California Energy Commission
DOCKETED
08-AFC-8A
TN # 68376
NOV 05 2012

OEHI Responses to CEC Data Requests Set Two Nos. A136-A138 and A171-A177

Amended Application for Certification
for
HYDROGEN ENERGY CALIFORNIA
(08-AFC-8A)
Kern County, California

November 2012

HYDROGEN ENERGY CALIFORNIA
(08-AFC-8A)

Energy Commission Staff’s Data Requests A124-A180

September 6, 2012

Technical Area: **Air Quality/Enhanced Oil Recovery and Carbon Capture & Sequestration**

Authors: William Walters
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THE ENHANCED OIL RECOVERY (EOR) AND CARBON CAPTURE AND SEQUESTRATION (CCS)

BACKGROUND: BOILER/HEATER EMISSION FACTOR ASSUMPTIONS

Staff's review of SJVAPCD regulations (Rules 4307 and 4320) indicate that the emissions factor assumptions in Appendix A of the AFC will not meet rule requirements for nitrogen oxides (NOx) emissions at the time three of the proposed process heaters would be permitted. Staff needs clarification of whether there are any applicable exemptions assumed or if emissions should be re-evaluated based on Rule limits.

DATA REQUEST

A136. Please identify if there are any rule exemptions assumed for three heaters rated above 1 million Btu per hour heat input so that the Rule 4307 or 4320 requirements for NOx limits would not apply. If there are no applicable rule exemptions, then please update the emissions estimates for these three heaters based on compliance with the NOx emissions limits provided in District Rules 4307 and 4320.

The proposed emission limits for the heater subject to Rule 4307 and the heaters subject to Rule 4320 are correct, and no rule exemptions are assumed. Conformance with each rule is described further below:

1. Rule 4307

Rule 4307 establishes oxides of nitrogen (NOx) emission limits for process heaters, boilers and steam generators having a heat input rate between 2 MMBtu/Hr and up to and including 5.0 MMBtu/Hr.

a. Glycol Dehydration Unit (5 MMBtu/Hr)

The facility will include a glycol dehydrator with a heat input rate between 2.0 MMBtu/Hr and less than or equal to 5.0 MMBtu/Hr. The dehydrator is subject to the Rule 4307 limit specified in Table-B1 (30 ppmv NOx at 3% excess O2). Occidental of Elk Hills (OEHI) has evaluated the emissions from the unit using 30 ppmv NOx (at 3% excess O2). The lower limits specified in Rule 4307, Table-2 apply to new units or replacement units after January 1, 2016.

2. Rule 4320

Rule 4320 establishes oxides of nitrogen (NOx) emission limits for process heaters, boilers and steam generators having a heat input rate greater than 5 MMBtu/Hr. As noted above, this unit does not exceed 5 MMBtu/Hr.

a. Molecular Sieve Heater (10 MMBtu/Hr)

The facility will include a 10.0 MMBtu/Hr heater that will be used for regenerating the molecular sieves (“mol-sieve”). The heater is subject to the 9 ppmv NOx emission limit (at 3% excess O2) specified in Table-1, Category-A.a. OEHI has proposed to permit the unit at a more stringent NOx emission limit of 7 ppmv NOx (at 3% excess O2).

The Table-1, Category-A.b limit is not applicable to new units. The enhanced schedule specified in Category-A.b was included in Rule 4320 to extend the final compliance deadline to 2014 for existing units for those operators willing to accept a more stringent final compliance target (6 ppmv NOx at 3% O2).

b. Reinjection Heater (60 MMBtu/Hr)

The facility will include a 60.0 MMBtu/Hr heater that will be used for heating gas prior to its reinjection. The heater is subject to the 7 ppmv NOx emission limit (at 3% excess O2) specified in Table-1, Category-B.a. OEHI has proposed to permit the unit at a NOx emission limit of 7 ppmv NOx (at 3% excess O2).

The Table-1, Category-B.b limit is not applicable to new units. The enhanced schedule 2014, for existing units for those operators willing to accept a more stringent final compliance target of 5 ppmv NOx (at 3% O2).

BACKGROUND: PIPING SYSTEM FUGITIVE VOC EMISSION FACTORS

Staff has not been able to match all of the applicant’s VOC fugitive emissions factor calculations, which were noted to come from Table 5-7 of the USEPA Protocol for Equipment Leak Emissions Estimates. Staff needs additional information to understand the rationale for the differences in the calculated emission factors or a corrected emissions estimate to be provided.

DATA REQUESTS

A137. Please review and as necessary correct the emission factor calculations/values and VOC emissions calculations for the following piping systems and component types provided in the Operational Phase Criteria Pollutant Emissions appendix to AFC Appendix A:

a. Reinjection Compression Facility (RCF)
    i. Gas/Light Liquid Valves

b. Carbon Dioxide Recovery Plant (CRP)
    i. Gas/Light Liquid Valves
    ii. Heavy Crude Oil Valves
    iii. Light Crude Oil Connectors

c. Central Tank Battery
    i. Gas/Light Liquid Valves
    ii. Heavy Crude Oil Valves
    iii. Light Crude Oil Connectors

d. Production Satellite Settings
    i. Gas/Light Liquid Valves

  - ii. Light Crude Oil Connectors
  - iii. Light Oil Open-Ended Lines

e. Crude Oil and Natural Gas Production Wells
  - i. Gas/Light Liquid Valves
  - ii. Light Crude Oil Connectors
  - iii. Light Oil Open-Ended Lines

f. CO2 Injection Wells
  - i. Gas/Light Liquid Valves
  - ii. Light Crude Oil Connectors
  - iii. Light Oil Open-Ended Lines

Emissions from fugitive sources such as valves, flanges, connectors (etc.) were calculated using the EPA average leak rate equations (ALR) for estimating fugitive emissions of volatile organic compounds (VOC). The formula used for calculating the ALR for valves used in "gas and light liquid service" included an error. The formula has been corrected and the VOC emissions resulting from the various process systems have been recalculated. The revised emission estimates are summarized below. Corrected tables are attached. **See attached PDF file, Attachment I.**

Revised Fugitive VOC Emission Estimates

Process Description		Fugitive VOC (Lb/Day)		
		Original	Revised	Change
a.	Reinjection Compression Facility	12.270	13.427	1.157
b.	Carbon Dioxide Recovery Plant	35.723	40.397	4.674
c.	Central Tank Battery	5.387	5.742	0.355
d.	Production Satellite Settings	11.425	11.425	0.000
e.	Crude Oil and Natural Gas Production Wells	126.043	170.155	44.112
f.	CO2 Injection wells	0.00	0.00	0.000
Total Fugitive VOC Emissions		190.848	241.146	50.298

Note:

1. Existing wells will be converted to CO2 injection wells. Consequently, there will not be an appreciable increase in fugitive VOC emissions from these wells

2. The change in fugitive VOC emissions will be offset pursuant to SJVAPCD Rule 2201.

A138. Please confirm that there are no piping components and/or zero VOC composition, or provide completed emissions calculations, for the following two piping component systems shown in the emissions calculations: Gathering System for Crude Oil and Natural Gas Production (p. 23 of 29); and CO2 Intake and CO2 Distribution System for Injection (p. 24 of 29).

Please note that if fugitive VOC emission calculations are necessary for either of these piping systems the emissions factors need to address the issues identified above in data request 14.d through 14.f.

The components used by the production gathering system and the carbon dioxide (CO2) intake and distribution system were assumed to be welded. Consequently, the piping systems are not expected to result in appreciable emissions of fugitive VOC.

Technical Area: Cultural Resources

Authors:

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Gabriel Roark

INTRODUCTION

All responses to these Data Requests containing references to specific archaeological site location or information, or cultural resources of concern to Native Americans, should be submitted under a request for confidentiality.

BACKGROUND

Five cultural resource inventories have been conducted along or overlapping the portion of the proposed CO2 pipeline corridor that extends south of the California Aqueduct (Farmer 2008; Hamusek-McGann et al. 1997; Jackson et al. 1998; Peak & Associates 1991; Stantec 2011). Six archaeological resources have been identified in or less than 200 feet from the proposed pipeline within Section 22: P-15-6776 (CA-KER-5041), HECA-6, HECA-7, HECA-8, HECA-12, and Isolated Artifact 1. Archaeological sites HECA-7 and HECA-12 have been recommended as California Register-eligible resources (Farmer 2008:5-8, 5-10). P-15-6776 has been found ineligible for listing on the National Register of Historic Places, but recent work indicates that the significance of the site needs to be reconsidered (Jackson et al. 1998: Table 8.2; Stantec 2011:8). No archaeological resources have been found in the proposed pipeline alignment south of Section 22.

The findings of these previous inventories raise three issues. First, there is a disparity between the results of survey work in Section 22 and south of Section 22. Second, the boundaries of P-15-6776 and other archaeological sites in or adjacent to the proposed pipeline corridor are incompletely defined. Third, the proposed pipeline would intersect at least one previously identified archaeological resource, necessitating test excavation to determine resource significance and possibly mitigation measures.

Concerning the different survey results in Section 22 and south of it, the methods employed by archaeologists to identify archaeological resources appear unsuited to the visibility of archaeological materials south of Section 22. Consequently, archaeological resources are incompletely defined along this portion of the proposed CO2 pipeline. If not corrected, significant impacts to cultural resources will likely result and could include discoveries of archaeological materials during construction.

The purpose of archaeological survey varies with the goals of the survey. The context of the Energy Commission's environmental review focuses on the discovery of archaeological objects, sites, places, and areas (14 California Code of Regulations 15064.5[a][3]). The typical unit of archaeological discovery is the individual feature (for instance, a house pit depression or mining tailings) or artifact (such as an arrow point or bottle). Artifacts or features that are found close to one another are grouped into archaeological sites for the purposes of future study and management. Archaeological sites in turn may be grouped into larger units (places or areas)—usually termed archaeological districts or landscapes—if the sites show functional, chronological, or other connections (Office of Historic Preservation 1995:1–3).

In planning and conducting an archaeological survey, important considerations include the visibility and obtrusiveness of archaeological resources in the study area. Visibility refers to the ease with which archaeological materials can be seen. During the typical pedestrian archaeological survey, factors affecting archaeological visibility include lighting, weather, the attentiveness and experience of surveyors, the pace of survey, the presence of flood deposits or other soil cover atop archaeological resources, and the density and type of vegetation in the study area. Obtrusiveness of archaeological materials refers to the ease with which the archaeologist can recognize materials as archaeological. For instance, a large and dense scatter of stone-tool debris is easier to encounter and recognize during a survey than one that is small, sparse, or both. Standing structures or their ruins are easier to recognize as archaeological or cultural materials than are house pit depressions. Without exception, as the visibility and obtrusiveness of archaeological materials decreases, the archaeologist must increase the intensity of survey in order to identify archaeological materials. Greater intensity—and probability for finding and accurately describing the range of archaeological materials—can be achieved in several ways. Most commonly, the spacing between surveyors (transect interval) is reduced or set no wider than the minimal dimension of archaeological resources in the study area. For example, in an area where the average diameter of archaeological sites is 60 feet, transect intervals in a survey should be no wider than 60 feet. Another reasonable way of increasing survey intensity in areas with dense vegetation is to clear vegetation at regular intervals. (Feder 1997:46–49, 54–55.)

Energy Commission staff find that the survey methods employed in the proposed CO2 pipeline corridor do not conform to the standards described above and are probably responsible for the lack of archaeological resources found south of Section 22. A review of previous surveys in the immediate vicinity will make the situation plain.

In 1991, Peak & Associates surveyed the eastern half of Section 22 in 60-foot transect intervals. Where the ground surface was not clearly visible, Peak & Associates cleared the ground surface at 60-foot intervals. The survey report does not state how obscured the ground surface was before the decision was made to scrape away vegetation, nor how large the surface scrapes were. Survey of this area identified a scatter of freshwater mussel shells, a gray chert chopper[1], two flakes, and a single bowl mortar[2]. (Peak & Associates 1991:45, 64, 88, 112, Figure 6.) This site was later designated P-15-6776 (CA-KER-5041.

[1]. A large pebble, cobble, or core tool that is flaked to form an axe-like cutting edge; it is used for chopping and cleaving work.

[2] A stone or wooden bowl-like artifact in which seeds, berries, meat, pigment, and other substances are pulverized or ground with a pestle.

Jackson and colleagues revisited the area in 1997, surveying after a wildfire had burned the area. The wildfire produced excellent ground surface visibility since most of the vegetation succumbed to the fire. Say Jackson et al. (1998:72), “The excellent ground surface visibility resulting from the wildfire revealed constituents [artifacts] that otherwise would lie obscured beneath continuous vegetation.” These materials were identified near Peak & Associates’ recordation of P-15-6776.

In 2008, URS archaeologists surveyed the northern half of Section 22, overlapping with Peak & Associates (1991) and Jackson et al.’s (1998) survey coverage (Farmer 2008). The survey was conducted by 2–6 persons walking transects spaced 50 feet apart. Ground surface visibility ranged from 50–100 percent, with the “vast majority” of the survey area being free of vegetation. Once an archaeological site was located, the survey crew walked 15-foot transects over the site to determine its boundaries. URS identified four archaeological resources and one historic structure (road) in or within 200 feet of the current proposed CO_2 pipeline: HECA-6, HECA-7, HECA-11, HECA-12, and KRM-010H. (Farmer 2008:4-1.)

At archaeological site P-15-6776, URS found that the site contained far more surface artifacts than were recorded by previous investigators and that the site extended further south and west. Two potential house-pit depressions were also observed on the site surface. URS attributed their additional finds to surveying after recent field disking and 10 years of erosion since the site was last recorded. (Farmer 2008:5-21, 6-1.)

In February 2011, Stantec archaeologists surveyed the current proposed CO_2 pipeline by walking parallel transects spaced 50 feet between surveyors. Ground surface visibility was poor throughout the proposed pipeline corridor (10–20 percent) and Stantec does not describe attempts to improve the ground surface visibility by clearing vegetation. Stantec reports that archaeological site P-15-6776 extends west (into the proposed pipeline corridor) and north of the previously identified site boundaries. Given the clear track record shown in previous investigations of the pipeline vicinity, the amount of ground cover—and whether one clears obscuring vegetation—strongly conditions the reliability of archaeological survey results. In the context of 10–20 percent visibility and no vegetation clearing, the results of survey south of Section 22 appear unreliable.

The second issue with the archaeological survey for the proposed pipeline corridor is that archaeological site boundaries within and adjacent to the pipeline corridor are incompletely defined. This is particularly true of P-15-6776, which Stantec (2011:Figure 2) maps as extending into areas mapped as archaeological sites HECA-8, HECA-BUF1, HECA-7, HECA-ISO-1, and HECA-ISO-2 (Farmer 2008). The Stantec (2011) report contains no reference to these archaeological sites or to URS’s survey (Farmer 2008), indicating that Stantec was unaware that these five resources were recorded near one another and to P-15-6776. Stantec (2011:8) states that “further survey, and possibly additional testing [should] be conducted in the area of site number PS-15-006776 [sic] when the exact pipeline corridor is established and ground visibility has improved.”

Third, the proposed pipeline corridor would probably affect at least one archaeological resource, P-15-6776. Although Jackson et al. (1998) recommended P-15-6776 as ineligible for listing on the National Register, they did not evaluate the site for California Register eligibility and subsequent researchers found additional surface artifacts and features at the site in sufficient numbers to warrant reconsideration of its boundaries and significance (Farmer 2008:5-20, 5-21, Table 5-2; Stantec 2011:8). For Energy Commission staff to determine whether the proposed project would result in a substantial adverse change to historical or unique archaeological resources, staff needs to know whether archaeological site P-15-6776 qualifies as a historical or unique archaeological resource. This matter is solvable by conducting a test excavation program at the site.

DATA REQUESTS

A141. Please conduct an archaeological survey in the proposed CO_2 pipeline corridor south of Section 22, incorporating the following practices.

a. Fifty-foot-wide or narrower transect intervals.

b. Where the ground surface visibility is 50 percent or less in the proposed pipeline corridor due to vegetation, clear vegetation in 3-feet-by-3-feet patches at 50-foot intervals to inspect the ground surface.

OEHI is currently preparing a Plan to address CEC Data Requests A141 through A146. The Plan will include an implementation schedule to address the data requests based on the projected development of the project. The Plan will be submitted to CEC as soon as it is completed.

A142. Please prepare and submit an addendum to Amended AFC Appendices A-1 and A-2, Attachment B, that describes or contains:

a. The methods used to identify cultural resources in the proposed pipeline corridor.

b. The identity and qualifications of the personnel conducting the survey and report preparation.

c. The results of the archaeological survey.

d. Descriptions of newly recorded cultural resources in the proposed pipeline corridor.

e. An assessment of impacts to cultural resources in the proposed pipeline corridor.

f. Proposed mitigation measures for identified impacts.

g. Department of Parks and Recreation (DPR) 523 forms for all cultural resources identified during the survey as being 45 years or older or of exceptional importance.

h. Figures depicting survey coverage. The figures should also depict ground surface visibility in the survey areas, expressed as a percentage. Figures shall be on a 1:24,000-scale U.S. Geological Survey topographic quadrangle map. Previously and newly recorded cultural resources shall be mapped on the figures.

A143. Please provide a recommended avoidance plan describing and graphically demonstrating how impacts on specific archaeological resources in the proposed CO_2 pipeline corridor will be avoided. The plan should include:

a. Descriptions of the resource(s), with particular attention to the depth or thickness of archaeological materials and the resource boundaries.

b. Maps depicting the site boundaries and locations of any previous test excavation units for each resource. Maps shall meet the requirements laid out for DPR 523 Sketch Maps, but do not need to be generated on the site form template (see Office of Historic Preservation 1995:15).

c. Overlay the proposed pipeline corridor and all associated work areas and access roads onto the aforementioned sketch map.

d. Similar exhibits showing, plan and profile, the proposed methods for avoiding identified archaeological resources.

A144. If archaeological sites along the proposed CO_2 pipeline corridor cannot be avoided per data request 143, please provide, for staff review and approval, an archaeological testing plan that conforms to the standards described in Office of Historic Preservation (1991). The purpose of the testing plan is to determine whether archaeological resources in the proposed pipeline corridor meet CEQA's definition of a historical or unique archaeological resource. The research design shall be prepared by an archaeologist that meets the Secretary of the Interior's professional standards for archaeologists (see *Archeology and Historic Preservation: Secretary of the Interior's Standards and Guidelines*, 36 Code of Federal Regulations 61). The research design must include the following.

a. A statement of the problem and research goals.

b. A statement of methods to achieve the research goal.

c. A statement regarding how the results will be reported.

d. Maps depicting the site boundaries and locations of any previous test excavation units for each resource. Maps shall meet the requirements laid out for DPR 523 Sketch Maps, but do not need to be generated on the site form template (see Office of Historic Preservation 1995:15).

e. Overlay the proposed pipeline corridor and all associated work areas and access roads onto the aforementioned sketch map.

f. A schedule for implementation of the research design.

g. The preparer's résumé and the résumés of other key staff that are expected to implement the research design.

A145. Upon staff's approval of the research design described in data request 144 immediately above, please implement the archaeological investigation consistent with the approved research design.

A146. Following completion of the archaeological investigation specified in data request 145 above, please provide, for staff's review and approval, an archaeological evaluation report that identifies the methods employed and results of the investigation. The report shall contain the following.

a. A description of the research design and the methods employed during the study.

b. A description of the study results.

c. Recommendations as to eligibility for consideration as a historical or unique archaeological resource for each resource investigated.

d. A location map on a U.S. Geological Survey, 7.5-minute topographic quadrangle.

e. For archaeological resources that appear to meet the criteria of historical or unique archaeological resource, describe whether the proposed pipeline would result in impacts to them. Supplement the impact discussion with exhibits and quantify the estimated quantity of archaeological materials that would be damaged or removed.

f. Proposed mitigation measures for impacted archaeological resources. Supplement the mitigation discussion with exhibits as needed.

g. A Sketch map (see data request 143 above) that depicts the sampling locations and the location of any newly identified archaeological features.

h. Revised DPR 523 forms.

BACKGROUND

With suitable oil density and reservoir pressure, injected carbon dioxide mixes with the oil it contacts, such that the interfacial tension between these two fluids goes to zero. The CO_2-oil miscibility occurs above the minimum miscibility pressure (MMP). The higher the reservoir temperature is, the higher the MMP. Crude oil composition plays a crucial role. Usually the more intermediate components there are, the lower the MMP. Intermediate content is expressed variously as C_5+ molecular weight, $_{C1\text{-}C30}$ content, etc. In effect, for lighter crudes, whose API gravity is more than 22^0, viscosity less than 3 cp at reservoir conditions, and at reservoir depths above 3,000 ft, the crudes are usually miscible with CO_2 at first contact. If CO_2 is only partially miscible with the crude, as may be the case in Elk Hills, the total composition in the CO_2-crude mixing zone can change to develop miscibility in situ. Regardless of whether the displacement is first-contact miscible or develops later, the CO_2 must immiscibly displace any mobile water present with the oil and gas in the reservoir. Since CO_2 has a higher mobility than water, this immiscible displacement is usually very inefficient, creating viscous fingers of CO_2.

As a result, the injected CO_2 bypasses some water and oil. In addition, CO_2 is the least dense fluid in the reservoir and flows to the top ("overrides"), bypassing again significant quantities of oil and water below. Water slugs are injected in between CO_2 slugs to lower the unfavorable mobility ratio.

Based on the available data from 21 field CO_2–injection projects, it appears that at steady state that will follow CO_2 breakthrough in all wells, for each 1 volume of fresh CO_2 injected, 1 volume of CO_2 will be produced, separated, recompressed and reinjected on average. Therefore, with time, each gas injection well may have to inject two volumes of CO_2 per each volume of fresh CO_2 from the plant. The remainder of the injected CO_2 will fill an expanding zone of trapped CO_2. Oxy's assumed 2/3 volume of CO_2 produced for each volume of CO_2 injected seems low, given the expected high injection pressure and full-interval injection. Staff needs data demonstrating the sequestration of the claimed volume will be sequestered given past experience that shows this may likely not be the case.

DATA REQUEST

A171. Please provide data that demonstrate that each volume of injected CO_2 produces only 2/3 that volume of CO_2 at the production wells.

The trapping of injected CO2 is relative to hydrocarbon pore volume. For example, if a small portion of CO_2 is injected into a reservoir - say 5% Hydrocarbon Pore Volume Injected (HCPVI) - 95% of the CO_2 will be trapped in the reservoir. As the percent HCPVI is increased, the fraction of each incremental injected volume of CO_2 trapped in the reservoir will decrease. This trapping ratio relative to HCPVI is demonstrated well in SPE paper #24928 "Update of Industry Experience With CO2 Injection"; R.E. Hadlow, Exxon Co. USA Figure 4.
OEHI's stated 2/3 volume produced for every 1 Mscf injected is based on core measurements of trapped gas saturation of ~25 saturation units, which is ~41% of the available HCPV on a pore level. The trapped gas saturation is estimated to be only ~33% because of the areal and vertical sweep efficiencies built into Oxy's detailed geomodels, which reflect Oxy's actual results from previous waterflooding. When modeling the trapped gas saturation and sweep efficiencies, and adjusting for the designed HCPVI, the TOTAL trapped gas is ~33% of the TOTAL CO_2 injected. This is not an instantaneous number, but an estimated long term average based upon both analogous Oxy projects and actual OEHI data.

BACKGROUND

The minimum miscibility pressure for the Elk Hills conditions is approximately 3,000 psi, and the maximum injection pressure (overburden pressure) is close to 5,000 psi. Given the high and constant injection rate of CO_2, 2,000 psi of incremental pore pressure may be insufficient to put away the required volume of CO_2. This constraint will lead inevitably to the very high injection pressures at or above the overburden pressure, and a distinct possibility of activating faults and breaching the overlaying shale barriers. These increased pressures could fracture the rock and lead to leakage or compromise the formation's ability to store CO_2. Staff needs information on the proposed injection pressures and rates necessary to achieve sequestration.

DATA REQUESTS

A172. Please provide current estimates of CO_2 and water injection pressures required during the life of the project.

The CO_2 flood has been designed to inject the required water and CO_2 rates at a bottom hole pressure of 4500 psi. These rates are based on field measurements of CO_2 and water injection from the 2005 CO_2 Pilot and waterflood history of the Stevens Waterfloods. These design rates and pressures are within the DOGGR-permitted UIC requirements.

A173. Please provide representative downhole well injection rates of CO_2 and water at these injection pressures.

Water injection rates will vary across the field depending upon permeability and reservoir thickness. As an example, for a well that injects 2000 bwpd and 10 MMscfd, the respective subsurface rates at the bottom hole injection pressure of 4500 psi will be 2000 bwpd and 4700 reservoir bbls per day of CO_2.

A174. Please provide geomechanical data/calculations/simulations showing the state of stress of the reservoir rock and overburden just above the reservoir during CO_2 injection.

For a discussion of the rock properties see sections 3.1.2.2 Sealing Formation of the MRV plan. For a discussion of simulation study see section 3.2 Reservoir Simulation of the MRV plan.

A175. Given 4, what are the current predictions of fault activation and reservoir cap rock integrity? Please provide analysis.

For a discussion of the reservoir cap rock integrity, see section 3.1.2.2 Sealing Formation of the MRV plan. For a discussion of faulting, see sections 3.1.2 EHOF Structure and Geology and 3.3.3 Faults and Fractures of the MRV plan.

A176. Please provide a thorough description of actual or modeled boundaries of the targeted injection reservoirs (size and type of patterns, number of injectors and producers as a function of time, etc.).

The attached map demonstrates the timing and boundaries of the targeted injection reservoirs. All patterns are planned to be 18 acre 5 spot patterns (injection centered with four producers surrounding an injector) with the exception of the 26R reservoir. 26R will be a gas cap expansion/gravity drainage depletion mechanism. CO2 will be injected at the top of the reservoir and provide pressure to produce the oil from the downdip producers.

BACKGROUND

The CEC may have the need of verifying the emissions of CO_2 from the HECA power plant and from the sequestration activities in the Elk Hills. The CEC requires knowledge of the Elk Hills oil field and sequestration activities. The CEC cannot rely on the applicant's assessment alone to make this determination, nor does the CEC expect the DOGGR Class II permit review process to completely verify proposed sequestration volumes or oil field adequacy.

The submitted MRV plan contains a great deal of information necessary for the CEC to perform a complete analysis, but staff requires the following documents, which were prepared specifically for the HECA project and concern issues of implementation, scheduling, and design.

- *Pre-FEED Engineering Study, Process Design Basis, Mustang Engineering, April 15, 2010.*

- *Preliminary Project Description (Pre-FEED Stage), ManageTech Solutions, April 16, 2010.*

- *Pre-FEED Engineering Study, Execution Schedule, Mustang Engineering, April 23, 2010.*

- *Pre-FEED Engineering Study, Overall Design Basis, Mustang Engineering, April 28, 2010.*

- *Pre-FEED Engineering Study, Project design drawings, Mustang Engineering, misc dates.*

The documents listed above contain "Extensive information" about "the Elk Hills Oil Field, CO_2 EOR Project, and HECA Project."

DATA REQUEST

A177. Please submit all of the documents listed above.

Refer to attached documents

Technical Area: **Visual Resources**
Author: Elliott Lum

BACKGROUND

According to the Supplemental Environmental Information (SEI) package for the Occidental of Elk Hills, Inc. (OEHI) CO_2 Enhanced Oil Recovery (EOR) project, OEHI is proposing to utilize carbon dioxide from the HECA project to facilitate oil production in its Elk Hills Unit operations.

As stated in the Aesthetics section of the SEI, the project's Processing Facility will be visible in views from the City of Tupman. Additionally, some small components of the proposed project would be visible from the communities of Dustin Acres, Valley Acres, and motorists on portions of Elk Hills Rd, SR 58, Tupman Road, and SR 119 (see Section 4.1).

Six KOPs were selected to evaluate the visual impacts of the proposed project. Each impact discussion for the above KOPs confirms that components of the proposed project may be visible. The visual impacts to all six of the aforementioned KOPs have been characterized as less than significant (see Section 4.1-17 to 19). However, Energy Commission staff has concluded that additional project information is necessary before a significance conclusion can be reached.

DATA REQUESTS

A178. Please provide revised photographic simulations for each of the six KOP viewpoints reflecting the new aboveground elements of the Processing Facility, including the satellites, pipelines, and any other related aboveground structures that may be visible from the six KOPs.

OEHI will prepare photographic simulations for each of the six KOP viewpoints reflecting the new aboveground elements of the Processing Facility, satellites, pipelines, and any other related aboveground structures that may be visible from the six KOPs. Electronic and paper copies of 11-inch by 17-inch color photographic simulations at life size scale for each of the six KOP viewpoints will be provided to the CEC based on conceptual design parameters of the subject facilities. The simulations will be submitted to CEC as soon as they are completed.

A179. Please provide electronic and paper copies of 11-inch by 17-inch color photographic simulations at life size scale for each of the six KOP viewpoints.

Refer to A178

A180. Please provide information on the dimensions (i.e. height and width) of all the proposed above ground structures.

Refer to A178

Attachment A137-1

Revised Emission Factors and Revised VOC Emission Estimates

Attachment-I

Revised Emission Factors and Revised Fugitive VOC Emission Estimates

Revised Emission Factors

EPA Protocol For Equipment Leak Emission Estimates (November 1995)

Average Leak Rates For Components At Oil and Natural Gas Processing Facilities

ALR - Fugitive Emissions Factors For A 10,000 ppmv Leak Threshold

Component Type	Componen Service Type	Proposed Leak Fraction	EPA Table 5-7 ALR Equations For Proposed Leak Threshold (10,000 ppmv) And Specified leak fraction (LKFRAC)	ALR Factor lb/day per component
Valves	Gas/Light Liquid	0.0010	ALR = [(0.098 x LKFRAC) + 2.5E-5]*2.2*24	6.494E-03
	Light Crude Oil	0.0010	ALR = [(0.087 x LKFRAC) + 1.9E-5]*2.2*24	5.597E-03
	Heavy Crude Oil	0.0010	ALR = (8.4 E-6)*2.2*24	4.435E-04
Pump Seals	Gas/Light Liquid	0.0010	ALR = [(0.074 x LKFRAC) + 3.5E-4]*2.2*24	2.239E-02
	Light Crude Oil	0.0010	ALR = [(0.100 x LKFRAC) + 5.1E-4]*2.2*24	3.221E-02
	Heavy Crude Oil	0.0010	ALR = Below detection limit	0.000E+00
Others	Gas/Light Liquid	0.0010	ALR = [(0.089 x LKFRAC) + 1.2E-4]*2.2*24	1.104E-02
	Light Crude Oil	0.0010	ALR = [(0.083 x LKFRAC) + 1.4E-4]*2.2*24	1.177E-02
	Heavy Crude Oil	0.0010	ALR = (3.2 E-5)*2.2*24	1.690E-03
Connectors	Gas/Light Liquid	0.0010	ALR = [(0.026 x LKFRAC) + 1.0E-5]*2.2*24	1.901E-03
	Light Crude Oil	0.0010	ALR = [(0.026 x LKFRAC) + 9.7E-6]*2.2*24	1.885E-03
	Heavy Crude Oil	0.0010	ALR = Below detection limit	0.000E+00
Flanges	Gas/Light Liquid	0.0010	ALR = [(0.082 x LKFRAC) + 5.7E-6]*2.2*24	4.631E-03
	Light Crude Oil	0.0010	ALR = [(0.073 x LKFRAC) + 2.4E-6]*2.2*24	3.981E-03
	Heavy Crude Oil	0.0010	ALR = Below detection limit	0.000E+00
Open-ended Lines	Gas/Light Liquid	0.0010	ALR = [(0.055 x LKFRAC) + 1.5E-5]*2.2*24	3.696E-03
	Light Crude Oil	0.0010	ALR = [(0.044 x LKFRAC) + 1.4E-5]*2.2*24	3.062E-03
	Heavy Crude Oil	0.0010	ALR = [(0.030 x LKFRAC) + 7.2E-6]*2.2*24	1.964E-03

EPA Protocol For Equipment Leak Emission Estimates (November 1995)

Average Leak Rates For Components At Oil and Natural Gas Processing Facilities

ALR - Fugitive Emissions Factors For A 2,000 ppmv Leak Threshold

Component Type	Component Service Type	Proposed Leak Fraction	EPA Table 5-7 ALR Equations For Proposed Leak Threshold (2,000 ppmv) And Specified leak fraction (LKFRAC)	ALR Factor lb/day per component
Valves	Gas/Light Liquid	0.0010	ALR = [(0.083 x LKFRAC) + 1.4E-5]*2.2*24	5.122E-03
	Light Crude Oil	0.0010	ALR = [(0.075 x LKFRAC) + 1.4E-5]*2.2*24	4.699E-03
	Heavy Crude Oil	0.0010	ALR = [(0.0013 x LKFRAC) + 7.8E-6]*2.2*24	4.805E-04
Pump Seals	Gas/Light Liquid	0.0010	ALR = [(0.052 x LKFRAC) + 2.3E-4]*2.2*24	1.489E-02
	Light Crude Oil	0.0010	ALR = [(0.082 x LKFRAC) + 1.9E-4]*2.2*24	1.436E-02
	Heavy Crude Oil	0.0010	ALR = Below detection limit	0.000E+00
Others	Gas/Light Liquid	0.0010	ALR = [(0.066 x LKFRAC) + 4.5E-5]*2.2*24	5.861E-03
	Light Crude Oil	0.0010	ALR = [(0.067 x LKFRAC) + 6.4E-5]*2.2*24	6.917E-03
	Heavy Crude Oil	0.0010	ALR = (3.2 E-5)*2.2*24	1.690E-03
Connectors	Gas/Light Liquid	0.0010	ALR = [(0.020 x LKFRAC) + 8.5E-6]*2.2*24	1.505E-03
	Light Crude Oil	0.0010	ALR = [(0.022 x LKFRAC) + 8.6E-6]*2.2*24	1.616E-03
	Heavy Crude Oil	0.0010	ALR = Below detection limit	0.000E+00
Flanges	Gas/Light Liquid	0.0010	ALR = [(0.059 x LKFRAC) + 2.6E-6]*2.2*24	3.252E-03
	Light Crude Oil	0.0010	ALR = [(0.055 x LKFRAC) + 1.6E-6]*2.2*24	2.988E-03
	Heavy Crude Oil	0.0010	ALR = Below detection limit	0.000E+00
Open-ended Lines	Gas/Light Liquid	0.0010	ALR = [(0.045 x LKFRAC) + 7.5E-6]*2.2*24	2.772E-03
	Light Crude Oil	0.0010	ALR = [(0.036 x LKFRAC) + 6.7E-6]*2.2*24	2.255E-03
	Heavy Crude Oil	0.0010	ALR = [(0.020 x LKFRAC) + 6.0E-6]*2.2*24	1.373E-03

EPA Protocol For Equipment Leak Emission Estimates (November 1995)

