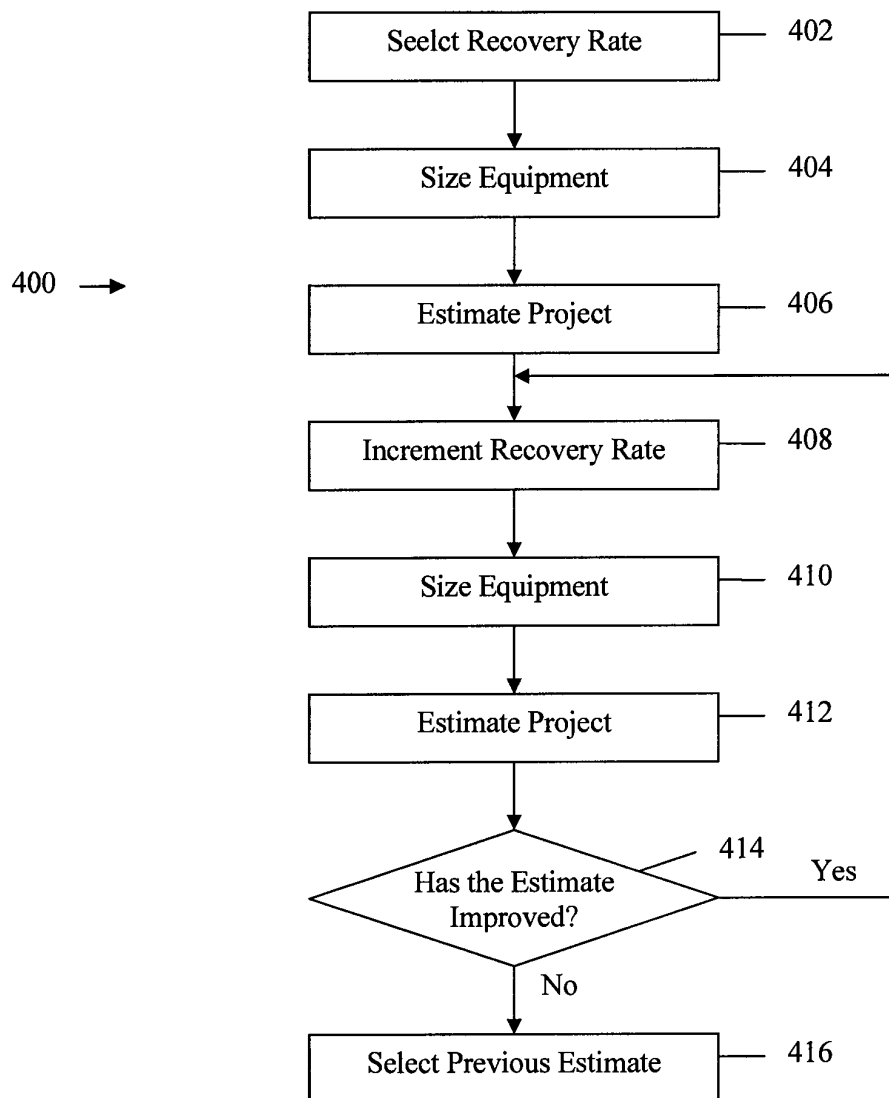


FIG. 4

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NATURAL GAS LIQUID RECOVERY PROCESS

CROSS-REFERENCE TO RELATED APPLICATIONS

The present application claims priority to U.S. Provisional Patent Application Ser. No. 60/938,726, filed May 18, 2007 by Eric Prim, and entitled "NGL Recovery Process," which is incorporated herein by reference as if reproduced in their entirety.

STATEMENT REGARDING FEDERALLY SPONSORED RESEARCH OR DEVELOPMENT

Not applicable.

REFERENCE TO A MICROFICHE APPENDIX

Not applicable.

BACKGROUND

Carbon dioxide (CO₂) is a naturally occurring substance in most hydrocarbon subterranean formations. Carbon dioxide may also be used for recovering or extracting oil and hydrocarbons from subterranean formations. One carbon dioxide based recovery process involves injecting carbon dioxide into an injection well, and recovering heavy hydrocarbons and perhaps some of the carbon dioxide from at least one recovery well. Carbon dioxide reinjection process may also produce natural gas liquids (NGLs).

SUMMARY

In one aspect, the disclosure includes a method comprising receiving a hydrocarbon feed stream, separating the hydrocarbon feed stream into a heavy hydrocarbon rich stream and a carbon dioxide recycle stream, separating the carbon dioxide recycle stream into a NGL rich stream and a purified carbon dioxide recycle stream, and injecting the purified carbon dioxide recycle stream into a subterranean formation.

In another aspect, the disclosure includes a plurality of process equipment configured to implement a method comprising receiving a recycle stream comprising at least one C₃₊ hydrocarbon and a gas selected from the group consisting of carbon dioxide, nitrogen, air, and water, and separating the recycle stream into a NGL rich stream and a purified recycle stream, wherein the NGL rich stream comprises less than about 70 percent of the C₃₊ hydrocarbons from the recycle stream.

In a third aspect, the disclosure includes a method comprising selecting a first recovery rate for a NGL recovery process, estimating the economics of the NGL recovery process based on the first recovery rate, selecting a second recovery rate that is different from the first recovery rate, estimating the economics of the NGL recovery process based on the second recovery rate, and selecting the first recovery rate for the NGL recovery process when the estimate based on the first recovery rate is more desirable than the estimate based on the second recovery rate.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. 1 is a process flow diagram for an embodiment of a carbon dioxide reinjection process.

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FIG. 2 is a schematic diagram of an embodiment of a NGL recovery process.

FIG. 3 is a chart depicting an embodiment of the relationship between the NGL recovery rate and the energy requirement.

FIG. 4 is a flowchart of an embodiment of a NGL recovery optimization method.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENTS

It should be understood at the outset that although an illustrative implementation of one or more embodiments are provided below, the disclosed systems and/or methods may be implemented using any number of techniques, whether currently known or in existence. The disclosure should in no way be limited to the illustrative implementations, drawings, and techniques illustrated below, including the exemplary designs and implementations illustrated and described herein, but may be modified within the scope of the appended claims along with their full scope of equivalents.

Disclosed herein is a NGL recovery process that may be implemented as part of a carbon dioxide reinjection process to recover NGLs from a carbon dioxide recycle stream. When implementing a carbon dioxide reinjection process, the carbon dioxide is typically injected downhole into an injection well and a stream comprising hydrocarbons and carbon dioxide is generally recovered from a recovery well. The carbon dioxide may be separated from the heavy hydrocarbons and then recycled downhole, e.g. in the reinjection well. In some cases, the carbon dioxide recycle stream may comprise some NGLs, which may be recovered prior to injecting the carbon dioxide recycle stream downhole. The NGL recovery process may be optimized by weighing the NGL recovery rate against the amount of energy expended on NGL recovery.

FIG. 1 illustrates an embodiment of a carbon dioxide reinjection process 100. The carbon dioxide reinjection process 100 may receive hydrocarbons and carbon dioxide from a subterranean formation 114, separate heavy hydrocarbons and some of the NGLs from the carbon dioxide, and inject the carbon dioxide downhole. As shown in FIG. 1, additional process steps may be included in the carbon dioxide reinjection process, such as compressing the carbon dioxide, dehydrating the carbon dioxide, and/or adding additional carbon dioxide to the carbon dioxide recycle stream. The specific steps in the carbon dioxide reinjection process 100 are explained in further detail below.

The carbon dioxide reinjection process 100 may receive a hydrocarbon feed stream 152 from a subterranean formation 114. The hydrocarbon feed stream 152 may be obtained from at least one recovery well as indicated by the upward arrow in FIG. 1, but may also be obtained from other types of wells. In addition, the hydrocarbon feed stream 152 may be obtained from the subterranean formation 114 using any suitable method. For example, if a suitable pressure differential exists between the subterranean formation 114 and the surface, the hydrocarbon feed stream 152 may flow to the surface via the pressure differential. Alternatively, surface and/or downhole pumps may be used to draw the hydrocarbon feed stream 152 from the subterranean formation 114 to the surface.

Although the composition of the hydrocarbon feed stream 152 will vary from one location to another, the hydrocarbon feed stream 152 may comprise carbon dioxide, methane, ethane, NGLs, heavy hydrocarbons, hydrogen sulfide (H₂S), helium, nitrogen, water, or combinations thereof. The term "hydrocarbon" may refer to any compound comprising, consisting essentially of, or consisting of carbon and hydrogen

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atoms. The term “natural gas” may refer to any hydrocarbon that may exist in a gas phase under atmospheric or downhole conditions, and includes methane and ethane, but may also include diminishing amounts of C₃-C₈ hydrocarbons. The term “natural gas liquids” or NGLs may refer to natural gases that may be liquefied without refrigeration, and may include C₃-C₈ hydrocarbons. Both natural gas and NGL are terms known in the art and are used herein as such. In contrast, the term “heavy hydrocarbons” may refer to any hydrocarbon that may exist in a liquid phase under atmospheric or downhole conditions, and generally includes liquid crude oil, which may comprise C₉₊ hydrocarbons, branched hydrocarbons, aromatic hydrocarbons, and combinations thereof.

The hydrocarbon feed stream **152** may enter a separator **102**. The separator **102** may be any process equipment suitable for separating at least one inlet stream into a plurality of effluent streams having different compositions, states, temperatures, and/or pressures. For example, the separator **102** may be a column having trays, packing, or some other type of complex internal structure. Examples of such columns include scrubbers, strippers, absorbers, adsorbers, packed columns, and distillation columns having valve, sieve, or other types of trays. Such columns may employ weirs, downspouts, internal baffles, temperature control elements, and/or pressure control elements. Such columns may also employ some combination of reflux condensers and/or reboilers, including intermediate stage condensers and reboilers. Alternatively, the separator **102** may be a phase separator, which is a vessel that separates an inlet stream into a substantially vapor stream and a substantially liquid stream, such as a knock-out drum, flash drum, reboiler, condenser, or other heat exchanger. Such vessels may also have some internal baffles, temperature control elements, and/or pressure control elements, but generally lack any trays or other type of complex internal structure commonly found in columns. The separator **102** may also be any other type of separator, such as a membrane separator. In a specific embodiment, the separator **102** is a knockout drum. Finally, the separator **102** may be any combination of the aforementioned separators **102** arranged in series, in parallel, or combinations thereof.

The separator **102** may produce a heavy hydrocarbon stream **154** and a carbon dioxide recycle stream **156**. The heavy hydrocarbon stream **154** may comprise most of the heavy hydrocarbons from the hydrocarbon feed stream **152**. In embodiments, the heavy hydrocarbon stream **154** may comprise at least about 90 percent, at least about 95 percent, at least about 99 percent, or substantially all of the heavy hydrocarbons from the hydrocarbon feed stream **152**. The heavy hydrocarbon stream **154** may be sent to a pipeline for transportation or a storage tank **104**, where it is stored until transported to another location or further processed. In contrast, the carbon dioxide recycle stream **156** may comprise most of the carbon dioxide from the hydrocarbon feed stream **152**. In embodiments, the carbon dioxide recycle stream **156** may comprise at least about 90 percent, at least about 95 percent, at least about 99 percent, or substantially all of the carbon dioxide from the hydrocarbon feed stream **152**. Similarly, the carbon dioxide recycle stream **156** may comprise at least about 80 percent, at least about 90 percent, at least about 95 percent, or substantially all of the natural gas from the hydrocarbon feed stream **152**. All of the percentages referred to herein are molar percentages until otherwise specified.

The carbon dioxide recycle stream **156** may enter a compressor **106**. The compressor **106** may be any process equipment suitable for increasing the pressure, temperature, and/or density of an inlet stream. The compressor **106** may be configured to compress a substantially vapor phase inlet stream,

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a substantially liquid phase inlet stream, or combinations thereof. As such, the term “compressor” may include both compressors and pumps, which may be driven by electrical, mechanical, hydraulic, or pneumatic means. Specific examples of suitable compressors **106** include centrifugal, axial, positive displacement, turbine, rotary, and reciprocating compressors and pumps. In a specific embodiment, the compressor **106** is a turbine compressor. Finally, the compressor **106** may be any combination of the aforementioned compressors **106** arranged in series, in parallel, or combinations thereof.

The compressor **106** may produce a compressed carbon dioxide recycle stream **158**. The compressed carbon dioxide recycle stream **158** may contain the same composition as the carbon dioxide recycle stream **156**, but at a higher energy level. The additional energy in the compressed carbon dioxide recycle stream **158** may be obtained from energy added to the compressor **106**, e.g. the electrical, mechanical, hydraulic, or pneumatic energy. In embodiments, difference in energy levels between the compressed carbon dioxide recycle stream **158** and the carbon dioxide recycle stream **156** is at least about 50 percent, at least about 65 percent, or at least about 80 percent of the energy added to the compressor **106**.

The compressed carbon dioxide recycle stream **158** may enter a dehydrator **108**. The dehydrator **108** may remove some or substantially all of the water from the compressed carbon dioxide recycle stream **158**. The dehydrator **108** may be any suitable dehydrator, such as a condenser, an absorber, or an adsorber. Specific examples of suitable dehydrators **108** include refrigerators, molecular sieves, liquid desiccants such as glycol, solid desiccants such as silica gel or calcium chloride, and combinations thereof. The dehydrator **108** may also be any combination of the aforementioned dehydrators **108** arranged in series, in parallel, or combinations thereof. In a specific embodiment, the dehydrator **108** is a glycol unit. Any water accumulated within or exiting from the dehydrator **108** may be stored, used for other processes, or discarded.

The dehydrator **108** may produce a dehydrated carbon dioxide recycle stream **160**. The dehydrated carbon dioxide recycle stream **160** may contain little water, e.g. liquid water or water vapor. In embodiments, the dehydrated carbon dioxide recycle stream **160** may comprise no more than about 5 percent, no more than about 3 percent, no more than about 1 percent, or be substantially free of water.

The dehydrated carbon dioxide recycle stream **160** may enter a NGL recovery process **110**. The NGL recovery process **110** may separate the dehydrated carbon dioxide recycle stream **160** into a NGL rich stream **162** and a purified carbon dioxide recycle stream **164**. The NGL rich stream **162** may only comprise a portion of the total NGLs from the dehydrated carbon dioxide recycle stream **160**. For example, the NGL rich stream **162** may comprise less than about 70 percent, from about 10 percent to about 50 percent, or from about 20 percent to about 35 percent of the NGLs from the dehydrated carbon dioxide recycle stream **160**. By taking a less aggressive cut of the NGLs and/or disregarding the recovery of methane, ethane, and optionally propane from the dehydrated carbon dioxide recycle stream **160**, the NGL recovery process **110** may produce a relatively high quality NGL rich stream **162** with relatively little process equipment or energy. A specific example of a suitable NGL recovery process **110** is shown in FIG. 2 and described in further detail below.

As mentioned above, the NGL recovery process **110** may produce a relatively high-quality NGL rich stream **162**. Specifically, while the NGL recovery process **110** recovers only a portion, e.g., about 20 to about 35 percent, of the NGLs in the dehydrated carbon dioxide recycle stream **160**, the result-

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ing NGL rich stream 162 is relatively lean with respect to methane, ethane, and acid gases. For example, the NGL rich stream 162 may comprise most of the butane and heavier components from the dehydrated carbon dioxide recycle stream 160. For example, the NGL rich stream 162 may comprise at least about 90 percent, at least about 95 percent, at least about 99 percent, or substantially all of the C_{4+} from the dehydrated carbon dioxide recycle stream 160. In embodiments, the NGL rich stream 162 may comprise no more than about 10 percent, no more than about 5 percent, no more than about 1 percent, or be substantially free of ethane. Similarly, the NGL rich stream 162 may comprise no more than about 5 percent, no more than about 3 percent, no more than about 1 percent, or be substantially free of methane. Moreover, the NGL rich stream 162 may comprise no more than about 5 percent, no more than about 3 percent, no more than about 1 percent, or be substantially free of acid gases, such as carbon dioxide or hydrogen sulfide. It will be realized that the composition of the NGL rich stream 162 may be dependent on the dehydrated carbon dioxide recycle stream 160 composition. The examples provided below show the composition of the NGL rich stream 162 for three different dehydrated carbon dioxide recycle stream 160 compositions. The NGL rich stream 162 may be sent to a pipeline for transportation or a storage tank, where it is stored until transported to another location or further processed.

As mentioned above, the NGL recovery process 110 may produce a purified carbon dioxide recycle stream 164. The purified carbon dioxide recycle stream 164 may comprise most of the carbon dioxide from the dehydrated carbon dioxide recycle stream 160, as well as some other components such as methane, ethane, propane, butane, nitrogen, and hydrogen sulfide. In embodiments, the purified carbon dioxide recycle stream 164 may comprise at least about 90 percent, at least about 95 percent, at least about 99 percent, or substantially all of the carbon dioxide from the dehydrated carbon dioxide recycle stream 160. In addition, the purified carbon dioxide recycle stream 164 may comprise at least about 90 percent, at least about 95 percent, at least about 99 percent, or substantially all of the methane from the dehydrated carbon dioxide recycle stream 160. As such, the purified carbon dioxide recycle stream 164 may comprise at least about 65 percent, at least about 80 percent, at least about 90 percent, or at least about 95 percent carbon dioxide. In embodiments, the purified carbon dioxide recycle stream 164 may comprise no more than about 10 percent, no more than about 5 percent, no more than about 1 percent, or be substantially free of C_{3+} . Similarly, the purified carbon dioxide recycle stream 164 may comprise no more than about 20 percent, no more than about 10 percent, no more than about 5 percent, or be substantially free of C_{2+} .

The purified carbon dioxide recycle stream 164 may enter a compressor 112. The compressor 112 may comprise one or more compressors, such as the compressor 106 described above. In a specific embodiment, the compressor 112 is a turbine compressor. The compressor 112 may compress the purified carbon dioxide recycle stream 164, thereby producing a carbon dioxide injection stream 168. The carbon dioxide injection stream 168 may contain the same composition as the purified carbon dioxide recycle stream 164, but at a higher energy level. The additional energy in the carbon dioxide injection stream 168 may be obtained from energy added to the compressor 112, e.g. the electrical, mechanical, hydraulic, or pneumatic energy. In embodiments, difference in energy levels between the carbon dioxide injection stream 168 and the purified carbon dioxide recycle stream 164 is at

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least about 50 percent, at least about 65 percent, or at least about 80 percent of the energy added to the compressor 112.

In some embodiments, a makeup stream 166 may be combined with either the purified carbon dioxide recycle stream 164 or the carbon dioxide injection stream 168. Specifically, as the carbon dioxide reinjection process 100 is operated, carbon dioxide and other compounds will be lost, e.g. by replacing the hydrocarbons in the subterranean formation 114, by leakage into inaccessible parts of the subterranean formation 114, and/or to other causes. Alternatively, it may be desirable to increase the amount of carbon dioxide and other compounds injected downhole. As such, the makeup stream 166 may be combined with either the purified carbon dioxide recycle stream 164 and/or the carbon dioxide injection stream 168, for example in the compressor 112. Alternatively or additionally, the makeup stream 166 may be combined with the carbon dioxide recycle stream 156, the compressed carbon dioxide recycle stream 158, the dehydrated carbon dioxide recycle stream 160, or combinations thereof. The makeup stream 166 may comprise carbon dioxide, nitrogen, methane, ethane, air, water, or any other suitable compound. In an embodiment, the makeup stream 166 comprises at least 75 percent, at least 85 percent, or at least 95 percent carbon dioxide, nitrogen, methane, air, water, or combinations thereof.

FIG. 2 illustrates an embodiment of a NGL recovery process 200. The NGL recovery process 200 may recover some of the NGLs from a carbon dioxide recycle stream described above. For example, the NGL recovery process 200 may be implemented as part of the carbon dioxide reinjection process 100, e.g. by separating the dehydrated carbon dioxide recycle stream 160 into a NGL rich stream 162 and a purified carbon dioxide recycle stream 164.

The NGL recovery process 200 may begin by cooling the dehydrated carbon dioxide recycle stream 160 in a heat exchanger 202. The heat exchanger 202 may be any equipment suitable for heating or cooling one stream using another stream. Generally, the heat exchanger 202 is a relatively simple device that allows heat to be exchanged between two fluids without the fluids directly contacting each other. Examples of suitable heat exchangers 202 include shell and tube heat exchangers, double pipe heat exchangers, plate fin heat exchangers, bayonet heat exchangers, reboilers, condensers, evaporators, and air coolers. In the case of air coolers, one of the fluids is atmospheric air, which may be forced over tubes or coils using one or more fans. In a specific embodiment, the heat exchanger 202 is a shell and tube heat exchanger.

As shown in FIG. 2, the dehydrated carbon dioxide recycle stream 160 may be cooled using the cooled, purified carbon dioxide recycle stream 258. Specifically, the dehydrated carbon dioxide recycle stream 160 is cooled to produce the cooled carbon dioxide recycle stream 252, and the cooled, purified carbon dioxide recycle stream 258 is heated to produce the purified carbon dioxide recycle stream 164. The efficiency of the heat exchange process depends on several factors, including the heat exchanger design, the temperature, composition, and flowrate of the hot and cold streams, and/or the amount of thermal energy lost in the heat exchange process. In embodiments, the difference in energy levels between the dehydrated carbon dioxide recycle stream 160 and the cooled carbon dioxide recycle stream 252 is at least about 60 percent, at least about 70 percent, at least about 80, or at least about 90 percent of the difference in energy levels between the cooled, purified carbon dioxide recycle stream 258 and the purified carbon dioxide recycle stream 164.

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The cooled carbon dioxide recycle stream **252** then enters a NGL stabilizer **204**. The NGL stabilizer **204** may comprise a separator **206**, a condenser **208**, and a reboiler **210**. The separator **206** may be similar to any of the separators described herein, such as separator **102**. In a specific embodiment, the separator **206** is a distillation column. The condenser **208** may receive an overhead **254** from the separator **206** and produce the cooled, purified carbon dioxide recycle stream **258** and a reflux stream **256**, which is returned to the separator **206**. The condenser **208** may be similar to any of the heat exchangers described herein, such as heat exchanger **202**. In a specific embodiment, the condenser **208** is a shell and tube, kettle type condenser coupled to a refrigeration process, and contains a reflux accumulator. As such, the condenser **208** may remove some energy **282** from the reflux stream **256** and cooled, purified carbon dioxide recycle stream **258**, typically by refrigeration. The cooled, purified carbon dioxide recycle stream **258** is substantially similar in composition to the purified carbon dioxide recycle stream **164** described above. Similarly, the reboiler **210** may receive a bottoms stream **260** from the separator **206** and produce a sour NGL rich stream **264** and a boil-up stream **262**, which is returned to the separator **206**. The reboiler **210** may be like any of the heat exchangers described herein, such as heat exchanger **202**. In a specific embodiment, the reboiler **210** is a shell and tube heat exchanger coupled to a hot oil heater. As such, the reboiler **210** adds some energy **284** to the boil-up stream **262** and the sour NGL rich stream **264**, typically by heating. The sour NGL rich stream **264** may be substantially similar in composition to the NGL rich stream **162**, with the exception that the sour NGL rich stream **264** has some additional acid gases, e.g. acid gases **270** described below.