Average Leak Rates For Components At Oil and Natural Gas Processing Facilities

ALR - Fugitive Emissions Factors For A 1,000 ppmv Leak Threshold

Component Type	Component Service Type	Proposed Leak Fraction	EPA Table 5-7 ALR Equations For Proposed Leak Threshold (1,000 ppmv) And Specified leak fraction (LKFRAC)	ALR Factor lb/day per component
Valves	Gas/Light Liquid	0.0010	ALR = [(0.076 x LKFRAC) + 1.1E-5]*2.2*24	4.594E-03
	Light Crude Oil	0.0010	ALR = [(0.069 x LKFRAC) + 1.2E-5]*2.2*24	4.277E-03
	Heavy Crude Oil	0.0010	ALR = (0.0013 x LKFRAC) + 7.8E-6)*2.2*24	4.805E-04
Pump Seals	Gas/Light Liquid	0.0010	ALR = [(0.052 x LKFRAC) + 2.3E-4]*2.2*24	1.489E-02
	Light Crude Oil	0.0010	ALR = [(0.079 x LKFRAC) + 1.5E-4]*2.2*24	1.209E-02
	Heavy Crude Oil	0.0010	ALR = Below detection limit	0.000E+00
Others	Gas/Light Liquid	0.0010	ALR = [(0.061 x LKFRAC) + 3.1E-5]*2.2*24	4.858E-03
	Light Crude Oil	0.0010	ALR = [(0.058 x LKFRAC) + 4.4E-5]*2.2*24	5.386E-03
	Heavy Crude Oil	0.0010	ALR = [(0.0011 x LKFRAC) + 2.1E-5]*2.2*24	1.167E-03
Connectors	Gas/Light Liquid	0.0010	ALR = [(0.018 x LKFRAC) + 8.0E-6]*2.2*24	1.373E-03
	Light Crude Oil	0.0010	ALR = [(0.021 x LKFRAC) +8.3E-6]*2.2*24	1.547E-03
	Heavy Crude Oil	0.0010	ALR = Below detection limit	0.000E+00
Flanges	Gas/Light Liquid	0.0010	ALR = [(0.051 x LKFRAC) + 1.8E-6]*2.2*24	2.788E-03
	Light Crude Oil	0.0010	ALR = [(0.046 x LKFRAC) + 1.2E-6]*2.2*24	2.492E-03
	Heavy Crude Oil	0.0010	ALR = Below detection limit	0.000E+00
Open-ended Lines	Gas/Light Liquid	0.0010	ALR = [(0.039 x LKFRAC) + 5.0E-6]*2.2*24	2.323E-03
	Light Crude Oil	0.0010	ALR = [(0.032 x LKFRAC) + 4.7E-6]*2.2*24	1.938E-03
	Heavy Crude Oil	0.0010	ALR = [(0.015 x LKFRAC) + 4.9E-6]*2.2*24	1.051E-03

EPA Protocol For Equipment Leak Emission Estimates (November 1995)

Average Leak Rates For Components At Oil and Natural Gas Processing Facilities

ALR - Fugitive Emissions Factors For A 500 ppmv Leak Threshold

Component Type	Component Service Type	Proposed Leak Fraction	EPA Table 5-7 ALR Equations For Proposed Leak Threshold (500 ppmv) And Specified leak fraction (LKFRAC)	ALR Factor lb/day per component
Valves	Gas/Light Liquid	0.0010	ALR = [(0.070 x LKFRAC) + 9.1E-6]*2.2*24	4.176E-03
	Light Crude Oil	0.0010	ALR = [(0.059 x LKFRAC) + 9.4E-6]*2.2*24	3.612E-03
	Heavy Crude Oil	0.0010	ALR = (0.0013 x LKFRAC) + 7.8E-6)*2.2*24	4.805E-04
Pump Seals	Gas/Light Liquid	0.0010	ALR = [(0.027 x LKFRAC) + 1.1E-4]*2.2*24	7.234E-03
	Light Crude Oil	0.0010	ALR = [(0.071 x LKFRAC) + 7.9E-5]*2.2*24	7.920E-03
	Heavy Crude Oil	0.0010	ALR = Below detection limit	0.000E+00
Others	Gas/Light Liquid	0.0010	ALR = [(0.055 x LKFRAC) + 1.8E-5]*2.2*24	3.854E-03
	Light Crude Oil	0.0010	ALR = [(0.053 x LKFRAC) + 3.4E-5]*2.2*24	4.594E-03
	Heavy Crude Oil	0.0010	ALR = [(0.0011 x LKFRAC) + 2.1E-5]*2.2*24	1.167E-03
Connectors	Gas/Light Liquid	0.0010	ALR = [(0.016 x LKFRAC) + 7.7E-6]*2.2*24	1.251E-03
	Light Crude Oil	0.0010	ALR = [(0.016 x LKFRAC) +7.7E-6]*2.2*24	1.251E-03
	Heavy Crude Oil	0.0010	ALR = Below detection limit	0.000E+00
Flanges	Gas/Light Liquid	0.0010	ALR = [(0.043 x LKFRAC) + 1.1E-6]*2.2*24	2.328E-03
	Light Crude Oil	0.0010	ALR = [(0.037 x LKFRAC) + 9.4E-7]*2.2*24	2.003E-03
	Heavy Crude Oil	0.0010	ALR = Below detection limit	0.000E+00
Open-ended Lines	Gas/Light Liquid	0.0010	ALR = [(0.037 x LKFRAC) + 4.1E-6]*2.2*24	2.170E-03
	Light Crude Oil	0.0010	ALR = [(0.030 x LKFRAC) + 3.8E-6]*2.2*24	1.785E-03
	Heavy Crude Oil	0.0010	ALR = [(0.012 x LKFRAC) + 4.3E-6]*2.2*24	8.606E-04

Revised Fugitive VOC Emissions

Fugitive VOC Emissions From Components
Calculated From Component Counts and EPA ALR Emission Factors

Fugitive Emissions From The Reinjection Compression Facility (RCF)

Type of Component	Component Service	Component Counts For RCF	Leak Threshold (ppmv)	Leak Fraction	EPA 1995 ALR TOG Factor lb/day*Component	Fugitive VOC Emissions (lb/day)	Equivalent Gas Volume (SCF/Day)
Valves	Gas/Light Liquid	319	500	0.0010	4.176E-03	1.333	20.630
	Light Crude Oil	384	500	0.0010	3.612E-03	1.387	10.429
	Heavy Crude Oil	12	500	0.0010	4.805E-04	0.006	0.007
Pump Seals	Gas/Light Liquid	0	500	0.0010	7.234E-03	0.000	0.000
	Light Crude Oil	0	500	0.0010	7.920E-03	0.000	0.000
	Heavy Crude Oil	2	500	0.0010	0.000E+00	0.000	0.000
Others	Gas/Light Liquid	43	500	0.0010	3.854E-03	0.167	2.577
	Light Crude Oil	61	500	0.0010	4.594E-03	0.281	2.114
	Heavy Crude Oil	1	500	0.0010	1.167E-03	0.001	0.002
Connectors	Gas/Light Liquid	1,496	500	0.0010	1.251E-03	1.873	28.977
	Light Crude Oil	3,850	500	0.0010	1.251E-03	4.817	36.225
	Heavy Crude Oil	7	500	0.0010	0.000E+00	0.000	0.000
Flanges	Gas/Light Liquid	1,050	500	0.0010	2.328E-03	2.445	37.835
	Light Crude Oil	558	500	0.0010	2.003E-03	1.118	8.406
	Heavy Crude Oil	26	500	0.0010	0.000E+00	0.000	0.000
Open-ended Lines	Gas/Light Liquid	0	500	0.0010	2.170E-03	0.000	0.000
	Light Crude Oil	0	500	0.0010	1.785E-03	0.000	0.000
	Heavy Crude Oil	0	500	0.0010	8.606E-04	0.000	0.000
Total Fugitive VOC Emissions From Associated Components (lb/day)						13.427	147.201
Weight percentage of VOC in the total organic compounds in gas ?						100.0	--------
Weight percentage of VOC in the total organic compounds in oil ?						100.0	--------

Fugitive VOC Emissions From Components
Calculated From Component Counts and EPA ALR Emission Factors

Fugitive Emissions From The Carbon Dioxide Recovery Plant (CRP)

Type of Component	Component Service	Component Counts For CRP	Leak Threshold (ppmv)	Leak Fraction	EPA 1995 ALR TOG Factor lb/day-Component	Fugitive VOC Emissions (lb/day)	Equivalent Gas Volume (SCF/Day)
Valves	Gas/Light Liquid	1,289	500	0.0010	4.176E-03	5.383	83.296
	Light Crude Oil	1,961	500	0.0010	3.612E-03	7.081	53.251
	Heavy Crude Oil	236	500	0.0010	6.864E-05	0.016	0.021
Pump Seals	Gas/Light Liquid	0	500	0.0010	7.234E-03	0.000	0.000
	Light Crude Oil	43	500	0.0010	7.920E-03	0.342	2.573
	Heavy Crude Oil	10	500	0.0010	0.000E+00	0.000	0.000
Others	Gas/Light Liquid	247	500	0.0010	3.854E-03	0.953	14.745
	Light Crude Oil	416	500	0.0010	4.594E-03	1.913	14.384
	Heavy Crude Oil	43	500	0.0010	1.167E-03	0.050	0.064
Connectors	Gas/Light Liquid	9,662	500	0.0010	1.251E-03	12.091	187.110
	Light Crude Oil	8,204	500	0.0010	0.000E+00	0.000	0.000
	Heavy Crude Oil	398	500	0.0010	0.000E+00	0.000	0.000
Flanges	Gas/Light Liquid	3,310	500	0.0010	2.328E-03	7.706	119.255
	Light Crude Oil	2,426	500	0.0010	2.003E-03	4.861	36.551
	Heavy Crude Oil	272	500	0.0010	0.000E+00	0.000	0.000
Open-ended Lines	Gas/Light Liquid	0	500	0.0010	2.170E-03	0.000	0.000
	Light Crude Oil	0	500	0.0010	1.785E-03	0.000	0.000
	Heavy Crude Oil	0	500	0.0010	8.606E-04	0.000	0.000
Total Fugitive VOC Emissions From Associated Components (lb/day)						40.397	511.249

Weight percentage of VOC in the total organic compounds in gas?	100.0	
Weight percentage of VOC in the total organic compounds in oil?	100.0	

Fugitive VOC Emissions From Components
Calculated From Component Counts and EPA ALR Emission Factors

Fugitive Emissions From The Central Tank Battery (CTB)

Type of Component	Component Service	Component Counts For CTB	Leak Threshold (ppmv)	Leak Fraction	EPA 1995 ALR TOG Factor lb/day*Component	Fugitive VOC Emissions (lb/day)	Equivalent Gas Volume (SCF/Day)
Valves	Gas/Light Liquid	98	500	0.0010	4.176E-03	0.409	6.334
	Light Crude Oil	688	500	0.0010	3.612E-03	2.485	18.685
	Heavy Crude Oil	0	500	0.0010	6.864E-05	0.000	0.000
Pump Seals	Gas/Light Liquid	0	500	0.0010	7.234E-03	0.000	0.000
	Light Crude Oil	16	500	0.0010	7.920E-03	0.127	0.953
	Heavy Crude Oil	0	500	0.0010	0.000E+00	0.000	0.000
Others	Gas/Light Liquid	22	500	0.0010	3.854E-03	0.085	1.312
	Light Crude Oil	80	500	0.0010	4.594E-03	0.367	2.763
	Heavy Crude Oil	0	500	0.0010	1.167E-03	0.000	0.000
Connectors	Gas/Light Liquid	324	500	0.0010	1.251E-03	0.405	6.274
	Light Crude Oil	982	500	0.0010	0.000E+00	0.000	0.000
	Heavy Crude Oil	0	500	0.0010	0.000E+00	0.000	0.000
Flanges	Gas/Light Liquid	100	500	0.0010	2.328E-03	0.233	3.603
	Light Crude Oil	814	500	0.0010	2.003E-03	1.631	12.262
	Heavy Crude Oil	0	500	0.0010	0.000E+00	0.000	0.000
Open-ended Lines	Gas/Light Liquid	0	500	0.0010	2.170E-03	0.000	0.000
	Light Crude Oil	0	500	0.0010	1.785E-03	0.000	0.000
	Heavy Crude Oil	0	500	0.0010	8.606E-04	0.000	0.000
Total Fugitive VOC Emissions From Associated Components (lb/day)						5.742	52.187
Weight percentage of VOC in the total organic compounds in gas?						100.0	
Weight percentage of VOC in the total organic compounds in oil?						100.0	

Fugitive VOC Emissions From Components
Calculated From Component Counts and EPA ALR Emission Factors

Fugitive Emissions From Production Satellite Settings

Type of Component	Component Service	Component Counts Per Setting	Leak Threshold (ppmv)	Leak Fraction	EPA 1995 ALR TOG Factor lb/day Component	Fugitive VOC Emissions (lb/day)	Equivalent Gas Volume (SCF/Day)
Valves	Gas/Light Liquid	0	2,000	0.0010	5.122E-03	0.000	0.000
	Light Crude Oil	572	2,000	0.0010	4.699E-03	2.688	20.213
	Heavy Crude Oil	0	2,000	0.0010	4.805E-04	0.000	0.000
Pump Seals	Gas/Light Liquid	0	2,000	0.0010	1.489E-02	0.000	0.000
	Light Crude Oil	0	2,000	0.0010	1.436E-02	0.000	0.000
	Heavy Crude Oil	0	2,000	0.0010	0.000E+00	0.000	0.000
Others	Gas/Light Liquid	208	2,000	0.0010	5.861E-03	1.219	18.865
	Light Crude Oil	0	2,000	0.0010	6.917E-03	0.000	0.000
	Heavy Crude Oil	0	2,000	0.0010	1.690E-03	0.000	0.000
Connectors	Gas/Light Liquid	2,106	2,000	0.0010	1.505E-03	3.169	49.042
	Light Crude Oil	936	2,000	0.0010	0.000E+00	0.000	0.000
	Heavy Crude Oil	0	2,000	0.0010	0.000E+00	0.000	0.000
Flanges	Gas/Light Liquid	286	2,000	0.0010	3.252E-03	0.930	14.395
	Light Crude Oil	1,144	2,000	0.0010	2.988E-03	3.419	25.709
	Heavy Crude Oil	0	2,000	0.0010	0.000E+00	0.000	0.000
Open-ended Lines	Gas/Light Liquid	0	2,000	0.0010	2.772E-03	0.000	0.000
	Light Crude Oil	0	2,000	0.0010	2.255E-03	0.000	0.000
	Heavy Crude Oil	0	2,000	0.0010	1.373E-03	0.000	0.000
Total Fugitive VOC Emissions From Associated Components (lb/day)						11.425	128.223
Weight percentage of VOC in the total organic compounds in gas?						100.0	
Weight percentage of VOC in the total organic compounds in oil?						100.0	

Fugitive VOC Emissions From Components
Calculated From Component Counts and EPA ALR Emission Factors

Fugitive Emissions From Crude Oil and Natural Gas Production Wells

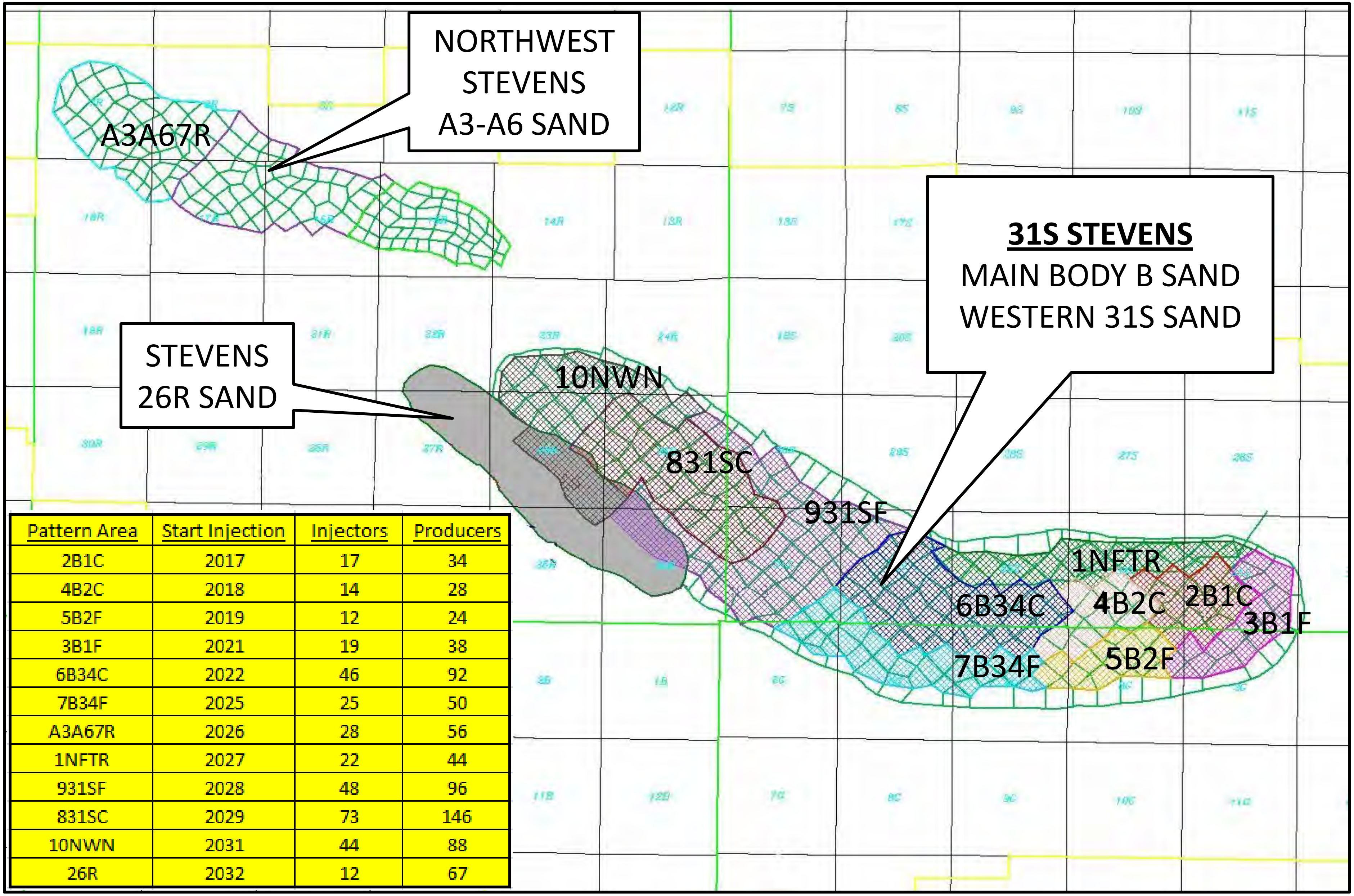
Type of Component	Component Service	Component Counts Per Well	Leak Threshold (ppmv)	Leak Fraction	EPA 1995 ALR TOG Factor lb/day-Component	Fugitive VOC Emissions (lb/day)	Equivalent Gas Volume (SCF/Day)
Valves	Gas/Light Liquid	10,260	2,000	0.0010	5.122E-03	52.548	813.171
	Light Crude Oil	3,600	2,000	0.0010	4.699E-03	16.917	127.214
	Heavy Crude Oil	0	2,000	0.0010	4.805E-04	0.000	0.000
Pump Seals	Gas/Light Liquid	720	2,000	0.0010	1.489E-02	10.721	165.899
	Light Crude Oil	0	2,000	0.0010	1.436E-02	0.000	0.000
	Heavy Crude Oil	0	2,000	0.0010	0.000E+00	0.000	0.000
Others	Gas/Light Liquid	360	2,000	0.0010	5.861E-03	2.110	32.650
	Light Crude Oil	1,080	2,000	0.0010	6.917E-03	7.470	56.174
	Heavy Crude Oil	0	2,000	0.0010	1.690E-03	0.000	0.000
Connectors	Gas/Light Liquid	25,380	2,000	0.0010	1.505E-03	38.192	591.016
	Light Crude Oil	19,800	2,000	0.0010	0.000E+00	0.000	0.000
	Heavy Crude Oil	0	2,000	0.0010	0.000E+00	0.000	0.000
Flanges	Gas/Light Liquid	7,020	2,000	0.0010	3.252E-03	22.832	353.330
	Light Crude Oil	6,480	2,000	0.0010	2.988E-03	19.365	145.624
	Heavy Crude Oil	0	2,000	0.0010	0.000E+00	0.000	0.000
Open-ended Lines	Gas/Light Liquid	0	2,000	0.0010	2.772E-03	0.000	0.000
	Light Crude Oil	0	2,000	0.0010	2.255E-03	0.000	0.000
	Heavy Crude Oil	0	2,000	0.0010	1.373E-03	0.000	0.000
Total Fugitive VOC Emissions From Associated Components (lb/day)						170.155	2285.077
Weight percentage of VOC in the total organic compounds in gas?						100.0	
Weight percentage of VOC in the total organic compounds in oil?						100.0	

Attachment A176-1

Oxy Phase 1 CO2 Project Boundaries and Pattern Schedule

CEC HECA Project Data Request A176

Oxy Phase 1 CO2 Project Boundaries and Pattern Schedule



NORTHWEST STEVENS A3-A6 SAND

STEVENS 26R SAND

31S STEVENS
MAIN BODY B SAND
WESTERN 31S SAND

Pattern Area	Start Injection	Injectors	Producers
2B1C	2017	17	34
4B2C	2018	14	28
5B2F	2019	12	24
3B1F	2021	19	38
6B34C	2022	46	92
7B34F	2025	25	50
A3A67R	2026	28	56
1NFTR	2027	22	44
931SF	2028	48	96
831SC	2029	73	146
10NWN	2031	44	88
26R	2032	12	67

Attachment A177-1

Pre-FEED Engineering Study, Process Design Basis, Mustang Engineering,

April 15, 2010.

Occidental of Elk Hills, Inc.

Elk Hills CO_2 Project
Pre-FEED Engineering Study

Process Design Basis

Document 16179-MUS-PRO-BD-00-0001

B	04/15/10	Issued for FEED	PMB	ARJ	SCW
A	01/29/10	Issued For Internal Review	PMB	ARJ	LAS
REVISION	**DATE**	**DESCRIPTION**	**ORIGINATOR**	**CHECKED**	**APPROVED**

Mustang Engineering L.P.
Project Number 16179

Document No.	Project	Originator	Discipline	Type	Area	Sequence No.
	16179	MUS	PRO	BD	00	0001

TABLE OF CONTENTS

1.0 INTRODUCTION

Hydrogen Energy (HECA) is evaluating installing a hydrogen plant near the Elk Hills property; the hydrogen will be used to fuel an electrical generation plant to provide power to the California markets. A by-product of the process is a fairly rich CO_2 stream that Oxy is considering taking delivery of and then inject it into various oil reservoirs for enhanced oil recovery. As a result, Oxy will need to install CO_2 supply/storage, field facilities/field piping systems, CO_2 processing plant and field utility systems in order to:

- Inject the CO_2 in the oil reservoirs.
- Produce and separate the oil, water and gas stream for sales and reinjection.
- Compress and process the CO_2/hydrocarbon gas stream for reinjection and sales.

There are approximately 250 injection wells and 325 production wells serving these facilities. The information in this document shall be used to determine design parameters of the CO_2 processing plant and field utility systems.

2.0 SITE DATA

The following site data is provided by Oxy.

Location - 25 miles SW of Bakersfield, CA

Project Access

• Highway/road limits	(attachment – area siting map)
• Nearest Commercial Airport	Bakersfield, CA

Site Elevation - ~ 1300 feet

Soil - Data available from other projects but assumption should be made that new soils reports will be obtained after pre-FEED study.

Seismic Risk And Wind Loading - Design shall comply with seismic and wind loading factors as defined by the 2008 Kern County Building Code. This code is based on the 2007 California Building Code. Seismic Zone 4

Temperature

Design Dry Bulb:	105 °F
Maximum Dry Bulb:	110 °F (Design for new air-cooled exchangers)
Design Maximum Wet Bulb:	72 °F (Corresponds to 33% R.H. at 95.6°F)
Design Minimum Dry Bulb:	40 °F
Annual Average	65 °F
January Average	48 °F
July Average	84 °F

Wind

Velocity: 6.0/5.4 mph average summer/winter
design wind loading per 2008 Kern County Building Code

Direction: Winter - prevailing SSW (direction from where wind is coming)
Spring – prevailing NNE
Summer - prevailing SSW (direction from where wind is coming)
Fall – prevailing NNE

Rainfall (Design) - 25 year maximum in one hour - Check with Weather Bureau and Airports

3.0 PROCESS FLUID DATA

The following process data is used for both design and simulation purposes.

Composition of Gas from HECA

Properties	**Expected Operating Conditions**	**Operational Excursions**
Components	**Volume %**	**Volume %**
Carbon Dioxide, CO_2	>97	>96
Nitrogen, N_2	< 2	2
Total Sulfur (H_2S & COS)	<65 ppmv	<220 ppmv
Hydrocarbons, (C_1-C_4)	<1	-
Hydrogen Sulfide	<10 ppmv	100 ppmv (max)
Oxygen	< 10 ppmv	-
SO_2	<10 ppmv	-
Ammonia	<1 ppmv	-
Particulate Matter (dust, sand, iron oxide, catalyst fines, silicates)	<1 ppmv	-
Carbon Monoxide	<800 ppmv	-
Solvent (Methanol)	<200 ppmv	-
Water, H_2O	0.61 lb/MMCF 13 ppmv Dew point 11 °F	1 lb/MMCF (max) 20 ppmv (max)

Makeup CO_2 delivery conditions and composition used in the HECA plant is assumed to be

Temperature	F	X
Pressure	psig	2500
CO_2	mol frac	0.97
N2	mol frac	0.02
HC	mol frac	0.01

Inlet gas properties and compositions to the gas plant change with time. Milestone years are shown below.

Year	**<none>**	**2015**	**2017**	**2019 CRP Installed)**	**2025 (peak gas)**	**2030 (peak Oil)**	**2035 (Peak Water)**
Vapor Fraction	<none>	1.000	1.000	1.000	1.000	1.000	1.000
Temperature	F	102	102	102	102	102	102
Pressure	psig	300	300	300	300	300	300
Mass Flow	lb/hr	62276	637110	1024051	1982253	1817124	1884217
Molecular Weight	<none>	30.86	40.34	42.01	42.90	43.70	43.70
Mass Enthalpy	Btu/lb	-3006	-3575	-3706	-3762	-3827	-3827
Std Gas Flow	MMSCFD	18	144	222	421	379	393
Mass Heat Capacity	Btu/lb-F	0.348	0.265	0.251	0.246	0.241	0.241
Mass Density	lb/ft3	1.75	2.34	2.44	2.50	2.56	2.56
SG Air	rel_to_air	1.066	1.393	1.450	1.481	1.509	1.509
Compressibility	<none>	0.923	0.902	0.898	0.895	0.892	0.892
Thermal Conductivity	Btu/hr-ft-F	0.016	0.013	0.012	0.012	0.012	0.012
Component Molar Fraction							
H_2O	<none>	0.004	0.004	0.004	0.004	0.004	0.004
Nitrogen		0.010	0.021	0.021	0.015	0.004	0.004
Oxygen		0.000	0.000	0.000	0.000	0.000	0.000
CO_2		0.433	0.815	0.901	0.941	0.982	0.982
H_2S		0.000	0.000	0.000	0.000	0.000	0.000
Methane		0.467	0.120	0.058	0.029	0.006	0.006
Ethane		0.032	0.014	0.006	0.004	0.001	0.001
Propane		0.024	0.011	0.004	0.003	0.001	0.001
i-Butane		0.006	0.003	0.001	0.001	0.000	0.000
n-Butane		0.014	0.007	0.003	0.002	0.001	0.001
i-Pentane		0.005	0.003	0.001	0.001	0.000	0.000
n-Pentane		0.006	0.004	0.002	0.001	0.000	0.000
C6s*		0.000	0.000	0.000	0.000	0.000	0.000
C7+*		0.000	0.000	0.000	0.000	0.000	0.000

4.0 PLANT PRODUCTS

Five plant products will be prepared from the gas plant. These products and their delivery pressure are:

CO_2 for injection delivery at 3000 psig*, pipeline design 3500 MAWP.
Hydrocarbon condensate (NGL) delivery to pipeline – to be determined in FEED
Natural Gas to pipeline delivery to pipeline 1200.
Produced water for injection delivery at 3000 psig*, pipeline design 3500 MAWP.
N_2 from an NRU delivery at 10 psig.
*Injection pressure is at top of hill.

Product Compositions (Mol Fract.) From HYSYS Simulation

	CO_2 Product	**NGL**	**Natural Gas**
H_2O	0.000	0.000	0.000
Nitrogen	0.009	0.000	0.019
Oxygen	0.000	0.000	0.000
CO_2	0.964	0.005	0.000
H_2S	0.000	0.000	0.000
Methane	0.018	0.000	0.966
Ethane	0.003	0.000	0.016
Propane	0.003	0.030	0.000
iButane	0.001	0.068	0.000
nButane	0.002	0.269	0.000
iPentane	0.001	0.228	0.000
nPentane	0.001	0.401	0.000
Total	1.000	1.000	1.000

*Estimated Natural Gas composition from NRU

5.0 PRODUCTION PROFILE

Below is the predicted profile for on a yearly basis for the Elk Hills facility. The table was created by compiling production forecast data from Oxy.

	Production Rates			**Injection Rates**		
	Oil Prod	**Tot WH gas**	**Wtr Prod**	**CO_2 Inj**	**Purchased CO_2**	**Wtr Inj**
	BPD	**MCFD**	**BPD**	**MCFD**	**MCFD**	**BPD**
Dec-2015	1,623	19,426	65,977	146,472	135,475	3,736
Dec-2016	5,951	98,453	109,201	232,700	176,633	51,199
Dec-2017	10,367	144,568	139,668	274,548	178,375	91,265
Oct-2018	13,495	199,171	147,379	283,000	138,982	124,814
Dec-2019	13,833	222,771	160,790	275,277	94,364	150,590
Dec-2020	15,082	277,036	200,856	369,284	139,075	169,956
Dec-2021	16,318	335,550	219,522	403,093	124,389	206,134
Dec-2022	16,492	360,642	241,677	417,517	104,245	231,595
Dec-2023	16,707	405,240	249,361	430,557	73,302	253,150
Dec-2024	15,586	418,196	277,026	460,069	82,617	277,614
Dec-2025	16,148	422,403	322,534	457,945	91,353	327,083
Dec-2026	14,737	366,174	354,495	377,361	56,825	372,640
Dec-2027	15,120	346,874	391,145	358,731	60,967	402,720
Dec-2028	15,489	355,086	455,350	463,509	158,123	429,562
Dec-2029	17,149	393,681	469,292	394,306	61,275	488,651
Dec-2030	17,518	379,543	516,249	417,975	93,089	518,445
Dec-2031	17,399	388,941	541,535	403,210	67,294	560,266
Dec-2032	17,458	400,675	564,950	401,597	51,545	586,005
Dec-2033	16,433	408,841	587,029	392,620	27,037	610,124
Dec-2034	15,407	402,165	628,437	395,866	35,738	649,699
Dec-2035	14,609	393,565	574,581	354,066	3,929	614,124
Dec-2036	12,777	351,703	529,593	293,554	(28,024)	571,652
Dec-2037	10,744	322,434	475,292	257,671	(39,915)	520,812
Dec-2038	8,303	261,128	456,276	205,461	(37,595)	498,704
Dec-2039	6,565	222,143	443,356	155,272	(53,027)	485,601
Dec-2040	4,826	172,247	414,964	113,080	(49,209)	451,474
Dec-2041	3,732	138,755	389,966	80,612	(50,956)	423,700

Production Profile for a single well is shown below. This profile is used for the sizing of the satellites.

	Production Rates			Injection Rates	
	Oil Prod	**Tot WH gas**	**Wtr Prod**	**CO2 Inj**	**Wtr Inj**
	BPD	MCFD	BPD	MCFD	BPD
Dec-2015	124	1627	3521	7,411	452
Dec-2016	176	2772	1573	3,301	2,024
Dec-2017	202	2504	1813	3,354	1,825
Oct-2018	180	3146	1773	3,152	2,018
Dec-2019	149	3142	1884	2,848	2,143
Dec-2020	141	3571	2016	3,751	2,045
Dec-2021	107	3222	2102	3,418	2,179
Dec-2022	104	3568	2143	3,406	2,245
Dec-2023	96	3815	2206	3,395	2,423
Dec-2024	68	3082	1975	1,466	3,020
Dec-2025	14	471	2689	0	3,105
Dec-2026	10	359	2791	0	3,000
Dec-2027	10	353	2807	0	2,990
Dec-2028	9	350	2831	0	3,004
Dec-2029	9	353	2925	0	3,094
Dec-2030	8	332	2825	0	2,980
Dec-2031	8	333	2929	0	3,080
Dec-2032	7	323	2984	0	3,128
Dec-2033	7	313	3057	0	3,193
Dec-2034	6	293	3117	0	3,245

6.0 MISCELLANEOUS

Refrigerant used is HD5 propane.

Attachment A177-2

Preliminary Project Description (Pre-FEED Stage), ManageTech Solutions, April 16, 2010.

PRELIMINARY PROJECT DESCRIPTION (PRE-FEED STAGE)

CO_2 ENHANCED OIL RECOVERY AT THE ELK HILLS OIL FIELD

April 16, 2010

Prepared for:

Occidental of Elk Hills, Inc.
10800 Stockdale Highway
Bakersfield, California 93311

Prepared by:

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SOLUTIONS
5000 E. Spring Street
Suite 720
Long Beach, California 90815
P: 562-740-1060

Tables

Figures

1 Introduction and Project Overview

Occidental of Elk Hills, Inc. (OEHI) operates a large, mature oil production field in the Elk Hills Unit near Bakersfield, California. The boundaries of the Elk Hills Unit are depicted in Figure 1-1 OEHI is proposing to extend its existing Enhanced Oil Recovery (EOR) operations by utilizing carbon dioxide (CO_2) from the proposed Hydrogen Energy California (HECA) project to facilitate oil production from its Elk Hills operations (hereinafter referred to as the "OEHI CO_2 EOR Project"). The HECA Project, which will be located approximately 4 miles north of the Elk Hills Unit, will generate CO_2 from an Integrated Gasification Combined Cycle (IGCC) power plant.

This Project Description has been prepared based on information available to OEHI from a Class 3 Preliminary Front End Engineering Design (Pre-FEED) analysis. The Project Description will be updated as the HECA Project is further detailed and in accordance with results from a final FEED analysis.

In CO_2 EOR, the injected CO_2 moves through the reservoir, encountering residual droplets of crude oil, becoming miscible with the oil, and forming a concentrated more mobile oil bank that is swept toward the production wells. The U.S. Department of Energy (DOE) estimates that CO_2 EOR has the potential to increase total U.S. oil reserves by 45 to 85 billion barrels of oil (bbo), which are 2 to 4 times the current U.S. total proven reserves. A significant portion of these potential oil reserves are in California (5 to 6 bbo). (DOE-NETL, 2008)

The OEHI CO_2 EOR Project will have the capacity to utilize all of the CO_2 delivered by the HECA Project, both on an annual basis and over the expected life of the HECA Project. Based on extensive studies of the subsurface at Elk Hills, OEHI has determined that there is more than adequate capacity within the target geological formations to inject and trap the total volume of CO_2 delivered by the HECA Project. The capacity, operational injection volumes and pressures will be reviewed as a part of OEHI's permitting process with California Division of Oil, Gas and Geothermal Resources (DOGGR). DOGGR will be the agency responsible for issuing Class II Underground Injection Control (UIC) permits for the planned operations under provisions of the state Public Resources Code and the federal Safe Drinking Water Act of 1974.

As with oil and gas, CO_2 has been naturally trapped in geologic formations for millions of years. The injection of CO_2 into such formations has been safely practiced on an industrial scale for decades, mostly in conjunction with hydrocarbon production. Further, the U.S. Environmental Protection Agency (EPA) has recognized that oil and gas reservoirs will play a valuable role in the

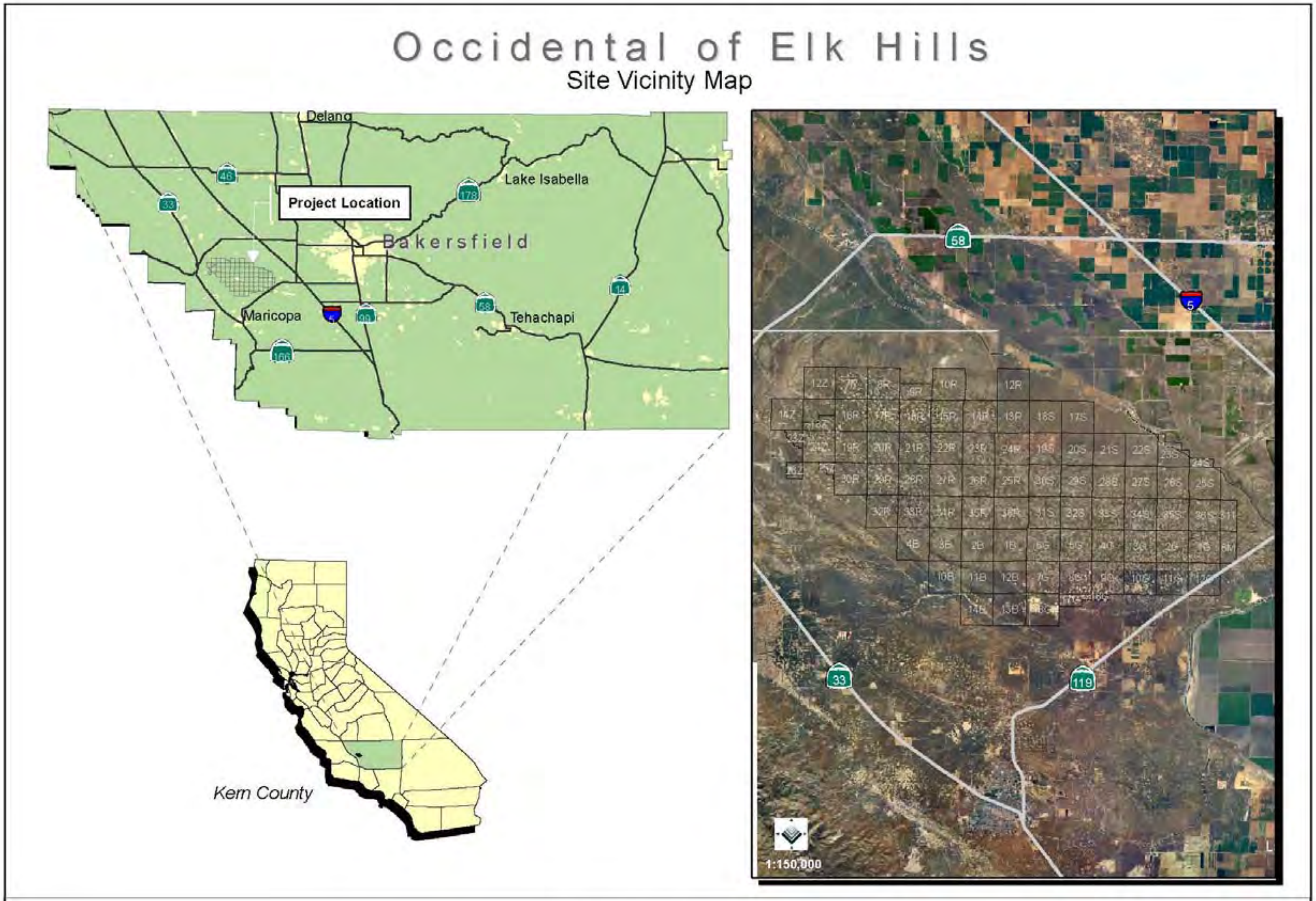

FIGURE 1-1 ELK HILLS OIL FIELD VICINITY MAP

geologic trapping of CO_2. Two of the reasons cited by EPA are: (1) oil and gas reservoirs are natural storage containers that have trapped fluids (both liquid and gaseous) for millions of years; and (2) oil and gas exploration and production activities have created a wealth of knowledge and geologic data that can support the site characterization process for geologic trapping. (See EPA's Proposed Rule: Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells, 73 Fed. Reg. 43492 541, July 25, 2008). In addition, a DOE report (DOE-NETL, 2008) states that oil and gas reservoirs can be ideal candidates for trapping of CO_2 since oil and gas reservoirs have proven capable of storing fluids and gases for millions of years and replacing the extracted oil and hydrocarbon gas with CO_2 is an excellent use of such natural reservoirs. Importantly, not only does trapping of CO_2 occur during active EOR operations, but it continues after EOR operations cease.

The OEHI CO_2 EOR Project would become part of OEHI's Elk Hills operations. The general location and extent of the Elk Hills Unit is illustrated in Figure 1-1. The structure and stratigraphy of the Elk Hills oil field (EHOF) has been exhaustively studied and is ideally suited for the injection of CO_2. The Stevens Reservoirs, which are prominent and long-producing geological structures located approximately 1 mile below the surface, provide excellent EOR targets and ample capacity for long-term CO_2 geologic trapping. Between the surface and the Stevens Reservoirs, there exists naturally occurring dense and thick overlying shales that serve as excellent seals and have proven capable of containing fluids and gases for millions of years. While faults are present within the EHOF, these faults are non-transmissive as indicated by variable oil-water contacts, pressures and temperatures within individual Stevens Reservoirs. Consequently, there are no natural pathways from the subsurface injection zones to the surface. Therefore, CO_2 leakage to the surface and atmosphere is highly improbable.

The EOR process begins when CO_2 is injected into reservoirs at a pressure to dissolve into the oil reservoir, but below a pressure that would fracture the confining geologic zone. Under appropriate conditions, CO_2 and crude oil are miscible, meaning they are capable of mixing in any ratio and becoming a single homogeneous solution. Due to the induced pressure gradient caused from the injection of the CO_2, the CO_2 will flow away from the injection well (Figure 1-2) and become miscible with the reservoir oil. The resulting miscible fluid has the favorable properties of lower viscosity, enhanced mobility, and lower interfacial tension as compared to reservoir oil without dissolved CO_2. In effect, this process mobilizes and recovers oil that would otherwise be trapped within the rock. Water injection will be alternated with CO_2 injection to sweep the miscible CO_2-oil mixture to production wells and to control the movement of CO_2 through the oil.

As part of the continuous EOR process, the CO_2 is separated from the produced hydrocarbons at the surface and reinjected to the reservoir using a closed loop operating system to recover additional hydrocarbons. The surface facilities will be designed to prevent releases of CO_2 to the atmosphere. As CO_2 is a valuable commodity, all of OEHI's EOR surface facilities are designed to contain, recover and recycle CO_2 used in the EOR process. The injected CO_2 is monitored closely through each stage of the process. The closed-loop system consists of surface and subsurface facilities for injection, production, processing, separation, compression and reinjection of CO_2. With each pass of the CO_2 stream through the oil reservoir, a portion, typically 30 to 50 percent, of the injected CO_2 becomes trapped in the reservoir. The balance is recovered, recycled, and blended with additional CO_2 purchased from the HECA Project before being injected. Ultimately, all of the injected CO_2 becomes trapped in the formation and is sequestered. Thus, sequestration is an inevitable consequence of EOR, and, for the purposes of this document, the term "sequestration" will be used interchangeably with the term "trapping."

As it relates to the HECA Project, the CO_2 EOR process will be subject to monitoring, measurement, and verification (MMV) requirements. A site-specific MMV Plan will be developed with the objective of demonstrating trapping of HECA-provided CO_2. The MMV Plan will include consideration of the existing detailed subsurface, seismic, geochemical characterization and wellbore construction details that have been generated from the extensive data covering the EHOF. Selection of the appropriate suite of tools to satisfy the MMV objectives will be based on an assessment of the potential risks, taking into account the unique characteristics of the EHOF and the performance expectations at the site.

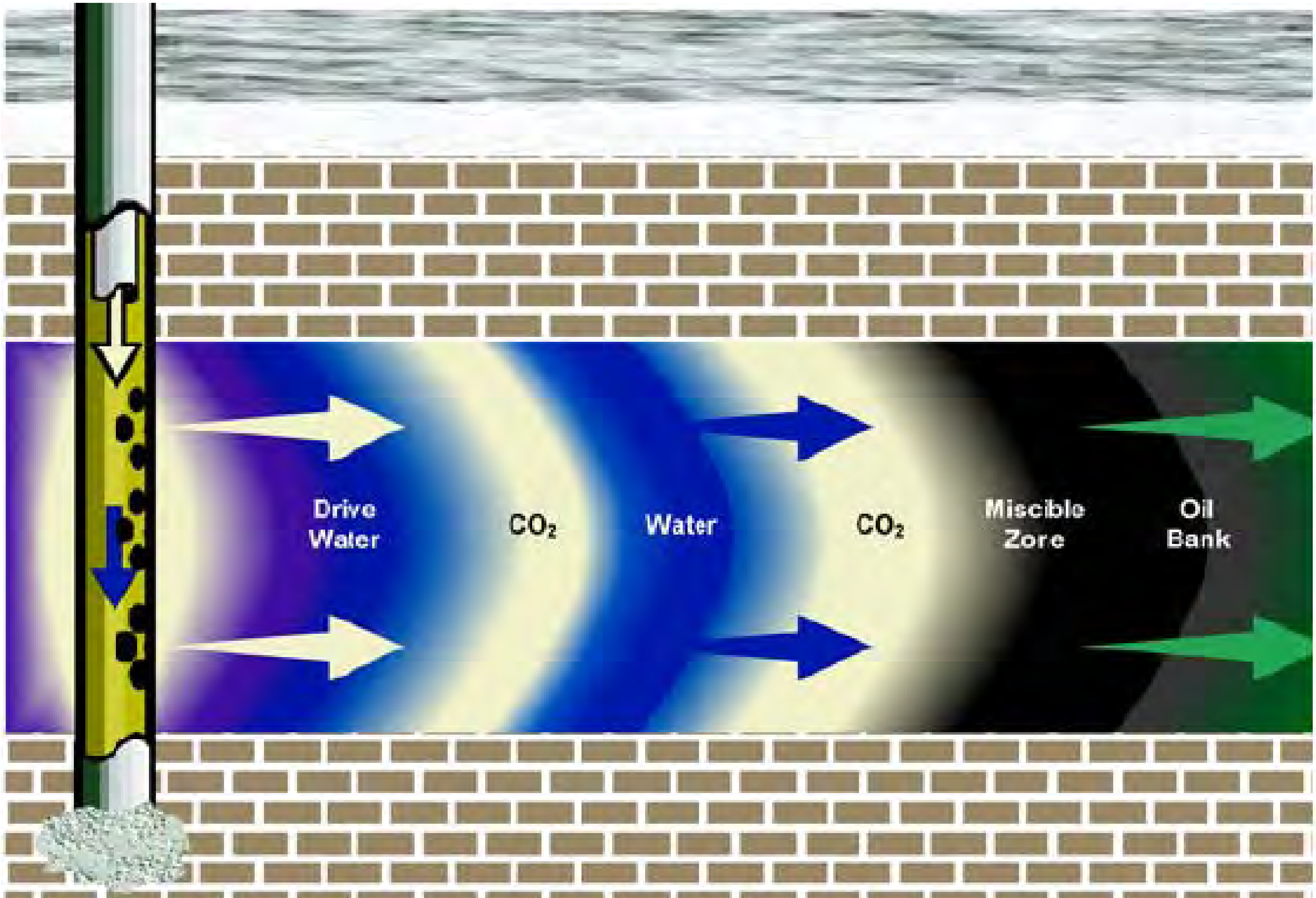

FIGURE 1-2 CO_2 EOR SCHEMATIC

1.1 Project Benefits

The OEHI CO_2 EOR Project will provide a variety of benefits at the local, state, regional, national and global levels. Among these benefits are the following:

- Extension and Enhancement of Production from Elk Hills Unit. Occidental's experience with EOR at Elk Hills and its world-leading expertise in CO_2 EOR will allow the OEHI CO_2 EOR Project to extend production at Elk Hills Unit.

- Reduction in Dependence on Foreign Oil. CO_2 EOR at Elk Hills Unit will extend production from a valuable domestic oil field for many years, partially alleviating the dependence of California and the United States on foreign oil supplies.

- Reduction in CO_2 Emissions. As a user of CO_2 from the nearby HECA Project, the OEHI CO_2 EOR Project will, as a co-benefit to the enhancement of oil recovery, act as a mitigation measure for the HECA Project by allowing for the sequestration of CO_2 emissions from the HECA operations and promote the siting of a valuable power generation resource in California.

- Minimizing Sensitive Habitat Disturbance. The OEHI CO_2 EOR Project will use much of the existing infrastructure such as roads, pipelines pathways and storage and processing facilities to extend recovery of oil and gas while minimizing impacts on the environment. In addition, the OEHI CO_2 EOR Project provides significant net environmental and economic benefits in habitat conservation and the efficient use of existing infrastructure.

- Economic Benefit. The OEHI CO_2 EOR Project will boost the local and California economy with jobs associated with construction and operations, as well as extend the life of the Elk Hills Unit where 345 employees and 2,650 contractors currently work.

1.2 Project Objectives

Project objectives are summarized as follows:

- Extend and enhance the useful and productive life of the Elk Hills Unit.

- Increase California and domestic energy supplies and enhance energy security by maximizing production of petroleum reserves.

- Economically maximize oil recovery within the Elk Hills Unit and safely sequester CO_2 in accordance with all county, state, and federal safety and environmental rules and regulations.

- Provide a mechanism to mitigate CO_2 emission impacts from the nearby HECA Project.

- Minimize environmental impacts associated with the construction and operation of the OEHI CO_2 EOR Project through choice of technology, project design and implementation of feasible and appropriate mitigation measures.

- Ensure the economic viability of the OEHI CO_2 EOR Project by minimizing costs while achieving other Project objectives.

1.3 Project Ownership

OEHI is the majority owner (78 percent) of the Elk Hills Unit and Chevron owns the remaining 22 percent. OEHI operates the Elk Hills Unit on behalf of Occidental and Chevron.

1.4 Proposed Project Schedule

Permitting activities	Ongoing
Start of construction	Spring 2012
Completion of construction	End of year 2014
Commissioning and initial startup	Spring 2015
Commercial operation of the Project	Summer 2015

1.5 Location

The Elk Hills Unit is located 26 miles (42 kilometers [km]) southwest of Bakersfield in western Kern County, California. The entire Elk Hills Unit (approximately 48,000 acres) includes land distributed across all or part of 81 sections within the following townships: T.30S, R.22E; T.30S, R23E; T.30S, R.24E; T.30S, R.25E; T.31S, R.25E; and T.31S, R.24E, Mount Diablo Baseline and Meridian (MDB&M).

The Elk Hills oil field was originally developed as part of the federal Naval Petroleum Reserves, and was designated as “NPR-1.” The U.S. Navy, the original operator of the field, did not use the customary cadastral survey conventions to refer to the location of a particular section. Instead, it employed a “short cut” method in which each distinct Township/Range was identified by a letter designation. Under the cadastral survey method, each township is comprised of 36 one-mile square sections, numbered

1 through 36; each section is referred to by section, township and range designations. Under the Navy's shortcut method, however, each section at the Elk Hills oil field was identified simply by its section number and the township/range letters. Thus, what would normally be described as "Section 7 of Township 30 South, Range 23 East" was described by the Navy simply as "Section 7R." The Navy's convention has persisted and, therefore, all sections within and adjacent to the Elk Hills oil field are still commonly referred to by this shortcut method, which is used in this document (Figure 1-3).

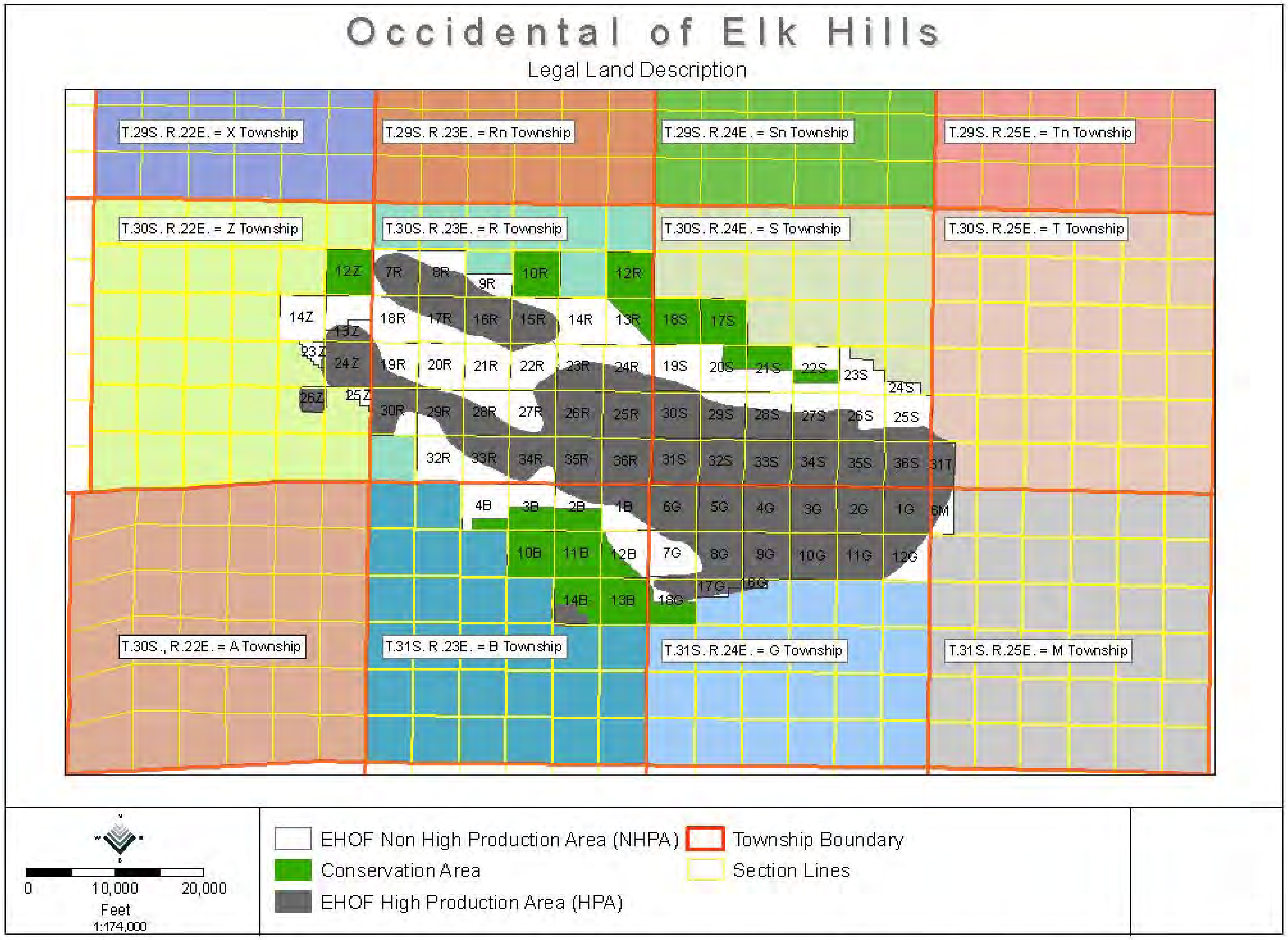

FIGURE 1-3 ELK HILLS OIL FIELD TOWNSHIP/RANGE NAMING CONVENTIONS SCHEMATIC

The Elk Hills Unit is located along the southwest edge of the San Joaquin Valley. This area is situated immediately south of, and contiguous with, the Lokern Area of Critical Environmental Concern (ACEC),[1] a part of which (3,110 acres) is controlled by the Bureau of Land Management (BLM). Portions of this surrounding area (2,050 acres) are managed by the Center for Natural Lands Management (CNLM) and OEHI (formerly Plains Exploration and Production Company and Nuevo Energy Company) Habitat Management Lands (200 acres) as conservation areas. The remainder is owned by Chevron Corporation and others. The City of Buttonwillow is located directly to the north.

McKittrick Valley and portions of Buena Vista Valley with Highway 33 running NW-SE are to the west. The cities of McKittrick and Derby Acres are located along Highway 33. Approximately 10 miles to the west and across the Temblor Range is the Carrizo Plain National Monument (also an ACEC; 199,030 acres).

To the south of the Elk Hills Unit is the Buena Vista Valley, the majority of which is within another oil field, NPR-2, which was recently transferred from the DOE ownership to the BLM. The City of Taft is located approximately 7 miles to the south. Mostly undeveloped areas are located along Highway 119 to the southeast of Elk Hills Unit.

Lands to the immediate east include Coles Levee Ecological Preserve (CLEP; 6,059 acres), Kern Water Bank Authority (19,900 acres), Tule Elk Reserve State Park and the Kern River. The California Aqueduct and the West Side Canal converge and flow along the north and eastern boundary of Elk Hills Unit, as does the Kern River. The Buena Vista Lake Bed is located immediately southeast of Highway 119. Bakersfield is approximately 26 miles to the northeast. The Elk Hills Unit is circumscribed by Highway 5 to the north and east, Highways 119 and 33 to the south, Highway 33 to the west and Highway 58 to the north. Elk Hills Road runs north and south and bisects the project area. Figure 1-4 provides an overview of the Elk Hills Unit with a regional context.

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[1] This ACEC designation is authorized by Section 202(c) (3) of the Federal Land Policy and Land Management Act of 1976 (FLPMA, P.L. 94-579). ACEC include public lands where special management attention and direction is needed to protect and prevent irreparable damage to important historic, cultural and scenic values, fish, or wildlife resources or other natural systems or processes or to protect human life and safety from natural hazards. ACEC designation indicates BLM recognizes the significant values of the area and intends to implement management to protect and enhance the resource values.

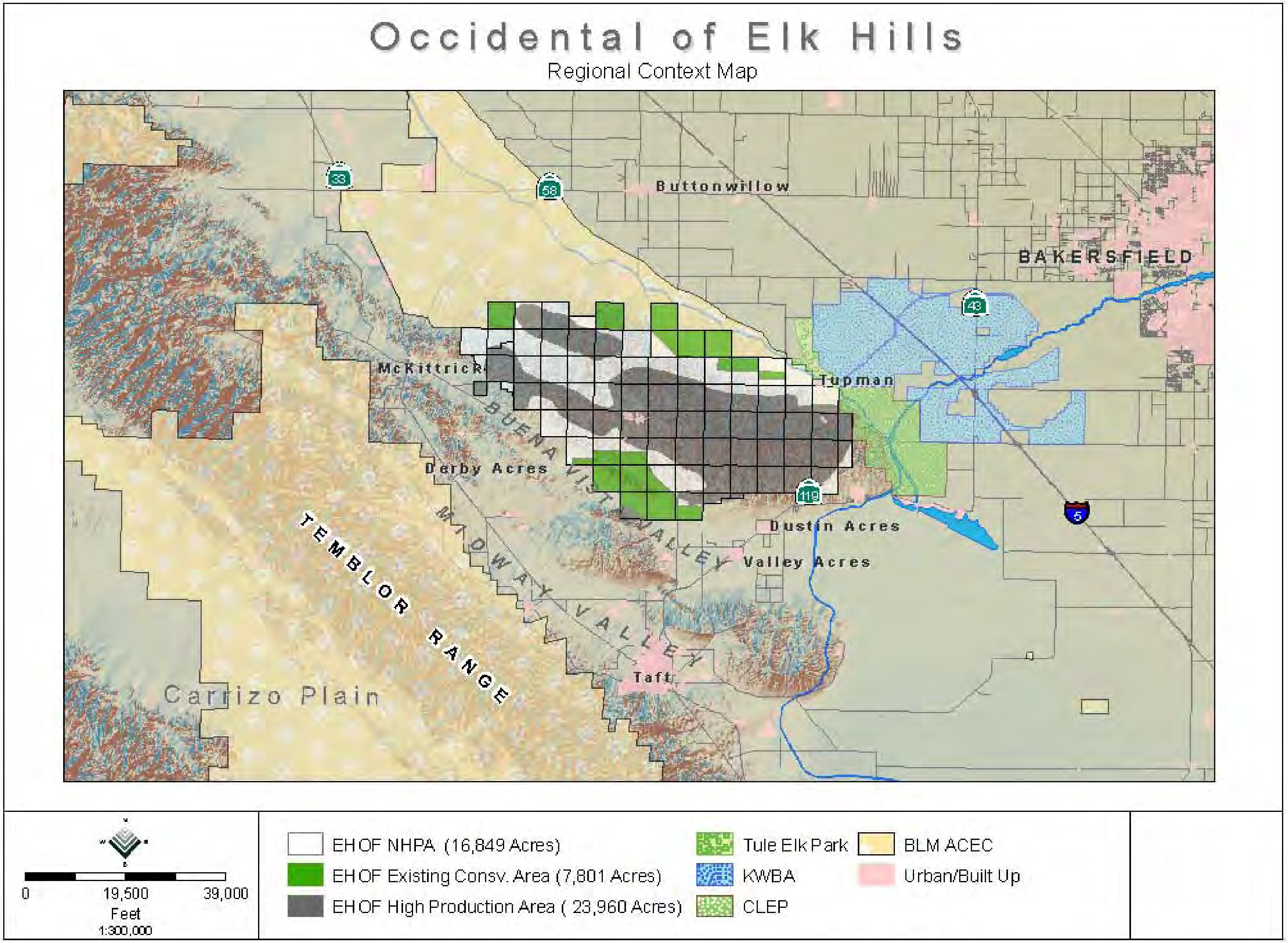


FIGURE 1-4 ELK HILLS OIL FIELD IN THE REGIONAL CONTEXT

1.6 Project Components

The OEHI CO_2 EOR Project components are listed below and described further in Sections 2 and 3.

- CO_2 Injection and Recovery Equipment
  - CO_2 Supply System
  - Satellite Gathering Stations
  - Infield Gathering and Injection Distribution Pipelines
- Recovered CO_2 Purification and Compression
  - Central Tank Battery (CTB)
  - Reinjection Compression Facility (RCF)
  - CO_2 Recovery Plant (CRP)
  - Water Treating and Injection Plant
- Backup CO_2 Injection Facility
- CO_2 Sequestration Monitoring and Verification
- Supporting Process Systems
  - Hazardous Material Management
  - Hazardous Waste Management
  - Stormwater Management
  - Fire Protection
  - Control Systems
  - Utilities
  - Project Buildings/Facilities
  - Security Systems
  - CO_2, Monitoring, Measurement, Verification and Closure

All temporary construction areas, including construction parking, offices, and construction laydown areas, will be located within the OEHI's existing operations.

The disturbed acreage associated with the OEHI CO_2 EOR Project will be estimated in more detail when the project moves to the FEED stage. The following general information regarding disturbed acreage is available:

- A significant portion of the development will occur in areas where disturbance has already occurred. OEHI will design project components to utilize existing disturbed acreage to the extent feasible.

- The CO_2 Facility and the 13 satellites are expected to occupy approximately 100 acres; however, until the FEED is completed, it is not possible to determine the extent of newly disturbed acreage. Newly disturbed acreage will be minimized to the extent feasible.
- The estimated total length of all new pipelines is 550 miles, much of which will be located in existing pipeline corridors that are already sited on disturbed acreage. Total disturbed acreage for the new pipelines and drilling pads will not be available until completion of the FEED. OEHI will utilize existing pipeline corridors, Rights of Way (ROWs) and disturbed acreage to the extent feasible.
- OEHI will design project components to minimize disturbed footprint during construction, as appropriate. Additionally, OEHI will restore temporarily disturbed acreage.
- The current estimated number of producing and injection wells is approximately 550. OEHI will attempt to use as many existing wells and drilling pads and locate new drilling pads in disturbed acreage as much as possible.

Table 1-1 summarizes site meteorology and other characteristics upon which the design will be based.

TABLE 1-1 SITE CHARACTERISTICS

Elevation	General site elevation varies from 250 – 1,325 feet above msl	
Design Ambient Temperature and Humidity	Dry Bulb °F	Relative Humidity (%)
Average Ambient	65°	55
Summer Design	97°	20
Winter	39°	82
Extreme Minimum Ambient	20°	85
Extreme Maximum Ambient	115°	15
Design Ambient Barometric Pressure		14.54 psia
Average Precipitation per year		5.7 inches (average. 2000 – 2006)
24-hour Max Precipitation (50-year storm)		1.8 inches

Source: Computed from Annual and Monthly Summaries (year span) of Bakersfield, California Meteorological Data, NOAA, National Climate Data Center, Asheville, North Carolina.

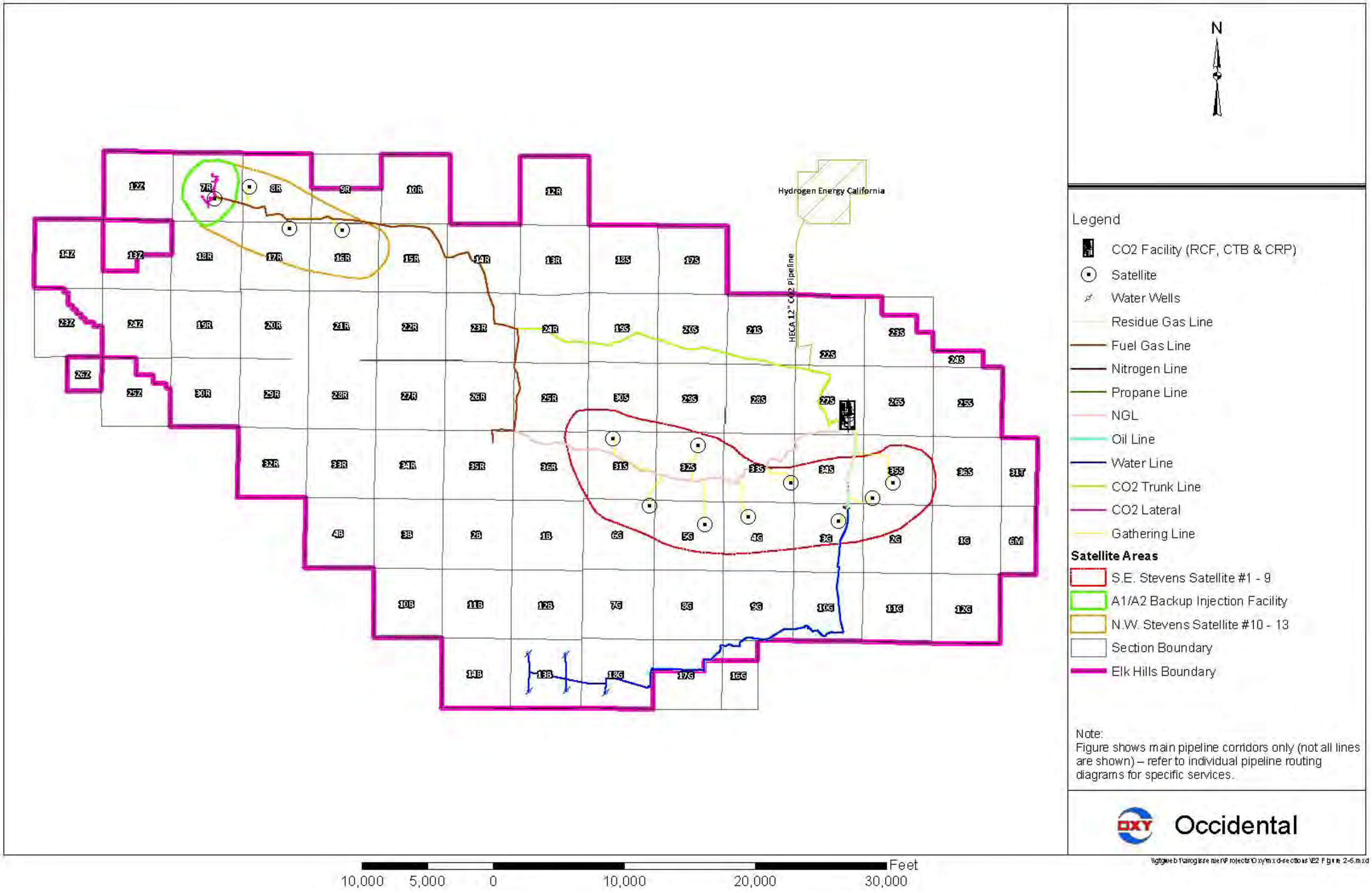
Notes:

ºF = degrees Fahrenheit
% = percent
msl = mean sea level
psia = pounds per square inch absolute

1.7 Site Plan

Figure 1-5 presents an overall site plan for the OEHI CO_2 EOR Project, including:

- Planned pipeline alignment from the HECA Project to OEHI operations
- Approximate location of injection wells, associated equipment and piping over the project life
- Location of the CO_2 Facility including Recovery Plant & Reinjection Compression Facility
- Alignment of piping to Backup CO_2 Injection Facility
- Location of Backup CO_2 Injection Facility



Note:
Figure shows main pipeline corridors only (not all lines are shown) – refer to individual pipeline routing diagrams for specific services.

FIGURE 1-5 CONCEPTUAL PLOT PLAN

2 CO_2 Enhanced Oil Recovery

High volume CO_2 injection for EOR, similar to the volumes anticipated for the OEHI CO_2 EOR Project, began in West Texas in the early 1970s. CO_2 EOR has proven capable of increasing oil production and extending the life of mature oil fields. CO_2 injection in the targeted zones of the Stevens Reservoirs has the potential to significantly increase recoverable oil reserves and extend the productive life of the Elk Hills Unit. The CO_2 EOR process involves the injection, recovery, processing and reinjection of CO_2 to allow trapped oil to flow more readily through the reservoir, thereby improving recovery. During the process, injected CO_2 becomes trapped in the reservoir.

The OEHI CO_2 EOR Project will utilize CO_2 generated by the proposed HECA Project. According to the HECA Project siting application, the HECA Project intends to utilize technology capable of capturing over 90 percent of the CO_2 produced during HECA facility operations. The OEHI CO_2 EOR Project is expected to receive an annual average rate of 107 million standard cubic feet per day (mmscfd) of CO_2 (approximately 2 million tonnes per year). This CO_2 will be compressed and delivered via pipeline to OEHI's CO2 Facility. The planned injection volumes and pressures will be reviewed as a part of the OEHI permitting process with DOGGR. During all phases of this project, OEHI will comply with UIC Class II regulations enforced by DOGGR.