The sour NGL rich stream **264** may then be cooled in another heat exchanger **212**. The heat exchanger **212** may be like any of the heat exchangers described herein, such as heat exchanger **202**. For example, the heat exchanger **212** may be an air cooler as described above. A cooled, sour NGL rich stream **266** exits the heat exchanger **212** and enters a throttling valve **214**. The throttling valve **214** may be an actual valve such as a gate valve, globe valve, angle valve, ball valve, butterfly valve, needle valve, or any other suitable valve, or may be a restriction in the piping such as an orifice or a pipe coil, bend, or size reduction. The throttling valve **214** may reduce the pressure, temperature, or both of the cooled, sour NGL rich stream **266** and produce a low-pressure sour NGL rich stream **268**. The cooled, sour NGL rich stream **266** and the low-pressure sour NGL rich stream **268** have substantially the same composition as the sour NGL rich stream **264**, albeit with lower energy levels.

The low-pressure sour NGL rich stream **268** may then be sweetened in a separator **216**. The separator **216** may be similar to any of the separators described herein, such as separator **102**. In an embodiment, the separator **216** may be one or more packed columns that use a sweetening process to remove acid gases from the low-pressure sour NGL rich stream **268**. Suitable sweetening processes include amine solutions, physical solvents such as SELEXOL or RECTISOL, mixed amine solution and physical solvents, potassium carbonate solutions, direct oxidation, absorption, adsorption using, e.g., molecular sieves, or membrane filtration. The separator **216** may produce the NGL rich stream **162** described above. In addition, any acid gases **270** accumulated within or exiting from the separator **216** may be stored, used for other processes, or suitably disposed of. Finally, while FIGS. 1 and 2 are described in the context of carbon dioxide reinjection, it will be appreciated that the concepts described

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herein can be applied to other reinjection processes, for example those using nitrogen, air, or water.

FIG. 3 illustrates an embodiment of a chart **300** depicting the relationship between the NGL recovery rate and the energy expended to recover NGLs in the NGL recovery process. The NGL recovery rate may be a percentage recovery, and may represent the amount of C_{3+} in the carbon dioxide recycle stream that is recovered in the NGL rich stream. The energy requirement may be measured in joules (J) or in horsepower (hp), and may represent the energy required to generate the condenser energy and reboiler energy described above. If additional compressors are needed at any point in the carbon dioxide reinjection process than would be required in an otherwise similar carbon dioxide reinjection process that lacks the NGL recovery process, then the energy required to operate such compressors may be included in the energy requirement shown in FIG. 3.

As shown by curve **302**, the energy requirements may increase about exponentially as the NGLs are recovered at higher rates. In other words, substantially higher energy may be required to recover the NGLs at incrementally higher rates. For example, recovering a first amount **304** of from about 20 percent to about 35 percent of C_{3+} may require substantially less energy than recovering a second amount **306** of from about 40 percent to about 65 percent of C_{3+} . Moreover, recovering the second amount **306** of from about 40 percent to about 65 percent of C_{3+} may require substantially less energy than recovering a third amount **308** of from about 70 percent to about 90 percent of C_{3+} . Such significant reduction in energy requirements may be advantageous in terms of process feasibility and cost, where relatively small decreases in NGL recovery rates may require significantly less energy and process equipment, yielding significantly better process economics. Although the exact relationship of the curve **302** may depend on numerous factors especially the price of C_{3+} , in an embodiment the economics of the NGL recovery process when the NGL recovery rate is in the second amount **306** may be better than the economics of the NGL recovery process when the NGL recovery rate is in the third amount **308**. Similarly, the economics of the NGL recovery process when the NGL recovery rate is in the first amount **304** may be significantly better than the economics of the NGL recovery process when the NGL recovery rate is in the second amount **306**. Such a relationship is counterintuitive considering that in many other processes, the process economics generally improve with increased recovery rates.

FIG. 4 illustrates an embodiment of a NGL recovery optimization method **400**. The NGL recovery optimization method **400** may be used to determine an improved or optimal project estimate for implementing the NGL recovery process and recovering NGLs at a suitable rate. As such, the NGL recovery process may be configured using appropriate equipment design based on the NGL recovery rate. Specifically, the NGL recovery optimization method **400** may design or configure the equipment size, quantity, or both based on an initial NGL recovery rate and required energy, and hence estimate the project feasibility and cost. The method **400** may upgrade or improve the project estimate by iteratively incrementing the initial NGL recovery rate, re-estimating the project, and comparing the two estimates.

At block **402**, the method **400** may select an initial NGL recovery rate. The initial NGL recovery rate may be relatively small, such as no more than about 20 percent recovery, no more than about 10 percent recovery, no more than about 5 percent recovery, or no more than about 1 percent recovery. Choosing the initial NGL recovery rate at a small percentage

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of the total NGL amount may result in a relatively low project estimate that may be increased gradually to reach improved estimates.

The method 400 may then proceed to block 404, where the project equipment size may be determined based on the initial NGL recovery rate. Specifically, the size of the equipment described in the NGL recovery process and any additional compressors as described above may be determined. In addition, the pressure and temperature ratings and material compositions of such equipment may be determined at block 404, if desired.

The method 400 may then proceed to block 406, where the project may be estimated. Project estimation may comprise an economic evaluation of the NGL recovery process, and may include the cost of obtaining, fabricating, and/or field constructing the equipment sized in block 404. In addition, project estimation may include the cost of operating and maintaining the NGL process, as well as the revenue generated by the sale or use of the products obtained by implementing the NGL process. As such, the project estimate may comprise the total project benefits (including production, sales, etc.) minus the total project capital and operating costs (including cost, equipment, etc.). In some embodiments, the project estimate may be based on an existing carbon dioxide reinjection plant that lacks the NGL recovery process.

The method 400 may then proceed to block 408, where the recovery rate is incremented. The NGL recovery rate may be incremented by a relatively small percentage, for example no more than about 10 percent, not more than about 5 percent, or no more than about 1 percent. The method 400 may then proceed to block 410, which is substantially similar to block 404. The method 400 may then proceed to block 412, which is substantially similar to block 406.

The method 400 may then proceed to block 414, where the method 400 may determine whether the project estimate has improved. For instance, the method 400 may compare the project estimate from block 412 with the previous project estimate (either block 406 or the previous iteration of block 412) and determine whether the revised estimate is more economically desirable. The method 400 may return to block 408 when the condition at block 414 is met. Otherwise, the method 400 may proceed to block 416.

At block 416, the method 400 may choose the previous project estimate as the final estimate. For example, the method 400 may select the previous NGL recovery rate (either block 406 or the previous iteration of block 412) instead of the estimate obtained at block 412. In some embodiments, the desired or optimum recovery rate selected at block 416 may represent a range of desirable or optimum points, as opposed to a single point. Accordingly, the method 400 may select the equipment sizing corresponding to the selected NGL recovery rate. The selected project estimate and sizing may then be used for the NGL recovery process. Of course, it will be appreciated that the method 400 may be revised to include a decremented, top-down estimation approach as opposed to an incremented, bottom-up estimation approach.

The method 400 may have several advantages over other project estimation methods. For example, process equipment of a specific size may be selected, and the corresponding recovery rate determined. Alternatively, a required recovery rate may be selected, and the equipment sized to achieve the recovery rate. However, it has been discovered that such approaches are inflexible and often yields suboptimal process economics. For example, relatively high NGL recovery rates will not lead to an improvement in process economics, e.g. because of the exponential increase in energy consumption.

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In contrast, the method 400 provides a flexible approach to determining a desirable or optimal project estimate.

In an embodiment, the equipment size may be configured to allow for variations in recovery rates to accommodate changes in economic conditions, such as C_{3+} or energy pricing. Specifically, the equipment described herein can be sized above or below the desired or optimum amount to allow the processes described herein to operate at recovery rates slightly greater than or slightly less than the desirable or optimum point obtained in method 400. As the process parameters and the energy requirements may be closely related, the ability of the process to continue to successfully operate under differing conditions may be reflected by constrained changes in the energy requirements of the process. When operating in the first amount 304 or the second amount 306 on the curve 302 in FIG. 3, significant increases or decreases in NGL recovery rate may be obtained with little change in the energy requirements. Such is not the case when operating in the third amount 308 on the curve 302 in FIG. 3, where significant increases or decreases in energy requirements yield only incremental changes in NGL recovery rate.

EXAMPLES

In one example, a process simulation was performed using the NGL recovery process 200 shown in FIG. 2. The simulation was performed using the Hyprotech Ltd. HYSYS Process v2.1.1 (Build 3198) software package. The NGL recovery process 200 separated the dehydrated carbon dioxide recycle stream 160 into the purified carbon dioxide recycle stream 164, the NGL rich stream 162, and the acid gas stream 270. The specified values are indicated by an asterisk (*). The physical properties are provided in degrees Fahrenheit (F), pounds per square inch gauge (psig), million standard cubic feet per day (MMSCFD), pounds per hour (lb/hr), U.S. gallons per minute (USGPM), and British thermal units per hour (Btu/hr). The material streams, their compositions, and the associated energy streams produced by the simulation are provided in tables 1, 2, and 3 below, respectively.

TABLE 1A

Material Streams			
Name	Dehydrated CO ₂ Recycle Stream 160	Cooled CO ₂ Recycle Stream 252	Cooled, Purified CO ₂ Recycle Stream 258
Vapor Fraction	0.9838	0.9392	1.0000
Temperature (F.)	104.0*	45.00*	4.011
Pressure (psig)	340.0*	335.0	330.0
Molar Flow (MMSCFD)	17.00*	17.00	15.88
Mass Flow (lb/hr)	8.049e+04	8.049e+04	7.254e+04
Liquid Volume Flow (USGPM)	218.1	218.1	192.3
Heat Flow (Btu/hr)	-2.639e+08	-2.658e+08	-2.577e+08

TABLE 1B

Material Streams			
Name	Purified CO ₂ Recycle Stream 164	Sour NGL Rich Stream 264	Cooled Sour NGL Rich Stream 266
Vapor Fraction	1.0000	0.00000	0.0000
Temperature (F.)	97.39	202.6	120.0*
Pressure (psig)	325.0	340.0	635.3*
Molar Flow (MMSCFD)	15.88	1.119	1.119

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TABLE 1B-continued

Material Streams				
Name		Purified CO ₂ Recycle Stream 164	Sour NGL Rich Stream 264	Cooled Sour NGL Rich Stream 266
Mass Flow	(lb/hr)	7.254e+04	7947	7947
Liquid Volume Flow	(USGPM)	192.3	25.84	25.84
Heat Flow	(Btu/hr)	-2.558e+08	-8.443e+06	-8.862e+06

TABLE 1C

Material Streams				
Name		Low-Pressure Sour NGL Rich Stream 268		
			Acid Gas Stream 270	NGL Rich Stream 162
Vapor Fraction		0.0000	1.0000	0.0000
Temperature (F.)		120.9	100.0*	111.8
Pressure (psig)		200.3*	5.304*	185.3*
Molar Flow (MMSCFD)		1.119	0.1030	1.016
Mass Flow (lb/hr)		7947	446.4	7501
Liquid Volume Flow (USGPM)		25.84	1.100	24.74
Heat Flow (Btu/hr)		-8.862e+06	-1.083e+06	-7.779e+06

TABLE 2A

Stream Compositions				
Name		Dehydrated CO ₂ Recycle Stream 160	Cooled CO ₂ Recycle Stream 252	Cooled, Purified CO ₂ Recycle Stream 258
Comp Mole Frac (H ₂ S)		0.0333*	0.0333	0.0327
Comp Mole Frac (Nitrogen)		0.0054*	0.0054	0.0058
Comp Mole Frac (CO ₂)		0.7842*	0.7842	0.8359
Comp Mole Frac (Methane)		0.0521*	0.0521	0.0558
Comp Mole Frac (Ethane)		0.0343*	0.0343	0.0348
Comp Mole Frac (Propane)		0.0406*	0.0406	0.0313
Comp Mole Frac (i-Butane)		0.0072*	0.0072	0.0022
Comp Mole Frac (n-Butane)		0.0171*	0.0171	0.0015
Comp Mole Frac (i-Pentane)		0.0058*	0.0058	0.0000
Comp Mole Frac (n-Pentane)		0.0057*	0.0057	0.0000
Comp Mole Frac (n-Hexane)		0.0070*	0.0070	0.0000
Comp Mole Frac (n-Octane)		0.0071*	0.0071	0.0000
Comp Mole Frac (H ₂ O)		0.0000*	0.0000	0.0000

TABLE 2B

Stream Compositions				
Name		Purified CO ₂ Recycle Stream 164	Sour NGL Rich Stream 264	Cooled Sour NGL Rich Stream 266
Comp Mole Frac (H ₂ S)		0.0327	0.0421	0.0421
Comp Mole Frac (Nitrogen)		0.0058	0.0000	0.0000
Comp Mole Frac (CO ₂)		0.8359	0.0500	0.0500
Comp Mole Frac (Methane)		0.0558	0.0000	0.0000
Comp Mole Frac (Ethane)		0.0348	0.0281	0.0281
Comp Mole Frac (Propane)		0.0313	0.1728	0.1728
Comp Mole Frac (i-Butane)		0.0022	0.0789	0.0789
Comp Mole Frac (n-Butane)		0.0015	0.2388	0.2388
Comp Mole Frac (i-Pentane)		0.0000	0.0887	0.0887
Comp Mole Frac (n-Pentane)		0.0000	0.0866	0.0866
Comp Mole Frac (n-Hexane)		0.0000	0.1063	0.1063

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TABLE 2B-continued

Stream Compositions				
Name		Purified CO ₂ Recycle Stream 164	Sour NGL Rich Stream 264	Cooled Sour NGL Rich Stream 266
Comp Mole Frac (n-Octane)		0.0000	0.1077	0.1077
Comp Mole Frac (H ₂ O)		0.0000	0.0000	0.0000

TABLE 2C

Stream Compositions				
Name		Low-Pressure Sour NGL Rich Stream 268		
			Acid Gas Stream 270	NGL Rich Stream 162
Comp Mole Frac (H ₂ S)		0.0421	0.4568	0.0000
Comp Mole Frac (Nitrogen)		0.0000	0.0000	0.0000
Comp Mole Frac (CO ₂)		0.0500	0.5432	0.0000
Comp Mole Frac (Methane)		0.0000	0.0000	0.0000
Comp Mole Frac (Ethane)		0.0281	0.0000	0.0309
Comp Mole Frac (Propane)		0.1728	0.0000	0.1903
Comp Mole Frac (i-Butane)		0.0789	0.0000	0.0869
Comp Mole Frac (n-Butane)		0.2388	0.0000	0.2630
Comp Mole Frac (i-Pentane)		0.0887	0.0000	0.0977
Comp Mole Frac (n-Pentane)		0.0866	0.0000	0.0954
Comp Mole Frac (n-Hexane)		0.1063	0.0000	0.1171
Comp Mole Frac (n-Octane)		0.1077	0.0000	0.1186
Comp Mole Frac (H ₂ O)		0.0000	0.0000	0.0000

TABLE 3

Energy Streams		
Name		Heat Flow (Btu/hr)
Condenser Q Energy Stream 282		1.469e+06
Reboiler Q Energy Stream 284		1.152e+06

In another example, the process simulation was repeated using a different dehydrated carbon dioxide recycle stream 160. The material streams, their compositions, and the associated energy streams produced by the simulation are provided in tables 4, 5, and 6 below, respectively.

TABLE 4A

Material Streams				
Name		Dehydrated CO ₂ Recycle Stream 160	Cooled CO ₂ Recycle Stream 252	Cooled, Purified CO ₂ Recycle Stream 258
Vapor Fraction		0.9874	0.9286	1.0000
Temperature (F)		104.0*	60.00*	22.77
Pressure (psig)		685.3*	680.3	590.0
Molar Flow (MMSCFD)		20.00*	20.00	18.86
Mass Flow (lb/hr)		8.535e+04	8.535e+04	7.780e+04
Liquid Volume Flow (USGPM)		258.0	258.0	232.2
Heat Flow (Btu/hr)		-2.741e+08	-2.760e+08	-2.683e+08

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TABLE 4B

Material Streams			
Name	Purified CO ₂ Recycle Stream 164	Sour NGL Rich Stream 264	Cooled Sour NGL Rich Stream 266
Vapor Fraction	1.0000	0.00000	0.0000
Temperature (F)	87.48	290.7	120.0*
Pressure (psig)	585.0	600.0	635.3*
Molar Flow (MMSCFD)	18.86	1.139	1.139
Mass Flow (lb/hr)	7.780e+04	7552	7552
Liquid Volume Flow (USGPM)	232.2	25.83	25.83
Heat Flow (Btu/hr)	-2.663e+08	-7.411e+06	-8.371e+06

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TABLE 4C

Material Streams			
Name	Low-Pressure Sour NGL Rich Stream 268	Acid Gas Stream 270	NGL Rich Stream 162
Vapor Fraction	0.0000	1.0000	0.0000
Temperature (F)	120.5	100.0*	118.6
Pressure (psig)	200.3*	5.304*	185.3*
Molar Flow (MMSCFD)	1.139	0.02943	1.110
Mass Flow (lb/hr)	7552	141.2	7411
Liquid Volume Flow (USGPM)	25.83	0.3421	25.49
Heat Flow (Btu/hr)	-8.371e+06	-5.301e+05	-7.841e+06

TABLE 5A

Stream Compositions			
Name	Dehydrated CO ₂ Recycle Stream 160	Cooled CO ₂ Recycle Stream 252	Cooled, Purified CO ₂ Recycle Stream 258
Comp Mole Frac (H ₂ S)	0.0004*	0.0004	0.0004
Comp Mole Frac (Nitrogen)	0.0153*	0.0153	0.0162
Comp Mole Frac (CO ₂)	0.6592*	0.6592	0.6975
Comp Mole Frac (Methane)	0.1813*	0.1813	0.1922
Comp Mole Frac (Ethane)	0.0620*	0.0620	0.0620
Comp Mole Frac (Propane)	0.0411*	0.0411	0.0275
Comp Mole Frac (i-Butane)	0.0064*	0.0064	0.0017
Comp Mole Frac (n-Butane)	0.0179*	0.0179	0.0024
Comp Mole Frac (i-Pentane)	0.0040*	0.0040	0.0000
Comp Mole Frac (n-Pentane)	0.0049*	0.0049	0.0000
Comp Mole Frac (n-Hexane)	0.0030*	0.0030	0.0000
Comp Mole Frac (n-Octane)	0.0045*	0.0045	0.0000
Comp Mole Frac (H ₂ O)	0.0000*	0.0000	0.0000

TABLE 5B

Stream Compositions			
Name	Purified CO ₂ Recycle Stream 164	Sour NGL Rich Stream 264	Cooled Sour NGL Rich Stream 266
Comp Mole Frac (H ₂ S)	0.0004	0.0008	0.0008
Comp Mole Frac (Nitrogen)	0.0162	0.0000	0.0000
Comp Mole Frac (CO ₂)	0.6975	0.0250	0.0250
Comp Mole Frac (Methane)	0.1922	0.0000	0.0000
Comp Mole Frac (Ethane)	0.0620	0.0613	0.0613
Comp Mole Frac (Propane)	0.0275	0.2670	0.2670
Comp Mole Frac (i-Butane)	0.0017	0.0836	0.0836
Comp Mole Frac (n-Butane)	0.0024	0.2751	0.2751
Comp Mole Frac (i-Pentane)	0.0000	0.0697	0.0697

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TABLE 5B-continued

Stream Compositions			
Name	Purified CO ₂ Recycle Stream 164	Sour NGL Rich Stream 264	Cooled Sour NGL Rich Stream 266
Comp Mole Frac (n-Pentane)	0.0000	0.0858	0.0858
Comp Mole Frac (n-Hexane)	0.0000	0.0527	0.0527
Comp Mole Frac (n-Octane)	0.0000	0.0790	0.0790
Comp Mole Frac (H ₂ O)	0.0000	0.0000	0.0000

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TABLE 5C

Stream Compositions			
Name	Low-Pressure Sour NGL Rich Stream 268	Acid Gas Stream 270	NGL Rich Stream 162
Comp Mole Frac (H ₂ S)	0.0008	0.0315	0.0000
Comp Mole Frac (Nitrogen)	0.0000	0.0000	0.0000
Comp Mole Frac (CO ₂)	0.0250	0.9685	0.0000
Comp Mole Frac (Methane)	0.0000	0.0000	0.0000
Comp Mole Frac (Ethane)	0.0613	0.0000	0.0629
Comp Mole Frac (Propane)	0.2670	0.0000	0.2740
Comp Mole Frac (i-Butane)	0.0836	0.0000	0.0858
Comp Mole Frac (n-Butane)	0.2751	0.0000	0.2824
Comp Mole Frac (i-Pentane)	0.0697	0.0000	0.0716
Comp Mole Frac (n-Pentane)	0.0858	0.0000	0.0881
Comp Mole Frac (n-Hexane)	0.0527	0.0000	0.0541
Comp Mole Frac (n-Octane)	0.0790	0.0000	0.0811
Comp Mole Frac (H ₂ O)	0.0000	0.0000	0.0000

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TABLE 6

Energy Streams	
Name	Heat Flow (Btu/hr)
Condenser Q Energy Stream 282	1.884e+06
Reboiler Q Energy Stream 284	2.211e+06

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In a third example, the process simulation was repeated using a different dehydrated carbon dioxide recycle stream 160. The material streams, their compositions, and the associated energy streams produced by the simulation are provided in tables 7, 8, and 9 below, respectively.

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TABLE 7A

Material Streams			
Name	Dehydrated CO ₂ Recycle Stream 160	Cooled CO ₂ Recycle Stream 252	Cooled, Purified CO ₂ Recycle Stream 258
Vapor Fraction	1.0000	0.9988	1.0000
Temperature (F)	104.0*	30.00*	4.617
Pressure (psig)	340.0*	335.0	330.0
Molar Flow (MMSCFD)	17.00*	17.00	16.82
Mass Flow (lb/hr)	8.083e+04	8.083e+04	7.968e+04
Liquid Volume Flow (USGPM)	203.4	203.4	199.5
Heat Flow (Btu/hr)	-3.016e+08	-3.032e+08	-3.025e+08

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TABLE 7B

Material Streams			
Name	Purified CO ₂ Recycle Stream 164	Sour NGL Rich Stream 264	Cooled Sour NGL Rich Stream 266
Vapor Fraction	1.0000	0.00000	0.0000
Temperature (F)	76.45	199.4	120.0*
Pressure (psig)	325.0	340.0	635.3*
Molar Flow (MMSCFD)	16.82	0.1763	0.1763
Mass Flow (lb/hr)	7.968e+04	1153	1153
Liquid Volume Flow (USGPM)	199.5	3.894	3.894
Heat Flow (Btu/hr)	-3.009e+08	-1.278e+06	-1.340e+06

TABLE 7C

Material Streams			
Name	Low-Pressure Sour NGL Rich Stream 268	Acid Gas Stream 270	NGL Rich Stream 162
Vapor Fraction	0.0000	1.0000	0.0000
Temperature (F)	120.4	100.0*	115.4
Pressure (psig)	200.3*	5.304*	185.3*
Molar Flow (MMSCFD)	0.1763	0.01048	0.1659
Mass Flow (lb/hr)	1153	48.82	1105
Liquid Volume Flow (USGPM)	3.894	0.1188	3.776
Heat Flow (Btu/hr)	-1.340e+06	-1.653e+05	-1.175e+06

TABLE 8A

Stream Compositions			
Name	Dehydrated CO ₂ Recycle Stream 160	Cooled CO ₂ Recycle Stream 252	Cooled, Purified CO ₂ Recycle Stream 258
Comp Mole Frac (H ₂ S)	0.0031*	0.0031	0.0030
Comp Mole Frac (Nitrogen)	0.0008*	0.0008	0.0008
Comp Mole Frac (CO ₂)	0.9400*	0.9400	0.9493
Comp Mole Frac (Methane)	0.0219*	0.0219	0.0222
Comp Mole Frac (Ethane)	0.0156*	0.0156	0.0157
Comp Mole Frac (Propane)	0.0116*	0.0116	0.0088
Comp Mole Frac (i-Butane)	0.0015*	0.0015	0.0002
Comp Mole Frac (n-Butane)	0.0031*	0.0031	0.0001
Comp Mole Frac (i-Pentane)	0.0007*	0.0007	0.0000
Comp Mole Frac (n-Pentane)	0.0006*	0.0006	0.0000
Comp Mole Frac (n-Hexane)	0.0005*	0.0005	0.0000

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TABLE 8A-continued

Stream Compositions			
Name	Dehydrated CO ₂ Recycle Stream 160	Cooled CO ₂ Recycle Stream 252	Cooled, Purified CO ₂ Recycle Stream 258
Comp Mole Frac (n-Octane)	0.0006*	0.0006	0.0000
Comp Mole Frac (H ₂ O)	0.0000*	0.0000	0.0000

TABLE 8B

Stream Compositions			
Name	Purified CO ₂ Recycle Stream 164	Sour NGL Rich Stream 264	Cooled Sour NGL Rich Stream 266
Comp Mole Frac (H ₂ S)	0.0030	0.0094	0.0094
Comp Mole Frac (Nitrogen)	0.0008	0.0000	0.0000
Comp Mole Frac (CO ₂)	0.9493	0.0500	0.0500
Comp Mole Frac (Methane)	0.0222	0.0000	0.0000
Comp Mole Frac (Ethane)	0.0157	0.0000	0.0000
Comp Mole Frac (Propane)	0.0088	0.2794	0.2794
Comp Mole Frac (i-Butane)	0.0002	0.1265	0.1265
Comp Mole Frac (n-Butane)	0.0001	0.2985	0.2985
Comp Mole Frac (i-Pentane)	0.0000	0.0713	0.0713
Comp Mole Frac (n-Pentane)	0.0000	0.0617	0.0617
Comp Mole Frac (n-Hexane)	0.0000	0.0482	0.0482
Comp Mole Frac (n-Octane)	0.0000	0.0550	0.0550
Comp Mole Frac (H ₂ O)	0.0000	0.0000	0.0000

TABLE 8C

Stream Compositions			
Name	Low-Pressure Sour NGL Rich Stream 268	Acid Gas Stream 270	NGL Rich Stream 162
Comp Mole Frac (H ₂ S)	0.0094	0.1584	0.0000
Comp Mole Frac (Nitrogen)	0.0000	0.0000	0.0000
Comp Mole Frac (CO ₂)	0.0500	0.8416	0.0000
Comp Mole Frac (Methane)	0.0000	0.0000	0.0000
Comp Mole Frac (Ethane)	0.0000	0.0000	0.0000
Comp Mole Frac (Propane)	0.2794	0.0000	0.2970
Comp Mole Frac (i-Butane)	0.1265	0.0000	0.1345
Comp Mole Frac (n-Butane)	0.2985	0.0000	0.3174
Comp Mole Frac (i-Pentane)	0.0713	0.0000	0.0758
Comp Mole Frac (n-Pentane)	0.0617	0.0000	0.0656
Comp Mole Frac (n-Hexane)	0.0482	0.0000	0.0512
Comp Mole Frac (n-Octane)	0.0550	0.0000	0.0584
Comp Mole Frac (H ₂ O)	0.0000	0.0000	0.0000

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TABLE 9

Energy Streams	
Name	Heat Flow (Btu/hr)
Condenser Q Energy Stream 282	6.236e+06
Reboiler Q Energy Stream 284	5.666e+06

While preferred embodiments of the invention have been shown and described, modifications thereof can be made by one skilled in the art without departing from the spirit and teachings of the invention. The embodiments described herein are exemplary only, and are not intended to be limiting. Many variations and modifications of the invention disclosed herein are possible and are within the scope of the invention. Specifically, while the process is described in terms of a continuous process, it is contemplated that the process can be implemented as a batch process. In addition, where numerical ranges or limitations are expressly stated, such express ranges or limitations should be understood to include iterative ranges or limitations of like magnitude falling within the expressly stated ranges or limitations (e.g., from about 1 to about 10 includes, 2, 3, 4, etc.; greater than 0.10 includes 0.11, 0.12, 0.13, etc.). Use of the term "optionally" with respect to any element of a claim is intended to mean that the subject element is required, or alternatively, is not required. Both alternatives are intended to be within the scope of the claim. Use of broader terms such as comprises, includes, having, etc. should be understood to provide support for narrower terms such as consisting of, consisting essentially of, comprised substantially of, etc. Moreover, the percentages described herein may be mole fraction, weight fraction, or volumetric fraction.

Accordingly, the scope of protection is not limited by the description set out above but is only limited by the claims that follow, that scope including all equivalents of the subject matter of the claims. Each and every claim is incorporated into the specification as an embodiment of the present invention. Thus, the claims are a further description and are an addition to the preferred embodiments of the present invention. The discussion of a reference in the herein is not an admission that it is prior art to the present invention, especially any reference that may have a publication date after the priority date of this application. The disclosures of all patents, patent applications, and publications cited herein are hereby incorporated by reference, to the extent that they provide exemplary, procedural, or other details supplementary to those set forth herein.

What is claimed is:

1. A method comprising:

receiving a hydrocarbon feed stream, wherein the hydrocarbon feed stream comprises carbon dioxide, natural gas liquid (NGL), heavy hydrocarbons, and acid gas, wherein the NGL comprises C_3 - C_8 hydrocarbons, and wherein the heavy hydrocarbons comprise C_{9+} hydrocarbons;

separating the hydrocarbon feed stream into a heavy hydrocarbon rich stream and a carbon dioxide recycle stream, wherein the heavy hydrocarbon rich stream comprises the C_{9+} hydrocarbons, and wherein the carbon dioxide recycle stream comprises the carbon dioxide, the C_3 - C_8 hydrocarbons, and the acid gas;

separating the carbon dioxide recycle stream into a sour NGL rich stream and a purified carbon dioxide recycle stream, wherein the sour NGL rich stream comprises the

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C_3 - C_8 hydrocarbons and the acid gas, and wherein the purified carbon dioxide recycle stream comprises the carbon dioxide; and

separating the sour NGL rich stream into a sweet NGL rich stream and an acid gas stream, wherein the sweet NGL rich stream comprises the C_3 - C_8 hydrocarbons, and wherein the acid gas stream comprises the acid gas, wherein the carbon dioxide is not removed from the hydrocarbon feed stream and is not removed from the carbon dioxide recycle stream prior to separating the carbon dioxide recycle stream into the sour NGL rich stream and the purified carbon dioxide recycle stream, and wherein the hydrocarbon feed stream, the carbon dioxide recycle stream, and the sour NGL rich stream are not subjected to cryogenic conditions, membranes, and carbon dioxide recovery solvents between being received and being separated into the heavy hydrocarbon rich stream, the purified carbon dioxide recycle stream, the sweet NGL rich stream, and the acid gas stream.

2. The method of claim 1, further comprising:

compressing the carbon dioxide recycle stream prior to separating the carbon dioxide recycle stream;

dehydrating at least part of the carbon dioxide recycle stream using a dehydration solvent prior to separating the carbon dioxide recycle stream;

combining a carbon dioxide makeup stream external to the method with the purified carbon dioxide recycle stream; and

injecting the combined carbon dioxide makeup stream and the purified carbon dioxide recycle stream into a subterranean formation.

3. The method of claim 1, further comprising cooling the carbon dioxide recycle stream with the purified carbon dioxide recycle stream.

4. The method of claim 3, wherein the sweet NGL rich stream comprises no more than 1 molar percent methane, no more than 1 molar percent ethane, and no more than 1 molar percent acid gases.

5. The method of claim 1, wherein the sweet NGL rich stream comprises from 20 molar percent to 40 molar percent of the C_{3+} hydrocarbons from the carbon dioxide recycle stream, and wherein the purified carbon dioxide recycle stream comprises at least 94 molar percent of the carbon dioxide, at least 94 molar percent of the methane, and at least 93 molar percent of the ethane from the carbon dioxide recycle stream.

6. The method of claim 1, wherein separating the carbon dioxide recycle stream into the sour NGL rich stream and the purified carbon dioxide recycle stream comprises:

refluxing part of the purified carbon dioxide recycle stream;

reboiling part of the sour NGL rich stream; and

cooling and throttling the sour NGL rich stream.

7. The method of claim 6, wherein the sour NGL rich stream comprises no more than 5 molar percent carbon dioxide, no more than 1 molar percent methane, and no more than 5 molar percent ethane, and wherein the sweet NGL rich stream is substantially free of carbon dioxide.

8. The method of claim 1, further comprising:

compressing the carbon dioxide recycle stream prior to separating the carbon dioxide recycle stream;

dehydrating at least part of the carbon dioxide recycle stream using molecular sieves prior to separating the carbon dioxide recycle stream;

combining a carbon dioxide makeup stream external to the method with the purified carbon dioxide recycle stream; and

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injecting the combined carbon dioxide makeup stream and the purified carbon dioxide recycle stream into a subterranean formation.

9. A method comprising:

receiving a hydrocarbon feed stream comprising at least one C_{3+} hydrocarbon, at least one C_{9+} hydrocarbon, acid gas, and a gas selected from the group consisting of carbon dioxide, nitrogen, air, and water;

separating the hydrocarbon feed stream into a heavy hydrocarbon rich stream and a recycle stream, wherein the heavy hydrocarbon rich stream comprises most of the C_{9+} hydrocarbon in the hydrocarbon feed stream, wherein the recycle stream comprises most of the C_{3+} hydrocarbon and most of the acid gas in the hydrocarbon feed stream, and wherein the acid gas is selected from the group consisting of carbon dioxide, nitrogen, air, and water;

separating the recycle stream into a sour natural gas liquid (NGL) rich stream and a purified recycle stream, wherein the sour NGL rich stream comprises some of the C_{3+} hydrocarbon and some of the acid gas in the recycle stream, and wherein the purified recycle stream comprises most of the C_{3+} hydrocarbon and most of the acid gas in the recycle stream; and

separating the sour NGL rich stream into a sweet NGL rich stream and an acid gas stream, wherein the sweet NGL rich stream comprises substantially all of the C_{3+} hydrocarbon in the sour NGL rich stream, and wherein the acid gas stream comprises substantially all of the acid gas in the sour NGL rich stream,

wherein the hydrocarbon feed stream, the recycle stream, and the sour NGL rich stream are not subjected to cryogenic conditions, membranes, and carbon dioxide recovery solvents between being received and being separated into the heavy hydrocarbon rich stream, the sweet NGL rich stream, the purified recycle stream, and the acid gas stream, and

wherein carbon dioxide, nitrogen, and air are not removed from the hydrocarbon feed stream and are not removed from the recycle stream prior to separating the recycle stream into the sour NGL rich stream and the purified recycle stream.

10. The method of claim 9, wherein the sweet NGL rich stream comprises at least 90 molar percent C_{3+} hydrocarbons, wherein the sweet NGL rich stream comprises from 20 molar percent to 40 molar percent of the C_{3+} hydrocarbons from the recycle stream, and wherein the purified recycle stream comprises at least 94 molar percent of the carbon dioxide, at least 94 molar percent of the methane, and at least 93 molar percent of the ethane from the recycle stream.

11. The method of claim 10, wherein the sweet NGL rich stream comprises no more than 5 molar percent ethane and no more than 1 molar percent methane, and wherein the purified recycle stream comprises no more than 10 molar percent C_{2+} .

12. The method of claim 9, wherein separating the recycle stream into the sour NGL rich stream and the purified recycle stream comprises:

refluxing part of the purified recycle stream; reboiling part of the sour NGL rich stream; and cooling and throttling the sour NGL rich stream.

13. The method of claim 12, further comprising:

cooling the sour NGL rich stream; expanding the sour NGL rich stream; and cooling the recycle stream using the purified recycle stream.

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14. The method of claim 13, further comprising:

compressing the recycle stream prior to separating the recycle stream; and

dehydrating at least part of the recycle stream using a dehydration solvent after separating the hydrocarbon feed stream and prior to separating the recycle stream.

15. The method of claim 13, wherein the sour NGL rich stream comprises no more than 5 molar percent carbon dioxide, no more than 1 molar percent methane, and no more than 5 molar percent ethane, and wherein the sweet NGL rich stream is substantially free of carbon dioxide.

16. The method of claim 13, further comprising:

compressing the recycle stream prior to separating the recycle stream; and

dehydrating at least part of the recycle stream using molecular sieves after separating the hydrocarbon feed stream and prior to separating the recycle stream.

17. The method of claim 14, wherein the heavy hydrocarbon rich stream comprises at least 90 molar percent of the C_{9+} hydrocarbons in the hydrocarbon feed stream, wherein the recycle stream comprises at least 90 molar percent of the carbon dioxide in the hydrocarbon feed stream, wherein the sweet NGL rich stream comprises at least 60 molar percent of the C_{4+} hydrocarbons in the recycle stream, and wherein the purified recycle stream comprises at least 90 molar percent of the carbon dioxide and at least 90 molar percent of the methane in the recycle stream.

18. The method of claim 14, further comprising combining a carbon dioxide makeup stream from a source external to the method with the purified recycle stream and subsequently injecting the combined carbon dioxide makeup stream and the purified recycle stream into a subterranean formation.

19. A method comprising:

receiving a hydrocarbon feed stream, wherein the hydrocarbon feed stream comprises carbon dioxide, natural gas liquid (NGL), and heavy hydrocarbons, wherein the NGL comprises C_3 - C_8 hydrocarbons, and wherein the heavy hydrocarbons comprise C_{9+} hydrocarbons;

separating the hydrocarbon feed stream into a heavy hydrocarbon rich stream and a carbon dioxide recycle stream, wherein the heavy hydrocarbon rich stream comprises most of the C_{9+} hydrocarbons in the hydrocarbon feed stream, and wherein the carbon dioxide recycle stream comprises most of the carbon dioxide and most of the C_3 - C_8 hydrocarbons in the hydrocarbon feed stream;

separating the carbon dioxide recycle stream into a sour NGL rich stream and a purified carbon dioxide recycle stream, wherein the sour NGL rich stream comprises some of the C_3 - C_8 hydrocarbons in the carbon dioxide recycle stream, and wherein the purified carbon dioxide recycle stream comprises most of the carbon dioxide in the carbon dioxide recycle stream;

separating the sour NGL rich stream into a sweet NGL rich stream and a carbon dioxide rich stream, wherein the sweet NGL rich stream comprises the substantially all of the C_3 - C_8 hydrocarbons in the source NGL rich stream, and wherein the carbon dioxide rich stream comprises substantially all of the carbon dioxide in the sour NGL rich stream;

combining a carbon dioxide makeup stream from a source external to the method with the purified carbon dioxide recycle stream; and

subsequently injecting the combined carbon dioxide makeup stream and the purified carbon dioxide recycle stream into a subterranean formation,

wherein the carbon dioxide is not removed from the hydrocarbon feed stream and is not removed from the carbon dioxide recycle stream prior to separating the carbon

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dioxide recycle stream into the sour NGL rich stream and the purified carbon dioxide recycle stream, and wherein the hydrocarbon feed stream, the carbon dioxide recycle stream, and the sour NGL rich stream are not subjected to cryogenic conditions, membranes, and carbon dioxide recovery solvents between being received and being separated into the heavy hydrocarbon rich stream, the purified carbon dioxide recycle stream, the sweet NGL rich stream, and the carbon dioxide rich stream.

20. The method of claim 19, further comprising: compressing the carbon dioxide recycle stream prior to separating the carbon dioxide recycle stream; dehydrating at least part of the carbon dioxide recycle stream using a dehydration solvent after separating the hydrocarbon feed stream and prior to separating the carbon dioxide recycle stream; and cooling the carbon dioxide recycle stream with the purified carbon dioxide recycle stream.

21. The method of claim 20, further comprising: cooling the sour NGL rich stream; expanding the sour NGL rich stream; and cooling the carbon dioxide recycle stream using the purified carbon dioxide recycle stream.

22. The method of claim 19, wherein the heavy hydrocarbon rich stream comprises at least 90 molar percent of the C_{9+} hydrocarbons in the hydrocarbon feed stream, wherein the carbon dioxide recycle stream comprises at least 90 molar percent of the carbon dioxide in the hydrocarbon feed stream, wherein the sweet NGL rich stream comprises at least 60 molar percent of the C_{4+} hydrocarbons in the carbon dioxide recycle stream, wherein the sweet NGL rich stream comprises no more than 5 molar percent ethane and no more than 1 molar percent methane, wherein the purified carbon dioxide recycle stream comprises at least 90 molar percent of the

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carbon dioxide and at least 90 molar percent of the methane from the carbon dioxide recycle stream, and wherein the purified carbon dioxide recycle stream comprises no more than 10 molar percent C_{2+} .

23. The method of claim 19, wherein separating the carbon dioxide recycle stream into the sour NGL rich stream and the purified carbon dioxide recycle stream comprises:

refluxing part of the purified carbon dioxide recycle stream;

reboiling part of the sour NGL rich stream; and cooling and throttling the sour NGL rich stream.

24. The method of claim 23, wherein the sour NGL rich stream comprises no more than 5 molar percent carbon dioxide, no more than 1 molar percent methane, and no more than 5 molar percent ethane, and wherein the sweet NGL rich stream is substantially free of carbon dioxide.

25. The method of claim 19, wherein the sweet NGL rich stream comprises at least 90 molar percent C_{3+} hydrocarbons, wherein the sweet NGL rich stream comprises from 20 molar percent to 40 molar percent of the C_{3+} hydrocarbons from the recycle stream, and wherein the purified carbon dioxide recycle stream comprises at least 94 molar percent of the carbon dioxide, at least 94 molar percent of the methane, and at least 93 molar percent of the ethane from the carbon dioxide recycle stream.

26. The method of claim 19, further comprising:

compressing the carbon dioxide recycle stream prior to separating the carbon dioxide recycle stream;

dehydrating at least part of the carbon dioxide recycle stream using molecular sieves after separating the hydrocarbon feed stream and prior to separating the carbon dioxide recycle stream; and

cooling the carbon dioxide recycle stream with the purified carbon dioxide recycle stream.

* * * * *

Exhibit P-2

**Chevron Mabee Plant
Air Permit Application
Texas Commission for Environmental Quality
("TCEQ")
(November 5, 2012)**

Bryan W. Shaw, Ph.D., *Chairman*
 Carlos Rubinstein, *Commissioner*
 Toby Baker, *Commissioner*
 Zak Covar, *Executive Director*



Permit
[Signature]

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
Protecting Texas by Reducing and Preventing Pollution

November 5, 2012

MR PETER J BOTES
 AIR ADVISOR
 CHEVRON USA INC
 15 SMITH RD
 MIDLAND TX 79705-5423

FILE COPY

Standard Permit Registration Number: 80221 Renewal Date: November 3, 2016
 Location: N on FM 1788 from FM 158 go 8 Mi and turn E at Chevron-Texaco Mabee sign follow lease rd to plant Midland, Andrews County
 City/County: Add NGL Recovery Plant to the Mabee CO2 Recycle Facility
 Project Description/Unit:
 Regulated Entity Number: RN102535796
 Customer Reference Number: CN600132484
 New or Existing Site: Existing
 Affected Permit (if applicable): None
 Standard Permit Type: Oil and Gas Production Facilities (effective 9/4/00)

Chevron USA, Inc. has registered the emissions associated with the addition of a NGL recovery plant to the existing Mabee CO2 Recycle Facility under the standard permit listed above as authorized by the Commissioners pursuant to Title 30 Texas Administrative Code § 116.602 (30 TAC § 116.602). Emissions are listed on the attached table. For rule information see www.tceq.texas.gov/permitting/air/nav/standard.html.

No planned MSS emissions have been represented or reviewed for this registration and none will be authorized.

The company is also reminded that these facilities may be subject to and must comply with other state and federal air quality requirements. In addition, under the applicability section for all Standard Permits, § 116.610(a)(2) states that "Construction or operation of the project must be commenced prior to the effective date of a revision to this subchapter."

If you have questions, please contact Ms. Donna Wurst at (512) 239-5258. This action is taken under authority delegated by the Executive Director of the TCEQ.

Sincerely,

[Signature]

Anne M. Inman, P.E., Manager
 Rule Registrations Section
 Air Permits Division
 Texas Commission on Environmental Quality

cc: Air Section Manager, Region 7 – Midland



**TECHNICAL REVIEW: STANDARD PERMIT FOR
INSTALLATION AND/OR MODIFICATION OF OIL AND GAS FACILITIES**

Permit No.:	80221	Company Name:	Chevron USA, Inc.,	APD Reviewer:	Ms. Donna Wurst
Project No.:	184091	Site/Area Name:	Add NGL Recovery Plant to the Mabee Ranch CO2 Plant	SP No.:	6002 - 116.620 (effective 9/4/00)

GENERAL INFORMATION			
Regulated Entity No.:	RN102535796	Project Type:	Standard Permit Application
Customer Reference No.:	CN600132484	Date Received by TCEQ:	October 12, 2012
Account No.:	AB-0111-T	Date Received by Reviewer:	October 30, 2012
City/County:	Midland, Andrews County	Physical Location:	n on fm 1788 from fm 158 drive 8 mi and turn e at chevron-texaco mabee sign follow lease rd to plant

CONTACT INFORMATION					
Responsible Official/Primary Contact Name and Title:	Mr. Peter J Botes Air Advisor	Phone No.:	(432) 687-7297	Email:	botespi@chevron.com
		Fax No.:	(866) 719-6224		
Technical Contact/Consultant Name and Title:	Mr. Russell Morris Air HES Specialist	Phone No.:	(432) 687-7491	Email:	Russell.morris@chevron.com
		Fax No.:	(866) 719-6224		m

GENERAL RULES CHECK	YES	NO	COMMENTS
Is confidential information included in the application?		X	
Are there associated NSR or Title V permits at the site?		X	There are no permits for this site and no pending permits for this operation. The site is represented as being below major source thresholds and will not require a Title V Operating Permit.
Is the application for renewal of an existing standard permit?		X	

DESCRIBE OVERALL PROCESS AT THE SITE
Chevron USA, Inc. owns and operates the Mabee CO2 Recycle Facility. - This is an existing facility that dehydrates and compresses gas from Chevron's Mabee Ranch tertiary oil recovery project. - The facility is authorized by Standard Permit Registration No. 80221.