As with oil and gas, CO_2 has been naturally trapped in geologic formations for millions of years. The injection of CO_2 into such formations has been safely practiced on an industrial scale for decades, mostly in conjunction with hydrocarbon production. Further, the EPA has recognized that oil and gas reservoirs will play a valuable role in the geologic trapping of CO_2. Two of the reasons cited by EPA are: (1) oil and gas reservoirs are natural storage containers that have trapped fluid (both liquid and gaseous) for millions of years; and (2) oil and gas exploration and production activities have created a wealth of knowledge and geologic data that can support the site characterization process for geologic trapping. (See EPA's Proposed Rule: Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells, 73 Fed. Reg. 43492 541, July 25, 2008). In addition, a DOE report (DOE-NETL, 2008) states that oil and gas reservoirs can be ideal candidates for trapping of CO_2 since oil and gas reservoirs have proven capable of storing fluids and gases for millions of years; and replacing the extracted oil and hydrocarbon gas with CO_2 is an excellent use of such natural reservoirs. Importantly, not only does trapping of CO_2 occur during active EOR operations, but it continues after EOR operations cease.

In 2005, the Intergovernmental Panel on Climate Change (IPCC), established by the World Meteorological Organization (WMO) and the United Nations Environment Programme (UNEP) in 1988, released a report entitled "Carbon Dioxide Capture and

Sequestration" (the "IPCC Report"). The IPCC is charged with providing relevant advice to policymakers on all aspects of climate change. The IPCC Report was written by 125 contributing authors, and was extensively reviewed by over 200 others, including technical experts and government representatives from around the world. The IPCC Report carefully weighs the technologies and the potential risk of CCS and concludes that, with appropriately selected and managed sites, CO_2 may be sequestered by injection into suitable geologic formations including oil and gas reservoirs. The IPCC Report notes that the early commercial scale CCS projects will probably employ CO_2 sequestration with EOR as their basis of design, which will extensively inform the technical development and safe deployment of CCS projects in other types of geologic formations.[2]

The EHOF reservoirs have the advantage of being well studied and provide a uniquely suited setting for large-scale geologic sequestration of CO_2, building on 100 years of oil and gas field operating experience in the EHOF and the oil industry's more than 35 years of CO_2 EOR operations. The appropriateness of using CO_2 EOR in any given oil field or reservoir cannot be determined until the geologic setting is evaluated to enable informed decisions in terms of reservoir management, safety, and carbon sequestration potential. As a result of thousands of wells being installed over the operational history of the EHOF, a significant database has been developed and utilized to model the proposed OEHI CO_2 EOR Project. This extensive database was transferred to OEHI when Elk Hills was acquired from the federal government in 1998. As a result, OEHI is in the unique position of possessing all of the subsurface information that has been accumulated over the nearly 100-year life of the field. As described in Section 2.1.1 and 2.2.2, the EHOF has been found to be an ideal candidate for CO_2 EOR.

2.1 CO_2 EOR Process Overview

The CO_2 EOR process can be described in two parts: subsurface process and aboveground CO_2 handling process.

2.1.1 Subsurface Process Overview

In CO_2 EOR operations, highly compressed CO_2 (which has the characteristics of a liquid) is injected into an oil reservoir through injection wells designed for CO_2 injection. Injection occurs at high pressure to maintain liquid-like state, facilitate transfer of the desired volume of CO_2 into the reservoir, and promote miscibility. Injection occurs at pressures below levels that could fracture the confining geologic

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[2] Notably, it is estimated that site characterization of saline reservoirs will likely cost tens of millions of dollars and it would take a decade or more to develop one large-scale commercial saline storage reservoir project exceeding 2 million tons/year of CO2.

zones or compromise the integrity of the reservoir. As a result of the pressure difference between the injection well and the reservoir, the CO_2 flows from the injection well (see Figure 2-1) and dissolves in the oil (CO_2 and oil are miscible under these reservoir conditions and form a single-phase solution). The miscibility of the CO_2 and the oil is dependent on the characteristics of both the oil reservoir, including pressure and temperature, and the chemical composition of the reservoir fluids. CO_2 EOR alters the oil properties, resulting in lower viscosity, enhanced mobility and lower interfacial tension when compared to oil extraction without CO_2 EOR. CO_2 EOR helps to mobilize oil naturally trapped in the rock, facilitating oil production. In order to enhance EOR performance, a technique of alternating cycles of water injection with cycles of CO_2 injection may be used (referred to as “Water Alternating Gas” or “WAG”). The introduction of water periodically behind the CO_2-oil miscible solution facilitates the “sweeping” of the CO_2-oil solution to production wells and further enhances oil recovery.

The current development of the Elk Hills Unit uses a mature pattern of water flood with over 200 water injection wells and an average injection rate for each well of nearly 900 barrels of water per day (bwpd) of water produced from the Elk Hills Unit. OEHI proposes to convert the reservoirs from the current application of water flood to a miscible-CO_2 EOR flood. During this process, many of the water injectors will be converted to CO_2 injectors, with estimated average injection rates between 2 and 20 mmscfd per injection well.

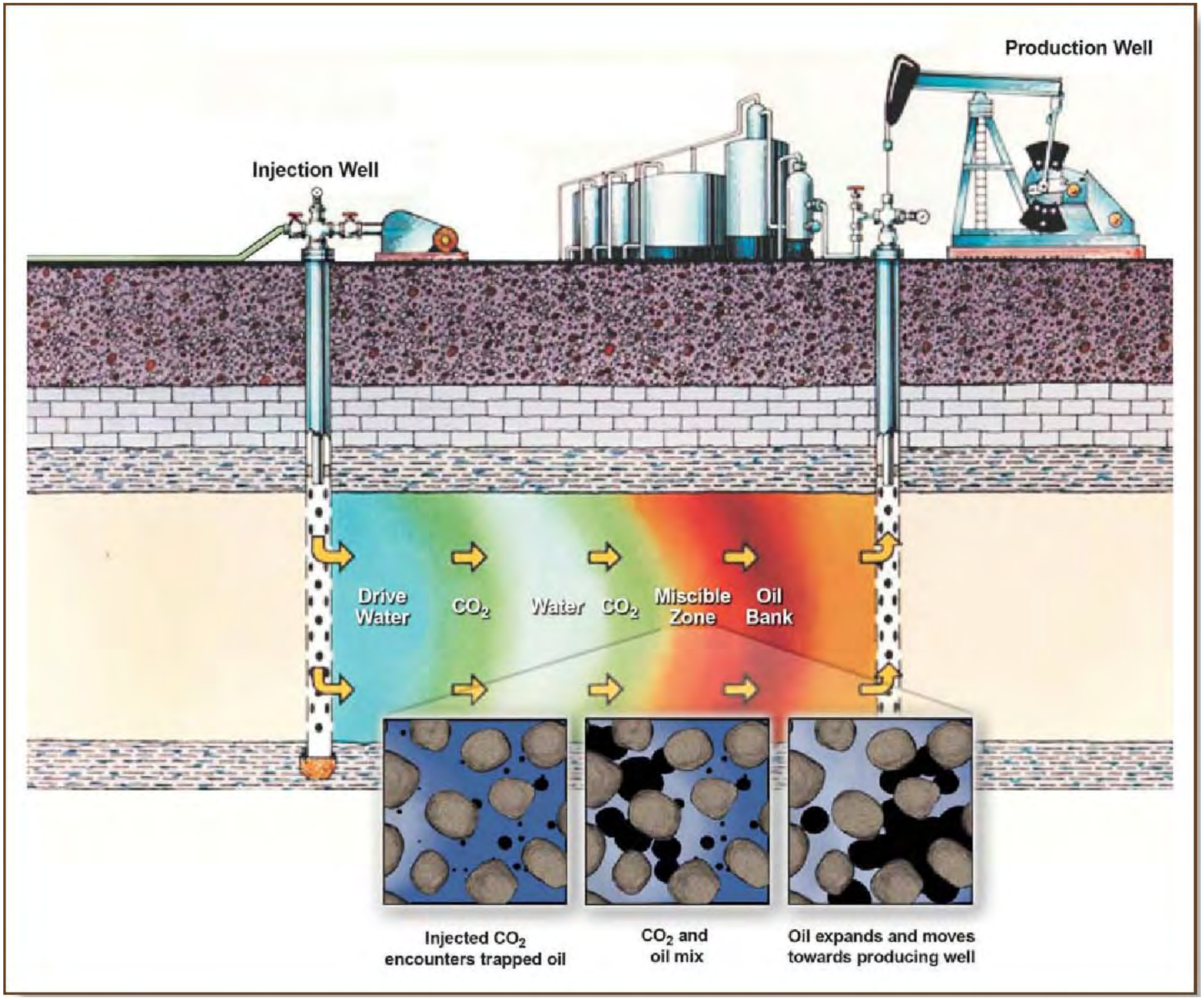


FIGURE 2-1 SCHEMATIC OF MISCIBLE-CO_2 FLOOD (DOE-NETL, 2008)

Production operations are designed to make the most efficient use of CO_2 from the HECA Project to maximize oil recovery and production. This is done by separating the CO_2 from the recovered hydrocarbons at the surface and recycling the CO_2 within a closed system for reinjection into the reservoir as part of the continuous EOR process. Injected and recycled quantities of CO_2 are monitored closely, as CO_2 is a valuable commodity that is purchased by OEHI from the HECA Project. However, trapping of CO_2 within the formation is inevitable with each injection cycle, necessitating the introduction of additional amounts of purchased CO_2 to continue the EOR operation.

The reservoir geological environment will determine the extent to which CO_2 will be immobilized, trapped and retained in the reservoir, making it difficult to predict the recovery (and trapped) fractions for each pass of CO_2 through the reservoir. Occidental's extensive experience as a world-wide leader in operating CO_2 EOR indicates that approximately 30 to 50 percent of the injected CO_2 mass remains trapped in the reservoir and is unrecoverable. Regardless of the fraction of CO_2 trapped during a cycle, all CO_2 injected eventually becomes trapped in the reservoir.

The key CO_2 trapping mechanisms that occur in the subsurface include physical trapping, residual gas trapping and geochemical trapping.

- Physical trapping (and trap filling) retains the CO_2 in the formation using structural and stratigraphic traps with low-permeability formations and faults. Physical trapping of the buoyant CO_2 is provided by the same impermeable "caprock" seal that traps the oil and hydrocarbon gases.
- Residual trapping and dissolution of the liquid or gaseous CO_2 occurs as a result of capillary forces retaining some of the CO_2 as disconnected droplets. Residual trapping is analogous to residual oil saturation (i.e., "trapped" oil) that remains after an oil reservoir is swept with injected water.
- Geochemical trapping describes a series of reactions of CO_2 with natural fluids and minerals in the target formation, principally consisting of CO_2 dissolution in brine (i.e., solubility trapping), CO_2 precipitation as mineral phases (i.e., mineral trapping) and CO_2 sorption onto mineral surfaces. Scientific research is continuing to increase the understanding of the chemical processes involved in geochemical trapping.

These trapping mechanisms operate on different time scales, beginning with initial injection of CO_2 and have different capacities to trap CO_2. The following schematic (Figure 2-2) depicts that over time, the process of physical and residual CO_2 trapping is enhanced by the increasing geochemical processes of solubility trapping and mineral trapping.

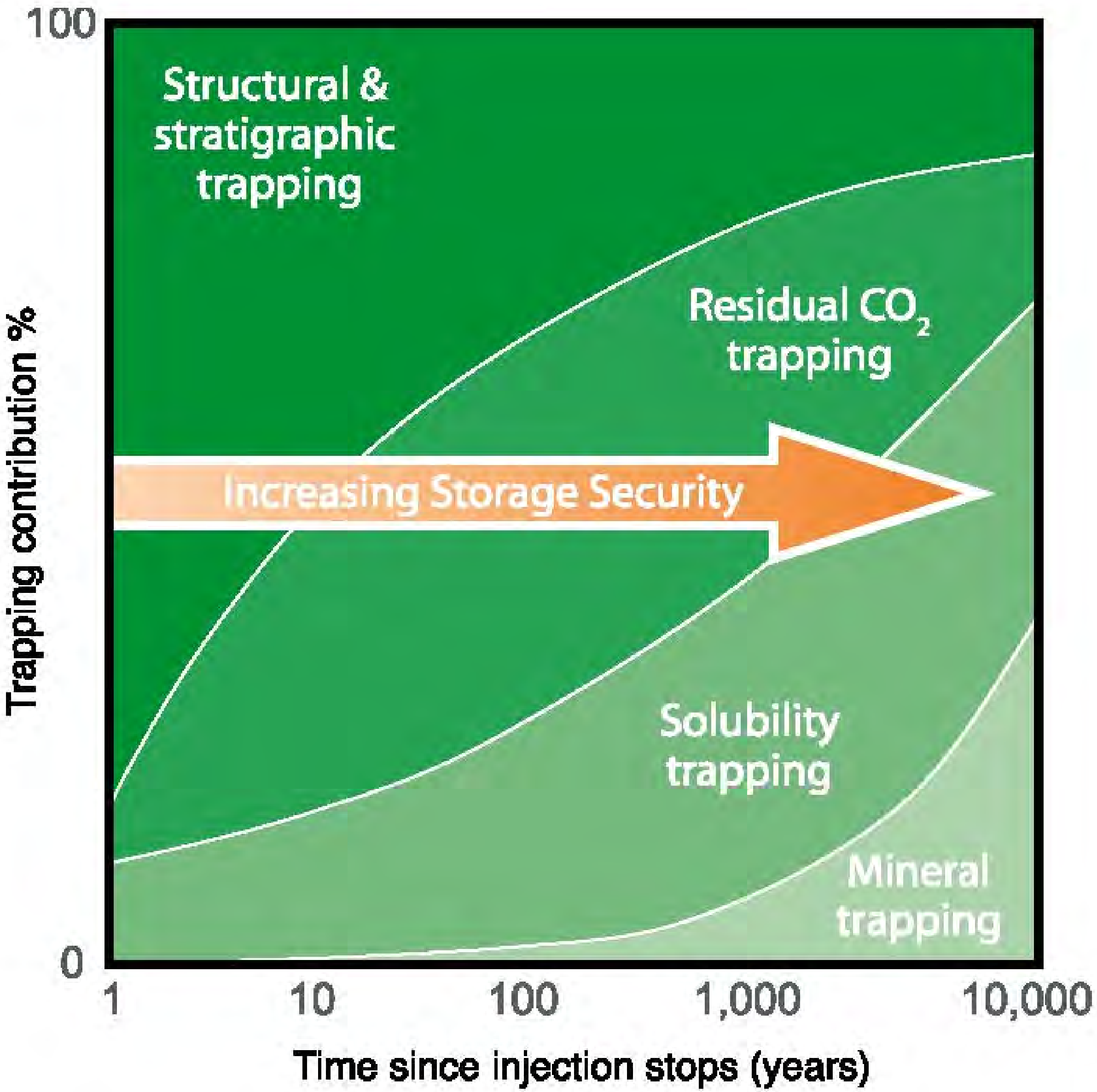


FIGURE 2-2 TYPES AND TIMESCALES OF CO_2 SEQUESTRATION MECHANISMS (IPCC, 2005)

2.1.2 Aboveground CO_2 Handling Process Overview

CO_2 from the HECA Project will be transported via a pipeline to the CO_2 Facility, at which point the CO_2 is distributed to CO_2 injection wells placed in a well pattern designed to optimize the recovery of oil from the reservoir.

There may be three, four or more production wells per injection well where oil and water is pumped to the surface to a centralized collection facility. Typically, these wells are arranged in a consistent geometrical pattern with an injection well in the center and production wells on the perimeter. For example, in a four-spot pattern, there would be four production wells on the four corners of a square geometric pattern, with a single injection well in the center of the pattern. The pattern of injection and production wells will vary with time, and is typically based on predictive computer simulations that model reservoir performance based on reservoir characterization and historical operations. Operational data will be obtained at well manifolds where an individual well's oil, gas and water fractions will be measured, which further helps assess the effectiveness of the CO_2 EOR process.

At the surface, the recovered fluids are transferred to a separator at the CO_2 Facility where the oil and natural gas are separated. The natural gas may include CO_2 as the injected gas begins to break through at the production wells. Separated natural gas enters a pipeline for transport to the existing gas processing facility in Section 35R of the Elk Hills Unit where it is combined with other produced gas from the field for sale to customers. The CO_2 is separated from the produced natural gas to meet sales specifications and the separated CO_2 is recompressed for reinjection along with additional purchased CO_2 from the HECA Project to further optimize the CO_2 EOR process.

A schematic of a typical miscible-CO_2 EOR operation is shown in Figure 2-3 below. The planned OEHI process is described in more detail in Section 2.3.

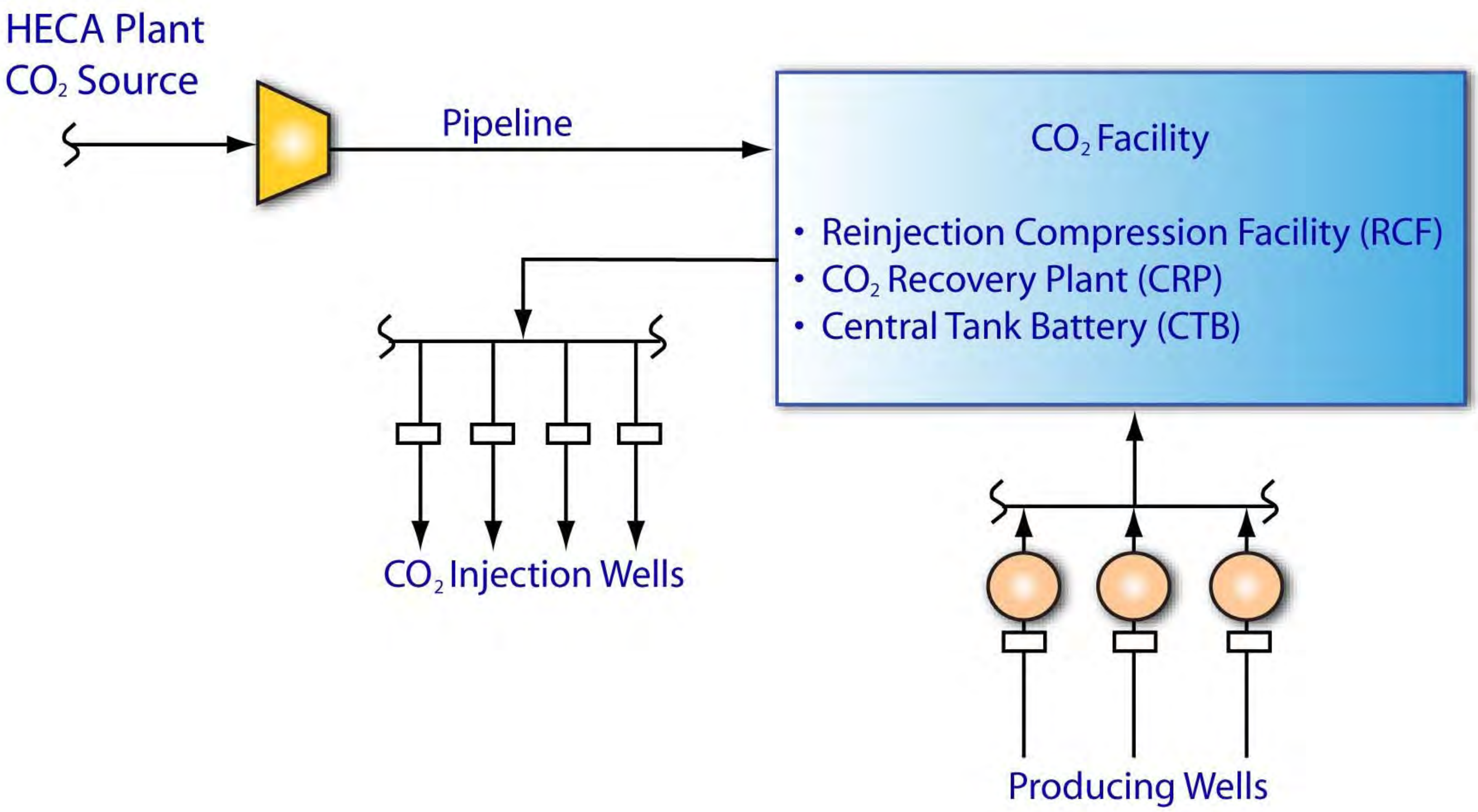


FIGURE 2-3 CO_2 EOR SURFACE PROCESS SCHEMATIC

2.2 Site Selection and Geological Setting

2.2.1 General Elk Hills Structure and Geology

The EHOF produces hydrocarbons (oil and gas) from several vertically-stacked Tertiary-aged (65 to 2 million years ago) coarse-grained clastic reservoirs interlayered with multiple layers of saling fine-grained shale. These layers have been folded and faulted, resulting in anticlinal structures containing hydrocarbons of probable Oligocene and Miocene (approximately 33 to 5 million years ago) source. The hydrocarbons were generated in the deep flanks of the Elk Hills structure and/or migrated into the structure from surrounding subbasins, beginning in the Pliocene, approximately 5 to 2.5 million years ago (Zumberge et al, 2005). The combination of multiple porous and permeable sandstone reservoirs interlayered with multiple impermeable shale seals and large anticlinal structure make the EHOF one of the most suitable locations for the extraction of hydrocarbons and the trapping of CO_2 in North America. The individual structures and geologic horizons within the EHOF are detailed in the following paragraphs.

At the surface, the EHOF presents as a large WNW-ESE trending anticlinal structure, approximately 17 miles long and over 7 miles wide. With increasing depth, the structure sub-divides into three distinct anticlines, separated at depth by high angle reverse faults (Figure 2-4). The anticlines are believed to have formed in a transpressional regime associated with formation of the San Andreas Fault, beginning in the Middle Miocene, which began approximately 16 million years ago (Callaway and Rennie Jr., 1991). The anticlines, labeled 29R, 31S and Northwest Stevens (Figure 2-5), formed bathymetric highpoints on the deep inland marine surface (seafloor), affecting geometry and lithology of the contemporaneously deposited turbidite sands and muds generated as subaqueous debris flows (Figures 2-5 and 2-6).

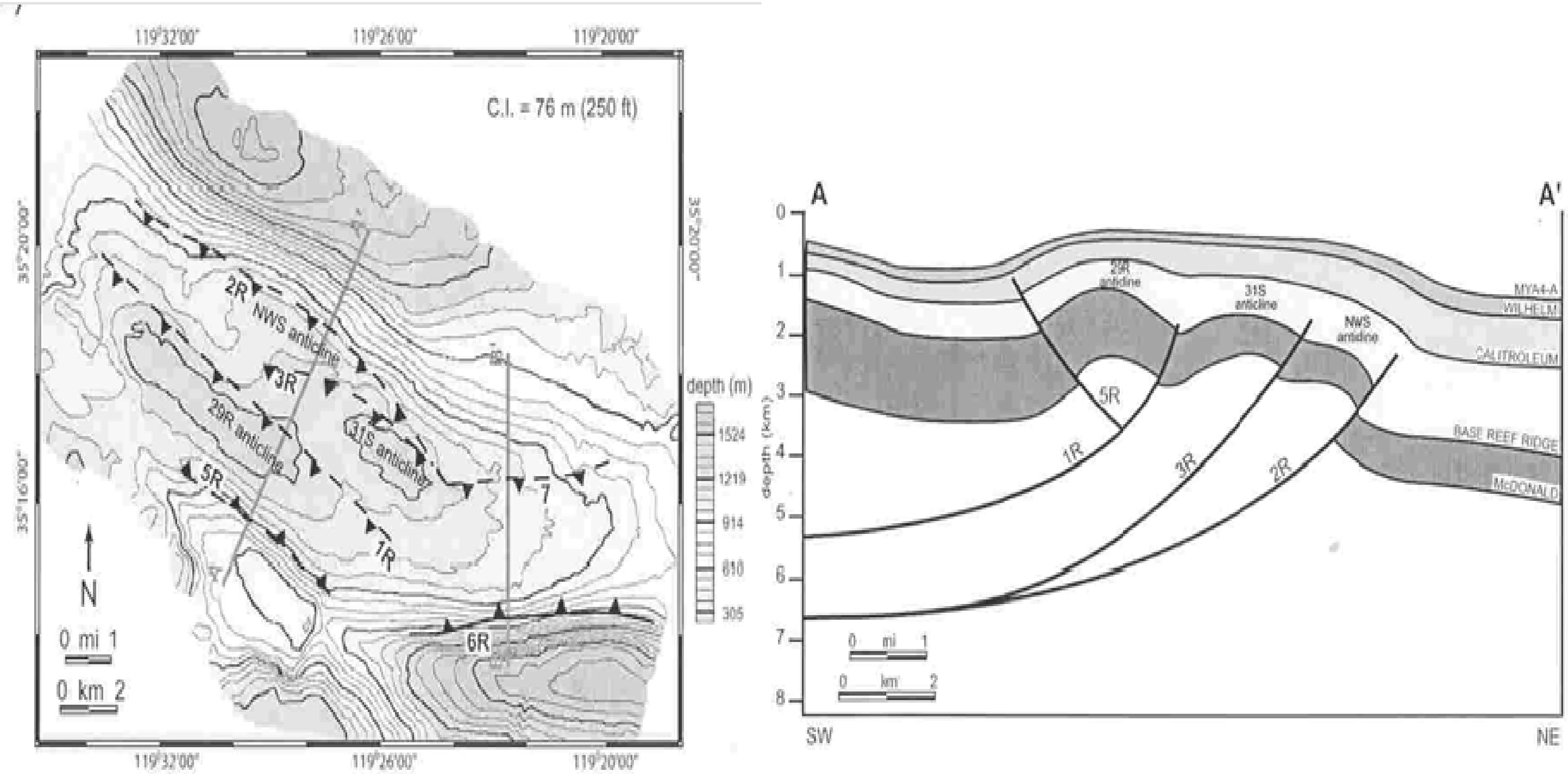


FIGURE 2-4 EHOF STRUCTURE CONTOUR MAP OF UPPER PLIOCENE ROCKS SHOWING FAULTS AND LOCATION OF CROSS SECTION A-A'; CROSS SECTION A-A' SHOWING STRUCTURE OF EHOF ANTICLINES. (FIORE, ET AL. 2007)

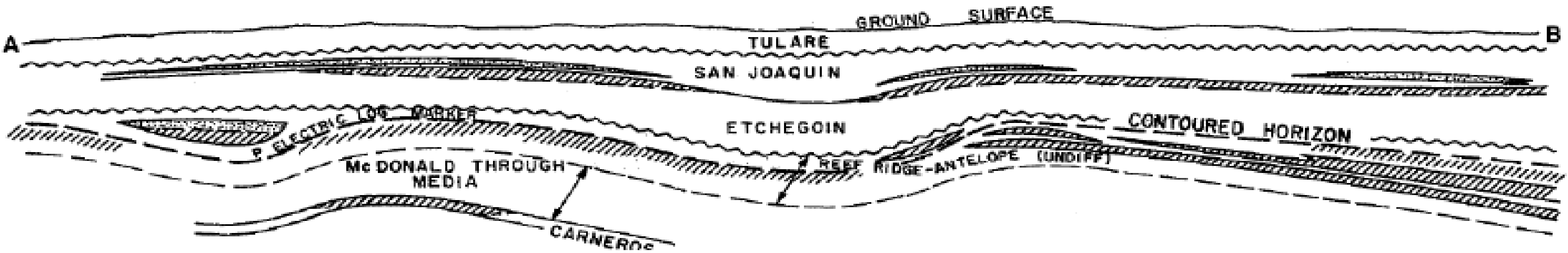


FIGURE 2-5 EHOF STRUCTURE CONTOUR MAP OF THE UPPER MIOCENE AND LOCATIONS OF CROSS SECTIONS A-B AND C-D, BELOW (DOGGR 1998)

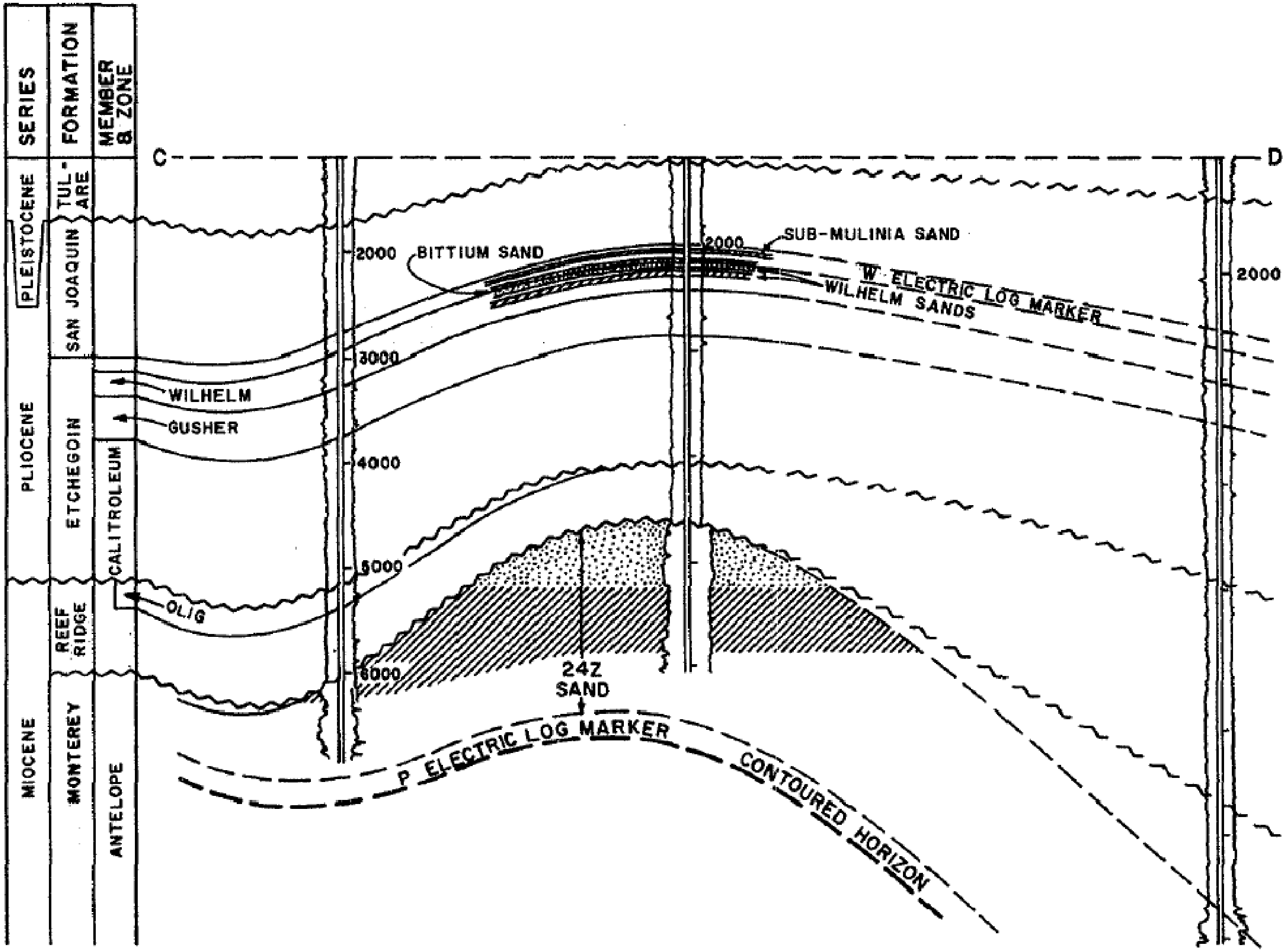


FIGURE 2-6 EHOF CROSS SECTIONS A-B AND C-D; LOCATION SHOWN IN FIGURE 2-5 (DOGGR 1998)

To date, there have been more than 6,000 wells drilled to various depths within the EHOF, creating an extensive library of information compiled within a comprehensive database. The deepest well in the field is the 934 29R, drilled to a total depth of 24,426 feet, bottoming in Mesozoic, Upper Cretaceous age (93 to 65 million years ago) sediments. A schematic diagram of the EHOF area stratigraphy based on well 934-29R is presented (Figure 2-7), as well as the electric log (Figure 2-8). The oldest rocks observed in the field are Upper Cretaceous in age but they are not productive. The Miocene-aged Carneros sandstone member of the Temblor Formation is the lowermost hydrocarbon producing interval in the field, although oil and gas shows have been recorded in deeper Oligocene- and Eocene-aged (55 to 23 million years ago) sediments. Above the Temblor is the Miocene aged Monterey Formation.

The Monterey (approximately 4,500 to 10,000 feet deep) is known locally as the EHOF member and this formation includes the EOR targeted Stevens oil sands that produce from stratigraphic-structural traps on three deep anticlines. Major Stevens Reservoirs include Main Body B (“MBB”), 26R, W31S, 24Z, 2B, A1A6 and T&N pools. The Stevens sands are composed of stacked fining upward turbidite deposits composed of lenticular sheet sands, channels and levee deposits within a submarine fan complex (Reid, 1990). Reservoir properties of the Stevens sands are excellent and have led to decades of hydrocarbon production, with porosities averaging between 20 and 25 percent, permeabilities averaging 150 millidarcy (mD) and net reservoir thicknesses that can exceed 1,000 feet. The uppermost Miocene formation is the Reef Ridge Shale, which is hard and siliceous (Nicholson, 1990) and acts as a stratigraphic trap keeping hydrocarbons below. A number of deep thrust and wrench faults, as well as a series of curvilinear normal faults, intersect the Stevens Reservoirs within the EHOF. These faults are believed to have influenced hydrocarbon migration from deeper source rocks (McJannet, 1996), but faults within the lower productive limits on the anticlinal structures die-out above in the overlying Reef Ridge Shale and Etchegoin Shale. These faults may provide some limited communication between some of the productive sands, though most units are not in communication with one another, having different oil-water contacts. Further, individual anticline sands are compartmentalized, as exhibited by different pressures and temperatures (C&C Resources, 2000).