DESCRIBE PROJECT AND INVOLVED PROCESS
The purpose of this submittal is to add a NGL Recovery Plant to the facility. The only changes to previously reported emissions, due to the addition of the NGL Recovery Plant, are the addition of a 3 MMBtu/hr hot oil heater, the addition of a 0.25 MMBtu/hr CO2 stripper heater, and increased fugitives from propane refrigeration, NGL's, an additional electric compressor, and the Sulfa-Treat tower. Incoming gas is routed through a knock-out drum to remove liquids before the gas is compressed. The liquids are sent to the water/condensate tank and then to field batteries for disposal. After compression, the gas is routed to the glycol dehydration unit. The dehydration gas is recompressed and sent to the Mabee Ranch Field for reinjection. Rich CO2 gas from the existing second stage compressors will be cooled, dehydrated via the existing TEG unit, and fed to a fractionation tower. The fractionation tower reboiler and condenser duty will be supplied by a hot oil furnace and propane refrigeration unit. The tower bottoms product NGL undergoes COS hydrolysis, air cooling, water separation, SulfaTreat, and storage before being pumped to the West Texas LPG Pipeline. H2S removed by the Sulfa-treat tower produces solid waste sulfur cakes. The addition of one 500 HP electric compressor along with current electric compression and will be used. A flare is used to burn purge gas from the compressor, inlet gas during planned maintenance on the recycle gas compressors, emissions from the water/condensate tank, and for emergency upsets. All existing emissions except for process fugitives are the same as previously represented. New emissions are from the hot oil heater and the CO2 stripper heater. Increased fugitives are from propane refrigeration, NGL's, an additional electric compressor, and the Sulfa-Treat tower. Existing Emissions Flare (EPN 3-1) During normal operation, the flare burns gases generated from the continuous purging of the compressor seals with 100% nitrogen and emissions from the water/condensate tank. Calculations are based on a conservative gas analysis from the flare scrubber. The purge gas flow rate is 75 MCFD and the flow rate from each of the three pilots is 0.83 SCFM. Pilot gas is sweet natural gas. The flow rates for the water/condensate tank were rounded up from emission rates calculated by the program E&P TANK. The flare is also used for maintenance and emission events. No startup, shutdown or maintenance emissions are included in this application. NOx and CO emissions were calculated using factors from the TCEQ's Technical Guidance Package for Flares and Vapor Oxidizers, dated October 2000. The flare is a non-assisted flare using fuel with heat content between 900 and 1000 Btu/scf. The higher of the NO and CO flare emission factors for low and high Btu fuels were used to calculate emissions. H2S and VOC emission rates were based on 98% destruction efficiency. However, a conservative 100% conversion of H2S to SO2 was assumed to calculate SO2 emission rates, which are based on 2.5 mol% H2S in the purge gas and 1.5 mol% H2S in the maintenance gas. All of the sulfur in the gas was assumed to be H2S. To conservatively calculate HAP emissions based on the Flare Scrubber Gas analysis, all C6 compounds were treated as n-hexane and as benzene, and all C7+ compounds were treated as ethylbenzene, toluene and xylenes.

**TECHNICAL REVIEW: STANDARD PERMIT FOR
INSTALLATION AND/OR MODIFICATION OF OIL AND GAS FACILITIES**

Permit No.:	80221	Company Name:	Chevron USA, Inc.,	APD Reviewer:	Ms. Donna Wurst
Project No.:	184091	Site/Area Name:	Add NGL Recovery Plant to the Mabee Ranch CO2 Plant	SP No.:	6002 - 116.620 (effective 9/4/00)

§116.610. Applicability.

- (a) Under the TCAA, §382.051, a project which meets the requirements for a standard permit listed in this subchapter or issued by the commission is hereby entitled to the standard permit, provided the following conditions listed in this section are met. For the purposes of this subchapter, project means the construction or modification of a facility or a group of facilities submitted under the same registration.
- (1) Any project that results in a net increase in emissions of air contaminants from the project other than carbon dioxide, water, nitrogen, methane, ethane, hydrogen, oxygen, or those for which a national ambient air quality standard has been established must meet the emission limitations of §106.261 of this title (relating to Facilities (Emission Limitations)), unless otherwise specified by a particular standard permit.

Chevron U.S.A. Inc.

All air contaminants meet the emission limitations of §106.261 or §106.262. The following compounds are emitted at rates no higher than 6 lb/hr and 10 tons/yr, which meet the emission limitations of §106.261(a)(2): butane, carbon monoxide, oxides of nitrogen and propane.

The following chemicals are emitted at rates no higher than 1.0 lb/hr and have L values greater than 200 mg/m³, and so meet the requirements of §106.261(a)(3): pentanes, hexanes, heptanes+, ethylbenzene, and xylene. Triethylene glycol is not listed or referenced in Table 262, and the emission rate is less than 1.0 lb/hr.

The remaining compounds: n-hexane, benzene, toluene, PM, and hydrogen sulfide meet the emission limitations of §106.262(a)(2). These compounds are not emitted at rates greater than 5 tons/yr and 6 lb/hr or a quantity greater than E lb/hr where E=L/K. The nearest off-plant receptor is located at a distance of greater than 3000 feet, so a value of 8 is used for K. See the Emission Rate Summary for speciated emission rates and L/K calculations.

- (2) Construction or operation of the project must be commenced prior to the effective date of a revision to this subchapter under which the project would no longer meet the requirements for a standard permit.

**TECHNICAL REVIEW: STANDARD PERMIT FOR
INSTALLATION AND/OR MODIFICATION OF OIL AND GAS FACILITIES**

Permit No.:	80221	Company Name:	Chevron USA, Inc.,	APD Reviewer:	Ms. Donna Wurst
Project No.:	184091	Site/Area Name:	Add NGL Recovery Plant to the Mabee Ranch CO2 Plant	SP No.:	6002 - 116.620 (effective 9/4/00)

- (b) Any project that constitutes a new major stationary source or major modification as defined in §116.12 of this title (relating to Nonattainment and Prevention of Significant Deterioration Review Definitions) is subject to the requirements of §116.110 of this title (relating to Applicability) rather than this subchapter.

Chevron U.S.A. Inc.

The emissions from the facility do not constitute a new major source or major modification under the FCAA, Part C or Part D.

- (c) Persons may not circumvent by artificial limitations the requirements of §116.110 of this title.

Chevron U.S.A. Inc.

No artificial limitations are employed to circumvent permit requirements.

- (d) Any project involving a proposed affected source (as defined in §116.15(1) of this title (relating to Section 112(g) Definitions)) shall comply with all applicable requirements under Subchapter E of this chapter (relating to Hazardous Air Pollutants: Regulations Governing Constructed or Reconstructed Major Sources (FCAA, §112(g), 40 CFR Part 63)). Affected sources subject to Subchapter E of this chapter may use a standard permit under this subchapter only if the terms and conditions of the specific standard permit meet the requirements of Subchapter E of this chapter.

Chevron U.S.A. Inc.

The facility is not an affected source as defined in §116.15(1).

§116.611. Registration to Use a Standard Permit.

- (a) If required, registration to use a standard permit shall be sent by certified mail, return receipt requested, or hand delivered to the executive director, the appropriate commission regional office, and any local air pollution program with jurisdiction, before a standard permit can be used. The registration must be submitted on the required form and must document compliance with the requirements of this section, including, but not limited to:
- (1) the basis of emission estimates;
 - (2) quantification of all emission increases and decreases associated with the project being registered;
 - (3) sufficient information as may be necessary to demonstrate that the project will comply with §116.610(b) of this title (relating to Applicability);

**TECHNICAL REVIEW: STANDARD PERMIT FOR
INSTALLATION AND/OR MODIFICATION OF OIL AND GAS FACILITIES**

Permit No.:	80221	Company Name:	Chevron USA, Inc.,	APD Reviewer:	Ms. Donna Wurst
Project No.:	184091	Site/Area Name:	Add NGL Recovery Plant to the Mabee Ranch CO2 Plant	SP No.:	6002 - 116.620 (effective 9/4/00)

§116.614. Standard Permit Fees.

Any person who registers to use a standard permit or an amended standard permit, or to renew a registration to use a standard permit shall remit, at the time of registration, a flat fee of \$900 for each standard permit being registered, unless otherwise specified in a particular standard permit. No fee is required if a registration is automatically renewed by the commission. All standard permit fees will be remitted in the form of a check, certified check, electronic funds transfer, or money order made payable to the Texas Commission on Environmental Quality (TCEQ) and delivered with the permit registration to the TCEQ, P.O. Box 13088, MC 214, Austin, Texas 78711-3087. No fees will be refunded.

Chevron U.S.A. Inc.

The permit fee of \$900 has been paid on line.

§116.615. General Conditions.

The following general conditions are applicable to holders of standard permits, but will not necessarily be specifically stated within the standard permit document.

- (1) **Protection of public health and welfare.** The emissions from the facility, including dockside vessel emissions, must comply with all applicable rules and regulations of the commission adopted under Texas Health and Safety Code, Chapter 382, and with the intent of the Texas Clean Air Act (TCAA), including protection of health and property of the public.

Chevron U.S.A. Inc.

The emissions from the facility will comply with all applicable rules and regulations of the commission adopted under the Texas Health and Safety Code, Chapter 382, and with the intent of the TCAA, including protection of health and property of the public.

- (2) **Standard permit representations.** All representations with regard to construction plans, operating procedures, and maximum emission rates in any registration for a standard permit become conditions upon which the facility or changes thereto, must be constructed and operated. It is unlawful for any person to vary from such representations if the change will affect that person's right to claim a standard permit under this section. Any change in condition such that a person is no longer eligible to claim a standard permit under this section requires proper authorization under §116.110 of this title (relating to Applicability). If the facility remains eligible for a standard permit, the owner or operator of the facility shall notify the executive director of any change in conditions which will result in a change in the method of control of emissions, a change in the character of the emissions, or an increase in the discharge of the various emissions as compared to the representations in the original registration or any previous notification of a change in representations. Notice of changes in

**TECHNICAL REVIEW: STANDARD PERMIT FOR
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Project No.:	184091	Site/Area Name:	Add NGL Recovery Plant to the Mabee Ranch CO2 Plant	SP No.:	6002 - 116.620 (effective 9/4/00)

- (D) A particular standard permit may modify start-up notification requirements.**

Chevron U.S.A. Inc.

The operation of the facility has commenced.

- (6) Sampling requirements.** If sampling of stacks or process vents is required, the standard permit holder shall contact the commission's appropriate regional office and any other air pollution control agency having jurisdiction prior to sampling to obtain the proper data forms and procedures. All sampling and testing procedures must be approved by the executive director and coordinated with the regional representatives of the commission. The standard permit holder is also responsible for providing sampling facilities and conducting the sampling operations or contracting with an independent sampling consultant.

Chevron U.S.A. Inc.

There are no sampling requirements for the facility.

- (7) Equivalency of methods.** The standard permit holder shall demonstrate or otherwise justify the equivalency of emission control methods, sampling or other emission testing methods, and monitoring methods proposed as alternatives to methods indicated in the conditions of the standard permit. Alternative methods must be applied for in writing and must be reviewed and approved by the executive director prior to their use in fulfilling any requirements of the standard permit.

Chevron U.S.A. Inc.

Chevron U.S.A. Inc. does not plan to use alternative methods.

- (8) Recordkeeping.** A copy of the standard permit along with information and data sufficient to demonstrate applicability of and compliance with the standard permit shall be maintained in a file at the plant site and made available at the request of representatives of the executive director, the United States Environmental Protection Agency, or any air pollution control agency having jurisdiction. For facilities that normally operate unattended, this information shall be maintained at the nearest staffed location within Texas specified by the standard permit holder in the standard permit registration. This information must include, but is not limited to, production records and operating hours. Additional recordkeeping requirements may be specified in the conditions of the standard permit. Information and data sufficient to demonstrate applicability of and compliance with the standard permit must be retained for at least two years following the date that the

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<i>Project No.:</i>	184091	<i>Site/Area Name:</i>	Add NGL Recovery Plant to the Mabee Ranch CO2 Plant	<i>SP No.:</i>	6002 - 116.620 (effective 9/4/00)

a condition of the permit, the determination of whether the distance, setback, or buffer is satisfied shall be made on the basis of conditions existing at the earlier of:

- (A) the date new construction, expansion, or modification of a facility begins; or**
- (B) the date any application or notice of intent is first filed with the commission to obtain approval for the construction or operation of the facility.**

Chevron U.S.A. Inc.

Chevron U.S.A. Inc. acknowledges this provision.

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- (5) Total Volatile Organic Compound (VOC) emissions from a natural gas glycol dehydration unit shall not exceed ten tons per year (tpy) unless the vapors are collected and controlled in accordance with subsection (b)(2) of this section.**

Chevron U.S.A. Inc.

The vapors from the glycol dehydration unit will be controlled by routing the emissions to the compressor suction for reinjection. This exceeds the requirements of subsection (b)(2) of this section.

- (6) Any combustion unit (excluding flares, internal combustion engines, or natural gas turbines), with a design maximum heat input greater than 40 million British thermal units (Btu) per hour (using lower heating values) shall not emit more than 0.06 pounds of nitrogen oxides per million Btu.**

Chevron U.S.A. Inc.

There are no combustion units with a design maximum heat input greater than 40 million Btu/hr authorized in the standard permit.

- (7) No facility which is less than 500 feet from the nearest off-plant receptor shall be allowed to emit uncontrolled VOC process fugitive emissions equal to or greater than ten tpy, but less than 25 tpy, unless the equipment is inspected and repaired according to subsection (c)(1) of this section.**

Chevron U.S.A. Inc.

Does not apply. The nearest off-plant receptor is greater than 500 feet away. Uncontrolled VOC process fugitive emissions are less than 25 tpy.

- (8) No facility which is 500 feet or more from the nearest off-plant receptor shall be allowed to emit uncontrolled VOC process fugitive emissions equal to or greater than 25 tpy unless the equipment is inspected and repaired according to subsection (c)(1) of this section.**

Chevron U.S.A. Inc.

Does not apply. The nearest off-plant receptor is greater than 500 feet away. Uncontrolled VOC process fugitive emissions are less than 25 tpy.

- (9) No facility which is less than 500 feet from the nearest off-plant receptor shall be allowed to emit uncontrolled VOC process fugitive emissions equal to or greater than 25 tpy unless the equipment is inspected and repaired according to subsection (c)(2) of this section.**

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and regulations promulgated thereunder, and with Subchapter C of this chapter (relating to Hazardous Air Pollutants: Regulations Governing Constructed or Reconstructed Major Sources (FCAA, §112(g), 40 CFR Part 63)) are being met. The oil and gas facility shall be required to meet the requirements of Subchapter B of this chapter (relating to New Source Review Permits) instead of this subchapter if a PSD or nonattainment permit or a review under Subchapter C of this chapter is required.

Chevron U.S.A. Inc.

There are no PSD, nonattainment, or MACT regulations applicable to the facility.

- (14) Documentation shall be submitted to demonstrate compliance with applicable New Source Performance Standards (NSPS, 40 CFR Part 60).

Chevron U.S.A. Inc.

The storage tanks and fugitives are the only sources with potentially applicable NSPS requirements. The storage tanks are not subject to NSPS Kb since they store condensate prior to custody transfer, and the design storage capacity is less than 1,589.874 m³. The site fugitives are subject to NSPS OOOO. Appropriate documentation will be submitted.

- (15) Documentation shall be submitted to demonstrate compliance with applicable National Emission Standards for Hazardous Air Pollution (NESHAP, 40 CFR Part 61).

Chevron U.S.A. Inc.

There are no NESHAP subparts applicable to the site.

- (16) Documentation shall be submitted to demonstrate compliance with applicable maximum achievable control technology standards as listed under 40 CFR Part 63, promulgated by the EPA under FCAA, §112 or as listed in Chapter 113, Subchapter C of this title (relating to National Emissions Standards for Hazardous Air Pollutants for Source Categories (FCAA §112, 40 CFR Part 63)).

Chevron U.S.A. Inc.

There are no MACT subparts applicable to the site. The site is an area source of HAP in which the glycol dehy unit has no emissions because it is hard piped back to the front end of the plant, so there are no MACT HH standards.

- (17) New and increased emissions shall not cause or contribute to a violation of any National Ambient Air Quality Standard or regulation property line standards as specified in Chapters 111, 112, and 113 of this title (relating to

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- (B) Mechanical shoe or liquid-mounted primary seals shall include a rim-mounted secondary seal on all external floating roofs tanks. Vapor-mounted primary seals will not be accepted.**
- (C) All floating roof tanks shall comply with the requirements under §115.112(a)(2)(A) - (F) of this title (relating to Control Requirements).**
- (D) In lieu of a floating roof, tank emissions may be routed to:**
 - (i) a destruction device such that a minimum VOC destruction efficiency of 98% is achieved; or**
 - (ii) a vapor recovery system such that a minimum VOC recovery efficiency of 95% is achieved.**
- (E) Independent of the permits by rule listed in this paragraph, if the emissions from any fixed roof tank exceed ten tpy of VOC or ten tpy of sulfur compounds, the tank emissions shall be routed to a destruction device, vapor recovery unit, or equivalent method of control that meets the requirements listed in subparagraph (D) of this paragraph.**

Chevron U.S.A. Inc.

The storage tanks at the site area are all less than 25,000-gallon capacity, so this requirement does not apply.

- (2) The VOC emissions from a natural gas glycol dehydration unit shall be controlled as follows.**
 - (A) If total uncontrolled VOC emissions are equal to or greater than ten tpy, but less than 50 tpy, a minimum of 80% by weight minimum control efficiency shall be achieved by either operating a condenser and a separator (or flash tank), vapor recovery unit, destruction device, or equivalent control device.**
 - (B) If total uncontrolled VOC emissions are equal to or greater than 50 tpy, a minimum of:**
 - (i) 98% by weight minimum destruction efficiency shall be achieved by a destruction device or equivalent; or**
 - (ii) 95% by weight minimum control efficiency shall be achieved by a vapor recovery system or equivalent.**

Chevron U.S.A. Inc.

The glycol dehydration unit still vent is routed through two Vapor Recovery Units and the vapors are sent to the compressor suction for reinjection. The only emissions associated with this vent are fugitive piping emissions.

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quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Flanges in VOC service shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

- (F) Each open-ended valve or line in VOC service, other than a valve or line used for safety relief, shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.
- (G) Accessible valves in VOC service shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. For valves equipped with rupture discs, a pressure gauge shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity, but no later than the next process shutdown. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc or venting to a control device are exempt from monitoring.
- (H) Dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system, submerged pumps, or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic driven pumps) are exempt from monitoring.
- (I) All other pump and compressor seals emitting VOC shall be monitored with an approved gas analyzer at least quarterly.
- (J) After completion of the required quarterly inspections for a period of at least two years, the operator of the oil and gas facility may request in writing to the Office of Permitting, Remediation, and Registration that the monitoring schedule be revised based on the percent of valves leaking. The percent of valves leaking shall be determined by dividing the sum of valves leaking during current monitoring and valves for which repair has been delayed by the total number of valves subject to the requirements.

This request shall include all data that has been developed to justify the following modifications in the monitoring schedule.

- (i) After two consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0%, an owner or operator may begin to skip one of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

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developed to justify the following modifications in the monitoring schedule.

- (i) After two consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0%, an owner or operator may begin to skip one of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.
- (ii) After five consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0%, an owner or operator may begin to skip three of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.
- (K) A directed maintenance program shall be used and consist of the repair and maintenance of VOC fugitive emission components assisted simultaneously by the use of an approved gas analyzer such that a minimum concentration of leaking VOC is obtained for each component being maintained. Replaced components shall be remonitored within 30 days of being placed back into VOC service.

Chevron U.S.A. Inc.

This section does not apply because Sections (a)(9) and (a)(10) do not apply to this standard permit. The facility process fugitives are controlled according to NSPS OOOO. Uncontrolled VOC process fugitives are less than 40 tons per year and the facility is greater than 500 feet from the nearest off-plant receptor.

- (3) For owners and operators who are subject to the applicable parts of subsection (a)(11) of this section, auditory and visual checks for SO₂ and H₂S leaks within the operating area shall be made every day. Immediately, but no later than eight hours upon detection of a leak, operating personnel shall take the following actions:
 - (A) isolate the leak; and
 - (B) commence repair or replacement of the leaking component; or
 - (C) use a leak collection/containment system to prevent the leak until repair or replacement can be made if immediate repair is not possible.

Chevron U.S.A. Inc.

Chevron U.S.A. Inc. will make auditory and visual checks for SO₂ and H₂S leaks within the operating area every day. Repairs will be made according to (c)(3) above.

- (d) Approved test methods.

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- (2) The results of the VOC leak detection and repair requirements shall be made available to the executive director or any air pollution control agency having jurisdiction upon request. Records, for all components, shall include:**

- (A) appropriate dates;**
- (B) test methods;**
- (C) instrument readings;**
- (D) repair results; and**
- (E) corrective actions. Records of flange inspections are not required unless a leak is detected.**

Chevron U.S.A. Inc.

Results of the VOC leak detection and repair requirements will be made available to the executive director or any air pollution control agency having jurisdiction upon request.

- (3) Records for repairs and replacements made due to inspections of H₂S and SO₂ components shall be maintained.**

Chevron U.S.A. Inc.

These records shall be maintained.

- (4) Records shall be kept for each production, processing, and pipeline tank battery or for each storage tank if not located at a tank battery, on a monthly basis, as follows:**
- (A) tank battery identification or storage tank identification, if not located at a tank battery;**
 - (B) compound stored;**
 - (C) monthly throughput in barrels/month; and**
 - (D) cumulative annual throughput, barrels/year.**

Chevron U.S.A. Inc.

These records shall be maintained.

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Project No.:	184091	Site/Area Name:	Add NGL Recovery Plant to the Mabree Ranch CO2 Plant	SP No.:	6002 - 116.620 (effective 9/4/00)

SPECIATED EMISSIONS RATE SUMMARY*

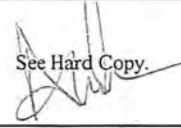
Component	Authorized using emission limitations of:	Emissions (lb/hr)	L Value (mg/m ³)	Allowable (lb/hr) (L/K or Max)	Is Hourly Total < Allowable?	Emissions (tons/yr)
Propane	106.261(a)(2)	0.10	NA	6.00	Yes	0.45
Butanes	106.261(a)(2)	0.09	NA	6.00	Yes	0.43
Pentanes	106.261(a)(3)	0.08	350	1.00	Yes	0.32
Hexanes	106.261(a)(3)	0.05	1760	1.00	Yes	0.25
Heptanes plus	106.261(a)(3)	0.25	350	1.00	Yes	1.07
n-Hexane	106.262(a)(2)	0.06	176	6.00	Yes	0.24
Benzene	106.262(a)(2)	0.053	3	0.33	Yes	0.26
Toluene	106.262(a)(2)	0.25	183	6.00	Yes	1.08
Ethylbenzene	106.261(a)(3)	0.25	434	1.00	Yes	1.07
Xylene	106.261(a)(3)	0.24	434	1.00	Yes	1.07
Hydrogen sulfide	106.262(a)(2)	0.16	10	1.25	Yes	0.72
Triethylene Glycol	106.261(a)(3)	0.014	NA	1.00	Yes	0.028
Carbon Monoxide	106.261(a)(2)	0.37	NA	6.00	Yes	3.83
Nitrogen Oxides	106.261(a)(2)	0.64	NA	6.00	Yes	2.78
Particulate Matter	106.262(a)(2)	0.040	10	1.25	Yes	0.18

* Emission increases are denoted by bold and italicized text.