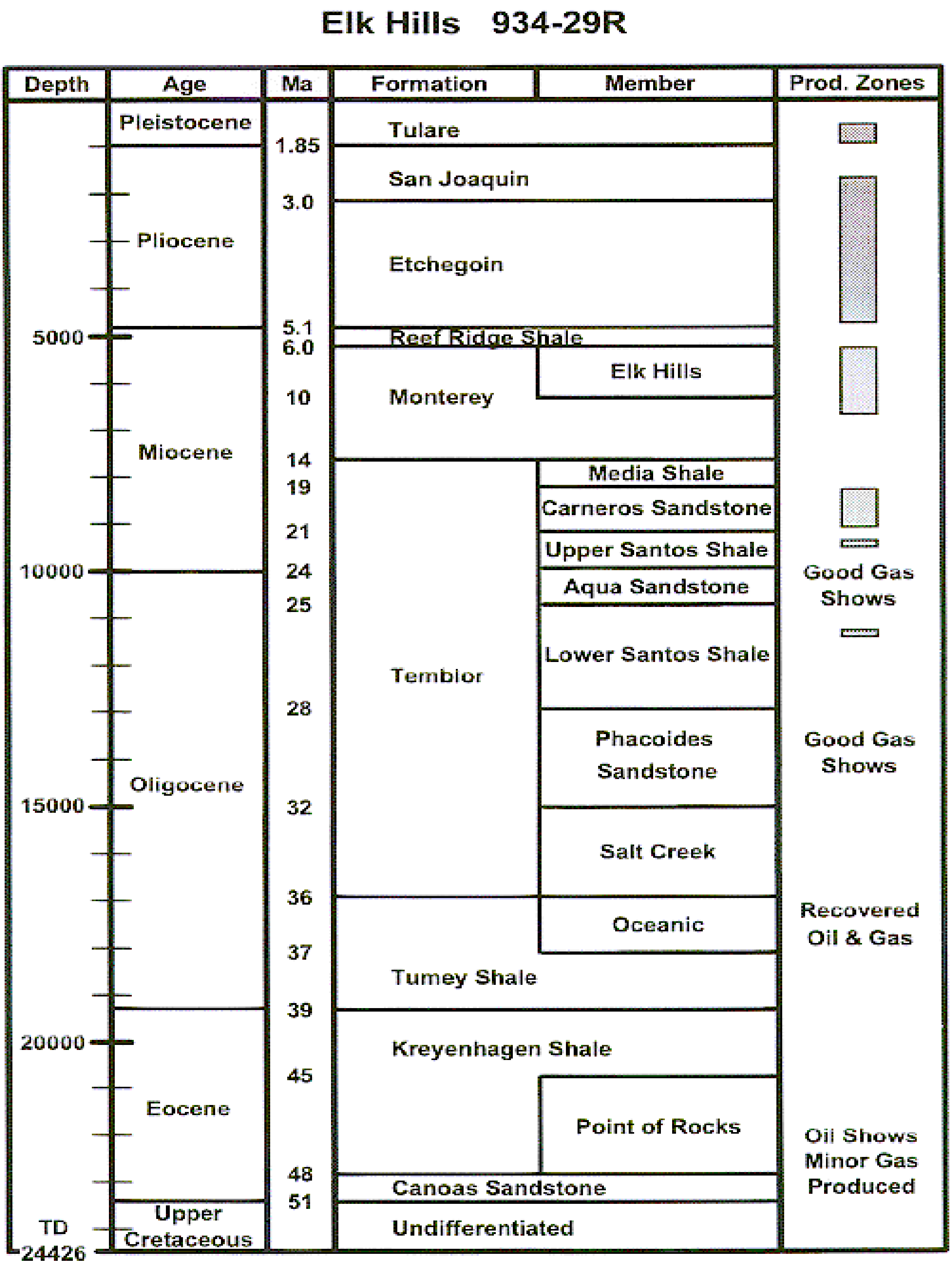


FIGURE 2-7 EHOF STRATIGRAPHY BASED ON 934 29R WELL (NICHOLSON 1990)

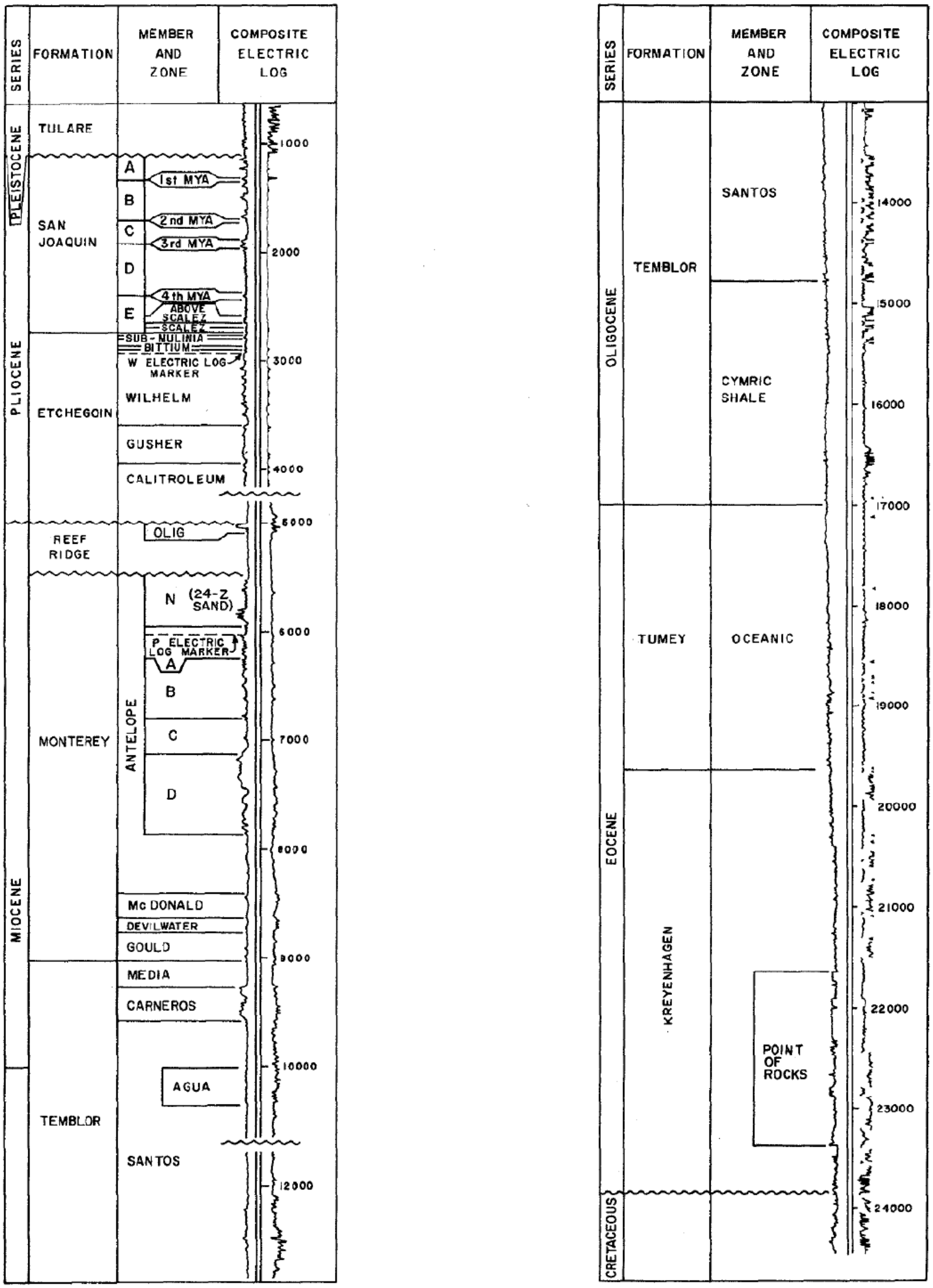


FIGURE 2-8 EHOF STRATIGRAPHIC COLUMN (DOGGR 1998)

The lithology overlying the Reef Ridge Formation is not targeted by the EOR, but the setting must be considered as part of the area of review. Overlying the Reef Ridge Formation is the Pliocene Etchegoin Formation, which includes several productive silty and sandy members (Calitroleum, Gusher, Wilhelm, Bittium and Sub-Mulinia) and intervening shales. Those are, in turn, overlain by the San Joaquin Formation, which includes the productive, basal Scalez sand member and overlying shales (Figures 2-6 and 2-8). These Pliocene rocks represent a depositional transition from deep water to shallow, including near-shore deposition. Isotopic analysis of these Pliocene oils suggests a separate Miocene source for the hydrocarbons in these reservoirs and refutes vertical leakage from the older Miocene Stevens Reservoirs as a source (Zumberger et al, 2005). The Pleistocene (approximately 2.5 million to 10,000 years ago) Tulare Formation is uppermost, from surface to 1,500 feet, in the EHOF and is comprised of fluvial and alluvial (river and surficial) sediments (Nicholson, 1990). The shallow Pliocene and Pleistocene section is cut by several shallow listric faults, some of which are sealing; however, these faults do not traverse through the Reef Ridge Shale and do not extend into the deeper Stevens Reservoirs (C&C Reservoirs, 2000) targeted for the EOR.

In summary, the structure and stratigraphy of the EHOF is ideally suited for the injection and trapping of CO_2. The CO_2 injection zones are within the Stevens Reservoirs. The stratigraphy within the Stevens Reservoirs is porous, permeable and can be very thick, providing an excellent EOR target and ample capacity for long-term CO_2 sequestration. Between the surface and the Stevens Reservoirs, there exist naturally occurring dense and thick overlying shales, which serve as excellent seals and have proven capable of containing fluids and gases for millions of years. While faults are present within the EHOF, these faults are non-transmissive as indicated by variable oil-water contacts, pressures and temperatures within individual Stevens Reservoirs. Furthermore, there are several productive horizons above the proposed injection zone within the Pliocene Etchegoin and San Joaquin Formations (approximately 1,500 to 4,000 feet deep.); however, isotopic evidence shows that the hydrocarbons within the shallow Pliocene reservoirs are not the result of simple vertical leakage from the deeper Miocene Stevens Reservoirs. Consequently, there are no natural pathways from the subsurface injection zones to the surface. Therefore, CO_2 leakage to the surface and atmosphere is highly improbable.

2.2.2 Summary of HECA Siting Study

To accommodate the HECA Project's need for CO_2 sequestration, a scoping/screening siting study was conducted to assess the potential for CO_2 sequestration near the HECA Project site (HECA, 2009). The southern end of the San Joaquin Basin located in and around Kern County and the northern end of the Ventura Basin located in and around Ventura County were targeted based on their carbon sequestration and EOR potential, as well as proximity to the HECA Project location. The study evaluated capacity, containment, and other specific criteria generally deemed important by current industry and scientific standards in carbon sequestration projects and deemed necessary to satisfy HECA Project objectives. This study identified at least one field within each basin that met these key factors of depth, pressure, lithology, porosity and permeability, structural integrity, and capacity:

- EHOF in the San Joaquin Basin, Kern County
- Ventura Field in the Ventura Basin, Ventura County

Based on this scoping/screening study, the focus of the subsurface effort was then directed to the EHOF in Kern County. The EHOF was determined to be the preferred field due to data obtained from previous CO_2 pilot studies. Another benefit was a shorter length of CO_2 pipeline to be installed, thereby decreasing construction impacts, time, and cost requirements. All of these findings are best aligned with the HECA Project objectives. The following excerpted discussion sets forth the further detailed study of the EHOF conducted in the site selection phase by the HECA Project (HECA, 2009).

> *"The Stevens Reservoirs are considered the best CO_2 EOR targets within EHOF. These reservoirs have been developed on 10 to 40 acre spacing and have produced in excess of 580 million barrels of oil (mmbo) to date. Reservoir pressure in the MBB sand is near the minimum miscibility pressure of approximately 2,415 pounds per square inch (psi) (Merchant 2006), indicating this reservoir is an ideal candidate for miscible-CO_2 EOR. By analog, documented West Texas miscible-CO_2 EOR's have produced an incremental 10 to 20 percent of oil, on average (Holtz et al. 2005). This range is also consistent with a CO_2 EOR pilot study in the Stevens sand at North Coles Levee field 2 miles east of EHOF conducted by ARCO (MacAllister 1989). The MBB reservoirs represent only a subset of the target Stevens Reservoirs currently suitable for miscible-CO_2 EOR."*

2.2.3 Geologic CO_2 Trapping Capacity

The OEHI site characterization confirms that the Stevens Reservoirs have sufficient volume to trap expected CO_2 deliveries from the HECA Project. Historic production records for the EHOF and injection data show that the volume of oil, gas, and water already extracted from the target injection zones exceeds the volume required to sequester the cumulative (full-life) volume of CO_2 expected from the HECA Project. Available capacity is demonstrated in the following tables.

Stevens Pore Volume Capacity

The Stevens Reservoirs within the 31S and North West Stevens (NWS) structures have been identified as the initial EOR and sequestration reservoirs. These reservoirs contain sufficient capacity to accommodate the injection of more than 20 years of expected CO_2 delivery from the HECA Project while maintaining reservoir pressures consistent with good EOR operating practices and below fracture pressures of the boundary zone. The available reservoir capacities were calculated using extensive available OEHI subsurface databases including electric logs, boring logs and historic extraction performance information.

	Billion Reservoir Barrels
Total Stevens Reservoir Capacity (31S and NWS Structures):	>7.5
Required Trapping Capacity for 20 years of Expected CO_2 Injection	<1.0

Cumulative Voidage to Date, from 31S and NWS Stevens Reservoirs

The table below shows that the net cumulative fluid volume produced to date, from the Stevens Reservoirs on the 31S and NWS structures, exceeds the CO_2 volume expected from the HECA Project.

	Billion Reservoir Barrels
Cumulative Fluid[1] Volume Produced:	>3.4
Cumulative Fluid[1] Volume Injected:	<2.1
Cumulative Net Fluid[1] Volume Produced:	>1.3
Required Trapping Capacity for 20 years of Expected CO_2 Injection:	<1.0

[1] Includes oil, gas, and water

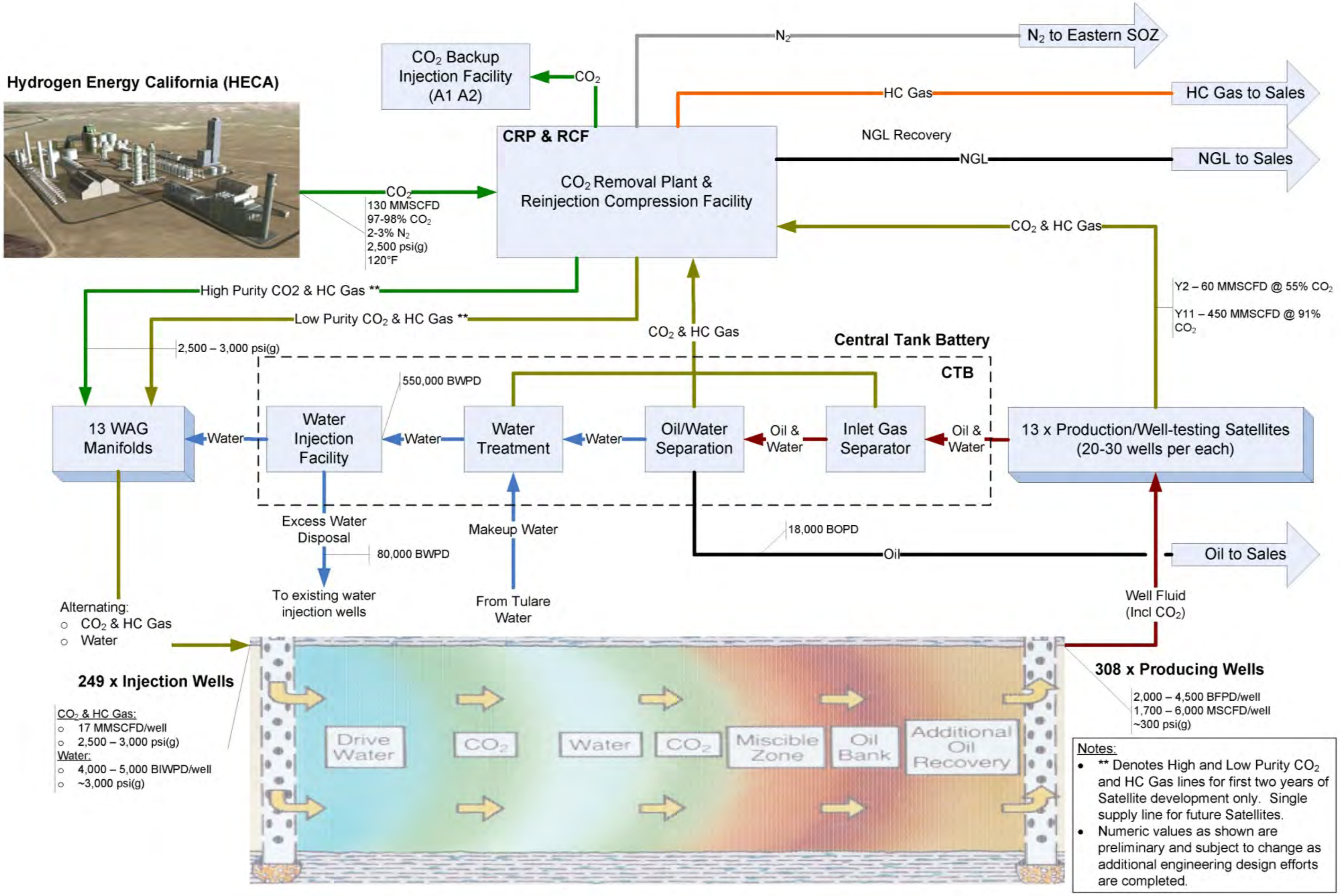
In addition to the available capacity calculated above, during EOR operations, the additional production of oil, gas, and water will create further reservoir void that will allow for injection of additional CO_2.

2.3 CO_2 Handling Processes

The production facilities required for OEHI to operate a CO_2 EOR process at the Elk Hills Unit will consist of the following primary production units:

- CO_2 Injection and Recovery Equipment
    - CO_2 Supply System
    - Satellite Gathering Stations
    - Infield Gathering and Injection Distribution Pipelines
- Recovered CO_2 Purification and Compression
    - Central Tank Battery (CTB)
    - Reinjection Compression Facility (RCF)
    - CO_2 Recovery Plant (CRP)
    - Water Treatment Plant
- Backup CO_2 Injection Facility

Figure 2-9 provides a basic process flow diagram for the planned production facilities. Numeric values shown on the figure are preliminary and subject to change as additional engineering design efforts are completed. Figure 2-10 presents an aerial view of the Elk Hills Unit, indicating locations of each of the major production facilities and associated pipelines. Figure 2-10 also serves as a key to a series of aerial views of each Section containing project components. This series of Section-by-Section aerial views is presented in Appendix A.



Notes:

- ** Denotes High and Low Purity CO_2 and HC Gas lines for first two years of Satellite development only. Single supply line for future Satellites.
- Numeric values as shown are preliminary and subject to change as additional engineering design efforts are completed.

FIGURE 2-9 BASIC PROCESS FLOW DIAGRAM OF PLANNED CO_2 EOR PRODUCTION FACILITIES

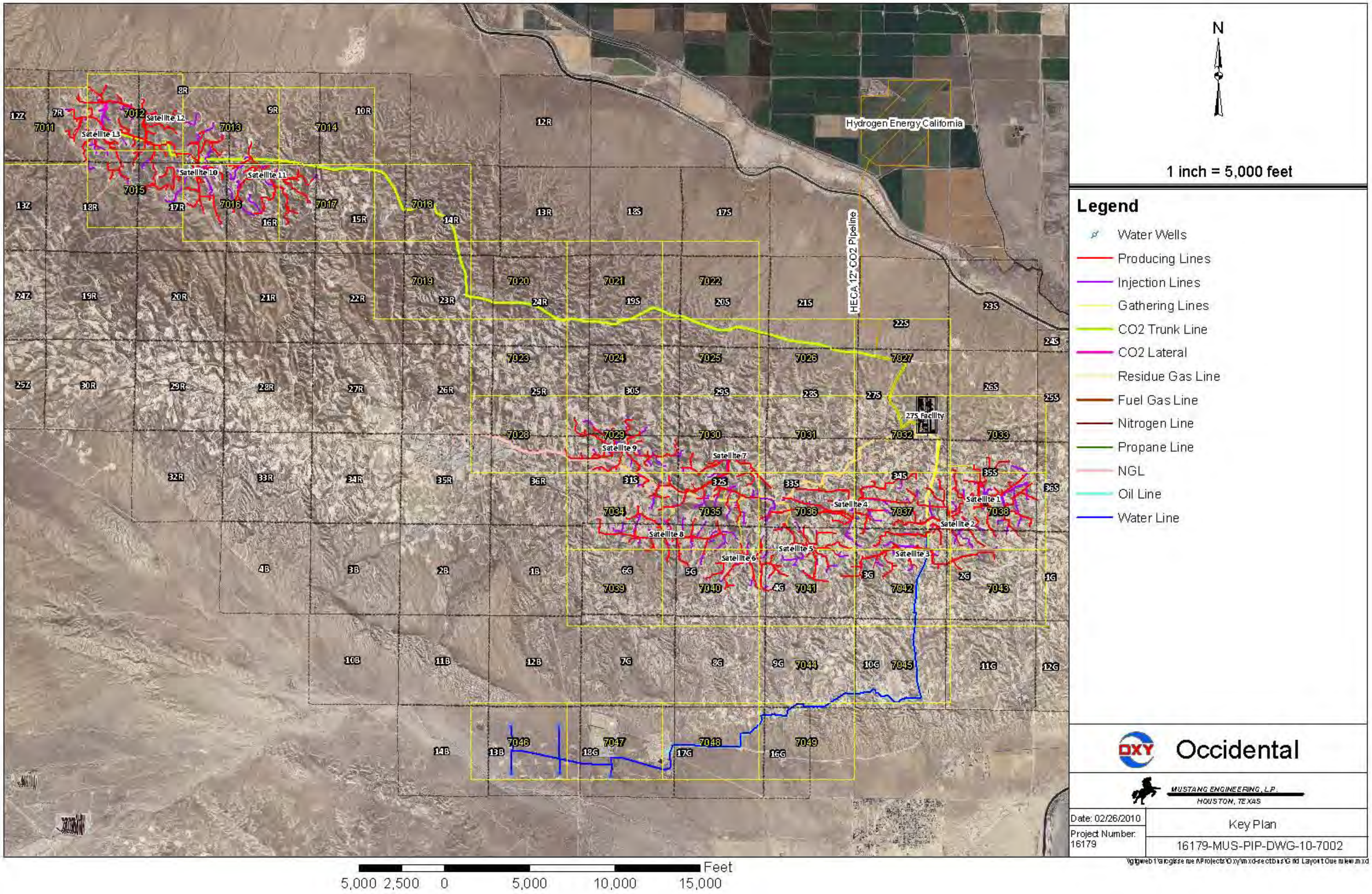


FIGURE 2-10 PROJECT OVERVIEW AND KEY PLAN FOR APPENDIX A

To facilitate CO_2 EOR from the Stevens Reservoirs, recovered fluids from the production wells will flow to one of 13 Satellite Gathering Stations, with three online initially and 10 additional systems added over time. The initial three Satellite Gathering Stations will be sufficient to accommodate CO_2 volumes provided by the HECA Project. The Satellite Gathering Stations will separate any produced gas from the oil and water. Installation of systems will start in the eastern portion (Sections 35S and 2G) and progress westerly (through Section 34S, 3G, 33S, 4G, 32S, 5G, 31S, 6G) as reservoir development evolves. Approximately 10 to 12 years after startup, injection systems will be installed in the northwest area (7R, 8R, 9R, 16R, 17R).

After separation, the gas and oil/water will flow separately via the infield gathering lines to the main process units for further processing. The liquid will flow to the CTB where the oil and water will be separated. The oil will be pumped to the existing oil shipment facility located at Section 18G of the Elk Hills Unit for export and sale. Produced water will be treated at the water treating portion of the CTB and pumped at injection pressure to the Satellite Gathering Stations for reinjection. All produced water will be reused in the reinjection process.

Produced gas from the Satellite Gathering Stations will initially flow to the RCF. At the RCF, the CO_2 gas will be dehydrated, compressed, blended with CO_2 purchased from the HECA Project, and reinjected in a closed loop system. As the volumes of recycled CO_2 increase over time, a CRP will be constructed to separate CO_2 from produced hydrocarbon gas and recycle the separated CO_2. The CRP will consist of several processing units for the separation of the CO_2 from the recovered natural gas.

The CO_2 from the CRP will be compressed and combined with the compressed CO_2-rich gas from the RCF and then combined with purchased CO_2 from the HECA Project. The CO_2 for injection will then be compressed to the required injection pressure and distributed back to the WAG units via CO_2 injection lines. The CO_2 and the injection water will be routed via the WAG manifold where the injection fluid will alternately be injected downhole as needed.

A backup CO_2 injection facility will be constructed at the A1/A2 producing reservoirs in the northwest area of the Elk Hills Unit. This facility will be constructed and available for:

1. Pressurization of the A1/A2 reservoirs for additional CO_2 EOR production; and,
2. Sequestration of CO_2 should there be a short term operating disruption at the HECA or Elk Hills facilities or an imbalance of supply and demand of CO_2.

OEHI will install a pipeline for CO_2 transport to the A1/A2 area in the northwest area of the Elk Hills Unit (Sections 7R, 18R).

Each of these processes is discussed in further detail below.

2.3.1 CO_2 Injection and Recovery Equipment

2.3.1.1 CO_2 Supply System

The CO_2 piped from the HECA plant will be received by the CO_2 supply system portion of the OEHI CO_2 Facility. The CO_2 supply system is the portion of the facility where recycled CO_2 from the RCF/CRP, combined with the supply CO_2 from the HECA Project, is compressed to the injection pressure.

In the initial years of CO_2 EOR operations, the average CO_2 content in the produced gas is relatively low. As a result, only the RCF equipment is initially required to process the lower quantities of CO_2. When CO_2 injected in the reservoir reaches the production wells in larger quantities, “breakthrough” has occurred. At this point, the CRP will be constructed to recover the larger quantities of CO_2.

The proposed plan is to inject two different levels of CO_2 purity during the initial years of CO_2 EOR. The recycled gas from the RCF will be blended with high-purity supply CO_2 from the HECA Project and injected as low-purity CO_2, while the rest of the supply CO_2 will be injected as high-purity CO_2. The high-purity CO_2 will be injected into the wells/areas that are just starting the CO_2 flood cycle, while the low-purity CO_2 will be injected into the areas that have been under CO_2 flood for some time.

This concept for the segregation of the CO_2 in the early years of the OEHI CO_2 EOR Project results in a design that has two separate headers and injection pumps: one for the high-purity system and a second for the low-purity system. Recycled gas from the RCF will flow to the low-purity header. CO_2 from the HECA Project will be mixed with this gas under flow control to maintain the desired concentration of the low-purity injection gas. The mixture will be compressed to the required injection pressure and injected through the low-purity discharge header. The remaining CO_2 from the HECA Project will flow under controlled pressure to the high-purity header.

2.3.1.2 Satellite Gathering Stations

The Satellite Gathering Stations (Satellites, also known as Production/Well-testing Satellites) will be a series of facilities that will provide primary separation of the oil/water and gas from the production well stream. Initially, three Satellites are scheduled to be installed to handle the expected production for the first several years of the field development. Ultimately, 13 Satellites are scheduled for full field development. Two different designs for Satellites are planned: one designed for 30 production wells and the second designed for 20 production wells. These two ‘standard’-sized Satellites are expected to handle the overall field configuration for the CO_2 EOR.

Each Satellite has an inlet manifold in which well flow lines associated with that Satellite are connected. Flow from each well flow line will be diverted into either the production separator or the test separator via automated manual valves.

- The production separator is a two-phase separator to handle primary vapor liquid separation of the fluid recovered from the production wells at each Satellite. Oil/water mixture will be separated from gases and flow under level control into the liquid gathering line and be routed to the CTB for further processing. The gases will be separated and routed to the inlet of the RCF and later the CRP. The entire field production pressure will be controlled at the RCF/CRP inlet header and the individual Satellites will 'float' on that pressure. Liquid and gas flow rates will be metered for production trending and monitoring.

- The test separator will be a three-phase, bucket and weir separator to allow for a 24-hour test cycle of each well serviced by that Satellite. The oil and water will be controlled by level control and the gas will be controlled by a back-pressure controller to hold the test separator pressure slightly above that of the associated production separator. Oil, water and gas from the test separator will be re-combined and directed to the inlet manifold and then to the production separator.

The Satellite also contains the water alternating gas (WAG) injection manifold. As described previously, water is injected under pressure to enhance the recovery of CO_2-oil mixture at the production wells. Alternating gas (CO_2) and water injection is a technique proven to enhance the recovery of oil. The CO_2 and water to be injected will be routed from the CRP/RCF via the high-pressure injection lines to the Satellite and to the WAG manifold. The WAG manifold for the initial Satellites will consist of three separate inlet headers:

1. Low-Purity CO_2
2. High-Purity CO_2
3. Injection Water

CO_2 or injection water will be manually directed from the manifold into the injection line from the manifold to the various injection wells. The injection fluid, CO_2 or water, will be metered at the WAG and flow will be controlled by an automatic choke at the injection well head.

2.3.1.3 Infield Gathering and Injection Distribution Flow Lines

The infield gathering flow lines and the injection distribution flow lines tie the various elements of the overall facilities together. The lines (four or five depending on

Satellite configuration) will be installed in a common trench or pipe-rack support for safety consideration and for ease of installation. Each Satellite will have a dedicated set of flow lines running to and from the Satellite and the CTB or RCF/CRP.

Flow lines planned for the OEHI CO_2 EOR Project include:

- 12-, 16- and 26-inch Gas Gathering lines
- 10-, 12- and 16-inch Liquid Gathering lines
- 10-, 12- and 16-inch Water injection lines
- 4-, 6- and 12-inch CO_2 injection lines

Satellites constructed later in the EOR project (after the first five or six) will only need a single 6-inch CO_2 injection line as the dual purity requirement for CO_2 handling will no longer be required as the average CO_2 content increases.

Additional preliminary design specifications for flow lines and wells include:

- Normal Operating Pressure – 300 - 400 pounds per square inch gauge (psig)
- Normal Operating Temperature - 20 – 140ºF, nominally assumed to be 110˚ F for simulation
- Maximum Allowable Working Pressure for the flow lines – 2,500 psig
- Average Production Well Flow Rate (at peak water rate) - Eight barrels oil per day (bopd)
- Average Injection Well Flow Rate (at peak water rate) - 4,550 bwpd or 59 thousand cubic feet CO_2 per day (mcfd)
- Average Production Well Flow Rate (at peak oil rate) - 300 bopd
- Average Injection Well Flow Rate (at peak oil rate) - 2,270 bwpd or 5057 mcfd CO_2
- Average Production Well Flow Rate (at peak gas rate) - 149 bopd
- Average Injection Well Flow Rate (at peak gas rate) - 2,234 bwpd or 5,956 mcfd CO_2
- Test Separators design rate - 500 bopd or 4,000 bwpd or 3 mcfd CO_2

2.3.1.4 Injection and Production Well Design Basis

Injection wells will conform to the provisions of DOGGR Class II UIC permits. Wellheads with CO_2 compatible metallurgy and corrosion-resistant coatings that are design-rated for the permitted injection pressure will be used on the injection wells. Casing on the injection wells is protected by cement on the exterior and the interior will be isolated from CO_2 by the injection packer. Wellheads with adequate design pressure rating on producing wells will be used, and will be protected by the injection of corrosion inhibitor chemicals to prevent any damage. A sample Class II UIC permit application for initial well construction will be provided to the California Energy Commission (CEC).

2.3.2 Recovered CO_2 Purification and Compression

2.3.2.1 Central Tank Battery

The CTB is the primary oil/water separation system for the CO_2 EOR process and will be collocated with the RCF and CRP at the CO_2 Facility at Section 27S of the Elk Hills Unit. It will consist of an inlet header system, gas separators, gas flume and vortex tanks (VT) for oil/water separation. The inlet liquid gathering lines from the Satellites will flow to the inlet liquid manifold where the oil and water will be manually directed to one of the three gas separator tanks.

The gas separator tanks will be designed for two-phase separation of the vapor and liquid. Two gas separators will be installed initially, with the third unit added as needed to handle the increasing liquid production. Gas from the CTB is transported to the inlet of the gas processing facilities, the CRP and RCF.

The liquid from the gas separators flows under level control to the gas flume where the oil and water are further de-gassed. The gas flume and VT will be designed based on two units operating at a maximum design capacity of 50 percent. One unit will be installed initially. The second unit will be installed when liquid production increases above 50 percent of maximum design capacity for the first unit. The gas from this process is combined with the gas from the gas separators. The oil and water from the flume flows by gravity to the VT where the oil and water separates by gravity. The VT is fitted with nozzles to impart a vortex spin to the water in the tank, allowing the water to remain in the tank longer and increasing separation. The oil is skimmed off the top of the VT and flows to the oil tanks, where it is pumped to Section 18G and metered for sale. The partially treated water flows to the water treating facilities.

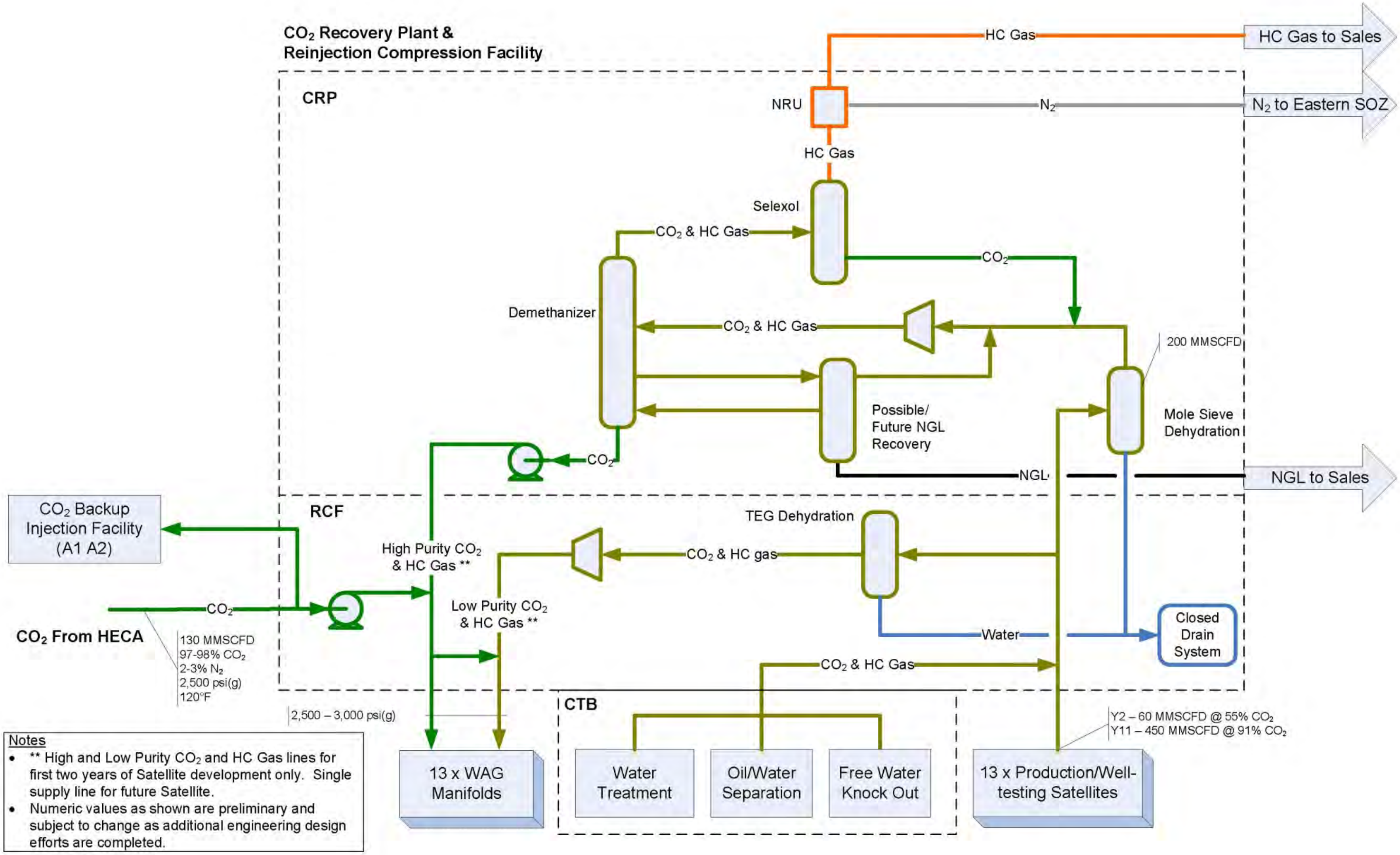
2.3.2.2 Reinjection Compression Facility

The RCF is the first portion of the CO_2 treating/recovery facilities to be installed. It will consist of three two-stage, electric motor driven, centrifugal compressor systems each sized at 50 percent of design capacity. The third unit will function as a redundant spare and will provide for enhanced uptime and reliability. Each of these systems ("trains") will have an inlet scrubber and discharge air cooler on each of the two stages of compression. The RCF will be sized for a nominal flow of approximately 214 mmscfd or 107 mmscfd per train. The inlet pressure to the compressor trains will be controlled by a variable speed gearbox between the motor and compressor to adjust the compressor speed to maintain the required inlet pressure with capacity for each train being set by a load sharing controller.

Prior to compression, the inlet gas will first flow to the inlet gas separator to remove any condensed liquids from the gathering line. Next, the gas will flow to the inlet gas filter and coalescer to remove particulates from the inlet gas. The gas will then be dehydrated by a standard triethylene glycol (TEG) dehydration system to the CO_2 water content specification. This early dehydration step will allow for the use of standard carbon steel (CS) material throughout the RCF.

Both RCF trains will be installed during the initial plant construction. The RCF will have sufficient capacity to operate for approximately the first 4 years of production. By that time, the CRP will be installed and both plants will operate at partial load until peak gas rate is reached approximately 6 years later.

Figure 2-11 presents a basic process flow diagram for the RCF and CRP facilities. Numeric values shown on the figure are preliminary and subject to change as additional engineering design efforts are completed.



Notes

- ** High and Low Purity CO$_2$ and HC Gas lines for first two years of Satellite development only. Single supply line for future Satellite.
- Numeric values as shown are preliminary and subject to change as additional engineering design efforts are completed.

FIGURE 2-11 BASIC PROCESS FLOW DIAGRAM FOR THE RCF AND CRP FACILITIES

2.3.2.3 CO_2 Recovery Plant

The CRP is the second part of the gas treating/recovery plant. The CRP consists of six primary elements: (1) Fractionation System - for bulk CO_2 recovery, (2) a Natural Gas Liquids (NGL) Recovery System – for fluids from the associated gas, (3) Demethanizer System – for bulk CO_2 recovery, (4) Selexol Unit - for final treatment of the hydrocarbon gas, (5) Refrigeration system - for process cooling and (6) Nitrogen Rejection Unit.

Fractionation System

The Fractionation system will consist of a Mol Sieve dehydration package, booster compressor and a demethanizer fractionation tower with its associated heat exchangers. Inlet gas from the gas header will first flow to the inlet gas separator to remove any condensed liquids (condensate) from the gathering line. Next, the gas will flow to the inlet gas filter and coalescer to remove particulate matter from the inlet gas. The gas will then flow though the Mol Sieve dehydrators where water is removed to prevent ice or hydrate formation in the cold sections of the Fractionation system. The Mol Sieve dehydration system will consist of three beds, two dehydrating and one bed in regeneration. The regeneration will be done by withdrawing a small slipstream of the dehydrated gas downstream of the Mol Sieve bed. This regeneration gas will be compressed and heated in a regeneration gas compressor and heater. This heated gas will then flow through the Mol Sieve bed to drive out/boil out the absorbed water from the Mol Sieve material. The regeneration gas from the top of the bed will be cooled in an air cooler and the condensed water removed in the regeneration gas separator. The regeneration gas is then routed to upstream of the Mol Sieve bed to be dehydrated again.

The booster compressor will consist of two units (“trains”) each sized at 50 percent of the required total capacity. These trains will consist of single-stage, electric motor driven, centrifugal compressor systems. Each train will have an inlet scrubber and a common discharge air cooler. The booster compressors will be sized for a nominal flow of approximately 205 mmscfd based on the nominal feed rate of 200 mmscfd to the fractionation system plus recycle flows from the Selexol system and the NGL recovery system. The inlet pressure to the compressor trains will be controlled by a variable speed gearbox between the motor and the compressor to adjust the compressor speed to maintain the required inlet pressure with capacity for each train being set by a load sharing controller.

Gas flow from the booster compressors are split with some of the hot discharge gas flowing under temperature control through the Demethanizer (De-C1) reboiler to provide most of the heat needed for the fractionation process. The flow through the reboiler is controlled to meet process requirements in the fractionation tower. The remainder of the hot discharge gas flows through the discharge air cooler where the rest of the heat of compression is removed. The cooled gas from the discharge cooler is then recombined with the slip stream used for heat in the reboiler.

The total inlet gas stream then flows through a series of heat exchangers to further cool the feed to a low temperature to feed the De-C1. The heat exchangers are comprised of the following components:

a. Side reboiler – Further process heat is removed from the feed to provide heat for the fractionation tower.
b. Feed/Overhead exchanger – For recovery of cooling from the cold overhead gas stream from the Demethanizer.
c. Demethanizer feed gas chiller – Cooling with propane refrigeration to final process operating conditions.

Between the feed/overhead exchanger and the gas chiller, the partially condensed feed gas is sent to the NGL Recovery system. The temperature of this stream controls the amount of CO_2 that is condensed to liquid. The temperature must be low enough to condense most of the recoverable NGLs, but not so low as to condense the CO_2 that would be recycled to the inlet and increase booster compressor requirements.

NGL Recovery System

In the NGL Recovery system, the partially condensed inlet gas is flashed in a two-phase vertical separator. The uncondensed CO_2 is returned to the main heat exchanger train for further cooling and fed to the Demethanizer, and the cold condensed liquid is fed to the top of the NGL stabilizer. Heat from the electric reboiler vaporizes some of the liquid and provides stripping gas for mass transfer operation in the stabilizer. The lighter components (e.g., CO_2) are boiled out and the NGL product then flows from the bottom of the tower where it is cooled and pumped to storage. The CO_2 that is stripped from the NGL system feed flows from the stabilizer overhead and is recycled to the booster compressor inlet. NGLs recovered from this process will be piped to 35R for combination with liquids from existing processing facilities.

Demethanizer System

Demethanization is a process in which the inlet gas is chilled through various heat exchangers and refrigeration. The chilling of the gas condenses most of the CO_2 out of the gas stream (also called bulk removal of CO_2) and allows it to be separated in a tower called the Demethanizer tower. The CO_2 is then pumped back to the field for reinjection. The gas stream off the top of the Demethanizer is sent to the Selexol process to recover the remaining CO_2.

Selexol Unit

After bulk CO_2 recovery in the Fractionation system, the remaining gas flows to the Selexol system for final CO_2 recovery and gas treatment to meet the export gas specification. Selexol is a physical absorbent to remove CO_2 and hydrogen sulfide (H_2S), if present, from the natural gas. The absorption occurs in the Selexol contactor where a solvent, dimethyl ethers of polyethylene glycol (DEPG), flows counter currently downward against the gas to be treated. DEPG is generally regenerated by mixture of heating or pressure reduction to flash the CO_2 from the solvent.

The cool inlet feed gas is cross exchanged with cold residue gas from the contactor overhead in the inlet gas/sales gas exchanger. The cooled feed gas is then fed to the bottom of CO_2 absorber and flows upward counter current to the solvent and treated gas exits from the top of the absorber and flows to the inlet cross exchanger. The CO_2-rich solvent is flashed to a lower pressure, approximately 250 psig. The flash gas, which is relatively rich in hydrocarbons, is compressed and recycled to the inlet of the Selexol unit so that the CO_2 can be absorbed.

The semi-rich solvent is then flashed to consecutively lower pressures with the last stage of flash at vacuum. The flash gas from these regeneration flash separators is compressed in a multi-stage compressor to approximately 250 to 300 psig and the CO_2 is recycled to the inlet of the CO_2 Fractionation system where the CO_2 is recovered.

The lean solvent from the last stage of flash regeneration is filtered and cooled with propane to approximately 15˚F and pumped under flow control to the top of the CO_2 absorber.

The Selexol unit is followed by a cryogenic Nitrogen Rejection Unit (NRU) to reduce the nitrogen content from approximately 38 percent to a total of 4 percent of inerts. Supplemental compression will be added downstream of the NRU to boost the sales gas to the required delivery pressure of 1,200 psig.

Refrigeration System

The primary utility system for the CRP is a propane refrigeration system. The propane refrigeration system will consist of two units (“trains”) each sized at 50 percent of the required total capacity. Each train will consist of a four-stage, centrifugal compressor package. The refrigeration will be produced at two temperature levels: 10˚F for the inlet feed gas chiller and the Selexol chiller and -35˚F for the Demethanizer overhead condenser.

Nitrogen Rejection Unit

The treated gas that comes off the Selexol absorber contains some amounts of CO_2 (approximately 3 percent) and Nitrogen (approximately 38 percent) that need to be removed in order for the hydrocarbon gas to meet the pipeline sales specification. This treated gas goes to the NRU to separate these components. The NRU contains a small acid gas removal unit to separate out the CO_2; the CO_2 goes to the vapor recovery unit and is recycled back to the RCF and CRP. The nitrogen is separated from the hydrocarbon gas by chilling and liquefying the hydrocarbon gas. The nitrogen is then compressed and sent to injection wells at the eastern Shallow Oil Zone (SOZ) in the Elk Hills Unit. The hydrocarbon gas is then vaporized, compressed, and put into a gas pipeline.

2.3.2.4 Water Treatment Plant

The oily water from the inlet section of the CTB flows to additional treatment to remove oil, solids and other contaminants from the produced water. It is then pressurized in the injection pumps and sent to the Satellites for injection.

From the VT, the oily water flows under level control to a series of flotation cells. In the flotation cell, fuel gas is introduced to enhance coalescing of oil droplets in the oily water to remove the oil from the water. The partially treated water is then pumped by filter charge pumps through filters to remove solids from the produced water. The water then flows to the water tanks that serve as a surge volume for the system. Makeup water from the Tulare formation is pumped by electrical submerged pumps via a new 10-inch pipeline to the CTB for periods when the CO_2 is not available from the HECA Project. It is introduced into the water system upstream of the filters to allow for filtering and also for solids removal.

From the water storage tanks, the produced water is pumped by booster pumps and the water injection pumps to the water injection distribution system and then via the water injection to the WAG manifolds at the Satellites for injection into the wells. Control is manual with the number of pumps online balanced with the demand for injection water.

Low-pressure gas collected from the flume/vortex in the CTB and the flotation cell in the Water Treatment area is compressed by VRU to approximately 35 psig, where it is combined with gas from the gas separator. The combined low pressure gas stream is then compressed by the low-pressure compressor and routed to the inlet of the RCF and CRP for processing.

2.3.3 Backup CO_2 Injection Facility

A backup injection facility will be constructed at the A1/A2 producing reservoirs in the northwest area of the Elk Hills Unit. This facility will be constructed and available for:

1. Pressurization of the A1/A2 reservoirs for additional CO_2 EOR production
2. Sequestration of CO_2 should there be a short-term operational disruption at the HECA Project or Elk Hills facilities or an imbalance of supply and demand of CO_2

OEHI will install a pipeline for CO_2 transport to the A1/A2 area in the northwest area of the Elk Hills Unit (Sections 7R, 18R). Flows of CO_2 to the A1/A2 reservoir will be monitored in the same fashion as those flows to the primary injection zones.

On the discharge side of the CO_2 injection pumps is a pressure control valve that will route excess CO_2 to the Backup CO_2 Injection Facility, should there be a localized imbalance. This is matched by a second pressure control valve on the supply line from the HECA Project downstream of the custody transfer meter to also route excess CO_2 to the Backup CO_2 Injection Facility. It opens as the backpressure on the supply line increases indicating excess flow from the HECA Project over the flow from the CO_2 injection pumps to the injection wells. The third system works in conjunction with the upstream pressure controller on the HECA Project supply line. This third system is a direct pathway independent of the pressure controllers to route all the HECA Project supplied CO_2 to the Backup CO_2 Injection Facility, should there be a operational disruption at the CO_2 Facility (eg., a power failure).

3 Supporting Process Systems

3.1 Hazardous Material Management

A variety of hazardous reagents and materials will be stored and used at the OEHI CO_2 EOR Project in conjunction with construction, operation, and maintenance of the OEHI CO_2 EOR Project. In general, the type and character of these materials will be the same as those used today at the Elk Hills Unit.

Construction

Hazardous materials used during the construction of the OEHI CO_2 EOR Project would mainly be limited to fuels and construction materials, including:

- Gasoline, diesel fuel, and motor oil for construction equipment
- Compressed gas cylinders containing oxygen, acetylene, and argon for welding
- Paint and cleaning solvents
- Concrete form release
- Miscellaneous lubricants, adhesives, and sealants

Each construction contractor will be responsible for maintaining a set of Material Safety Data Sheets (MSDSs) for each onsite chemical they control and notifying their construction workers where these chemicals are stored and the associated hazards.

The most likely accidents involving hazardous materials during construction might occur from small-scale spills during cleaning or use of other materials in the storage areas or during refueling of equipment. Such spills will be immediately cleaned up and materials containing hazardous substances will be properly disposed in accordance with applicable laws, ordinances, regulations and standards (LORS).

Operations

Hazardous materials that may be routinely stored in bulk and used in conjunction with the OEHI CO_2 EOR Project operations include, but are not limited to, petroleum products, flammable and/or compressed gases, cleaning chemicals, paints, and some solvents. Table 3-1, Hazardous Materials Usage and Storage during Operations, lists each material and describes the approximate annual quantity needed and use of the material during operations.

TABLE 3-1 HAZARDOUS MATERIALS USAGE AND STORAGE DURING OPERATIONS[1]

Material	Potential Hazardous Characteristics[2]	Purpose	Storage Location	Maximum Quantity Stored	Storage Type
Compressed Carbon Dioxide Gas[3]	Asphyxiant	EOR fluid; received from HECA; recovered from production wells	Outdoor	TBD	No aboveground storage, in process and transport pipelines only
Nitrogen[3]	Asphyxiant	Byproduct of hydrocarbon gas production and CO_2 separation, inert gas	Outdoor	TBD	No storage, in process and transport pipelines only
Natural Gas Liquids (NGL)	Flammable	Sales Product of Oil Recovery	Outdoor at 27S and transported to 35R plant via pipeline	TBD	No storage, in process and transport pipelines only
Produced Hydrocarbon Gas	Flammable	Sales Product of Oil Recovery	Outdoor at 27S and transported to 35R plant via pipeline	TBD	No storage, in process and transport pipelines only
DEPG or dimethyl ethers of polyethylene glycol	Flammable	Used in Selexol process for CO_2 recovery	Outdoor at 27S	TBD	AST with secondary containment
Chemical Reagents (acids/bases/—standards)	Corrosivity, Reactivity	Lab	Indoor chemical storage	<5 gallons	Small original containers

Material	Potential Hazardous Characteristics^2	Purpose	Storage Location	Maximum Quantity Stored	Storage Type
Miscellaneous Industrial Gases – Acetylene, Oxygen, Other Welding Gases, analyzer calibration gases	Ignitability, Toxicity	Maintenance Welding/ Instrumentation Calibration	Gas cylinder storage in Shop/ instrument shelters	Minimal	Cylinders of various volumes
Natural Gas	Ignitability	Startup/Backup /Auxiliary Fuel	Supply piping only	Utility supply on demand via pipeline	None
Diesel Fuel	Ignitability	Emergency generator/fire water pump fuel	Outdoors	2,000 gallons	ASTs with secondary containment
Paint, Thinners Solvents, Adhesives, etc.	Ignitability, Toxicity	Shop / Warehouse	Indoor chemical storage area	<20 gallons	Small original containers

Notes:

1 All numbers are approximate.

2 Potential hazardous characteristics based on material properties and potential health hazards associated with those properties.

3 Nitrogen and carbon dioxide are not hazardous materials but may be asphyxiants under some circumstances.

% = percent

< = less than

AST = aboveground storage tank

The storage, handling, and use of hazardous materials will be in accordance with applicable LORS. Storage will occur in appropriately designed storage areas. Bulk tanks will be provided with secondary containment to contain leaks or spills. Safety showers and eyewashes will be provided in appropriate chemical storage and use areas. Personnel who could potentially handle hazardous materials will be properly trained to perform their duties safely and to respond to emergency situations that may occur in the event of an accidental spill or release.

3.2 Hazardous Waste Management

3.2.1 Hazardous Construction Waste

The majority of hazardous waste generated during construction will consist of liquid waste such as waste oil from routine equipment maintenance, flushing and cleaning fluids, waste solvents, and waste paints or other material coatings. Additionally, some solid waste in the form of spent welding materials, oil filters, oily rags and absorbent, spent batteries, and empty hazardous material containers may also be generated.

Construction contractors will be required to employ practices consistent with the proper handling of all hazardous wastes in accordance with applicable LORS. This includes all licensing requirements, training of employees where required, accumulation limits and duration, and record keeping and reporting requirements. Wastes that are deemed hazardous will be collected in hazardous waste accumulation containers placed near the area of generation. After the end of each workday, the accumulation containers would be moved to the hazardous waste accumulation area, where hazardous wastes can be stored for up to 90 days after the date of initial generation. All hazardous wastes will be removed from the construction sites of the OEHI CO_2 EOR Project by a licensed hazardous waste management facility.

Table 3-2 lists the anticipated construction wastes including both hazardous and non-hazardous waste, and identifies the likely disposal method

TABLE 3-2 SUMMARY OF CONSTRUCTION WASTE STREAMS AND MANAGEMENT METHODS[1]

Waste	Waste Classification FIX	Amount	Disposal Method
Used Lube Oils, Flushing Oils	Hazardous or Non-Hazardous	1-10 55 gallon drums per month	Recycle
Hydrotest Water (One time per commissioning, reuse as practical, test for hazardous characteristics)	Hazardous or Non-Hazardous	TBD	Characterize. Drain non-hazardous to the Detention Basin. Dispose of hazardous at a hazardous waste disposal facility.
Solvents, Used Oils, Paint, Adhesives, Oily Rags	Cal-Hazardous[2] Recyclable	Unknown	Recycle or dispose of as hazardous waste.
Spent Welding Materials	Hazardous	Unknown	Dispose at a hazardous waste landfill.

Waste	Waste Classification FIX	Amount	Disposal Method
Used Oil Filters	Hazardous	Unknown	Dispose at a hazardous waste landfill.
Misc. Oily Rags, Oil Absorbent	Non-Hazardous or Hazardous Recyclable	(1) - 55 gallon drum per month	Recycle or dispose at a hazardous waste landfill.
Empty Hazardous Material Containers	Hazardous Recyclable	1 cubic yard per week	Recondition, recycle, or dispose at a hazardous waste landfill.
Used Lead/Acid and Alkaline Batteries	Hazardous Recyclable	No greater than 1 ton per year	Recycle
Sanitary Waste from Workforce (Portable Chemical Toilets)	Non-Hazardous	Approximately 390 gallons per day	Pump and dispose by sanitary waste contractor.
Site Clearing – Grubbing, Excavation of Non-Suitable Soils, Miscellaneous Debris	Non-Hazardous	Minimal	Reuse Soils or dispose at a non-hazardous waste landfill.
Scrap Materials, Debris, Trash (Wood, Metal, Plastic, Paper, Packing, Office Waste, etc.)	Non-Hazardous	Approximately 40 cubic yards per week	Recycle or dispose at a non-hazardous waste landfill.

Notes:
1 All Numbers are estimates
2 Under California regulations

3.2.2 Hazardous Operations Waste

As with construction hazardous waste described above, where appropriate, hazardous waste resulting from operation activities will also be collected in hazardous waste accumulation containers placed near the area of generation. After the end of each workday, the accumulation containers will be moved to hazardous waste accumulation areas where hazardous wastes can be stored for up to 90 days after the date of generation. All hazardous wastes will be properly removed from the OEHI CO_2 EOR Project Site in accordance with applicable LORS.

Table 3-3 lists the anticipated construction wastes which includes both hazardous and non-hazardous waste, and identifies the likely disposal methods.

TABLE 3-3 SUMMARY OF OPERATIONAL WASTE STREAMS AND MANAGEMENT METHODS[1]

Waste Stream	Waste Classification	Anticipated Maximum Amount per Year	Disposal Method
Water Treatment Plant Sludge and Used Water Filter Media	Non-Hazardous	**TBD**	Characterize and dispose as non-hazardous or hazardous waste.
Used Oil	Hazardous	**TBD**	Recycle. Expected to meet the regulatory exemption for used oil when recycled.
Spent Grease	Hazardous	**TBD**	Characterize and dispose as hazardous waste.
Miscellaneous Filters and Cartridges	Hazardous or Non-Hazardous	**TBD**	Characterize and dispose as non-hazardous or hazardous waste.
Tank Bottoms Sludge	Hazardous or Non-Hazardous	**TBD**	Characterize and dispose as non-hazardous or hazardous waste.
Triethylene Glycol	Hazardous or Non-Hazardous	**TBD**	Recycle. Characterize and dispose as non-hazardous or hazardous waste.
Miscellaneous Solvents	Hazardous	**TBD**	Recycle or disposal as hazardous waste.

Waste Stream	Waste Classification	Anticipated Maximum Amount per Year	Disposal Method
Flammable Lab Waste	Hazardous	**TBD**	Characterize and dispose as hazardous waste.
Universal Wastes	Hazardous	**TBD**	Recycle. Characterize and dispose as hazardous waste.
Waste Paper and Cardboard	Non-Hazardous	**TBD**	Recycle.
Combined Industrial Waste (Used PPE, materials, small amounts of refractory, slurry debris, etc.)	Non-Hazardous	**TBD**	Dispose at a non-hazardous waste landfill.

Notes:

1 All Numbers are estimates

2 PPE—personal protective equipment

3.3 Stormwater Management

Clean stormwater runoff from process areas (27S CO_2 Processing Facility) will be routed to an onsite stormwater retention basin during construction activities. Construction project site stormwater runoff in non-process areas but within the main plant area will be routed to a retention basin. Retention basins and stormwater collection/conveyance systems will be designed in accordance with the Kern County Development Standards.

Stormwater from non-process areas outside the main plant area but within the OEHI CO_2 EOR Project Site is expected to reflect natural discharge conditions. Runoff from these areas follows natural drainage patterns of the Elk Hills Unit and will be subject to the California Stormwater Construction General permit, as appropriate.

A project-specific construction stormwater pollution prevention plan (SWPPP) will be developed prior to construction, incorporating the recently updated California Stormwater Construction General permit. The OEHI CO_2 EOR Project stormwater will be managed using best management practices (BMPs), Rainfall Erosivity Waiver, or NOI coverage under California Stormwater Construction General permit, as appropriate.

3.4 Fire Protection

The OEHI CO_2 EOR Project Fire Protection Program includes both fire prevention and protection measures. Employment of conservative equipment layouts, segregation of critical components, and the remote location of non-essential resources, are the backbone of the fire mitigation/suppression measures employed.

Conservative equipment spacing and segregation of potentially hazardous activities from the balance of the OEHI CO_2 EOR Project are the guiding principles employed to protect personnel and property. Automation and sensing equipment will be strategically located throughout the OEHI CO_2 EOR Project to detect and alarm hazardous levels. Oil containment and equipment spacing will isolate large transformers from adjacent facilities. Structural steel will be protected with fire-proofing materials in strategic areas. Grading and paving plans will be prepared to complement this objective.

Preliminary design of the firewater system for the facilities includes a storage tank and two firewater pumps. Detailed design of the system will be performed in later stages of engineering; it will address system layout, automated and manual portions of the .system.

The degree and extent of fire protection and suppression systems provided will be in accordance with applicable LORS, standards, and company guidelines

3.5 Control Systems

CO_2 Gas Plant Facility

The CO_2 Facility will be controlled from a new CO_2 control building within the plant area. The control room is to cover the operation of the RCF, CTB, CRP, Satellites, producing and injection wells. The plant Integrated Control and Safety System (ICSS) will be a Distributed Control System with monitoring, control, and shutdown capabilities. The ICSS shall consist of both a Process Control System and a Safety Instrumented System that are fully redundant and independent of each other. The configuration, maintenance, and operating environment for these systems shall be achieved from the same Human Machine Interface (HMI)/Engineering station. There will be several HMIs that can view and monitor the entire facility and they will be capable of backing up and achieving the same functionality in case one HMI fails.

The new control room will contain Operator Workstations and Engineering Workstations to provide operators a means of interfacing and controlling the CO_2 Facility, and injection and production wells. New CO_2 control equipment will be added to the existing Elk Hills Unit control system, and will be connected via fiber optic ring from the CO_2 control building to the existing Central Control Facility.

For ease of maintenance and a preferred environment for electronic equipment, the control panels for the Control and Safety System shall be located in non-hazardous air-conditioned buildings inside the CO_2 Facility area.

Satellite Gathering Sites, Production and Injection Well Sites

Each satellite site will have a controller that is used to monitor and control any local satellite processes and conditions. It will communicate back to CO_2 Facility via a fiber optic cable.

A radio and antenna shall exist at each satellite site. The radio will be used to communicate to all the related production and injection wells control panels. The radio signal will then be communicated back to the CO_2 Plant for operator interaction, via fiber optics.

3.6 Utilities

OEHI has existing plans to install a new 320/115 kilovolt (kV) electrical substation and electrical distribution lines in the Elk Hills Unit. This planned upgrade will make up to 500 megawatts (MW) of power available from Pacific Gas and Electric (PG&E) (the local utility company) and will be completed prior to the OEHI CO_2 EOR Project construction. This upgrade will ensure that sufficient power is available to the OEHI CO_2 EOR Project.

Five wells will be drilled and equipped as make-up water wells. They are located in Sections 13B and 18G, and will produce nominally 10,000 bwpd each. Makeup Water pumps transport water to the CO_2 Facility in Section 27S for use as make-up injection water for the reservoirs when the HECA CO_2 gas is unavailable. Potable water will be supplied from the existing potable water system. An internal connection will be added from the 36S potable water tank and system.

The following tie-ins to the project are expected:

Commodity	Tie-In Location	Design Conditions
CO_2 from HECA	Nominally at main plant boundary in 27S	
Fuel Gas	In 35R adjacent to existing gas plants	

Commodity	Tie-In Location	Design Conditions
Water	Tulare water in 13B and 18G, pipeline to 27S	Not potable quality
Propane	Pipeline to 35R plant	HD5 propane
Electric Power	In the SW corner of 28S	115kV, assume required power is available
Potable Water	36S potable water tank	Connection from existing potable water system

3.7 Project Buildings/Facilities

Three new buildings are required at the CO_2 Facility:

- Administration/Control Building
- Maintenance/Warehouse Building
- Compressor Shelters

3.8 Security Systems

The Elk Hills Unit has a fully fenced perimeter with a roving security patrol that operates around the clock. Access into Elk Hills is through manned guard gates where pictured security ID badges are shown to gain entrance to the operations. The CO_2 Facility will be fenced and secure access provided adjacent to the administration/control building. The satellites and pipelines are located within the boundary limits of the Elk Hills Unit, and no additional specific security provisions have been made for these components since a gated security fence limits access at this time.

3.9 CO_2 Monitoring, Measurement, Verification and Closure

3.9.1 Monitoring, Measurement and Verification

As it relates to the HECA Project the CO_2 EOR process will be subject to monitoring, measurement, and verification (MMV) requirements. A site-specific MMV Plan will be developed with the objective of demonstrating permanent trapping of HECA-provided CO_2. The MMV Plan will include consideration of the existing detailed subsurface, seismic, geochemical characterization and wellbore construction details that have been generated from the extensive data covering the EHOF. Selection of the appropriate suite of tools to satisfy the MMV objectives will be based on an assessment of the potential risks, taking into account the unique characteristics of the EHOF and the performance expectations at the site.

There are several components that will be incorporated into the MMV Plan. OEHI's development plan for the Elk Hills Unit, which includes injection of CO_2 for EOR, will be used to predict the field's future production over a period of many years. Reservoir characterization, which includes geologic and petro-physical analysis, and reservoir simulation modeling will be used to develop reliable recovery forecasts. Reservoir characterization and forecasting will be confirmed by applying the following:

Demonstration of Well Integrity

- Monitoring of wellhead and annular pressures of all wells completed in EOR reservoirs, supplemented by downhole pressure and temperature measurements, where available

- Well integrity monitoring and cement evaluation

Demonstration of Horizontal Containment

- Monitoring of wellhead and annular pressures of wells completed in vertically adjacent reservoirs, supplemented by downhole pressure and temperature measurements in the offset reservoirs, where available

Demonstration of Sequestered Volumes

- Material balance

- Recovered fluid geochemical sampling

In connection with the foregoing, OEHI will supply any requested information to address the following:

- Subsurface data to characterize and represent in 3 dimensions the sedimentary section, structural geology and seismicity of the injection zone and overlying areas

- Subsurface data to characterize and demonstrate that the injection zone is sufficiently porous to receive CO_2 under expected operating conditions and extensive enough to receive the anticipated volume of CO_2 injected

- Subsurface data to characterize and demonstrate that the confining zone is sufficiently impervious to restrict vertical movement of CO_2 beyond the confining zone under expected operating conditions and extensive enough to contain the anticipated volume of CO_2 injected

- Geo-mechanical data to characterize rock stress, rock strength and fault stability

- Over the period of CO_2 injection, geochemical data to characterize formation fluids in the injection zone and the lowermost porous unit above the confining zone

- Over the period of CO_2 injection, well-related injection data to allow physical and chemical characterization of injection fluids, including injection pressure, flow rate and temperature

- Over the period of CO_2 injection, well-related mechanical integrity data to demonstrate integrity of the wellbore such as concrete seals and wellbore packers and other as may be required by permit

3.9.2 CO_2 EOR Well Field Closure

The OEHI CO_2 EOR operations will be closed after all economic production of hydrocarbons has been exhausted, which is not expected for at least 20 years. The closure phase consists of site decommissioning, well plugging and abandonment, and appropriate post-injection care and monitoring. In addition to those measures generally required for closure of UIC Class II wells, OEHI will conduct closure activities that demonstrate that the injected CO_2 is properly contained within the confinement zone and is not endangering human health or the environment. Closure will be conducted pursuant to a post-injection closure plan that will be performance-based and specifically tailored for the OEHI CO_2 EOR Project.

4 Project Construction

OEHI is currently in the early stages of project economic and engineering development. Specific details regarding project construction are not yet available. As OEHI moves through its project development FEED process, this section will be populated and submitted to interested parties.

This section will contain the following material when completed:

4.1 Project Site Construction

4.2 Construction Planning

4.3 Mobilization

4.4 Construction Facilities, Parking, and Lay-down Areas

4.5 Emergency Facilities

4.6 Construction Utilities and Site Services

4.7. Construction Materials and Heavy Equipment Deliveries

4.8 Hazardous Materials Storage

4.9 Construction Disturbance Area

4.10 Stormwater Runoff Prevention Plan

4.11 Linear Construction

4.12 Construction Workforce

4.13 Construction Equipment Requirements

4.14 Construction Traffic

5 Project Operation Scenarios

OEHI is currently in the early stages of project economic and engineering development. Specific details regarding project operation are not yet available. As OEHI moves through its project development FEED process, this section will be populated and submitted to interested parties.

This section will contain the following material when completed:

5.1 Startup Operations

5.2 Normal Operations

5.3 Upset Operations

5.4 Shutdown and Decommissioning

5.5 Project Staffing

6 Facility Safety Design

Occidental has a long-standing commitment to protecting community, employee and contractor health and safety, and the environment. Maintaining strong health, environment, safety and security (HES&S) programs is one of Occidental's highest priorities and the company strives for continual improvement in HES&S performance.

OEHI has a management system that effectively coordinates HES&S activities. This Health, Environment and Safety Management System (HESMS) includes the following seven elements:

Basic HESMS Elements	Description
Leadership and Commitment	Addresses management’s commitment to the Occidental Petroleum Corporation’s HES&S Principles, Policy Statement and the management culture essential to success.
Policy and Strategic Objectives	Address corporate intentions, principles of action and HES&S goals.
Organization, Resources and Documentation	Addresses organizing people, resources and documentation for sound HES&S performance.
Evaluation and Risk Management	Addresses identifying and evaluating HES&S risks for activities, products and services, and developing risk reduction measures.
Planning	Addresses planning work activities, including planning for change and emergency response.
Implementation and Monitoring	Addresses HES&S performance and monitoring activities and necessary corrective action.
Auditing and Reviewing	Addresses periodic assessments of systems performance, effectiveness and fundamental suitability.

Integration of Safety and Health into Management Planning

At OEHI, HES&S includes the functional areas of occupational health, industrial hygiene, safety, product stewardship, process safety, transportation and pipeline safety, environmental protection, remediation, physical security and management of risks pertaining to the foregoing areas. The entire OEHI organization – including the OEHI Leadership Team and all plant and field managers, supervisors, employees and contractor personnel – are responsible for implementing the HESMS and are accountable for HES&S performance.

Operation, maintenance, and safety design features at the Elk Hills Unit will ensure that all Project-related surface equipment, including but not limited to, well safety systems, wellheads, separators, pumps, manifolds, valves, and pipelines used for the OEHI CO_2 EOR Project, will be maintained in good condition at all times to safeguard life, health, property, and natural resources.

Safety Philosophy

OEHI's management, employees and contractors are committed to continuously reducing workplace hazards while striving for an injury-free workplace. Safety and health philosophy and expectations are summarized in the Elk Hills Safety Credo, which is distributed to OEHI employees and contractor personnel, and summarized below:

- Safety is a core business value
- All accidents are preventable
- Working safely is a condition of employment
- No job is so important that it cannot be done safely
- Safe production is our standard

Each employee and contractor is responsible for his or her safety and the safety of others while working on OEHI properties. The HES&S Department is responsible for ensuring that there are effective programs to protect the health and safety of employees, contractors, subcontractors, visitors and neighbors.

Safety and health responsibilities for OEHI employees and contractors are detailed in OEHI's Safety Handbook and include, but are not limited to, the following:

- Performing every job safely for the benefit of self, coworkers, contractors, subcontractors, visitors, the public, and for the protection of company assets and the environment.
- Immediately reporting job-related injuries, equipment damage, near misses, spills, and fires, regardless of severity, to a supervisor and to the Communication Operations Center (COC).
- Taking necessary actions to P.A.U.S.E. (People Actively Using Stop Work Enforcement), or intervene and correct any unsafe condition, practice, situation, or the unsafe behavior of any person.

- Actively participating in safety meetings, safety training, and pre-job safety tailgate meetings and the safety observation process.