K value = 8 for 3000 ft

MAXIMUM EMISSION RATES TABLE (MERT)

EPN / Emission Source	VOC		NOx		CO		PM ₁₀ / PM _{2.5}		SO ₂		H ₂ S		HAPs (in VOC total)	
	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy	lbs/hr	tpy
3-1: Flare (Purge Operation)	0.52	2.27	0.11	0.47	0.43	1.89	<0.01	<0.01	14.00	61.30	0.14	0.62	0.76	3.30
2-1: Open Drain Tank	0.10	0.10												
4-3: Glycol Storage Tank	0.01	0.01												
4-1: Glycol Reboiler	0.01	0.04	0.17	0.76	0.15	0.64	0.01	0.06	0.03	0.11				
FE-001: Process Fugitives	0.33	1.29									0.02	0.10	0.09	0.40
HTR-1: Hot Oil Heater	0.02	0.08	0.33	1.43	0.27	1.20	0.03	0.11	0.05	0.21				
HTR-2: CO2 Stripper Heater	<0.01	0.01	0.03	0.12	0.02	0.10	<0.01	0.01	<0.01	0.02				
TOTAL EMISSIONS (TPY):		3.80		2.78		3.83		0.18		61.64		0.72		3.70
MAXIMUM OPERATING SCHEDULE:	Hours/Day		24		Days/Week		7		Weeks/Year		52		Hours/Year	
													8760	

	TECHNICAL REVIEWER	PEER REVIEWER	FINAL REVIEWER
SIGNATURE:			
PRINTED NAME:	Ms. Donna Wurst		
DATE:	November 5, 2012		

BASIS OF PROJECT POINTS	POINTS
Base Points: O&G SP 6002	2.50
Project Complexity Description and Points: completed in <15 days	1.00
Technical Reviewer Project Points Assessment:	3.5
Final Reviewer Project Points Confirmation:	

CHEVRON U.S.A. INC.
MABEE CO₂ RECYCLE FACILITY
REVISION TO STANDARD PERMIT REGISTRATION NO. 80221

OCTOBER 2012

ATTACHMENT V.B

PROCESS DESCRIPTION AND FLOW DIAGRAM

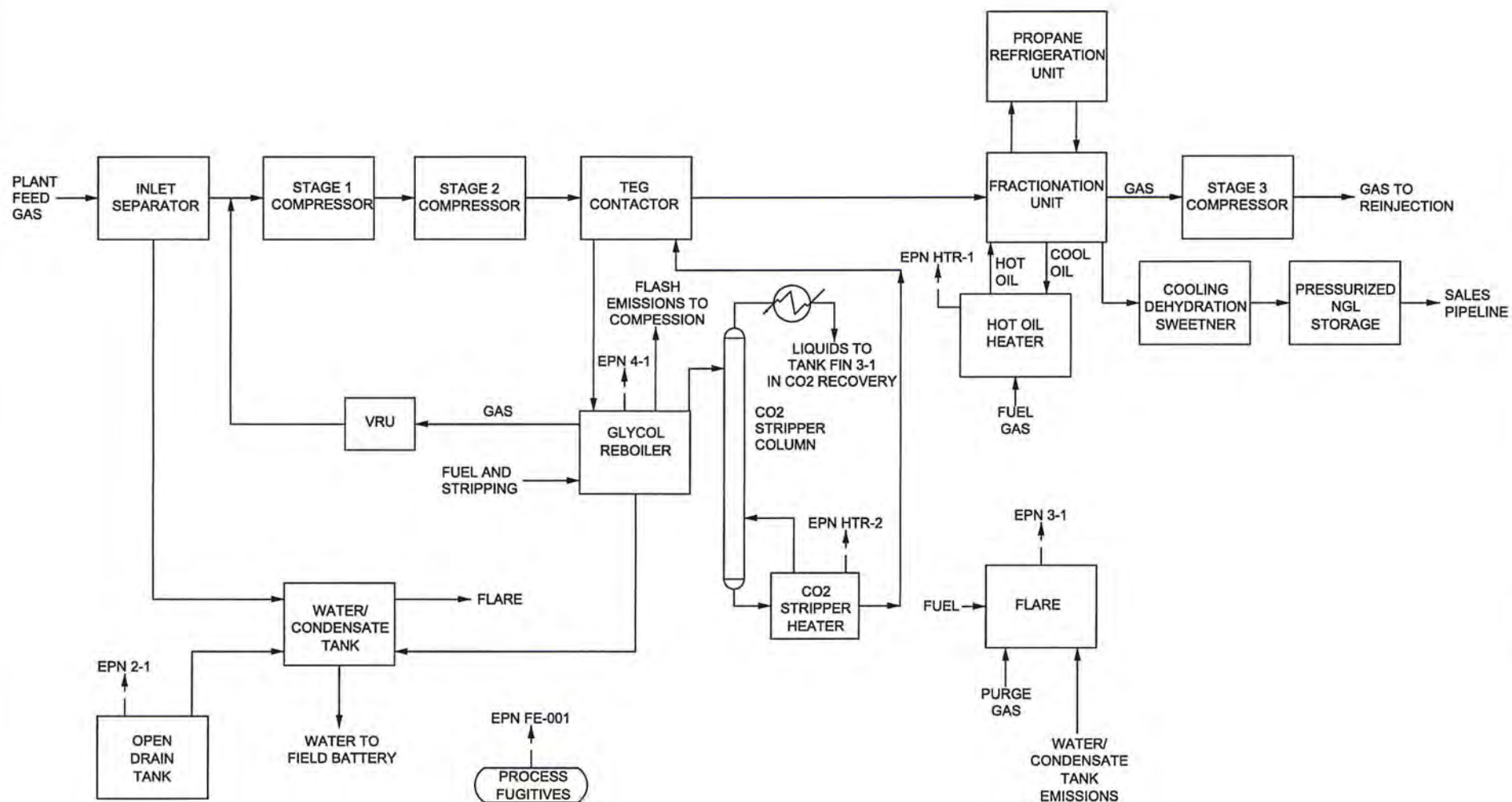
Mabee CO₂ Recycle Facility is an existing facility that dehydrates and compresses gas from Chevron's Mabee Ranch tertiary oil recovery project. The facility is authorized by Standard Permit Registration No. 80221. The purpose of this submittal is to add a NGL Recovery Plant to the facility. The only changes to previously reported emissions, due to the addition of the NGL Recovery Plant, are the addition of a 3 MMBtu/hr hot oil heater, the addition of a 0.25 MMBtu/hr CO₂ stripper heater, and increased fugitives from propane refrigeration, NGL's, an additional electric compressor, and the Sulfa-Treat tower.

Incoming gas is routed through a knock-out drum to remove liquids before the gas is compressed. The liquids are sent to the water/condensate tank and then to field batteries for disposal. After compression, the gas is routed to the glycol dehydration unit. The dehydration gas is recompressed and sent to the Mabee Ranch Field for reinjection.

Rich CO₂ gas from the existing second stage compressors will be cooled, dehydrated via the existing TEG unit, and fed to a fractionation tower. The fractionation tower reboiler and condenser duty will be supplied by a hot oil furnace and propane refrigeration unit. The tower bottoms product NGL undergoes COS hydrolysis, air cooling, water separation, SulfaTreat, and storage before being pumped to the West Texas LPG Pipeline. H₂S removed by the Sulfa-treat tower produces solid waste sulfur cakes. The addition of one 500 HP electric compressor along with current electric compression and will be used.

A flare is used to burn purge gas from the compressor, inlet gas during planned maintenance on the recycle gas compressors, emissions from the water/condensate tank, and for emergency upsets.

MABEE RANCH CO2 RECYCLE FACILITY PROCESS FLOW DIAGRAM



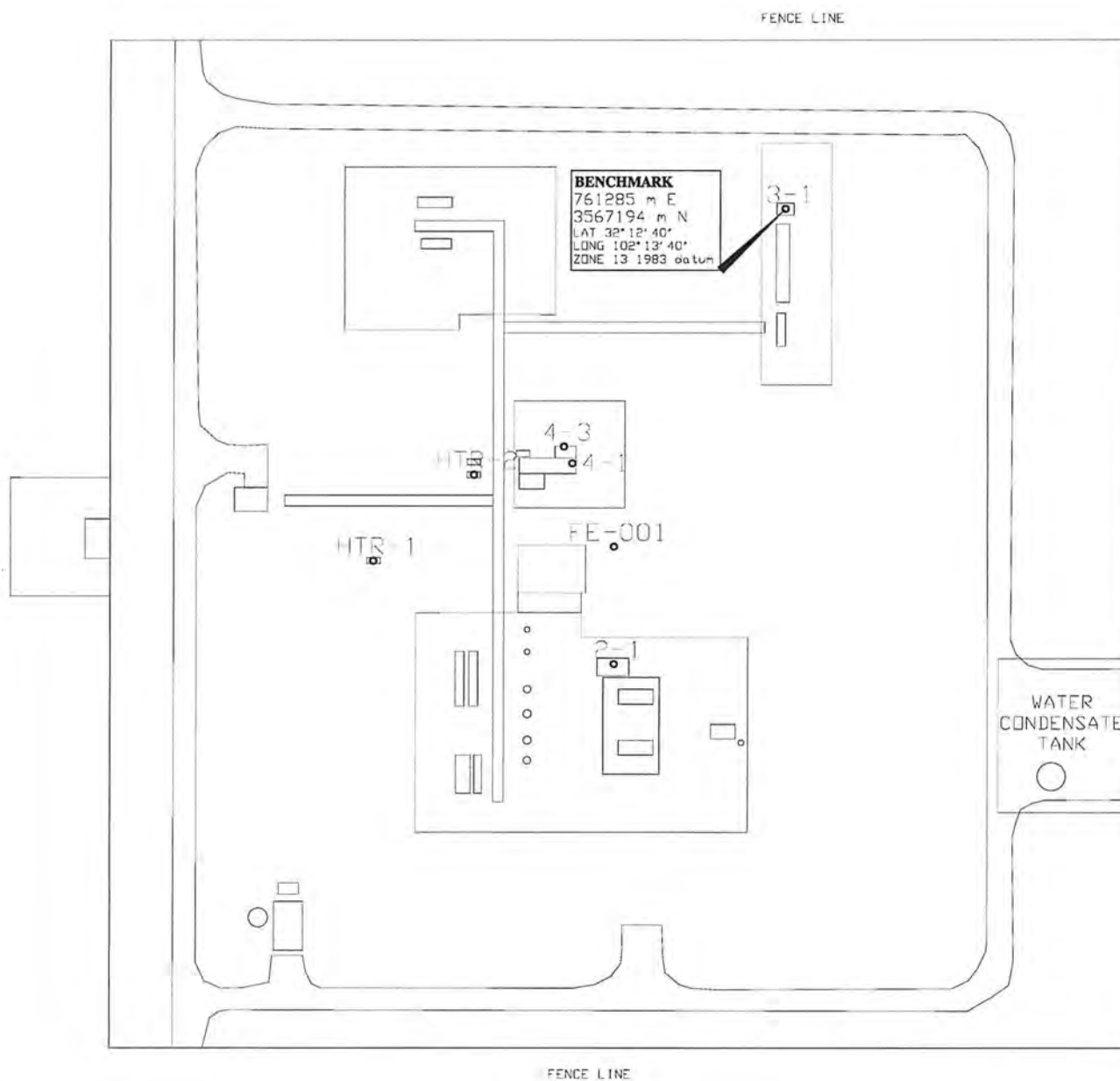
W&AID ENVIRONMENTAL

CHEVRON U.S.A. INC.

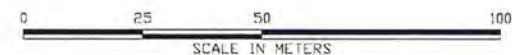
MABEE RANCH CO2 RECYCLE FACILITY PROCESS FLOW DIAGRAM

Drawn By	Start Date	Rev. Date	Sheet No.	Total No.
DWW	5/24/06	9/25/12	FLOW	6

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Emission Point Number	Name	Location Easting, Northing (meters)
2-1	OPEN DRAIN TANK	761244, 3567085
3-1	FLARE	761285, 3567194
4-1	GLYCOL REBOTTLE	761234, 3567133
4-3	GLYCOL STORAGE TANK	761232, 3567137
FE-001	PROCESS FUGITIVES	761244, 3567113
HTR-1	HOT OIL HEATER	761186, 3567110
HTR-2	CO2 STRIPPER HEATER	761211, 3567130



WAID ENVIRONMENTAL				
CHEVRON U.S.A. INC.				
MABEE RANCH CO2 RECYCLE FACILITY				
Drawn By	Start Date	Rev. Date	Drawn Name	Rev. No.
DWW	5/24/06	9/14/12	PL018698	4
H:\CLIENTS\CHEVRON-TEX\CTX8698\ACAD				

Exhibit P-3
Notice Letter
from Pilot Energy Solutions to Chevron
(August 15, 2013)



August 15, 2013

Mr. Tyler Hahn,
Chevron North America Exploration and Production Company
1400 Smith
Houston, Tx. 77002

RE: Mabee Plant and U.S. Patent No. 8,505,332

Dear Mr. Hahn:

I am writing to outline the chronology of meetings and conversations with various Chevron representatives about our concerns that Chevron might be incorporating Pilot Energy Solutions LLC's proprietary technology in its Mabee plant.

In August 2007 Pilot Energy Solutions and Chevron began discussions about processing the recycle CO₂ gas at Mabee for NGL extraction, using Pilot technology (the "Mabee Plant"). During these discussions Pilot and Chevron executed a Confidentiality Agreement in 2008, and again in 2009. Subsequently, Pilot shared drawings, process simulations, heat and material balances, preliminary cost estimates, and made multiple visits to the Mabee Plant site. During 2007-2008 we attended several meetings with Chevron personnel, including Matthew Passmore, Julie Huff, Stan Shitaku, and Alan Hein. In November 2007 and again in April 2008, Pilot made formal proposals to build a plant, at its sole cost, to third-party process the CO₂ recycle gas at the Mabee recompression station. Chevron's continuing evaluation of the Pilot proposals included a field trip to our plant in Wyoming in Chevron's corporate plane, to allow Chevron personnel to further evaluate our proprietary process and speak to the operations staff. During this period there were also a number of meetings with Chevron to discuss the possibility of using Pilot's technology at Chevron's Reinecke field. All discussions were suspended until July 2009, when Aubrey Arms, (Facilities Engineer, CO₂ team), contacted Pilot. Ms. Arms asked Pilot for an updated evaluation, based on the most current flow and composition data for the Mabee facility. Pilot promptly provided this information to Ms. Arms. Other than addressing a few additional technical questions about the Mabee Plant proposal, we had no additional discussions until May 2010 when we received an email from Ms. Arms telling us that Chevron had a "two year plan" and that no final decision would be made on the Mabee Plant until 2012. In August 2010 we received a follow-up email from Ms. Arms letting us know that Chevron was still evaluating Pilot's technology and its processing proposal for the Mabee Plant. In response we offered to explore the possibility of alternative deal structures including a third party arrangement or a joint venture with Chevron for the Mabee Plant. We did not receive a response from either Chevron or Ms. Arms.

In January 2012, Pilot learned through several industry contacts, familiar with our technology, that Chevron was building the Mabee Plant and that it appeared the Plant was going to use

Pilot's technology. This information prompted us to look up the Mabee Plant's air permit application at the TCEQ (Texas Commission for Environmental Quality) to review the plant design. Based on this information, I contacted Rick Sweeney, then Manager of the Midland office. I suggested to Mr. Sweeney that because of the turnover in Chevron's Houston office they might not be aware that Pilot had previously disclosed its proprietary process under a confidentiality agreement and that Chevron may be using that technology at the Mabee Plant. Mr. Sweeney asked me a few questions about the technology and said he would check into the matter. We did not hear back from Mr. Sweeney.

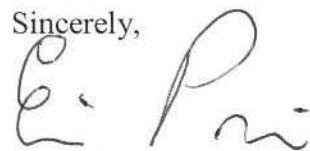
Naomi Baker, Pilot's Director of Operations and Engineering, received a call from Allen Hein on February 14, 2012. During the call Ms. Baker reiterated Pilot's concern that Chevron may have used Pilot's proprietary, patent pending technology at its Mabee Plant. Mr. Hein asked what protected technology Pilot believed Chevron was using. Ms. Baker did not have a copy of the patent application at the time of the call and she could not give specifics. She did however, remind Mr. Hein that he was involved in several of the meetings where the technology was discussed, and also participated in the field trip to Wyoming which toured the operating plant employing the technology. Ms. Baker suggested Pilot and Chevron sit down together and discuss Pilot's patent application and go over Chevron's Mabee Plant drawings. We have not heard from Chevron.

In meetings with Chevron, we had disclosed that the process in question was patent pending and was covered under our confidentiality agreements. On August 13, 2013 U.S. Patent No. 8,505,332 ("the '332 Patent") was issued from the United States Patent and Trademark Office to Pilot. The '332 Patent covers the technology disclosed to Chevron in Pilot's proposals for the Mabee Plant.

Pilot would like to schedule a meeting to go over the '332 Patent and compare it to the technology used by Chevron at the Mabee Plant. If it is determined Chevron is not using Pilot's technology, we will be happy to drop the matter.

We would like to schedule the suggested meeting within the next few days. Please feel free to call me at my office (281.260.4081) or cell phone (713.715.8785) to discuss a meeting time and location.

Sincerely,



Eric Prim
President
Pilot Energy Solutions



Exhibit P-4
Response Letter
from Chevron to Pilot Energy Solutions
(August 29, 2013)



Maurice E. Teixeira
Senior Counsel

Law Department
Chevron Services Company
1400 Smith, 5th Floor
Houston, TX 77002
Tel 713 372 9070
mtgl@chevron.com

August 29, 2013

Pilot Energy Solutions LLC
Attn: Mr. Eric Prim
333 N. Sam Houston Pkwy, Suite 600
Houston, Texas 77060

Re: Mabee Plant and U.S. Patent No. 8,505,332

Dear Mr. Prim:

We are in receipt of your letter dated August 15, 2013 with regards to the above-referenced matter to Chevron North America Exploration and Production Company, a division of Chevron U.S.A. Inc. ("Chevron").

Chevron takes any allegation of infringement of intellectual property seriously. It is our policy to avoid infringement of the valid intellectual property rights of others.

We reviewed U.S. Patent No. 8,505,332 (the "332 Patent") and the processes used by Chevron for conditioning and recycling CO₂ gas at the Mabee Plant. Chevron does not infringe any of the claims of the 332 Patent. As such we consider this matter to be closed.

Please direct any future communications regarding this matter to me.

Yours truly,

A handwritten signature in blue ink, appearing to read "M. Teixeira".

Maurice Teixeira
Senior Counsel

Exhibit P-5
United States
Patent No. 4,753,666
("Pastor")

United States Patent [19]

Pastor et al.

[11] **Patent Number:** 4,753,666[45] **Date of Patent:** Jun. 28, 1988[54] **DISTILLATIVE PROCESSING OF CO₂ AND HYDROCARBONS FOR ENHANCED OIL RECOVERY**4,547,209 10/1985 Netzer 62/17
4,563,202 1/1986 Yoa et al. 62/20[75] **Inventors:** Gerald R. Pastor, Englewood; Janet F. Peters, Littleton; Wayne K. Larsen, Aurora; Al C. Iakovakis, Englewood, all of Colo.[73] **Assignee:** Chevron Research Company, San Francisco, Calif.[21] **Appl. No.:** 889,975[22] **Filed:** Jul. 24, 1986[51] **Int. Cl.⁴** F25J 3/02[52] **U.S. Cl.** 62/24; 62/37; 62/54[58] **Field of Search** 62/9, 11, 23, 24, 27, 62/28, 54, 37[56] **References Cited****U.S. PATENT DOCUMENTS**

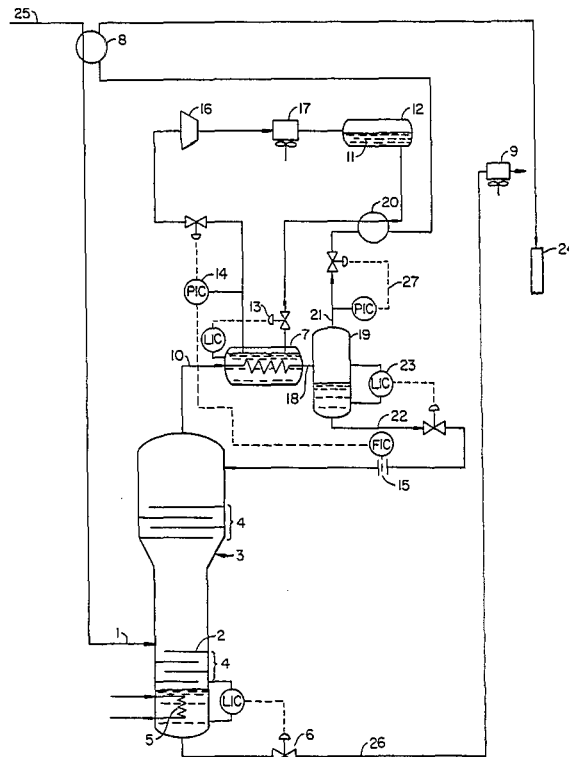
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 "Texas EOR Project Proposed", Oil & Gas Journal (7/22/85).
 B. C. Price, "Looking at CO₂ Recovery in Enhanced Oil Recovery Projects", Oil & Gas Journal (12/24/84).
 J. E. Johnson et al.; "Gas Processing Needs for EOR", Hydrocarbon Processing (10/1985).

Primary Examiner—Ronald C. Capossela*Attorney, Agent, or Firm*—S. R. LaPaglia; E. J. Keeling; V. A. Norviel[57] **ABSTRACT**

A method of treating CO₂ rich gas for injection into a petroleum reservoir is described. CO₂ rich gas containing methane, nitrogen, ethane, propane, butanes, and heavier components is distilled such that substantially all of the heavier components are produced as a bottoms product and substantially all of the CO₂, ethane, and propane are produced as an overhead vapor. The presence of ethane and propane in the overhead vapors overcomes the effect of nitrogen and methane on minimum miscibility pressure in the reservoir, and the problems created by CO₂ freezing and the CO₂/ethane azeotrope are avoided, furthermore, a readily marketable liquid product is produced.

15 Claims, 2 Drawing Sheets

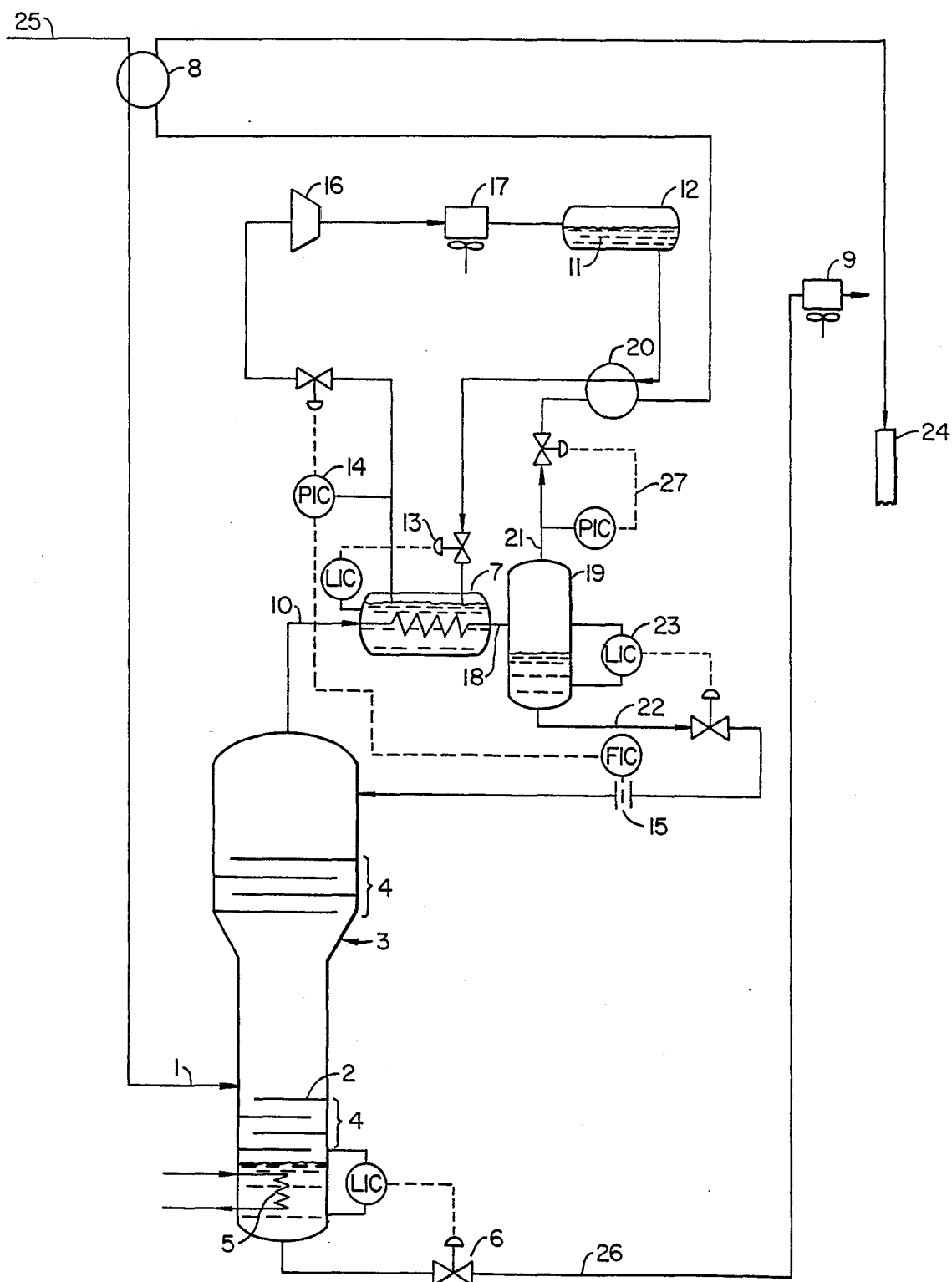


FIG. 1.

U.S. Patent

Jun. 28, 1988

Sheet 2 of 2

4,753,666

FIG. 2.

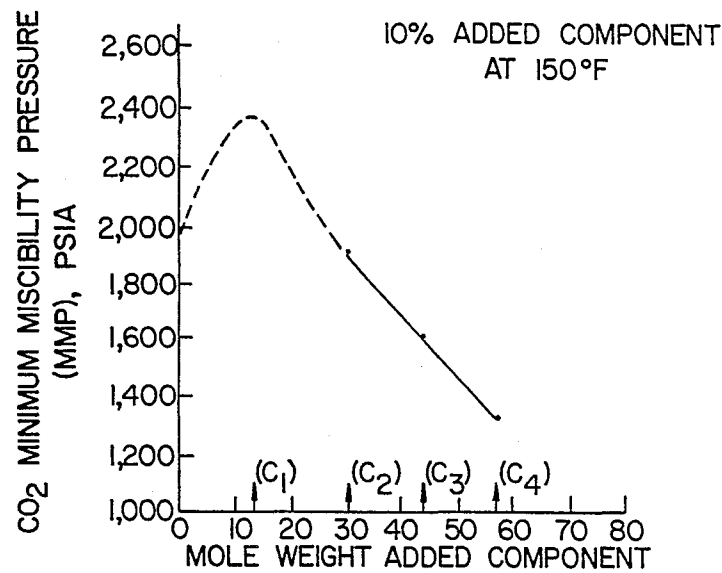


FIG. 3.

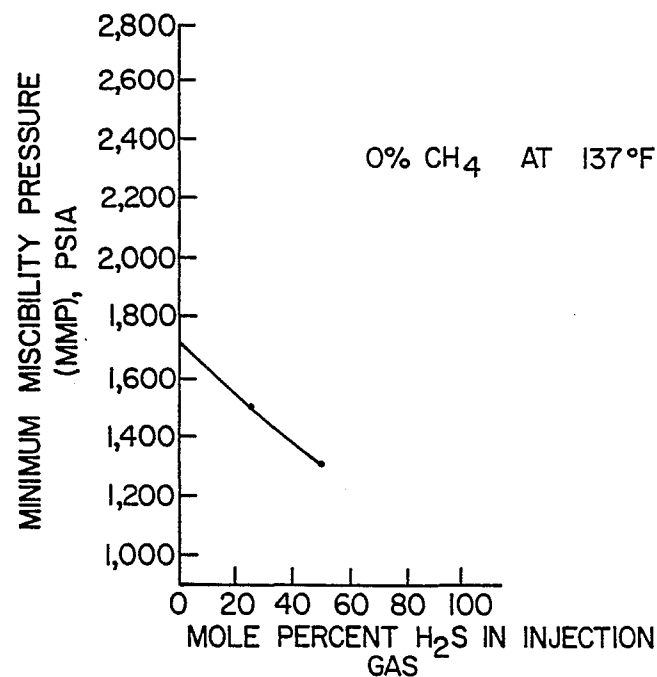
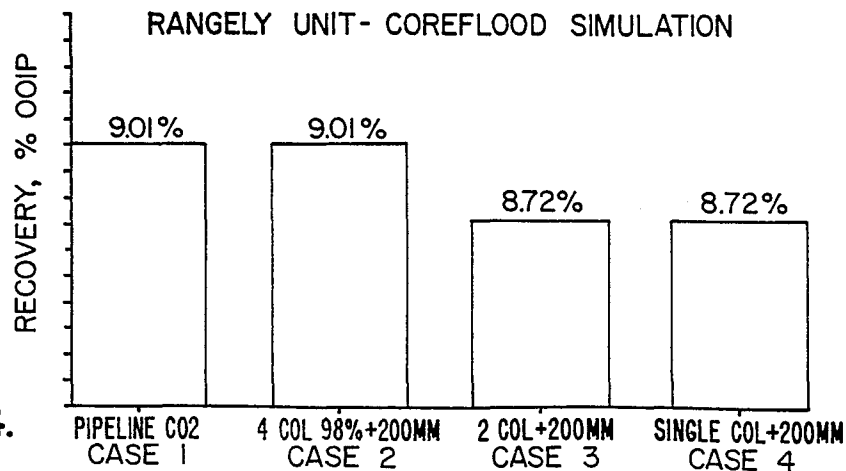


FIG. 4.



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DISTILLATIVE PROCESSING OF CO₂ AND HYDROCARBONS FOR ENHANCED OIL RECOVERY

FIELD OF THE INVENTION

This invention relates generally to an improved method for enhanced oil recovery. More specifically the invention provides an improved method for treating CO₂ rich gas streams for injection into oil-bearing formations.

BACKGROUND OF THE INVENTION

It is well known that only a small fraction of the original oil in place in a petroleum reservoir can be recovered with so called "primary" and "secondary" production methods. Various "tertiary" methods of increasing the recovery of oil contained in oil-bearing rocks have been devised. Among these tertiary recovery techniques is the method of injecting a miscible compound into the reservoir. The most common miscible compound used is carbon dioxide (CO₂).

In the initial stages of a CO₂ flood, CO₂ gas is commonly purchased from a large CO₂ distribution pipeline. The price of gas purchased from these pipelines is presently in the range of \$1.00 to \$1.50 per thousand standard cubic feet (MSCF).

After injecting CO₂ into the reservoir for a period of time, associated gas production will contain increasingly high percentages of CO₂ due to breakthrough of the injected CO₂ gas. It is often economical to recycle this gas into the petroleum reservoir. However, this recycled gas commonly has several undesirable components contained in it and it must be processed before reinjection. The primary constituents that must be considered in processing of this gas are methane (CH₄) and nitrogen (N₂) because these gases will dramatically reduce the miscibility of the injected gas. Other components that should be considered are heavier hydrocarbons (because of both their economic value as separate products and because of their ability to offset the miscibility problems created by CH₄ and N₂), H₂S (because of safety concerns and sales specifications), and water (because of hydrate problems).

Extensive efforts have been devoted to developing an economical method for treating these gas streams and a large number of process schemes have been devised.

Chemical solvents (such as amines) have been considered for removal of CO₂ from the hydrocarbon components. Use of these solvents becomes impractical in gas streams containing high concentrations of CO₂ because of the large energy demand of amine reboilers and other equipment. Further, the CO₂ is saturated with water in amine plants and this can create hydrate and corrosion problems downstream.

Distillation of CO₂ from methane has also been considered. The relative volatility of methane and CO₂ is very high and this distillation is in theory quite easy. However, the process must operate at relatively high pressure and low temperature and, therefore, the possibility of a solid carbon dioxide phase coexisting with vapor/liquid CO₂/CH₄ mixture is high. Solutions to this problem have been proposed in U.S. Pat. Nos. 4,318,723, 4,293,322 et al. in which an additive (generally natural gasoline recycled from elsewhere in the plant) is introduced into the feed. This prevents CO₂ freezing and also aids in breaking an ethane/CO₂ azeotrope. These processes have several inherent disadvantages, however.

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Initially, these processes are extremely expensive from both a capital and operating perspective since it is necessary to provide multiple distillation columns and massive refrigeration capacity to cool the entire inlet gas stream to -40° F. or colder. For example, in the example labeled "Table II" in U.S. Pat. No. 4,318,723, the feed temperature is reduced to -65° F. This also results in the need to use exotic materials of construction for the process equipment.

Further, the process produces sour, high vapor pressure liquid streams that must be subjected to additional processing before sale. Further, the ultimate value of the liquid products is offset by the need to purchase additional CO₂ as a result of the lost gas volume, i.e., there is significant shrinkage associated with the process.

Simpler techniques for treating hydrocarbon rich CO₂ streams have also been proposed in broad conceptual terms. For example, in "Looking at CO₂ Recovery in Enhanced-Oil-Recovery Projects," *Oil and Gas Journal*, Dec. 24, 1984, the authors show a "Straight Refrigeration" process for separating hydrocarbons from CO₂. However, this process also has several inherent disadvantages. Initially, as with the processes described in the above-mentioned patents, the inlet gas stream must be cooled to -40° F. or colder for recovery of C₃+, requiring extremely high refrigeration capacity. Further, the liquid stream produced by this process would require further treatment before sale since it will have a high vapor pressure (approximately 40 psia RVP) as well as unacceptable CO₂ and H₂S concentrations. Finally, a large portion of the C₄+ would go overhead and be unnecessarily wasted since no rectification section is provided on the column.

In summary, it is desirable to create a process that recognizes the ability of ethane, propane and butane to overcome the negative effects of nitrogen and methane on the miscibility of CO₂ injection gas. It is further desirable to create a process that produces both acceptable CO₂ injection gas and saleable liquid products. It is further desirable to create a process that treats CO₂ injection gas in an economical manner from both a capital investment and operating expense perspective. It is further desirable to create a process that does not require elaborate processing to overcome the CO₂/C₂H₆ azeotrope or to avoid CO₂ solid formation. It is further desirable to create a process which minimizes the shrinkage of the CO₂ injection gas.

BRIEF SUMMARY OF THE INVENTION

Accordingly, the present invention provides a method and apparatus for treating hydrocarbon rich CO₂ gas streams for injection into oil-bearing formations in an effective and economical manner. A hydrocarbon rich CO₂ gas stream is compressed to approximately 350 psia. The gas enters a multi-tray distillation column at an intermediate tray. Overhead vapor from the column is cooled in an overhead condenser to approximately -20° to 0° F. with propane refrigerant to produce a two-phase stream. The two-phase stream is separated into a liquid and a vapor (product) stream in a reflux drum. Vapor from the reflux drum is further compressed for injection into an oil-bearing formation. Liquid from the reflux drum is returned to the top tray of the column as reflux.

A reboiler on the bottom of the column maintains the bottom temperature at approximately 360° F. An NGL

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bottoms product consisting of a large fraction of the C_4+ in the inlet stream is removed from the column, cooled, and sold.

Most of the C_2 and C_3 and a significant fraction of the C_4 go overhead with the CO_2 injection gas. By leaving the C_2 , C_3 , and a portion of the C_4 (mostly isobutane) in the CO_2 , the negative effects of C_1 on the miscibility of the CO_2 injection gas are overcome. The recovery of C_3/C_4 can be monitored to control the miscibility of the CO_2 injection gas and optimize the economical operation of the plant.

H_2S is concentrated in the overhead gas. H_2S is known to enhance the miscibility of injection gas. Furthermore, H_2S would have to be removed from a liquid product requiring expensive processing equipment.

The process produces a CO_2 gas stream with a relatively low minimum miscibility pressure with a minimum capital investment since only one distillation column, and only a fraction of the refrigeration capacity needed in other processes is necessary. The use of exotic materials of construction is also minimized because of the higher plant operating temperature and lower operating pressures. Further, since the distillation split takes place at the temperatures and pressures necessary to make a split at the C_4 level, the CO_2/C_2 azeotrope and CO_2 solid formation are not problems. Shrinkage is also minimized because most of the C_1 to C_3 remains in the CO_2 gas product.

DESCRIPTION OF THE DRAWINGS

FIG. 1 is a schematic flow diagram showing the distillative apparatus for carrying out the invention described herein. (PIC=Pressure Indicating Controller, FIC=Flow Indicating Controller, and LIC=Level Indicating Controller.)

FIG. 2 is a graph showing minimum miscibility pressure versus the molecular weight of an added component for a selected crude oil.

FIG. 3 is a graph showing the minimum miscibility pressure versus mole percent H_2S for injection gas.

FIG. 4 is a bar graph showing the percentage of original oil in place recovered using the present invention and various prior art devices.

DETAILED DESCRIPTION OF THE INVENTION

The present invention provides a method for economically treating hydrocarbon rich CO_2 gas for injection into an oil-bearing formation utilizing the steps of introducing a feed stream into distillation equipment. The feed stream may contain a mixture of carbon dioxide, methane, ethane, propane, butanes, and heavier hydrocarbons. The feed stream is distilled in the distillation equipment to produce an overhead stream and a bottoms stream. The overhead stream contains substantially all of the carbon dioxide, methane, ethane and propane, and the bottoms stream contains substantially all of said heavier hydrocarbons. The overhead stream is then injected into a hydrocarbon bearing formation.

Referring to FIG. 1, in the preferred embodiment of the invention, a CO_2 gas stream 25 containing a substantial percentage of hydrocarbons and potentially containing hydrogen sulfide, nitrogen, mercaptans and other trace components is cross-exchanged in heat exchanger 8 with the column overhead product 21 and flows onto the feed tray 2 of a distillation column 3 containing a plurality of vapor/liquid contacting devices 4 such as bubble cap trays, sieve trays or packing.

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In the preferred embodiment of the invention, the feed 1 enters the column at approximately 350 psia and 90° F. Other temperatures and pressures may be chosen. For example, lower feed temperatures may be desirable in some cases. 90° F. is chosen as being easy to achieve with an air cooler that may be located upstream of the process and feed/product heat exchanger 8.

In the preferred embodiment, the rectification portion of the column 3 is a larger diameter than the stripping section, as shown in FIG. 1. This feature is desirable because large vapor loadings will be present in the upper portion of the column.

The bottom portion of the column is equipped with a reboiler 5 that supplies heat to the column via hot oil or steam. The reboiler is equipped with temperature control equipment that maintains the temperature of the bottoms at approximately 360° F. in the preferred embodiment. The bottom of the column is also equipped with level control equipment 6 which maintains the liquid level at a point above the reboiler but sufficiently below the first tray. The bottoms product 26 flows from the bottom of the column to a bottoms air cooler 9 to be cooled to approximately ambient temperature for sale or blending with crude oil.

The overhead vapors 10 flow to an overhead condenser 7 which cools and partially condenses the overhead vapors. In the preferred embodiment, propane is used as a refrigerant. Other refrigerants could be used, as would be readily obvious to one skilled in the art (for example, ammonia). Liquid propane 11 is supplied from a propane surge drum 12. A level control system 13 maintains the level of propane above tubes in the overhead condenser. The pressure in the overhead condenser is maintained with a pressure control system 14 which, in the preferred embodiment, has its pressure set-point determined by a reflux flow measuring device 15. This control system enables the operator to maintain a fixed quantity of reflux to the column.

Propane vapors from the overhead condenser are compressed in a compressor 16, condensed in a propane condenser 17, and returned to the propane surge drum 12. A propane subcooler 20 may also be desirable to increase the energy efficiency of the process.

The two-phase mixture 18 flowing from the overhead condenser is separated in a reflux drum 19. The two-phase mixture is separated into an overhead product stream 21 and a reflux stream 22. A level control system 23 maintains a constant amount of liquid in the reflux drum, and is opened to allow liquid to flow into the column.

The pressure at which the distillation equipment operates is controlled by pressure control equipment 27. The product vapor stream flows from the reflux drum to the propane/overhead subcooler 20 and then to the overhead/feed heat exchanger 8. The overhead product stream is further compressed in a compressor (not shown) and sent to injection wells 24.

To illustrate the operation of the above described process, the program PROCESS™ (Simulation Sciences Inc., Version 1.01, 1985) was used to simulate the operation of the process on a typical CO_2 /hydrocarbon gas stream. The results of the simulation are illustrated in Table I:

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TABLE I

Summary of PROCESS™ Simulation of the Present Invention on a Typical CO ₂ /Hydrocarbon Stream			
No. of Ideal Trays in Column	20		
Feed Point Tray	7		
Gas Feed Rate	110 MMSCF		
Reflux Drum Pressure	350 psia		
Column Differential Pressure	5 psia		
Condenser Duty	17 MM BTU/Hour		
Reboiler Duty	8 MM BTU/Hour		
Reflux Temperature	1.2° F.		
Bottoms Temperature	360° F.		

	Stream Name		
	Feed	Overhead Product	Bottoms Product
Rate	110 MMSCF	107 MMSCF	2620 BPD
H ₂ S (ppmv)	500	514	—
	Mole Percent		
N ₂	3.4	3.5	—
CO ₂	83.9	86.3	—
C ₁	6.6	6.9	—
C ₂	1.4	1.4	—
C ₃	1.1	1.1	0.02
iC ₄	0.5	0.4	3.1
nC ₄	0.7	0.3	16.7
iC ₅	0.4	0.001	16.0
nC ₅	0.6	—	23.3
C ₆	0.6	—	24.4
C ₇₊	0.4	—	16.4

As can be seen, operation of the process in the above-described manner results in a separation in which essentially all of the propane and ethane go into the overhead stream while most of the butane and essentially all of the pentane and heavier components are present in the bottoms stream.

Although the invention has been illustrated with regard to the above example, a range of operating pressures and temperatures might be selected to make the above described separation. The optimum range of the major process variables are described in Table II:

TABLE II

Optimum Process Variables	
Column Pressure	150 to 400 psia
Overhead Condenser Temperature	—40 to 20° F.
Reboiler Temperature	225 to 400° F.
Reflux Ratio	0.21 to 0.30
Number of Trays	22 to 40
Number of Trays above Feed Point	10 to 20
Number of Trays Below Feed Point	15 to 25

An important advantage of the above described process is that the negative effects of methane and nitrogen on the miscibility of the injection gas are largely overcome with the presence of ethane, propane and butane, and the process does not require elaborate process steps to avoid CO₂ freezing and/or to overcome the CO₂/Ethane azeotrope.

FIGS. 2 and 3 (adapted from "Miscible Displacement", F. I. Stalkup, Society of Petroleum Engineers of AIME, 1983, pages 141 and 140, respectively), and 4 generally illustrate the effect of distilling the CO₂ injection gas in the described method. FIG. 2 shows the effect of various alkyl hydrocarbons on CO₂ miscibility at 150° F. when 10% of the alkyl hydrocarbon is added to CO₂. As shown in FIG. 2, methane has a negative effect, i.e. the miscibility pressure is increased. By contrast, the presence of ethane, propane and butane is a positive one, i.e. the minimum miscibility pressure is decreased below that of pure CO₂. Similarly, the pres-

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ence of H₂S is positive, as illustrated in FIG. 3. As the percentage of H₂S in the gas increases, the minimum miscibility pressure decreases, regardless of the concentration of methane present.

The present invention takes full advantage of these effects. Unlike prior art processes, methane is left in the overhead gas, thereby overcoming the many problems associated with methane/CO₂ distillation discussed above. To offset the effect of methane or minimum miscibility pressure, H₂S, ethane, propane, and a portion of the butane remain in the overhead gas. Further, an easily saleable liquid product is produced.

To further illustrate this advantage, various reservoir simulations were performed to determine the effect of various process schemes on the ultimate recovery of oil in a petroleum reservoir in Rangely, Colo., using a miscible flood reservoir simulation program of the type familiar to one skilled in the art. The program was run assuming the following:

Case 1 It was assumed that "pipeline quality" (99.3%) CO₂ was purchased and used exclusively for injection. Produced gas would be flared or otherwise disposed of in this case.

Case 2 It was assumed that a "Four Column Ryan-Holmes Plant" similar to that described in FIG. 13 of "Looking at CO₂ Recovery in Enhanced Oil Recovery Projects" was used to treat produced gas and that the CO₂ product from this plant was injected along with 200 MMSCF of pipeline quality gas.

Case 3 It was assumed that a "Two Column Ryan-Holmes Plant" similar to that described in FIG. 12 of "Looking at CO₂ Recovery in Enhanced Oil Recovery Projects" was used to treat produced gas and that the CO₂ product from this plant was injected along with 200 MMSCF of pipeline quality gas.