- Becoming familiar with emergency procedures applicable to the job and the OEHI Safety Handbook and other pertinent OEHI safety policies, procedures and guidelines, manuals, handbooks and publications.

OEHI uses a number of management techniques to ensure that employees, managers/supervisors and contractors demonstrate accountability for OEHI HES&S goals.

Contractor Management Program

OEHI's contractor safety management program has been developed to promote a safe working environment for OEHI employees, contractors, subcontractors, visitors and the public. This program establishes the minimum requirements and expectations for contractors and their subcontractors and includes criteria for prequalification, selection, site safety and health orientation, pre-job activities, work in progress, and performance evaluation.

All contractors and service providers must pre-qualify prior to a bid award or performing any onsite task or service. Contractors are selected for the bid process upon completion of the safety and health criteria evaluation and a review of the contractor's ability to comply with OEHI applicable safety and health requirements. The final contractor selection is made based on the contractor's HES&S performance, cost, availability and technical qualifications.

Contractors must prepare a comprehensive health and safety plan before performing and completing any work. Contractors are also required to (1) hold regular safety meetings; (2) conduct Job Safety Analysis to identify and eliminate workplace hazards; (3) have an active Behavioral Based Safety (BBS) Observation program that identifies at-risk behaviors and mentors/coaches employees on safe work practices; (4) report and investigate significant and important incidents; (5) be familiar with OEHI's Emergency Procedures and (6) ensure that new contractor personnel (including both contractor employees and subcontractors) are familiar with OEHI safety practices.

Audits are conducted for selected projects to determine compliance with safety policies and practices and assessment of hazards. All hazards must be mitigated by the contractor or the OEHI facility, as appropriate, and non-compliance issues promptly corrected.

Facility Design and the Management of Process Risks

OEHI Process Risk Management (PRM) program provides the means to identify and increase the awareness of foreseeable processes and operational risks that could potentially lead to an unplanned and unwanted event, and leads to recommendations that would eliminate or mitigate such risks. It provides a framework for continuous improvement in managing HES&S risks and facilitating the integration of HES&S risk management into business planning and decision making processes.

The requirements of the PRM program are designed to ensure a consistent and risk-based methodology for HES&S risk management and to ensure mitigation or discontinuance of participation in any activity that poses an unacceptable HES&S risk. Key elements include: i) compliance with applicable laws and regulations pertaining to HES&S risk management, ii) that facilities and equipment shall be designed, constructed, operated and maintained to meet internal OEHI standards, and iii) that recognized and generally accepted good engineering practices be applied.

In addition to any federal/country, state, and/or local regulatory programs for managing process-related risks, the following OEHI internal requirements are generally applicable.

- Facility Technical Information - Provide complete and accurate technical information to provide a basis for identifying and understanding chemical, technology and equipment related hazards.

- Management of Change - Identify and control HES&S hazards created by proposed changes in personnel, processes, equipment, structures, and procedures.

- Mechanical Integrity & Quality Assurance - Verify critical equipment, piping, components and instrumentation are designed, engineered, procured, fabricated, installed, tested, inspected and maintained according to required design specifications and standards.

- Operating & Maintenance Procedures - Provide clear instruction for safely conducting critical activities, including handling of hazardous materials, permit to work activities, inspection, and maintenance.

- Pre-Startup Safety Reviews - Verify that all new or significantly modified facilities have been thoroughly checked for safety, operability, and maintenance viability prior to startup.

- Process Hazards Reviews - Provide systematic approach for identifying and assessing HES&S Hazards and their possible consequences.

6.1 Natural Hazards

The OEHI CO_2 EOR Project will be planned, engineered, designed, constructed, and operated to meet the requirements of all applicable LORS. An overview of hazards that will be addressed in the OEHI CO_2 EOR Project is provided below.

6.1.1 Seismicity

In the context of CO_2 EOR, it is important as part of site selection to understand the risks of potential CO_2 leakage from the reservoirs due to seismicity. These reservoir risks are generally twofold: the first is induced seismicity from injection activities, and the second is potential leakage risk due to naturally occurring seismic activity. The OEHI CO_2 EOR Project evaluated both of these concerns with respect to the EHOF. The results are presented below.

6.1.1.1 Induced Seismicity

Even with decades of fluid injection for EOR, there is no public record of measurable induced seismicity at Elk Hills. The Elk Hills Unit contains significant volumes of gas in place and has undergone significant water and gas injection operations, including a pilot CO_2 injection project conducted in 2004.

In 2008, a regional seismicity study was conducted for the EHOF. The study found:

> *The risk of induced seismicity due to* CO_2 *injection operations was remote and highly unlikely (Terralog Technologies, 2008). Furthermore, even in the unlikely case of an induced seismic event, any such seismic event would likely be less than magnitude 4, based on the geologic setting, areal extent and depth of proposed operations, and anticipated pressure and stress changes (Terralog Technologies, 2008). Seismic events on the order of magnitude 3 to 4 may be felt within the immediate area (approximately 1 km), but would not be expected to cause structural damage to facilities or buildings for several reasons. Most surface structures near the EHOF are likely to be at distances of about 6 to 30 miles (10 km to 50 km) from the epicenter of any induced seismic event. Assuming the highly unlikely scenario of an induced seismicity event of magnitude 4 located at a depth of about 6 miles (10 km), the induced horizontal ground acceleration would be on the order of 0.01 g, which is an order of magnitude lower than the California seismic codes. Seismic codes in California require structures to withstand horizontal acceleration in excess of 0.1 g, with varying strength depending on the seismic zone location and the use of the structure. Therefore, even with the assumption of an induced seismic*

> *event, there is minimal risk that any damage would result to surface structures. This induced seismicity of this magnitude also would not cause any damage to injection equipment or the reservoirs, as detailed in the following section. (HECA, 2009).*

6.1.1.2 Naturally Occurring Seismicity

Since 1990, there have been 129 naturally occurring earthquakes recorded with a magnitude greater than 3.0 within a 60-mile (100 km) radius of Elk Hills (Figure 6-1). The vast majority of these have occurred along the White-Wolf fault, approximately 30 miles southeast of Elk Hills (Southern California Earthquake Data Center web site). The EHOF is situated about 15 miles east of the San Andreas Fault.

Natural seismicity of magnitude 3 to 6 is not likely to impact field operations and is highly unlikely to lead to leakage of any injected CO_2 from the EHOF. This assessment is based on decades of historical data for earthquake effects on wells in oil and gas operations in Southern California. It is also based on the geological setting of the injection project, which is in relatively soft and shallow (approximately 6,000 feet below ground surface) sediments. Most major earthquakes with a magnitude 6 and above in California occur at depths of 6 miles or more in brittle basement rock, while the proposed injection reservoirs at Elk Hills Unit is less than 2 miles deep in relatively soft sandstone. The strength of seismic waves decreases with distance; therefore, the large separation between major earthquake source and injection reservoirs would help prevent well damage (W. Foxall and J. Friedmann, 2008).

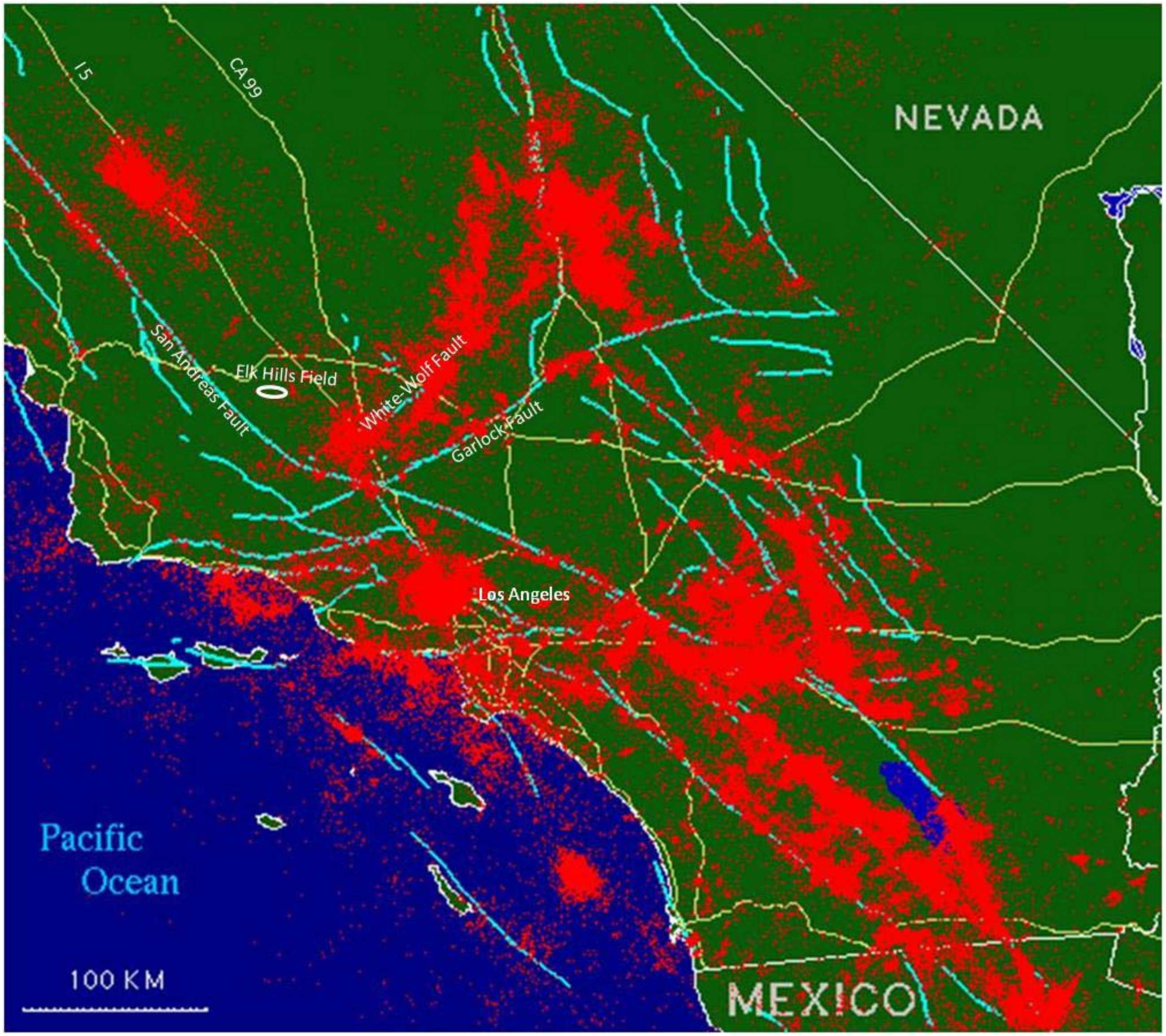


FIGURE 6-1 SEISMIC EVENTS IN SOUTHERN CALIFORNIA FROM 1932 TO 1996 (SOUTHERN CALIFORNIA EARTHQUAKE DATA CENTER)

In summary, the risk of induced seismicity from CO_2 EOR and Sequestration is remote. Moreover, even in the unlikely event of induced seismicity, the predicted magnitude would be no greater than 4.0. This type of event (4.0 magnitude) is comparable to the existing natural seismicity in the EHOF area and, as discussed above, would not cause structural damage to surface facilities in the nearby area. With respect to natural seismic events, there is abundant historical data and information demonstrating that a rather significant seismic event (on the order of magnitude 6), even if located in the immediate area of the EHOF, should not cause significant damage to wells or lead to leakage of injected CO_2. Finally, due to the numerous shale-sealed formations above the target injection zone, any vertical gas migration that might occur from the injection interval would be contained and not reach the surface.

6.1.2 Floods

The OEHI CO_2 EOR Project is not located within an area identified as having flood hazards or shallow groundwater. Based on the Federal Emergency Management Agency Flood Insurance Rate Map “Kern County, California, and Incorporated Areas” (Map 06029C2225E), dated 2008, the OEHI CO_2 EOR Project is not in the 100-year flood zone. Provided proper drainage design, the OEHI CO_2 EOR Project is not likely to experience flooding.

6.1.3 Wind Loads

The basic design wind speed (3 second gust) is 85 miles per hour as per CBC 2007. Wind loads on structures, systems, and components will be determined from ASCE 7 05 and CBC 2007.

6.2 Emergency Systems and Safety Precautions

6.2.1 Community and Stakeholder Awareness

OEHI values the importance of community awareness in the Kern County area and will engage in dialogue with the community and various stakeholders to maintain public confidence in the integrity of the OEHI CO_2 EOR Project.

Community/Stakeholder issues will be identified through the CEC siting process for the HECA Project by listening and consulting with concerned stakeholders: employees, contractors, regulatory agencies, public organizations, and communities. All communications will be responded to in a timely manner.

6.2.2 Emergency Preparedness

The OEHI CO_2 EOR Project will develop and use communications and response plans for emergency situations in accordance with applicable LORS. Prior to any activity, the response plan will be reviewed by the appropriate manager, who will take necessary actions to prepare to respond to an emergency event. All plans will be coordinated with the local emergency response organizations within Kern County, and the Bakersfield area in particular. Area hospitals and clinical medical services have been identified along with fire protection.

6.2.3 Specific Project Emergency Systems

The OEHI CO_2 EOR Project's auxiliary systems described below support, protect, and control the Project.

Fire Protection

See Section 3.4, Fire Protection, for details on the fire protection system for the OEHI CO_2 EOR Project.

Lighting System

The lighting system provides plant personnel with illumination in both normal and emergency conditions. The system consists primarily of alternating current (AC) lighting, and includes direct current (DC) lighting for activities or emergency egress required during an outage of the OEHI CO_2 EOR Project's AC electrical system. Lighting fixtures will be directionally oriented, shielded, and hooded to minimize offsite migration of light. The electrical distribution system also provides AC convenience outlets for portable lamps and tools.

Grounding System

The OEHI CO_2 EOR Project's electrical systems and equipment are susceptible to ground faults, switching surges, and lightning, which can impose hazardous voltage and current on Project equipment and structures. To protect against personnel injury and equipment damage, the grounding system provides an adequate path to dissipate hazardous voltage and current under the most severe conditions. Bare conductor is installed below grade in a grid pattern, and each junction of the grid is bonded together by welding or mechanical clamps. The grid spacing is designed to maintain safe voltage gradients. Ground resistivity readings are used to determine the necessary grid spacing and numbers of ground rods. Steel structures and non-energized parts of Project electrical equipment are connected to the grounding grid.

Emergency Relief System

The OEHI CO_2 EOR Project is furnished with pressure relief devices to protect equipment from overpressure. At the satellite units, any releases from pressure relief devices are routed through a local tank to capture any liquids entrained in the release. Gases including CO_2 and produced hydrocarbons would be vented directly to atmosphere in this emergency situation. At the CO_2 Facility, any excess gas resulting from a pressure relief would be routed to a flare relief system designed to handle an emergency or upset condition.

Cathodic and Lightning Protection System

Cathodic protection may be utilized using an impressed current or buried anode system to prevent corrosion of buried carbon steel piping and structures. Protective coatings are applied as primary protection and to minimize cathodic protection current requirements. The requirement for a cathodic protection system will be determined during detailed design. Lightning protection will be furnished for buildings and structures as appropriate.

Instrument Air System

The instrument air system provides dry, filtered air to pneumatic operators and devices throughout the OEHI CO_2 EOR Project. Air from the service air system is dried, filtered, and pressure-regulated prior to delivery to the instrument air piping network. This supports continual safe operation of the instruments controlling Project operation. The instrument air system will include two compressors each with the capacity for 100 percent of operating needs.

Emergency Response Procedures

Prior to commencement of construction activities, all requisite parties, i.e., the contractor, project management, and OEHI's assigned operations and management staff, will meet and develop a site-specific construction emergency response program. A review of the developed programs with local government emergency response organizations will ensure completeness and proper coordination.

6.3 Technology Selection and Facility Reliability

6.3.1 Technology Selection

EOR technologies have been utilized at the Elk Hills Unit for many years and such technologies have been widely used in the oil and gas (O&G) industry for even longer. CO_2 EOR has been employed for almost 40 years at Permian basin fields owned by

Occidental. The proposed technologies for the OEHI CO_2 EOR Project have been demonstrated effective and reliable for similar EOR projects at Elk Hills Unit and within the O&G industry.

The OEHI CO_2 EOR Project utilizes common technologies for the injection, production, separation and gas processing associated with the process fluids (oil, water, CO_2, hydrocarbon gas, etc). In comparison with the complex chemical reactions and associated equipment found at a refinery or chemical plant, the processes and technology options for the OEHI CO_2 EOR Project are relatively limited. The composition, flow rates and pressures of the produced fluids and gas streams determine the type, size and configuration of process equipment selected. Potential design options for certain equipment will also be limited by applicable LORS, such as those pertaining to protection of air quality and process safety. Material selection is important due to the process conditions, for instance the corrosive nature of CO_2 when free water is present (sometimes also called wet CO_2) and requires mitigation and design attention.

Production systems at the satellites and CTB will consist of separators and tanks to separate the gas vapor (i.e. CO_2, hydrocarbon gas, nitrogen mixture) from the liquid (oil and water). The gas vapors evolve out of the liquids and rise to the top of these processes because they are less dense while the liquids are heavier and removed separately. Tanks are used to separate the oil from the water because oil will float to the top of water and can be skimmed off. The gas from the separators and tanks are gathered via vapor recovery units and compressors, preventing release of gases to the atmosphere during normal operations. These are the conventional proven technologies in the O&G industry for both EOR and non-EOR projects.

Recovered gas is sent to the RCF and/or CRP from the satellites and the CTB for further gas handling. Gas gathering manifolds on the front end of the gas handling processes will permit sending lower CO_2 content to the CRP and the higher CO_2 content gas to the RCF by using valves to divert gas from the incoming satellites to the two different trains, as required. The RCF and CRP use demonstrated and commonly used technologies for gas handling and processing for EOR projects that are efficient, effective and reliable in the O&G industry. The RCF train consists of dehydration and compression. The dehydration system removes the free water so that the gas is non-corrosive and then the compressors boost the pressure of the process gas so that it can be reinjected into the injection wells.

The CRP is designed to remove the NGL's and hydrocarbon gas for sales. The concentrated CO_2 stream is reinjected into the injection wells. The CRP consists primarily of a demethanizer, Selexol process and NRU to separate the components in the gas stream. These are common, proven technologies to separate the components in the gas stream. The demethanizer chills the CO_2 so that much of it condenses as a liquid and is pumped back to the field for reinjection. The gas that doesn't condense goes to the Selexol process where CO_2 is further removed. The nitrogen and hydrocarbon mixture goes to the NRU so that it can be separated in order to meet natural gas pipeline specifications. Some of the sub-processes to achieve desired results are a dehydration system to remove the water from the gas, compression to boost the gas to the desired pressure before entering the demethanizer, propane refrigeration system to achieve the cooling of the gases to condense NGLs and CO_2 at desired temperatures, pumps to move the fluids, and heat exchangers to cool the process gases after they have been compressed. Even though the processes that are being utilized are reliable and common technologies, further design optimization will be undertaken in the FEED and detailed engineering of the project

The OEHI EOR CO_2 Project will use appropriate materials for the respective process conditions that exist throughout the project. Detailed material selection specifications and drawings will be developed during the FEED and detailed engineering of the project. Pipelines that are buried underground will have external coatings to protect the pipe from water and external corrosion. Process streams that contain CO_2 or mixtures of hydrocarbon gas and CO_2 without free water will be transported through carbon steel plant piping and pipelines because the CO_2 is non-corrosive when there is no free water present. The dehydration systems that were previously discussed remove the free water from these process streams. For piping systems that contain free water and that could have a corrosive environment, material selections will consist of internally plastic coated carbon steel pipe, poly-lined carbon steel pipe, or stainless steel pipe. These material selections are common in other EOR projects and have been proven to mitigate corrosion. Process equipment like separators, pumps, tanks, compressors, etc will either be IPC, stainless steel or fiberglass/epoxy composites for corrosion protection, as appropriate. Some of the process systems that will have free water present are as follows

- Producing well flowlines
- Satellite separators and piping
- Gas gathering lines from the satellites to the CRP and RCF
- Liquid gathering lines from the satellites to the CTB
- CTB equipment
- RCF and CRP piping and systems prior to the dehydration systems
- Water injection pumps and piping
- Injection well tubing

Much of the gas processing equipment and piping will be in non-corrosive service for which carbon steel is appropriate. Portions of the demethanizer and NRU unit operations will be stainless steel or low-temperature carbon steels because of some of the expected low-process temperatures.

6.3.2 Facility Reliability

As mentioned above, processes and materials that are common to CO_2 EOR projects in the O&G industry are being utilized, as appropriate, for the facilities and pipelines of the OEHI CO_2 EOR Project. Operating and maintenance practices will follow industry requirements. Automation and control systems, as previously described, will enhance operational control and ensure the safety and reliability of the facilities. Maintenance programs and mechanical integrity practices will be developed and followed to contribute to the reliability of the facilities. Reliability and availability studies, equipment and spare part philosophy and process hazards analysis will be performed in FEED and detailed engineering stages to identify other options to maintain reliability of the facilities. These items will contribute significantly to the reliability of the facilities and pipelines.

7 Compatibility with Laws, Ordinances, Regulations and Standards

There are many LORS that impact operations at the Elk Hills Unit, most notable are the DOGGR permitting process and the CEC process. There are numerous other LORS and/or permits to which project activities are subject. Some of these permits or agency reviews will certainly be required and others of them may become applicable pending final decisions on location or site specific activities.

7.1 Division of Oil, Gas and Geothermal Resources

The OEHI EOR CO_2 Project plans to construct and operate CO_2 Class II injection wells to enhance oil recovery within the Elk Hills Unit. Permitting of injection wells associated with EOR operations is well established and regulated by the DOGGR under authority granted through EPA’s existing UIC Class II regulations. Under California law, DOGGR has responsibility for permitting injection and extraction wells and associated well facilities, including those anticipated for the OEHI CO_2 EOR Project. DOGGR has been given primacy to permit Class II injection wells in the State of California under the UIC program pursuant to Section 1425 of the Federal Safe Drinking Water Act, 42 U.S.C. § 300h-4 (see 48 Fed. Reg. 6336 [Feb. 11, 1983]). The wells and associated well facilities will be permitted pursuant to authority provided to DOGGR in the Public Resources Code and in accordance with applicable DOGGR regulations (see generally Cal. Pub. Res. Code Division 3, Chapter 1 and 14 Cal. Code Regs. Division 2). DOGGR has statutory responsibility under Division 3 of the Public Resources Code to regulate all oilfield operations in the State of California.

The Tulare Aquifer, underlying the Elk Hills Unit, is defined as a producing unit in the California Oil and Gas Fields (Vol 1). In 2004, DOGGR granted permit #22800022, allowing injection of disposal water into this reservoir. As part of the OEHI EOR CO_2 Project, applications will be submitted and approvals sought from DOGGR for additional water and CO_2 injection in various locations of the Elk Hills Unit.

7.2 Biological Resources

Numerous biological resources occur within and around the Elk Hills Unit. Some of these resources are protected and/or identified as threatened or endangered by state and federal laws and regulations. OEHI has worked closely with the resource agencies having jurisdiction over protected species since ownership of the Elk Hills Unit was transferred to OEHI in 1998.

7.2.1 Endangered Species Act of 1973

Through federal action and by encouraging the establishment of state programs, the 1973 Endangered Species Act (ESA) provided for the conservation of ecosystems upon which threatened and endangered species of fish, wildlife, and plants depend.

Section 7 of the ESA requires federal agencies to ensure that any action authorized, funded or carried out by them is not likely to jeopardize the continued existence of listed species or modify their critical habitat. Prior to the transfer of the Elk Hills Unit to OEHI, DOE’s oil production activities complied with the ESA via a series of formal Section 7 Consultations with the United States Fish and Wildlife Service (USFWS), which resulted in the issuance of several Biological Opinions (BOs).[3] The BOs included authorization for take of listed species that is incidental to an otherwise lawful act. This is called an Incidental Take Statement. The most recent BO and associated Incidental Take Statement were issued in 1995, which allowed for the maximum efficient rate (MER) of oil recovery and authorized the incidental take of several listed species.

When Congress directed DOE to sell NPR-1 (National Petroleum Reserve – 1), they were also directed and authorized to transfer the Incidental Take Statement (“permit”) to the purchaser of NPR-1 and provided that the transferred permit “shall cover the identical activities, and shall be subject to the same terms and conditions as apply to the permit at the time of transfer.”[4] This provision was interpreted by the U.S. Department of the Interior to mean that the 1995 BO and accompanying Incidental Take Statement were to be transferred to the purchaser of NPR-1. OEHI completed the purchase of NPR-1 in February 1998, and has since been operating the Elk Hills Unit consistent with the BO and associated Incidental Take Statement.

7.2.2 California Endangered Species Act

The California Endangered Species Act (CESA) states that all native species of fishes, amphibians, reptiles, birds, mammals, invertebrates, and plants, and their habitats, threatened with extinction and those experiencing a significant decline which, if not halted, would lead to a threatened or endangered designation, will be protected or preserved. CESA is under the jurisdiction of the California Department of Fish and Game (CDFG) and they have been directed to work with all interested persons, agencies and organizations to protect and preserve such sensitive resources and their

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[3] USFWS. 1995. Reinitiation of Formal Consultation Concerning Oil Production at Maximum Efficient Rate on Elk Hills Naval Petroleum Reserve, Kern County, California

[4] 3413(d) of National Defense Authorization Act for Fiscal Year 1996

habitats. Similar to the federal ESA, CESA also allows for take incidental to otherwise lawful development projects under Section 2081(b).[5]

To comply with CESA, OEHI has also operated under the terms of a 1997 Memorandum of Understanding[6] (MOU) with CDFG that was subsequently amended to extend its term to 2009. OEHI has been working with CDFG to amend and extend the MOU for an additional period and anticipates executing the amendment soon. The MOU incorporated by reference the 1995 BO and all of its requirements as part of the agreement. The MOU included several additional measures that relate to species with State of California protection. OEHI continues to operate in compliance with the MOU.

7.2.3 Habitat Conservation Plan

Both the BO and the MOU anticipated the possible sale of the Elk Hills Unit by the federal government and the subsequent need for issuance to the new, non-federal owner of a section 10(a)(1)(B) permit under the ESA (and a section 2081(b) permit under CESA). Limits related to habitat disturbance in the BO were based on a series of assumptions of productivity and extraction rates, which were based on DOE's history of oil extraction activities at the site. OEHI has been working with the USFWS to accommodate continued operation beyond habitat disturbance limits set by the BO originally issued to the DOE in 1995 and to obtain incidental take authorization through the ESA Section 10 process and the CESA Section 2081(b) process, both of which require the development and submittal to the USFWS and CDFG of a Habitat Conservation Plan (HCP). A draft HCP has been submitted to both the USFWS and CDFG for review; however, the HCP process is often long (5 to 15 years) and until such time that the HCP is reviewed and approved by the agencies, OEHI continues operation of the Elk Hills Unit in accordance with the conservation measures and mitigation requirements set forth on the 1995 BO and 1997 MOU.

The draft HCP covers all of the approximately 47,884 acre (74.8 square miles) Elk Hills Unit (the area covered by the BO is 47,409 acres, the difference being the more than 475 acres that were purchased as future mitigation land after the original Purchase Sale Agreement with the DOE), as well as selected rights of way within a 2-mile conservation buffer around the Elk Hills Unit.

7.2.4 Covered Species

The 1995 BO and Incidental Take Statement authorized take of the following species: San Joaquin kit fox (Vulpes macrotis mutica), blunt-nosed leopard lizard (Gambelia sila), the giant kangaroo rat (Dipodomys ingens), and Tipton's kangaroo rat

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[5] California Fish and Game Code Section 2080-2081 Consistency Determinations

[6] CDFG. 1997. California Endangered Species Act Memorandum of Understanding and Take Authorization for Occidental of Elk Hills; December.

(Dipodomys nitratoides nitratoides). Measures were also incorporated to minimize adverse effects on several plant species, including the Hoover's woolly-star (Eriastrum hooveri), which has been delisted under the ESA, Oil nest straw (Stylocline citroleum), Kern mallow (Eremalche kernensis; no subspecies designation) and San Joaquin woolly threads (Monolopia congdoni).

The MOU applies to and authorizes take for all of the species covered by the USFWS BO (although no direct take of blunt-nose leopard lizard is authorized by the MOU), as well as species not listed under the ESA, but having California State protection including: western burrowing owl (Athene cunicularia hypugea), San Joaquin antelope squirrel (Ammospermophilus nelsoni), and also San Joaquin wooly-threads (Lembertia congdonii).

7.2.5 OEHI Operations and Species Affects

OEHI has operated since 1998 under the MOU (as amended) and the USFWS BO, adhering to all of the requirements contained therein. These agreements apply to all ground-disturbing activities (both temporary and permanent) within the Elk Hills Unit. Typical ground-disturbing activities include: oil production, extraction, development and transport, access road construction, pipeline, utility and service line excavation and construction, associated oil production facility construction, etc. The BO contains conservation and mitigation measures that include pre-construction surveys, species and habitat monitoring requirements, post-construction conservation measures and assigns values to habitats impacted as a result of ground disturbance. All of these measures are intended to avoid and minimize potential effects to listed species and their habitat and to provide compensation for those effects that are unavoidable (i.e. habitat removal due to construction).

Habitat values are determined by the degree of disturbance that exists within each section of land. High or Red Zone has < 10 percent disturbance, Medium or Green Zone has 11 – 25 percent disturbance, and low or White Zone has > 25 percent disturbance. The Elk Hills HCP that is in draft form also sets habitat values for lands within the Elk Hills Unit as Low, Moderate and High Relative Value Lands. The majority of the lands that fall within the Elk Hills Unit boundaries (~47,000 acres) are considered moderate value (~74 percent), followed by high-value lands (~24 percent) with a very small area of low-value lands (2 percent). The base mitigation ratio is 3:1 (acquired land: impacted land). If the acquired land is of higher value than the affected land, the ratio could be lowered to 2:1.

Since ownership was transferred to OEHI in 1998, no direct or indirect take of any covered species has occurred as a result of project construction and/or operation. Additionally, as required in the BO and reiterated in the MOU, 7,075 acres were to be acquired as Habitat Management lands on or adjacent to the Elk Hills site. This acreage has been acquired by OEHI and is ready for placement in a conservation easement for management as species' habitat in perpetuity. The conservation easement for these lands is currently under review by CDFG. Once the conservation easement is approved, it will be recorded with Kern County, encumbering the surface title to the lands, thereby ensuring they are always maintained as Habitat Management Lands.

In anticipation of ongoing operation, OEHI has continued to acquire mitigation lands to offset future ground-disturbing activities within the Elk Hills Unit. OEHI has acquired significant additional acres that will be used as mitigation for future impacts. Activities associated with EOR are part of the ongoing activities covered by the BO and MOU and, thus, would be handled in accordance with requirements of those agreements. All preconstruction surveys, species monitoring, post-construction requirements and mitigation assignments on Habitat Management lands for ground disturbance will be included as part of the EOR activities proposed at the Elk Hills Unit.

7.3 Permits and Approvals

There are several other approvals which may be required for activities related to EOR in Elk Hills. The following sections contain brief summaries of each.

7.3.1 Clean Water Act Section 404 Permit

The U.S. Army Corps of Engineers (USACE) has jurisdiction over wetlands and waters of the U.S. Construction of access roads to new or existing oil wells, pipeline construction or associated EOR facilities is not likely to affect aquatic features under USACE jurisdiction. Efforts to avoid or minimize potential effects to these jurisdictional features will be made, but in the event avoidance is not feasible, OEHI will secure a Clean Water Act (CWA) Section 404 permit for fill of wetlands and waters of the U.S. from USACE.

7.3.2 CWA Section 401 Water Quality Certification and Waste Discharge Requirements

The State Water Resources Control Board (SWRCB) has jurisdiction over waters of the State of California and has been delegated authority for issuance of CWA Section 401 Water Quality Certifications from the EPA. That authority to issue 401 Water Quality Certifications has been delegated to the Regional Water Quality Control Board (RWQCB). Construction of access roads to new or existing oil wells, pipeline construction or associated EOR facilities could potentially affect aquatic features under RWQCB jurisdiction. Efforts to avoid or minimize potential effects to these jurisdictional features will be made, but in the event avoidance is not feasible, OEHI will secure a Section 401 Water Quality Certification (or waiver) from the RWQCB.

7.3.3 San Joaquin Valley Air Pollution Control District

The San Joaquin Valley Air Pollution Control District (SJVAPCD) implements several regulations that apply to both construction and operation of OEHI. Regulation VIII Fugitive Dust Rules apply to all construction activities. Standards for the control of visible emissions will be required during all construction and drilling phases of the OEHI EOR CO_2 Project. Portable Equipment Registration for certain portable emissions units would be required for well drilling, service or workover rigs, pumps, compressors, generators and field flares. Any new air emitting equipment that would be installed as part of the OEHI CO_2 EOR Project would be subject to SJVAPCD Regulation II

7.3.4 Groundwater and Water Quality

Well-drilling activities would need to comply with all requirements established by the RWQCB, including Title 27 California Code of Regulations (CCR), Section 20090(g), or Waiver Resolution No. R5-2008-0182. All downhole well operations would be conducted in a manner that protects groundwater in accordance with Title 14 CCR Division 2, Chapter 4, Subchapter 1. As previously mentioned, the OEHI CO_2 EOR Project is not located within an area identified as having shallow groundwater.

The SWRCB recently adopted a new Construction General Permit, Order 99-08-DWQ in July 2009. The General Construction Permit has requirements for preventing untreated runoff from entering waterways. The Construction General Permit requires monitoring of stormwater runoff and measures to prevent sedimentation, turbidity and pollution from impacting receiving waters. All excavation and construction activities would be required to comply with the Construction General Permit requirements which may require preparation of a SWPPP and ongoing project stormwater monitoring.

The SWRCB also has an Industrial General Permit, Order 97-03-DWQ. This statewide permit is applicable to only certain types of operations. The Statewide Industrial General Permit applies to current operations at Elk Hills Unit and will apply to the OEHI CO_2 EOR Project.

Stormwater is managed, not only at the statewide level, but also at the local level. Compliance with all local stormwater requirements would also be required.

The agencies listed in Table 7-1 below are expected to use this document in their decisionmaking process. Table 7-1 also lists permits and approvals that will be required to implement the OEHI CO_2 EOR Project, and a list of related environmental review and consultation requirements imposed by federal, state, or local laws, regulations, or policies.