Case 4 It was assumed that a 1 column plant as described in the present invention was used to treat produced gas and that the CO₂ product from this plant was injected along with 200 MMSCF of pipeline quality gas.

The results of those reservoir simulations are shown in FIG. 4. As would be expected in Case 1, the pure pipeline quality gas recovers the greatest percentage of the original oil in place. The elaborate 4 column Ryan-Holmes plant in Case 2 achieves essentially the same results as Case 1 since the gas is processed to almost pipeline quality.

It is seen in Case 4 that the simpler 1 column plant described in the present invention achieves essentially the same results as the more complex 2 column Ryan-Holmes plant used in Case 3. However, the present invention has the advantages of having a lower capital cost lower refrigeration requirements, and lower overall operating costs. Similarly, the plant described in Case 4, while achieving a lower percentage recovery of original oil in place than Case 2, would have dramatically lower capital and operating costs than the 4-Column Ryan-Holmes plant used in Case 2. These lower costs could (in many situations) result in better overall economics.

It is intended that the above description be illustrative and not restrictive. Variations on the above process will be readily apparent to those skilled in the art. The scope of the invention should, therefore be limited not to the above description but by the appended claims.

What is claimed is:

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1. A method for treating hydrocarbon rich CO₂ gas for injection into an oil-bearing formation comprising the steps of:

- (a) introducing a feed stream into distillation equipment, said feed stream comprising a mixture of carbon dioxide, methane, ethane, propane, butanes, and heavier hydrocarbons;
- (b) distilling said feed stream with said distillation equipment to produce an overhead stream and a bottoms stream, said overhead stream containing substantially all of said carbon dioxide, methane, ethane and propane, and said bottoms stream containing substantially all of said heavier hydrocarbons; and
- (c) injecting said overhead stream into a hydrocarbon bearing formation.

2. A method for treating a gas stream, containing carbon dioxide, methane, ethane, propane, butane, and heavier hydrocarbons for reinjection into an oil-bearing formation comprising the steps of:

- (a) introducing the gas stream into a distillation column at a feed tray, said distillation column containing a plurality of vapor/liquid contacting devices, said feed tray below a rectification section and above a stripping section;
- (b) operating said distillation column to produce an overhead stream containing substantially all of said carbon dioxide, methane, ethane and propane, and a bottoms stream containing substantially all of said heavier hydrocarbons, and;
- (c) injecting said overhead stream into an oil-bearing formation.

3. A method for treating hydrocarbon-rich CO₂ gas containing carbon dioxide, methane, ethane, propane, butane, and heavier hydrocarbons for injection into an oil-bearing formation in an economical manner comprising the steps of:

- (a) introducing said hydrocarbon-rich gas stream into a multi-tray distillation column at an intermediate tray;
- (b) cooling an overhead vapor from said distillation column in a partial condenser to produce a two-phase stream;
- (c) separating said two-phase stream in a reflux drum to produce a reflux stream and a product stream;
- (d) introducing said reflux stream onto a top tray of said distillation column;
- (e) reboiling said distillation column with a reboiler;
- (f) injecting said product stream into a hydrocarbon-bearing formation; and
- (g) said steps of introducing said gas stream into a distillation column, chilling, separating, introduc-

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ing said reflux stream onto a top tray of said distillation column, and reboiling carried out under conditions which most of said methane, ethane, and propane are contained in said product stream.

4. The method of claim 2 wherein said step of operating said distillation column further comprises the step of cooling an overhead stream in a partial condenser.

5. The method of claim 2 wherein said step of operating said distillation column further comprises the step of reboiling a bottoms stream in a reboiler.

6. The method of claim 1 wherein said distillation equipment further comprises a distillation column, a condenser, and a reboiler.

7. The method of claim 2, 3 or 6 wherein said distillation column operates in a range of pressures from 150 to 400 psia.

8. The method of claim 3, 4 or 6 wherein said condenser operates in the temperature range from -40° F. to 20° F.

9. The method of claim 3, 4 or 6 wherein said reboiler operates in the temperature range from 225° F. to 400° F.

10. The method of claim 3, 4 or 6 wherein said condenser is cooled with a propane refrigerant.

11. The method of claim 3, 4 or 6 wherein said condenser is cooled with an ammonia refrigerant.

12. The method of claim 10 further comprising the step of setting a pressure of said propane refrigerant based on a reflux flow rate.

13. The method of claim 12 further comprising the step of warming said overhead gas with said propane.

14. The method of claim 13 further comprising the step of cooling said feed stream with said overhead stream.

15. A method for treating hydrocarbon-rich CO₂ gas for injection into an oil-bearing formation consisting essentially of the steps of:

- (a) introducing a feed stream into distillation equipment, said feed stream comprising a mixture of carbon dioxide, methane, ethane, propane, butanes, and heavier hydrocarbons;
- (b) distilling said feed stream with said distillation equipment to produce an overhead stream and a bottoms stream, said overhead stream containing substantially all of said carbon dioxide, methane, ethane and propane, and said bottoms stream containing substantially all of said heavier hydrocarbons; and
- (c) injecting said overhead stream into a hydrocarbon-bearing formation.

* * * * *

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Exhibit P-6
Hydrate Formation
in Chevron Mabee Unit
for NGL Recovery and
CO₂ Purification for EOR
(Submitted to Gas Processors
Association 2017)

Hydrate Formation in Chevron Mabee Unit for NGL Recovery and CO₂ Purification for EOR

Abstract

In the early 1990's, Chevron installed a new process to recover natural gas liquids (NGLs) from recycled CO₂ in their Rangely Weber Sand Unit. The facility was designed based on a patent issued in June of 1988 (U.S. Patent # 4,753,666). The process, as claimed in the patent, used a refluxed distillation tower to produce an overhead stream virtually free of n-butane and heavier components and a bottoms stream containing the majority of the heavier components. Based on the success of the Rangely plant's operation, a similar facility was designed and fabricated by Dickson Process Systems and installed in Chevron's Mabee field near Midland, Texas.

When the Mabee plant faced some unique challenges in the NGL Recovery unit, Chevron contacted Dickson Process Systems, Bryan Research & Engineering (BR&E), and Sulzer Chemtech USA to help troubleshoot the process to operate as designed. The Mabee NGL Recovery unit is a distillation column with a partial condenser and a reboiler. The condenser, operating between 4-15 °F, experienced what were described as "reflux events", where liquid level would rapidly buildup in the reflux accumulator.

While troubleshooting, it was found that hydrates formed in the top section of the column, restricting the liquid from continuing down to the next tray. The resulting buildup of liquid not only prevented reflux from entering the column, but also flooded the trays and quickly overwhelmed the top section of the column. This paper describes the process used to identify and address the formation of hydrates in the top section of the distillation column and the use of process simulation modelling combined with plant data to improve plant operability.

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Introduction

In 2013, an NGL recovery unit designed and fabricated by Dickson Process was added onto the existing compressor station in Chevron's Mabee field outside of Andrews, TX. This unit was installed between 2nd and 3rd stage compression following the existing triethylene glycol (TEG) dehydrator. The NGL recovery unit was designed based on a feed gas water content of 3 lbs/MMscf in accordance to Chevron's US Patent 4,753,666 [1]. TEG dehydration units routinely remove water to levels below 7 lb/MMscf in the dry gas. If stripping gas is utilized, the water content of 3 lbs/MMscf can be achieved [2]. In this system, NGLs are extracted using a reflux column to produce an overhead stream free of n-butane and heavier components and a bottoms stream containing the heavier components.

The distillation column is a 26-tray tower equipped with a partial condenser and reboiler, as shown in Figure 1. A pressure differential transmitter spans from tray 1 through tray 26. Temperature transmitters are equipped at the column overhead, column inlet located at tray 15, tray 23, and column bottoms. Propane is used as the refrigerant in the partial condenser. The reflux accumulator level is maintained through the use of continuously operating pumps along with a level control valve feeding the reflux back into the column and a flow control valve recycling reflux back to the accumulator.

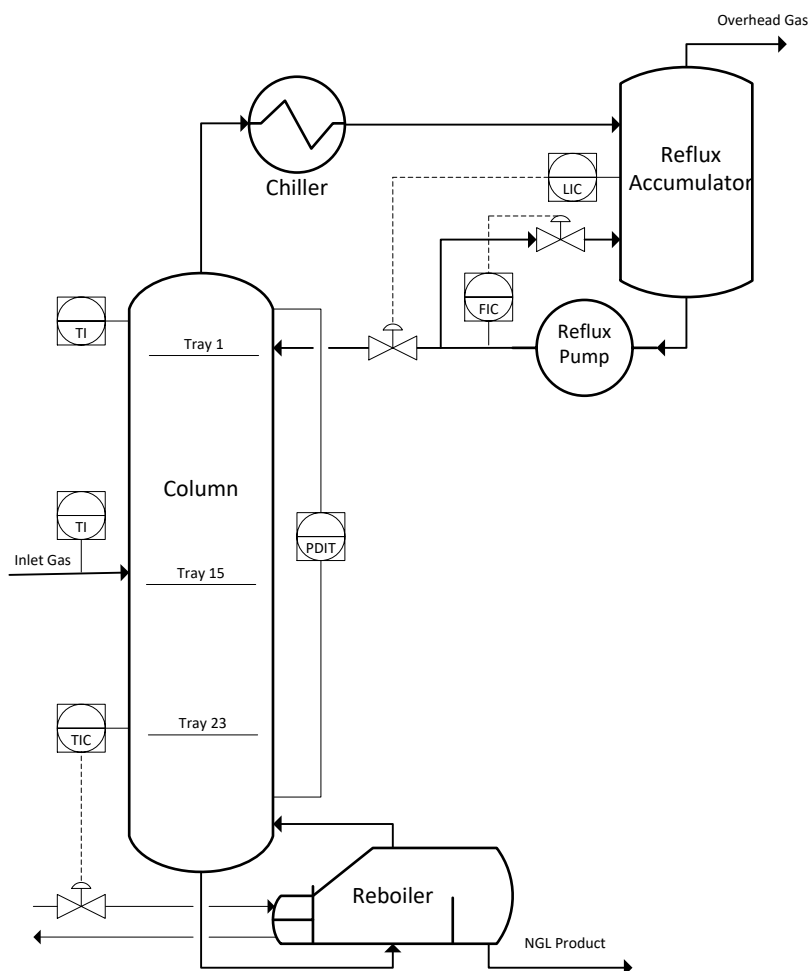


Figure 1: Process Flow Diagram of Distillation Column and Reflux

After deployment, the distillation tower experienced what plant operations coined as “reflux events.” During these events, the reflux level in the reflux accumulator would suddenly rise at a rapid rate. The level would remain high and overwhelm the tower reflux system. Corrective action involved warming up the chiller outlet temperature to stop liquid generation until the reflux accumulator level fell within the normal operating range. This pattern is shown in Figure 2. These corrective measures disrupted the temperature profile across the column, reduced NGL production, increased H₂S content in the NGL product, and required continuous involvement from plant operators.

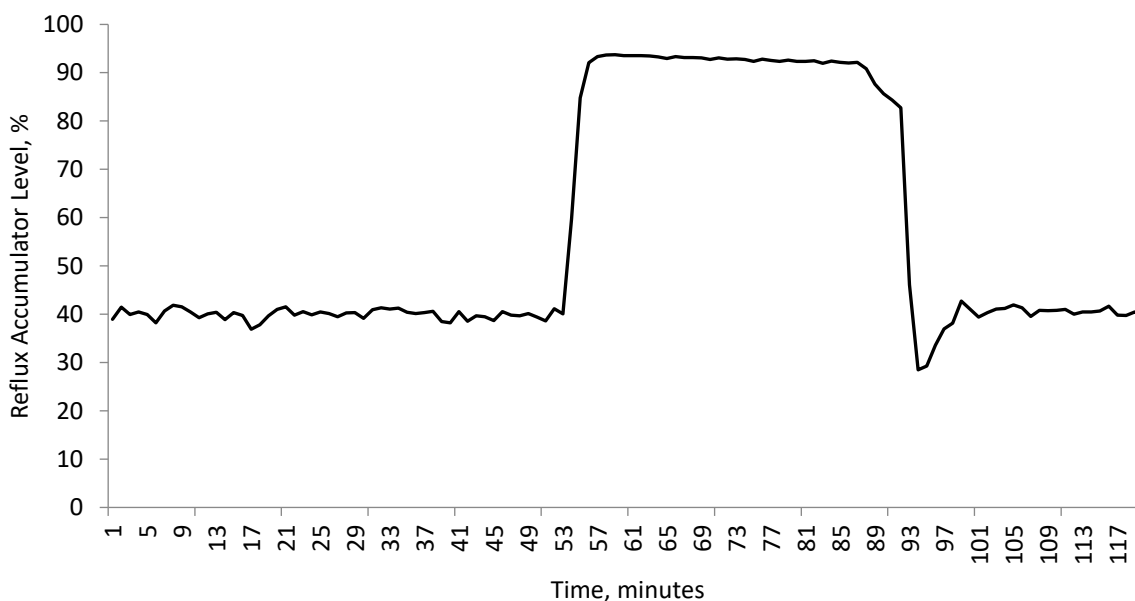


Figure 2: Example of Reflux Accumulator Level Versus Time During a Reflux Event

While this solution maintained operability in the short-term, a long-term solution was desired. Therefore, a team consisting of engineers from Chevron, Dickson Process Systems, Bryan Research & Engineering, Inc., and Sulzer Chemtech USA, Inc. was assembled to quality check and troubleshoot the process to ensure the facility operated as designed. With Sulzer Chemtech’s assistance, column hydraulics were ruled out as the source of the reflux events.

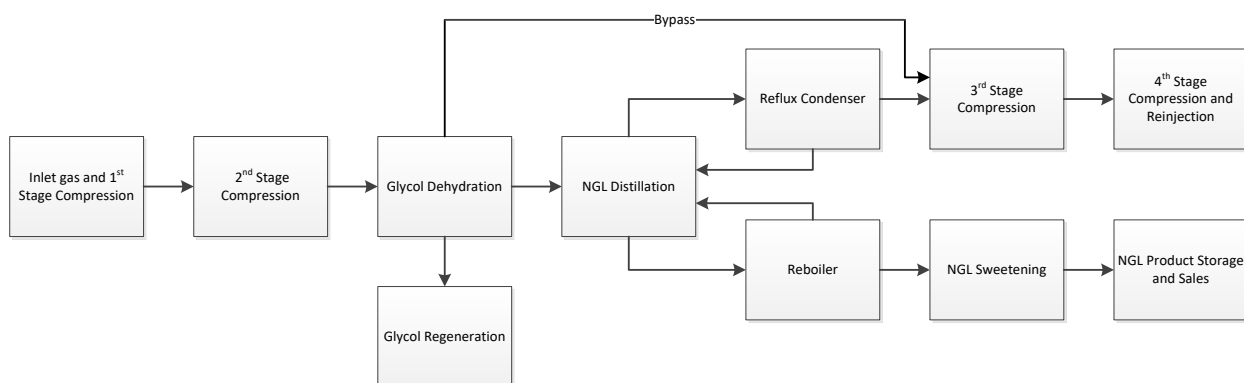
Identifying the Cause of Rapid Liquid Buildup in the Reflux Accumulator

The first step was to develop a process simulation of the distillation column to model the process conditions and study the possible causes of the reflux events. The NGL extraction model was developed in ProMax® [3] based on data collected from the field. The composition results from the simulator agreed with the data well, as shown in Table 1.

Table 1: Model Validation of Plant Data

	Field	Model
Condenser Temp, F	5.7	5.7
Reboiler Temp, F	260	260
NGL Composition, mol %		
Propane	6.02	5.48
i-Butane	17.11	16.75
n-Butane	41.78	38.39
i-Pentane	14.57	14.20
n-Pentane	9.50	8.96
Hexane +	10.84	10.96

To thoroughly diagnose the abnormal conditions, the team reviewed the operations upstream of the NGL Recovery Unit. As shown by Figure 3, upstream of the distillation tower, glycol dehydration removes water from the process gas in preparation for NGL extraction. If water exceeds certain thresholds in the NGL recovery column, the water can become trapped in the tower trays, leading to blockages and, if conditions allow, hydrate formation.

**Figure 3: Mabee Gas Plant Block Flow Diagram**

Initially, it was thought that the reflux events were not a result of hydrate formation or trapped water as field instrumentation indicated very low water content in the feed gas. When modeled with an inlet feed water content below 3 lbs/MMscf, the process simulation model predicted no hydrate formation in the NGL recovery column. Additionally, the pressure differential transmitter across the tower spanned 0 to 1 psi across the tower trays, offering little insight as to the tray loading both leading up to and during the events. Figure 4 illustrates data collected in the facility where reflux events were observed despite data indicating moisture content to the tower well below the design requirement of 3 lb/MMscf.

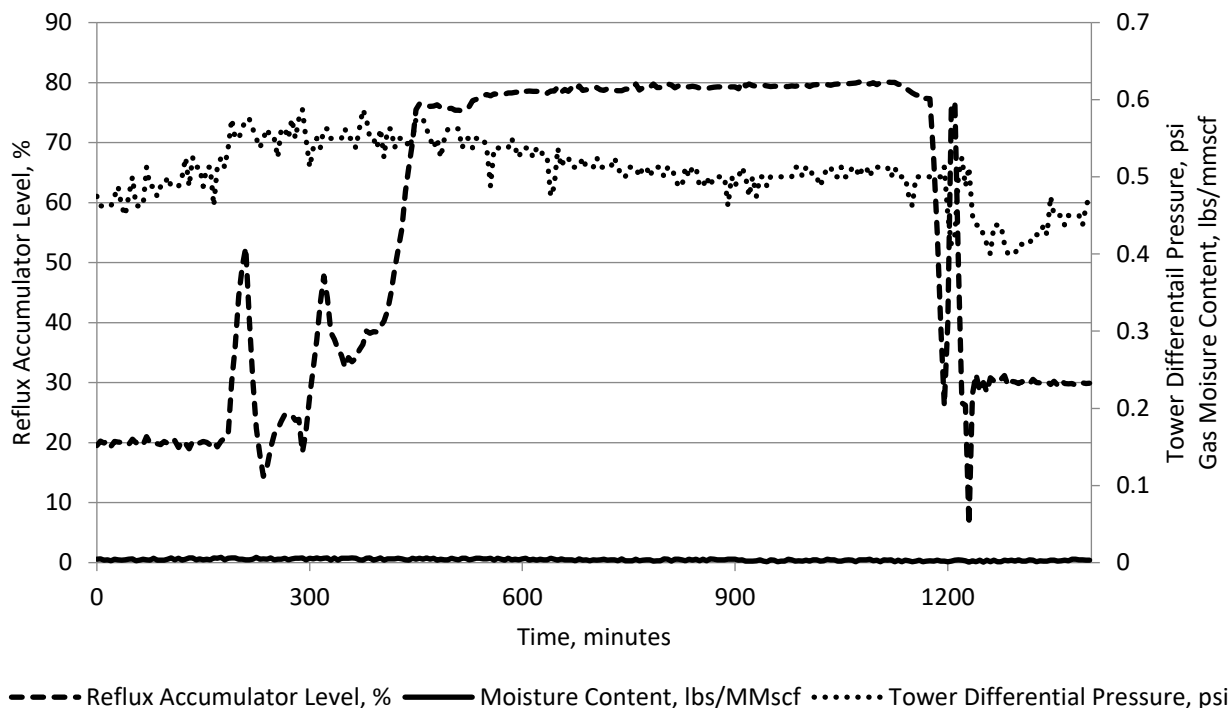


Figure 4: A Typical Reflux Event as Shown Through Reflux Accumulator Level, Inlet Moisture Content, and Tower Differential Pressure

In the interest of creating a model of the entire plant to evaluate upstream effects on this process, a model of the dehydration unit was added with current operating data and integrated with the NGL recovery model. Once the team modeled the upstream TEG dehydration unit, the predicted water content at the inlet of the NGL recovery unit was noticeably higher than what instrumentation indicated.

As designed by Dickson Process Systems, the NGL recovery unit required a dried feed gas with a water content of no more than 3 lbs/MMscf. When modeled at the operating conditions, a gas water content of 9 lbs/MMscf was predicted. The plant engineers manually measured the moisture content in the inlet feed to the NGL recovery column using Draeger tubes and a hand-held automatic dew point hygrometer, both of which confirmed the higher water content predicted by the model. The in-line water content analyzer was found to be miscalibrated, which explained why it was difficult to identify the cause of the reflux events. In the interest of collecting the most accurate data moving forward, the in-line moisture analyzer was recalibrated and currently delivers reasonable values.

The updated model of the NGL recovery unit showed significant hydrate formation in the rectifying section of the column, which led to a belief that hydrates or trapped water blocked the liquid return from the reflux accumulator to the column. The pressure differential transmitter was recalibrated, rescaled, and converted to report values in inches of water to identify these blockages. Prior to the modifications to the pressure differential transmitter, Figure 4 shows that there was no indication of a flooding within the tower. Recalibration of the instruments helps identify these issues through rises in column differential pressure.

Accurately modeling the entire plant provided a very good reality check and proved to be a useful tool for troubleshooting the integrated facility. Chevron was able to quickly identify the cause of the reflux events and immediately moved to resolve it.

The Solution

Improvements to the operation of the existing facility were required to be fully aligned with pre-deployment expectations for the performance of the integrated NGL recovery unit. The team focused on reducing water content to the NGL recovery unit through process optimization. The dehydration system, in place before the addition of the NGL recovery unit, uses triethylene glycol as a solvent to physically absorb water. The water rich glycol is then regenerated and returned to the contactor to start the process all over again as shown in Figure 5.

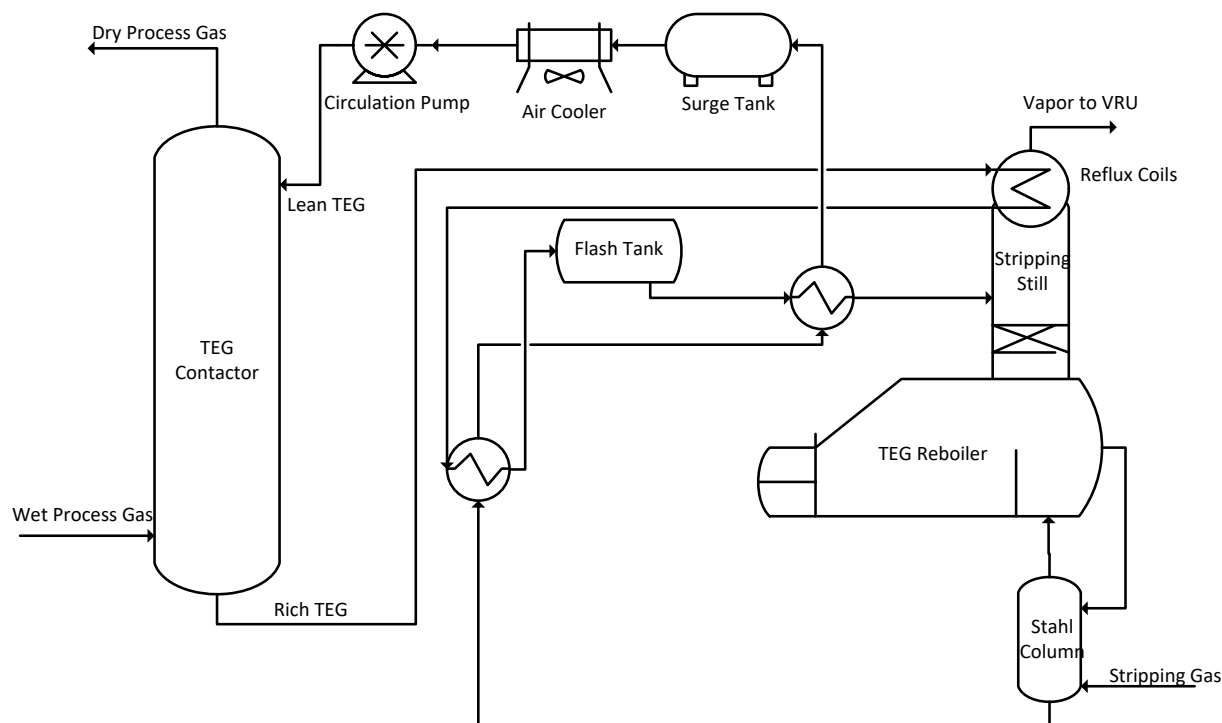


Figure 5: Process Flow Diagram for Gas Dehydration and Glycol Regeneration

The solvent circulation rate, reboiler temperature, stripping gas flowrate and process gas inlet temperature were all considered during optimization. At the time of troubleshooting, the reboiler temperature was 375 °F while circulating 25 sgpm of TEG without stripping gas.

The circulation rate was modeled and evaluated, as shown in Figure 6. Roughly one pound per minute of water was required to be removed, indicating about three gallons per minute of glycol needed to be contacted with the gas [2].

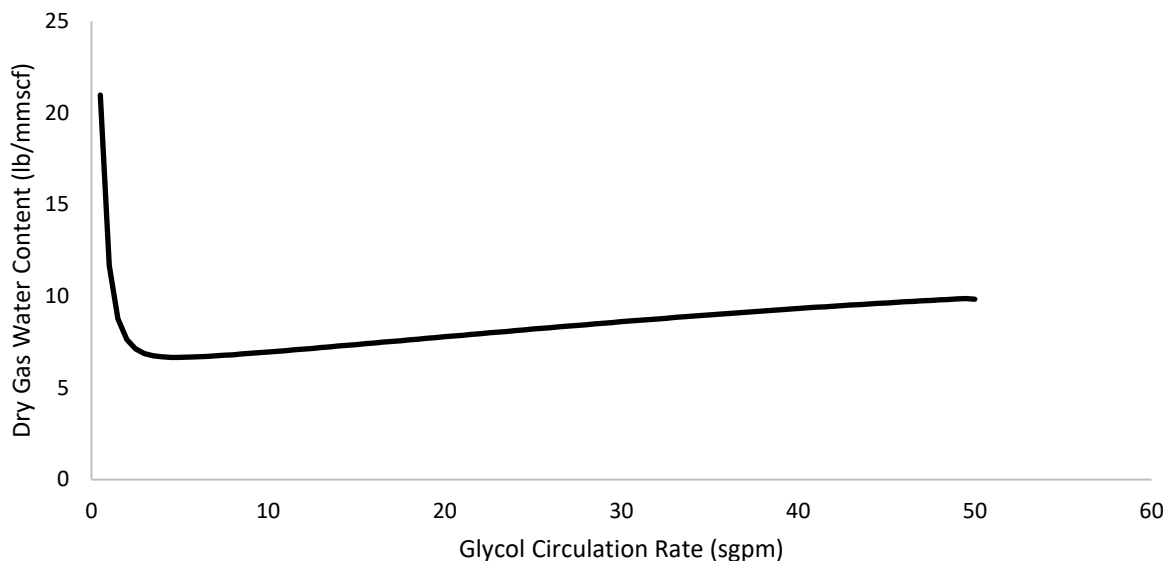


Figure 6: TEG Circulation Effect on Dry Gas Water Content Without Stripping Gas

The trend may counter previously held understandings that more glycol circulation results in a dryer gas, but is easily explained when looking at the temperature effect the solvent circulation has on the dry gas. The lean TEG will have a higher temperature than the wet gas. Typically, the lean TEG temperature effect on the dry gas temperature is negligible due to the significantly lower flowrate when compared to the high flowrate of the gas, as it is common to maintain a 3:1 ratio of glycol being circulated to water being removed. The Mabee plant was operating at about 25 gallons of glycol per pound of water being removed. If the lean glycol flowrate is increased, it increases the temperature of the column, which shifts the water equilibrium point in the gas. A warmer gas holds more water [2]. At low flowrates of TEG, the temperature effect is insignificant. Having knowledge of this trend prevents the temptation to circulate more TEG. Keeping the circulation rate low ensures the gas stays as cool as possible through the contactor.

While the optimum TEG circulation rate was found to be near 3 sgpm, pump constraints prevented the TEG rate from being less than 12 sgpm. Therefore, the TEG circulation rate was reduced from 25 sgpm to 12 sgpm. Optimizing the circulation rate in and of itself would not reduce the dry gas water content to hydrate free levels in the NGL recovery unit. The addition of stripping gas was needed to accomplish this goal. At a constant glycol circulation rate of 12 sgpm, the dry gas water content was studied at various reboiler temperatures and stripping gas rates in Figure 7.

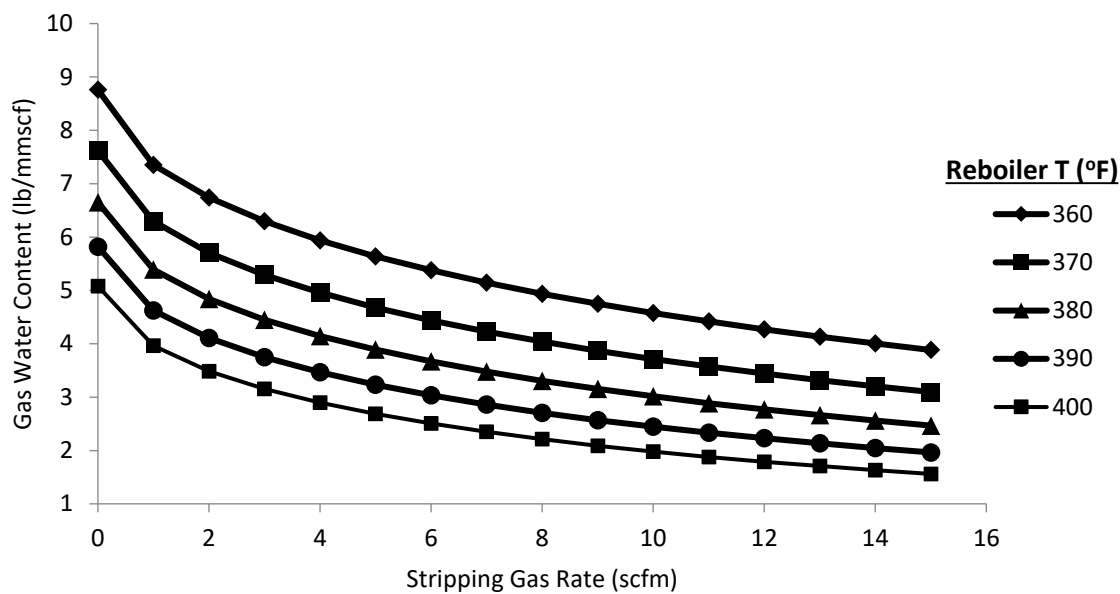


Figure 7: The Effect of Stripping Gas and Reboiler Temperature on Dry Gas Water Content

With no stripping gas to the dehydration unit, Figure 7 shows that even a reboiler temperature of 400 °F is not sufficient to reduce feed gas moisture content below 3 lbs/MMscf [4]. As glycol is known to degrade at temperatures higher than 400 °F, it is necessary to introduce some stripping gas to the system in order to achieve the desired water content [4]. Since multiple combinations of reboiler temperature and stripping gas rate can achieve the desired result, operational costs can be calculated and compared across the probable cases to determine the most cost effective solution. In this case, the reboiler temperature and stripping gas rate were increased to 390 F and 6 scfm, respectively, in order to achieve a moisture content averaging around 3 lbs/MMscf to the tower.

Finally, the inlet gas temperature was evaluated against the dry gas water content in Figure 8.

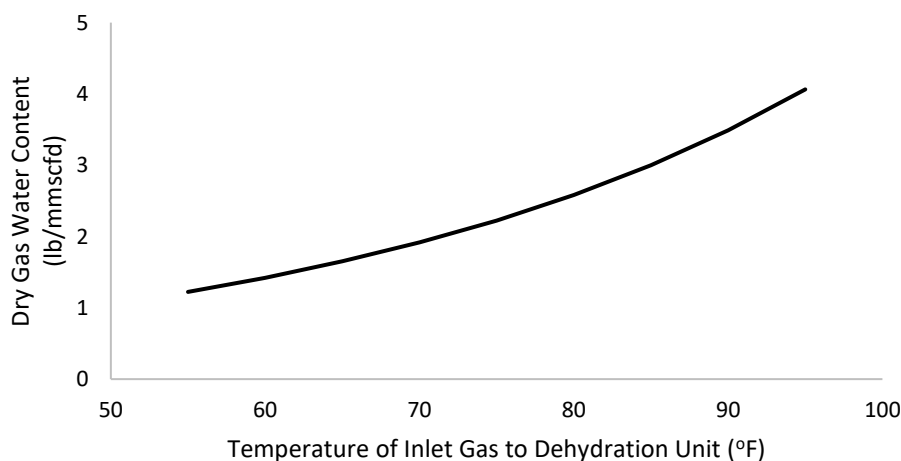


Figure 8: Effect of Inlet Temperature on the Dry Gas Water Content for 390 °F Reboiler and 6 scfm Stripping Gas

As expected, the trend shows lower dry gas water content at lower inlet gas temperatures [2]. By reducing the inlet gas temperature, the dry gas water content could be reduced well below the design limit. Based on the optimization study, the dehydration plant operating conditions were changed to the conditions summarized in Table 2.

Table 2: Summary of Changes Made to the Dehydration Unit

	Previous	Present Day
Inlet Gas Temperature (°F)	85	60
Glycol Circulation Rate (sgpm)	25	12
Reboiler Temperature (°F)	375	390
Stripping Gas (scfm)	0	6
Dry Gas Water Content (lb/mmcsf)	9	1.5

Once the changes were made in the plant, new data was collected which showed close agreement with the predictions from the simulator.

Distillation Tower Operations

While operating the dehydration unit at its optimum is important, operators need to know what temperature to operate the NGL distillation tower in order to mitigate the risk of hydrate formation. Figure 9 was created to give clear recommendations for operation of the tower temperatures at various inlet water contents. Although the margin is thin, Figure 9 shows operational flexibility.

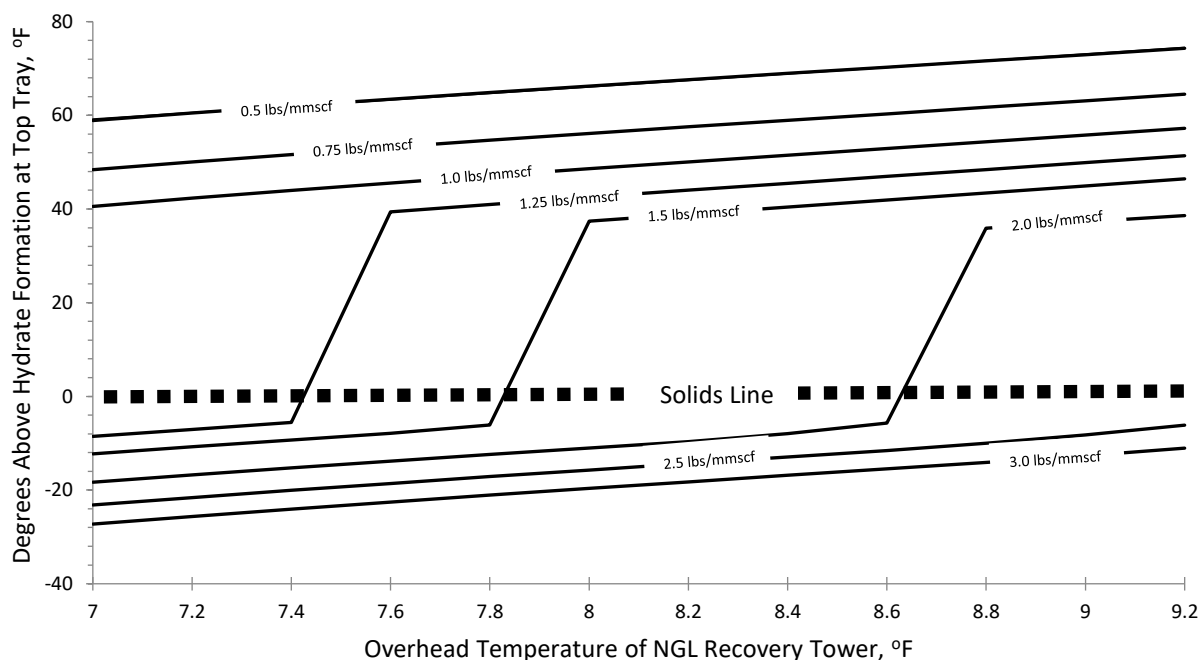


Figure 9: Operator Reference Guide to Avoid Hydrate Formation at Various Inlet Water Contents

With reduced reflux events bringing on smoother operations and better understanding of tower internals, the team then identified an opportunity to improve the top tower controls to more directly control the reflux accumulator level while achieving NGL product to the desired specification.

Conclusions

The water content of the inlet gas to the incorporated NGL recovery unit greatly affected the expected operational reliability of the rectifying section. Once the pressure differential and moisture analyzer transmitters were rescaled to report accurate values, the team identified the need to optimize the existing TEG regeneration unit to meet the design feed conditions. An operator reference guide was created to monitor the NGL recovery tower condenser temperature to avoid hydrate risk, resulting in more reliable operations and a reduction the operational demands of the unit.

In order to take the appropriate steps to troubleshoot process issues, instrumentation should be functioning reliably and reporting accurate data to properly identify the issues. Process models like ProMax® are valuable tools in identifying instrumentation reliability and opportunities for improvement. Process models can be used to validate data being received from the plant and identify the most effective operating parameters for process optimization. And finally, involving the right team of people in troubleshooting efforts can accelerate solutions.

An accurate model was essential to making meaningful decisions about operating the NGL recovery and glycol dehydration units. Since the optimization effort, the Mabee Gas Plant is operating reliably and reflux events of this nature are rarely observed.

Works Cited

- [1] G. R. Pastor, J. F. Peters, W. K. Larsen and A. C. Iakovakis. United States of America Patent 4,753,666, 1988.
- [2] Gas Processors Suppliers Association, Engineering Data Book, Tulsa, 1998.
- [3] Bryan Research & Engineering, Inc., "ProMax 4.0," Bryan, 2016.
- [4] A. L. Kohl and R. Nielsen, Gas Purification, Gulf Professional Publishing, 1997.

Exhibit P-7
Claim Chart
(‘332 Patent Claim 1)

U.S. Patent No. 8,505,332
Representative Claim 1

Claim 1	Mabee Air Permit Application (Ex. P-2, Chevron Mabee Plant Air Permit Application (Nov 5, 2012) (“Air Permit”))	Mabee Hydrate Formation Paper (Ex. P-6, Hydrate Formation in Chevron Mabee Unit) (“Hydrate Formation Paper”))
1. A method comprising: receiving a hydrocarbon feed stream, wherein the hydrocarbon feed stream comprises carbon dioxide, natural gas liquid (NGL), heavy hydrocarbons, and acid gas, wherein the NGL comprises C₃-C₈ hydrocarbons, and wherein the heavy hydrocarbons comprise C₉₊ hydrocarbons;	The “INLET SEPARATOR” receives “PLANT FEED GAS.” (Air Permit Fig. 1 of 2, Mabee Ranch CO₂ Recycle Facility Process Flow Diagram (hereinafter “Process Flow Diagram”). The Process Flow Diagram in the Air Permit shows the inlet stream in the stages of the process after most of the heavy hydrocarbons have been removed from the plant feed gas. (Process Flow Diagram)	Figure 3 in the Hydrate Formation paper shows the inlet stream in the stages of the process after most of the heavy hydrocarbons have been removed from the plant feed gas. (Hydrate Formation Paper Fig. 3, Mabee Gas Plant Block Flow Diagram) (hereinafter “Block Flow Diagram”). The Abstract on page 1 of the Hydrate Formation paper states that the Chevron Mabee Unit is similar to the Chevron Rangely Weber Sand Unit that is designed based on U.S. Patent 4,753,666 (“Pastor”). The Pastor patent describes injecting carbon dioxide into a hydrocarbon bearing formation to recover oil (e.g., C₉₊ hydrocarbons). (Pastor 1:14-22 and 3:47-59)

		The Pastor patent states that the feed includes N₂, CO₂, C₁, C₂, C₃, iC₄, nC₄, nC₅, C₆, and C₇₊ (e.g., carbon dioxide and C₁-C₇₊ hydrocarbons). (Pastor, Table 1) The Hydrate Formation paper shows that the NGL Composition includes propane, i-butane, n-butane, i-pentane, n-pentane, and hexane plus (e.g., C₃-C₆₊). (“Table 1: Model Validation of Plant Data” on page 4) The Hydrate Formation paper states that: “These corrective measures disrupted the temperature profile across the column, reduced NGL production, increased H₂S content in the NGL product, and required continuous involvement from plant operators” (Page 3). H₂S is an acid gas, so “increased H₂S content in the NGL product” shows that the feed stream includes acid gas. The Hydrate Formation paper includes an “NGL Sweetening” block. “NGL Sweetening” is used to remove acid gas (Block Flow Diagram). This shows that the feed stream includes acid gas.
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separating the hydrocarbon feed stream into a heavy hydrocarbon rich stream and a carbon dioxide recycle stream, wherein the heavy hydrocarbon rich stream comprises the C₉₊ hydrocarbons, and wherein the carbon dioxide recycle stream comprises the carbon dioxide, the C₃-C₈ hydrocarbons, and the acid gas;	As stated above, The Process Flow Diagram in the Air Permit shows the inlet stream in the stages of the process after most of the heavy hydrocarbons have been removed from the plant feed gas. (Process Flow Diagram)	As stated above, Figure 3 in the Hydrate Formation paper shows the inlet stream in the stages of the process after most of the heavy hydrocarbons have been removed from the plant feed gas. (Block Flow Diagram)
separating the carbon dioxide recycle stream into a sour NGL rich stream and a purified carbon dioxide recycle stream, wherein the sour NGL rich stream comprises the C₃-C₈ hydrocarbons and the acid gas, and wherein the purified carbon dioxide recycle stream comprises the carbon dioxide; and	The “FRACTIONATION UNIT” separates the stream from the “TEG CONTACTOR” (the carbon dioxide recycle stream) into a “GAS” stream that is sent to the “STAGE 3 COMPRESSOR” and then to “REINJECTION” (the purified carbon dioxide recycle stream), and a stream that is sent to a “COOLING DEHYDRATION SWEETENER” (the sour NGL rich stream). (Process Flow Diagram)	The “NGL Distillation” separates the stream from the “Glycol Dehydration” (the carbon dioxide recycle stream) into a purified carbon dioxide stream that is sent to “3rd Stage Compression” through a “Reflux Condenser” and then to “Reinjection,” and a sour NGL rich stream that is sent to “NGL Sweetening” through a “Reboiler.” (Block Flow Diagram) The Hydrate Formation paper shows that the NGL Composition includes propane, i-butane, n-butane, i-pentane, n-pentane, and hexane plus (e.g., C₃-C₆₊) (“Table 1: Model Validation of Plant Data” on page 4). The Hydrate Formation paper states that: “These corrective measures disrupted the temperature profile across the column, reduced NGL production, increased H₂S

		content in the NGL product, and required continuous involvement from plant operators” (Page 3). H₂S is an acid gas, so “increased H₂S content in the NGL product” shows that the sour NGL rich stream includes acid gas. The Hydrate Formation paper includes an “NGL Sweetening” block. “NGL Sweetening” is used to remove acid gas (Block Flow Diagram). This shows that the sour NGL rich stream includes acid gas.
separating the sour NGL rich stream into a sweet NGL rich stream and an acid gas stream, wherein the sweet NGL rich stream comprises the C₃-C₈ hydrocarbons, and wherein the acid gas stream comprises the acid gas,	The “COOLING DEHYDRATION SWEETENER” receives the stream from the “FRACTIONATION UNIT” (the sour NGL rich stream) and produces a stream that is sent to “PRESSURIZED NGL STORAGE” and then to the “SALES PIPELINE” (the sweet NGL rich stream). The sweetening process performed by the “COOLING DEHYDRATION SWEETENER” separates the sour NGL rich stream into the sweet NGL rich stream and an acid gas stream. (Process Flow Diagram)	The “NGL Sweetening” receives the sour NGL rich stream from the “Reboiler” and produces a stream that is sent to “NGL Product Storage and Sales” (the sweet NGL rich stream). The sweetening process performed by the “NGL Sweetening” separates the sour NGL rich stream into the sweet NGL rich stream and an acid gas stream. (Block Flow Diagram). The Hydrate Formation paper shows that the NGL Composition includes propane, i-butane, n-butane, i-pentane, n-pentane, and hexane plus (e.g., C₃-C₆₊). (“Table 1: Model Validation of Plant Data” on page 4).

		The Hydrate Formation paper states that: “These corrective measures disrupted the temperature profile across the column, reduced NGL production, increased H ₂ S content in the NGL product, and required continuous involvement from plant operators” (Page 3). H ₂ S is an acid gas, so “increased H ₂ S content in the NGL product” shows that the acid gas stream includes acid gas.
wherein the carbon dioxide is not removed from the hydrocarbon feed stream and is not removed from the carbon dioxide recycle stream prior to separating the carbon dioxide recycle stream into the sour NGL rich stream and the purified carbon dioxide recycle stream, and	No carbon dioxide removal is performed between “PLANT FEED GAS” being received at “INLET SEPARATOR” and the stream being fed to “FRACTIONATION UNIT.” (Process Flow Diagram)	No carbon dioxide removal is performed between “Inlet gas and 1 st Stage Compression” and “NGL Distillation.” (Block Flow Diagram)
wherein the hydrocarbon feed stream, the carbon dioxide recycle stream, and the sour NGL rich stream are not subjected to cryogenic conditions, membranes, and carbon dioxide recovery solvents between being received and being separated into the heavy hydrocarbon rich stream, the purified carbon dioxide recycle stream, the sweet NGL rich stream, and the acid gas stream.	There are no cryogenic conditions, membranes, or carbon dioxide recovery solvents in the process. “TEG CONTACTOR” is for dehydrating the stream and not for carbon dioxide recovery. (Process Flow Diagram)	There are no cryogenic conditions, membranes, or carbon dioxide recovery solvents in the process. “Glycol Dehydration” is for dehydrating the stream and not for carbon dioxide recovery. (Block Flow Diagram)