TABLE 7-1 LISTING OF APPLICABLE AGENCIES

Agency	Permits/Approvals	Environmental Review/Consultation Requirements
Department of Conservation, Division of Oil, Gas and Geothermal Resources (DOGGR)	• Application for permits to drill	• Responsible agency • Consulted during process • Reviews Draft Environmental Impact Report (EIR)
San Joaquin Valley Air Pollution Control District (SJVAPCD)	• SJVAPCD Regulation VIII Fugitive Dust Rules • Mobile Equipment Permits (drill rigs, flares, etc.) • Stationary source permitting requirements for equipment requiring a permit to construct/operate	• Responsible agency • Consulted during process • Reviews Draft EIR
California Regional Water Quality Control Board (RWQCB)	Waste Discharge Requirements/ Waiver (if necessary), Section 401 Water Quality Certification (if necessary)	• Responsible agency • Consulted during process • Reviews Draft EIR
California Department of Fish and Game (CDFG)	CESA 2081(b) take permitting, Section 1600 Lake or Streambed Alteration Agreement(s) (SAA) for impacts to waterways or lakes (OEHI has a long-term SAA that expires in 2020).	• Responsible agency/Trustee agency • Reviews Draft EIR

Agency	Permits/Approvals	Environmental Review/Consultation Requirements
U.S. Fish and Wildlife Service (USFWS)	ESA Incidental Take Authorization (via approval of an HCP or individual Section 7 Consultation)	• Reviewing agency
U.S. Army Corps of Engineers (USACE)	Section 404 Clean Water Act permitting for impacts to wetlands or waters of the U.S.	• Reviewing agency • Permit issuance if access roads, facility or other construction activities impacted jurisdictional aquatic resources
State Water Resources Control Board	General Construction Permit, Order 99-08-DWQ General Industrial Permit	• Reviewing Agency • Permit issuance
Kern County	Building permits, grading permits (although well drilling is exempt from grading permits in Kern County, roadway and facility construction may require Kern County grading permits), National Pollutant Discharge Elimination System (NPDES)/County stormwater compliance and other ministerial type permits	• Reviewing agency • Consulted during process • Reviews Draft EIR
The Department of Toxic Substances Control (DTSC)	Issues Hazardous Waste Facility Permits required by Health and Safety Code, section 25200	• Reviewing Agency • Issues Hazardous Waste Permits

8 Alternatives

To implement the policy of reducing significant environmental impacts, CEQA requires that an EIR identify both feasible mitigation measures and feasible alternatives that could avoid or substantially lessen the OEHI CO_2 EOR Project's significant environmental effects (Pub Res C §§21002, 21002.1(a), 21100(b)(4), 21150). Additionally, an EIR must describe a reasonable range of alternatives to the proposed project, or to its location, that would feasibly attain most of the Project's basic objectives while reducing or avoiding any of its significant effects.

There are four threshold tests for suitable alternatives. Potential alternatives are reviewed to determine whether they:

- Can substantially reduce significant environmental impacts;
- Can attain most of the basic project objectives;
- Are potentially feasible; and
- Are reasonable and realistic.

Alternatives to the proposed project that did not satisfy all four criteria were excluded from analysis in accordance with CEQA Guidelines (14 CCR §15126.6(c)). Two Alternatives scenarios that will be carried forward for analysis are listed below – the mandatory No Project analysis and an analysis of alternate pipeline routes and Rights of Way (ROW). In addition, it is important to note that other viable alternatives may be identified later during the public scoping process and subsequently carried forward for analysis.

No Project Alternative

According to CEQA, an EIR's discussion of alternatives to the project must include a "No Project" alternative, along with an analysis of the impacts of that alternative. The purpose of a discussion of the No Project alternative is to allow a comparison of the environmental impacts of approving the proposed project with the effects of not approving it (14 CCR §15126.6(e)(1)). The No Project Alternative will consider the continued operation of the Elk Hills Unit under OEHI’s current operational policies and plans for the foreseeable future.

Alternate Pipeline and ROW Routes to Facilitate Project

This alternative will analyze different pipeline routes and ROW access routes to project-related equipment such as the Satellite Gathering Stations or the Reinjection

Compression Facility. The intent of this analysis is to ascertain if alternate routes for pipelines or ROW can lessen potential ground disturbance impacts that would occur if the proposed project were implemented.

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List of Acronyms

AC	alternating current
ACEC	Area of Critical Environmental Concern
AFFF	Aqueous Fire Fighting Foam
BBO	Billion Barrels of Oil
BBS	Behavioral Based Safety
BLM	Bureau of Land Management
BMP	Best Management Practices
BO	Biological Opinion
BOPD	Barrels of Oil Per Day
BWPD	Barrels of Water Per Day
CCF	Central Control Facility
CCR	California Code of Regulations
CCS	Carbon Capture and Sequestration
CDFG	California Department of Fish and Game
CEC	California Energy Commission
CESA	California Endangered Species Act
CEQA	California Environmental Quality Act
CLEP	Coles Levee Ecological Preserve
CNLM	Center for Natural Lands Management
CO_2	Carbon Dioxide
COC	Communications Operations Center
CRP	CO_2 Recovery Plant
CS	Carbon Steel
CSA	Canadian Standards Association
CTB	Central Tank Battery
CWA	Clean Water Act
DC	Direct Current
De-C1	Demethanizer
DEPG	Dimethyl Ethers of Polyethylene Glycol
DOE	Department of Energy
DOGGR	California Division of Oil, Gas, and Geothermal Resources
EHOF	Elk Hills Oil Field
EIR	Environmental Impact Report
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental Protection Agency
ESA	Endangered Species Act

List of Acronyms *(continued)*

FEED	Front End Engineering Design
FM	Factory Mutual Research Corporation
GS	Geologic Sequestration
H2S	Hydrogen Sulfide
HCP	Habitat Conservation Plan
HECA	Hydrogen Energy California
HES	Health, Environment, and Safety
HES&S	Health, Environment, Safety and Security
HESMS	Health, Environment, and Safety Management System
HMI	Human Machine Interface
ICSS	Integrated Control and Safety System
IEEE	Institute of Electrical and Electronic Engineers
IGCC	Integrated Gasification Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
ISA	Instrument Society of America
Km	kilometer
kV	kilovolt
LORS	Laws, Ordinances, Regulations, and Standards
MCFD	Thousands of Cubic Feet Per Day
mD	millidarcy
MDB&M	Mount Diablo Baseline and Meridian
MER	Maximum Efficient Rate
MMSCFD	Millions of Standard Cubic Feet Per Day
MMV	Monitoring, Measurement, and Verification
MOU	Memorandum of Understanding
MSDS	Material Safety Data Sheet
Msl	mean sea level
MW	Megawatt
NETL	National Energy Technology Laboratory
NGL	Natural Gas Liquids
NPDES	National Pollutant Discharge Elimination System
NPR	National Petroleum Reserve
NRU	Nitrogen Rejection Unit
NWS	North West Stevens
OEHI	Occidental of Elk Hills, Inc.
O&G	Oil and Gas

List of Acronyms *(continued)*

OOG	Occidental Oil and Gas Corporation
PG&E	Pacific Gas and Electric
PPE	Personal Protective Equipment
PPM	Parts Per Million
PRM	Process Risk Management
PSIG	Pounds Per Square Inch Gauge
RCF	Reinjection Compression Facility
ROW	Rights of Way
RWQCB	Regional Water Quality Control Board
SAA	Streambed Alteration Agreement
SOZ	Shallow Oil Zone
SJVAPCD	San Joaquin Valley Air Pollution Control District
SWPPP	Stormwater Pollution and Prevention Plan
SWRCB	State Water Resources Control Board
TEG	Triethylene Glycol
UIC	Underground Injection Control
UL	Underwriter's Laboratories
UNEP	United Nations Environment Programme
USACE	United States Army Corps of Engineers
USDW	Underground Sources of Drinking Water
USFWS	United States Fish and Wildlife Service
VT	Vortex Tank
WAG	Water Alternating Gas
WMO	World Meteorological Organization

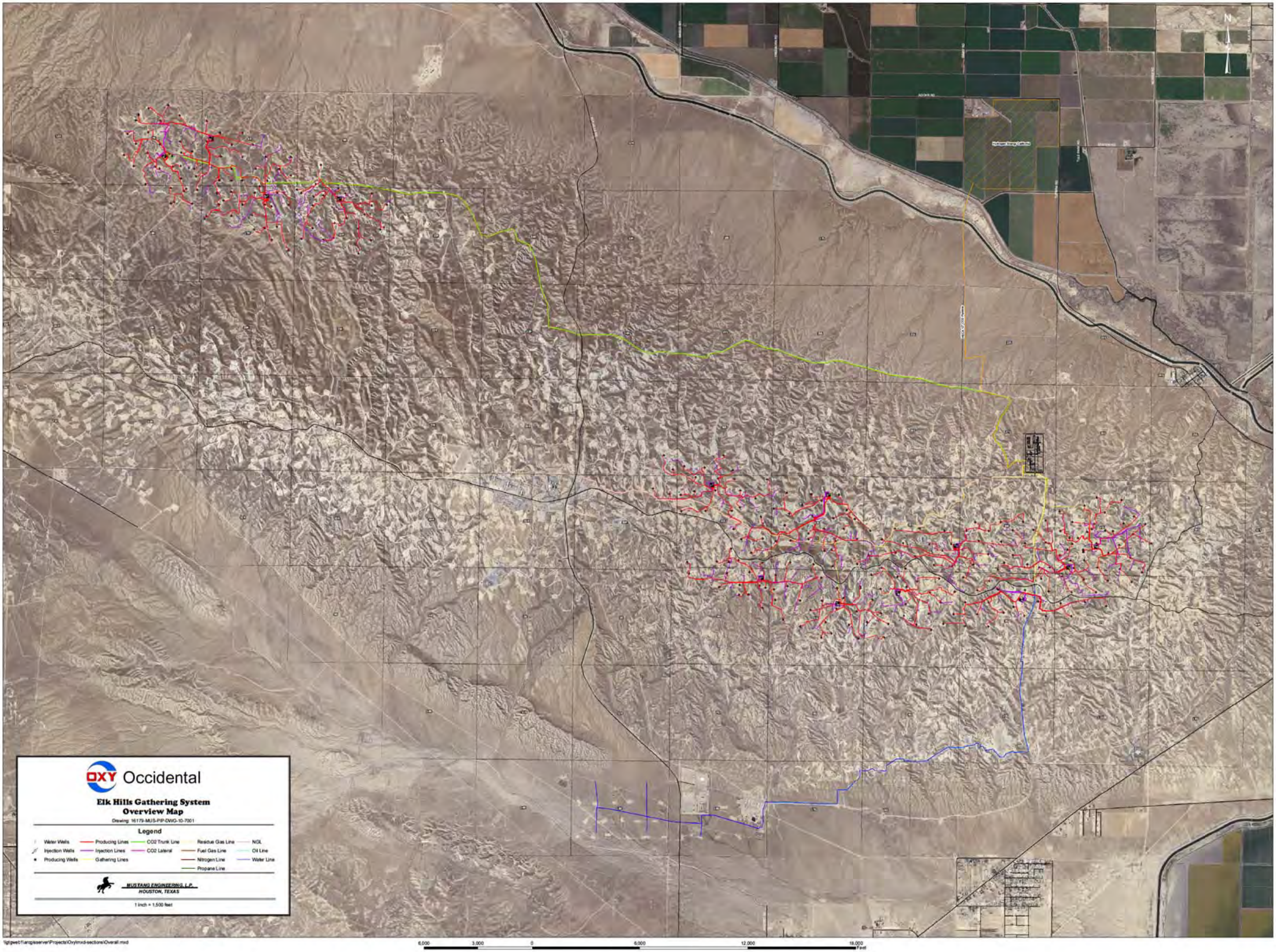
Glossary of Terms

Asphyxiant	Inducing or tending to induce asphyxia (the extreme condition caused by lack of oxygen and excess of carbon dioxide in the blood, produced by interference with respiration or insufficient oxygen in the air; suffocation). A substance, such as a toxic gas, or an event, such as drowning, that induces asphyxia.
Corrosivity	Corrosive wastes are acids or bases (pH less than or equal to 2, or greater than or equal to 12.5) that are capable of corroding metal containers, such as storage tanks, drums, and barrels.
CO_2 Facility	The central processing facility at Section 27S where purchased CO_2 is received and produced fluids and gases are received, processed, separated, distributed, compressed and distributed for re-injection. This unit consists of the CTB, RCF, CRP and all associated ancillary equipment.
Hazardous	A situation that poses a level of threat to life, health, property, or environment.
Ignitability	Ignitable wastes can create fires under certain conditions, are spontaneously combustible, or have a flash point less than 60 °C (140 °F). Examples include waste oils and used solvents.
Interfacial Tension	A property of the surface of a liquid that causes the surface portion of liquid to be attracted to another surface, such as that of another portion of liquid
Metallurgy	A domain of materials science that studies the physical and chemical behavior of metallic elements, their intermetallic compounds, and their mixtures, which are called alloys.
Miscible	The property of liquids to mix in all proportions, forming a homogeneous solution. In principle, the term applies also to other phases (solids and gases), but the main focus is usually on the solubility of one liquid in another.
Reactivity	Reactive wastes are unstable under "normal" conditions. They can cause explosions, toxic fumes, gases, or vapors when heated, compressed, or mixed with water.

Sequester	In the context of carbon dioxide, sequestration refers to the placement of the carbon dioxide molecules in a location where they are separated from the atmosphere of the planet, in this case in the subsurface in formations currently holding crude oil and hydrocarbon gas.
Supercritical	Refers to carbon dioxide that is in a fluid state while also being at or above both its critical temperature and pressure, yielding rather uncommon properties. Carbon dioxide usually behaves as a gas in air at STP or as a solid called dry ice when frozen. If the temperature and pressure are both increased from STP to be at or above the critical point for carbon dioxide, it can adopt properties midway between a gas and a liquid.
Toxicity	Toxic wastes are those containing concentrations of certain substances in excess of regulatory thresholds which are expected to cause injury or illness to human health or the environment.
Trapping	In the context of carbon dioxide, trapping refers to the physical, geophysical or geochemical retention of carbon dioxide molecules in the subsurface in formations currently holding crude oil and hydrocarbon gas.
Wellbore	Any hole drilled for the purpose of exploration for or extraction of natural resources such as water, gas or oil where a well may be produced and a resource is extracted for a protracted period of time.
Wellhead	A general term used to describe the component at the surface of an oil well that provides the structural and pressure containing interface for the drilling and production equipment.

Appendix A

Detailed Section Maps



Occidental

Elk Hills Gathering System
Overview Map
Drawing: 16179-MUS-PIP-DWG-10-7001

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

1 inch = 1,500 feet

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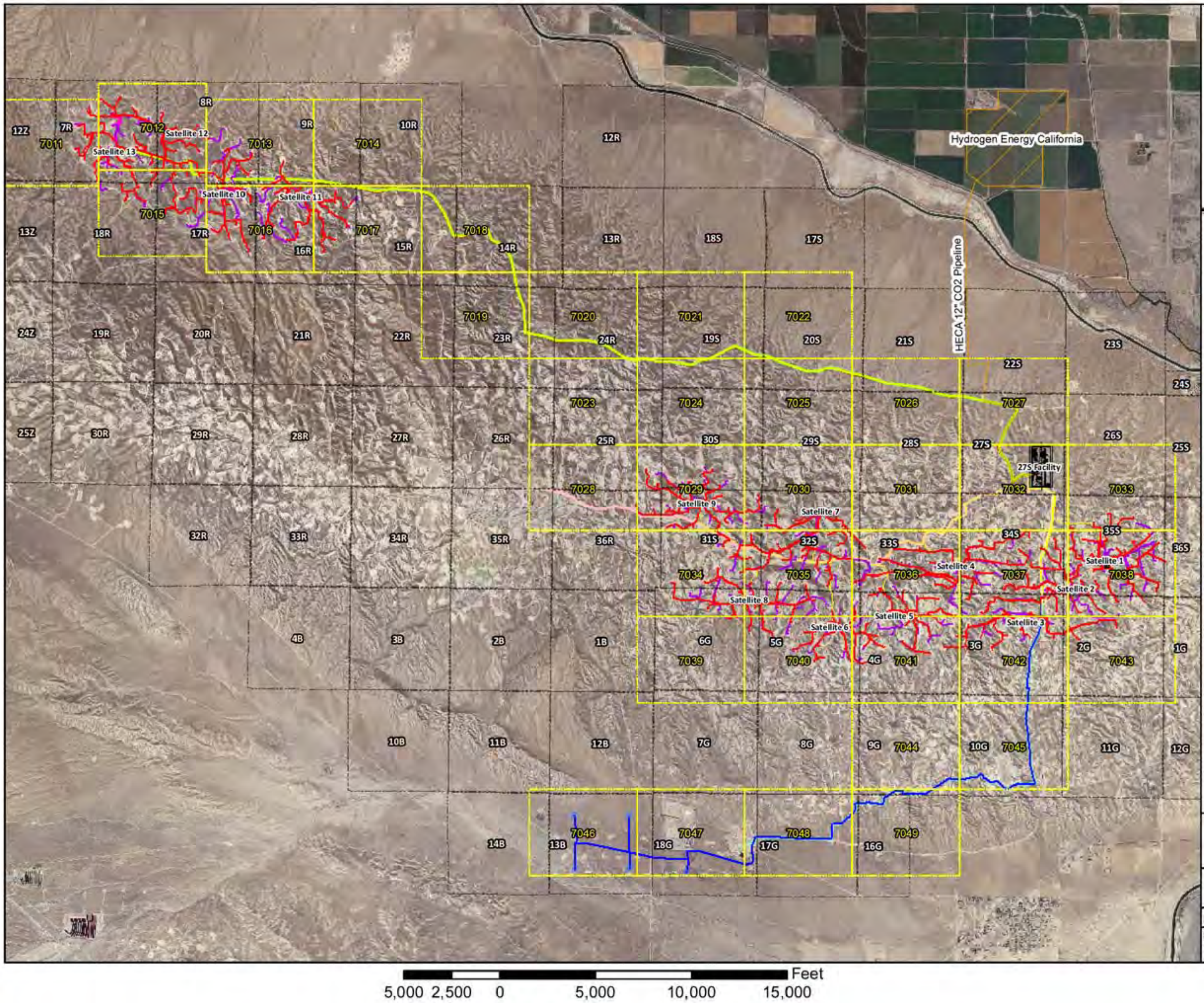

N

1 inch = 5,000 feet

Legend

- Water Wells
- ━ Producing Lines
- ━ Injection Lines
- ━ Gathering Lines
- ━ CO2 Trunk Line
- ━ CO2 Lateral
- ━ Residue Gas Line
- ━ Fuel Gas Line
- ━ Nitrogen Line
- ━ Propane Line
- ━ NGL
- ━ Oil Line
- ━ Water Line

OXY Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010	Key Plan
Project Number: 16179	16179-MUS-PIP-DWG-10-7002

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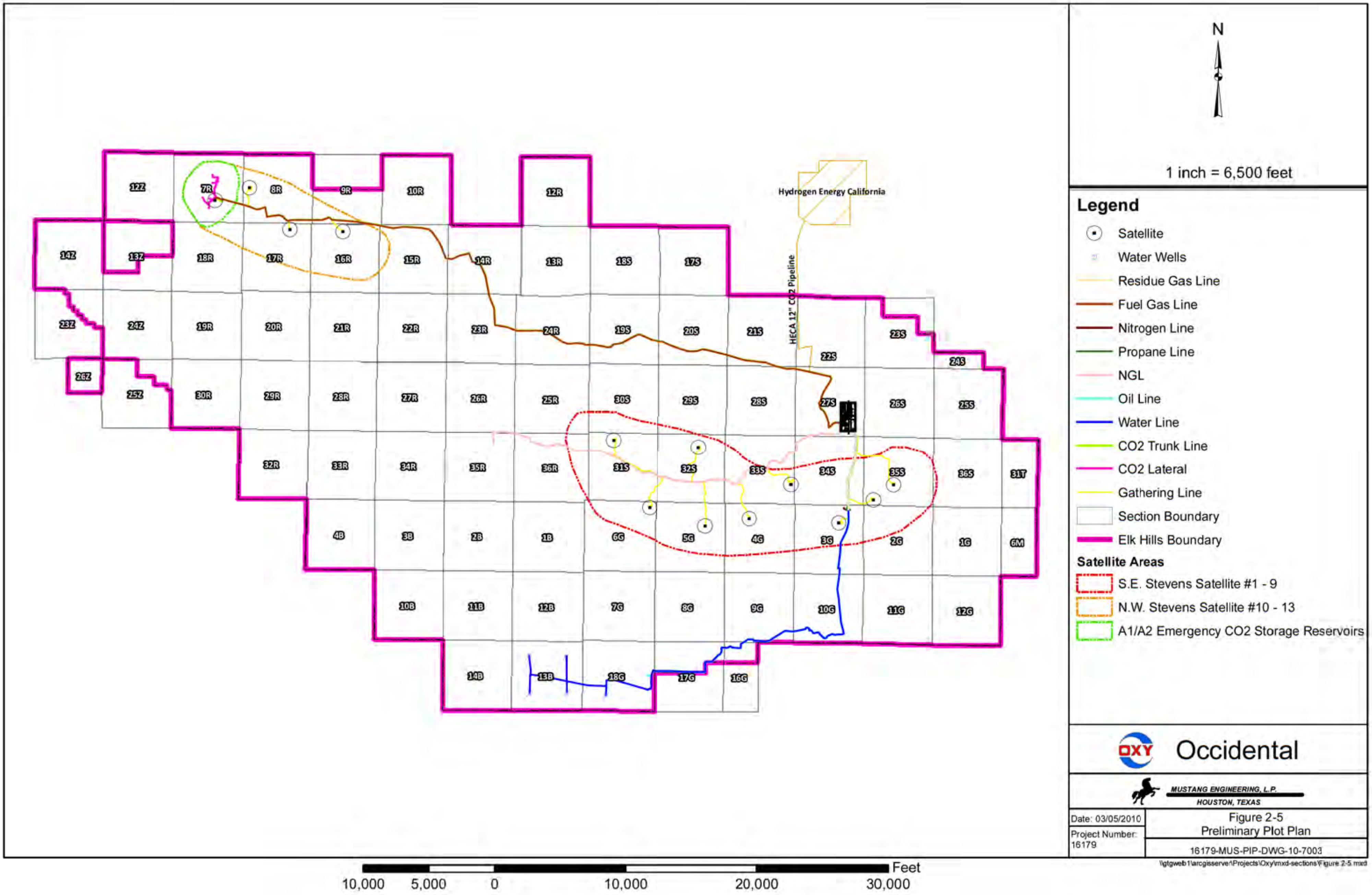

Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 03/05/2010

Project Number: 16179

Figure 2-5
Preliminary Plot Plan

16179-MUS-PIP-DWG-10-7003

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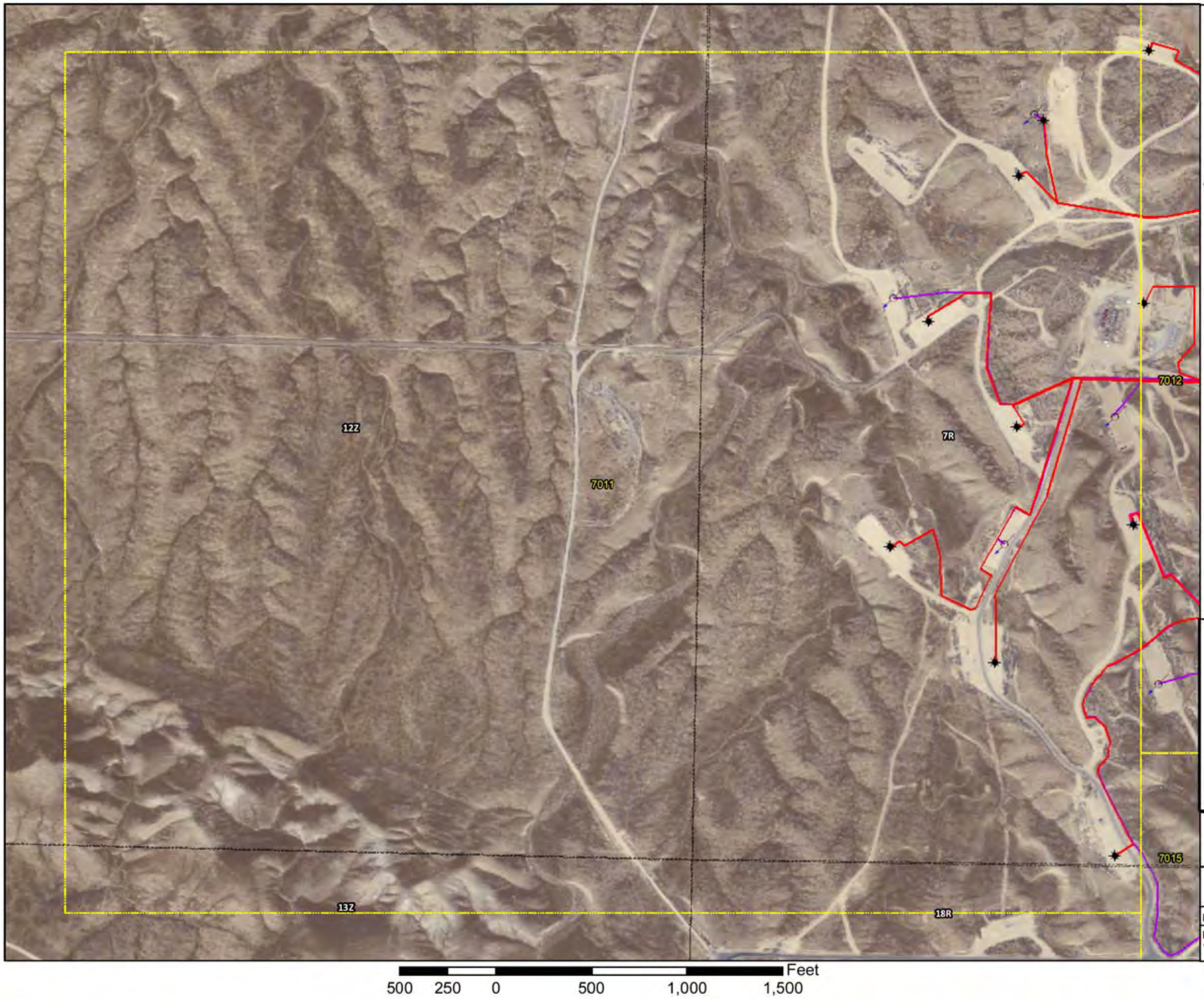
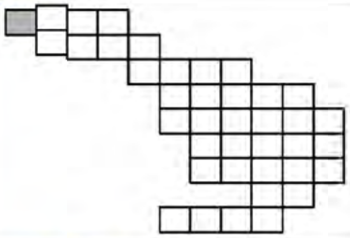


N

1 inch = 500 feet

Legend

▫	Water Wells
✸	Producing Wells
○	Injection Wells
🟥	Producing Lines
🟪	Injection Lines
🟨	Gathering Lines
🟩	CO2 Trunk Line
🟪	CO2 Lateral
🟧	Residue Gas Line
🟧	Fuel Gas Line
🟫	Nitrogen Line
🟩	Propane Line
🟥	NGL
🟦	Oil Line
🟦	Water Line



Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010	Area 7011
Project Number: 16179	16179-MUS-PIP-DWG-10-7011

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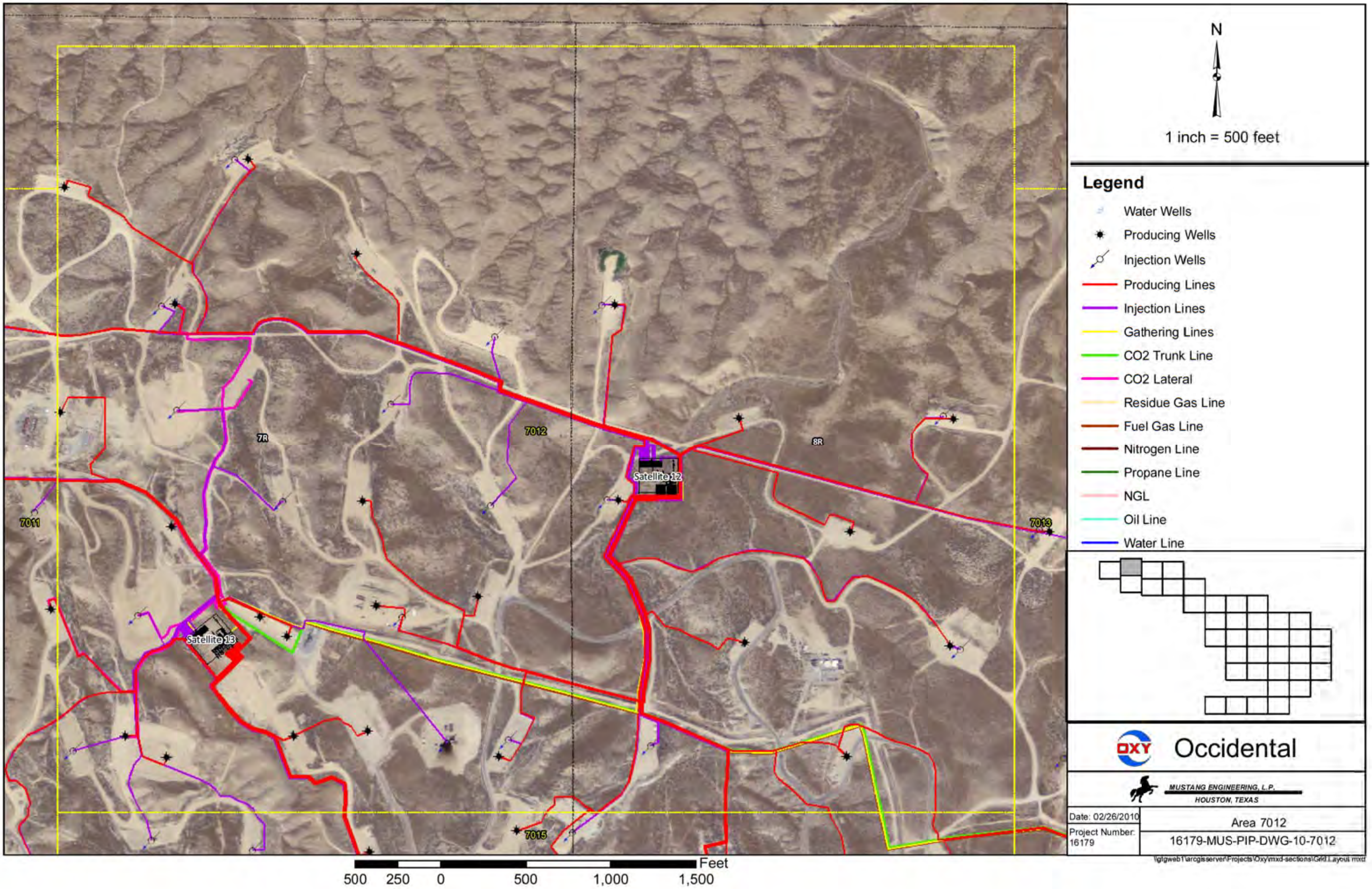

Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010	Area 7012
Project Number: 16179	16179-MUS-PIP-DWG-10-7012

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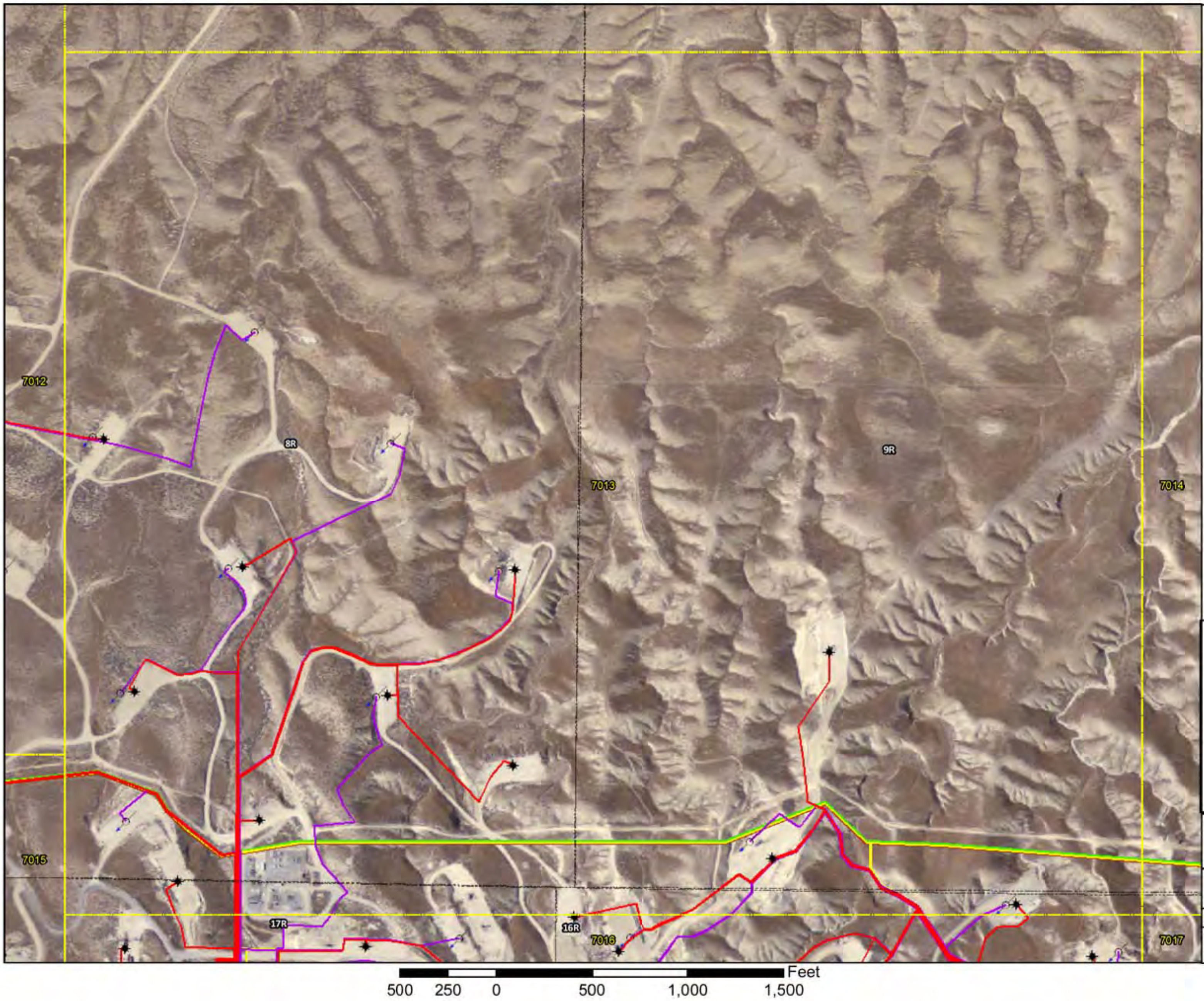
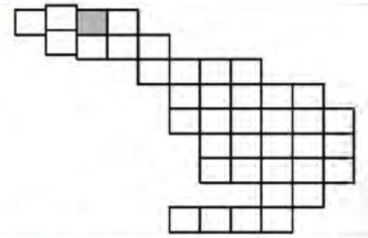


N

1 inch = 500 feet

Legend

- Water Wells
- ✷ Producing Wells
- Injection Wells
- 🟥 Producing Lines
- Injection Lines
- 🟨 Gathering Lines
- 🟩 CO2 Trunk Line
- CO2 Lateral
- Residue Gas Line
- Fuel Gas Line
- Nitrogen Line
- Propane Line
- NGL
- Oil Line
- Water Line



OXY Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010	Area 7013
Project Number: 16179	16179-MUS-PIP-DWG-10-7013

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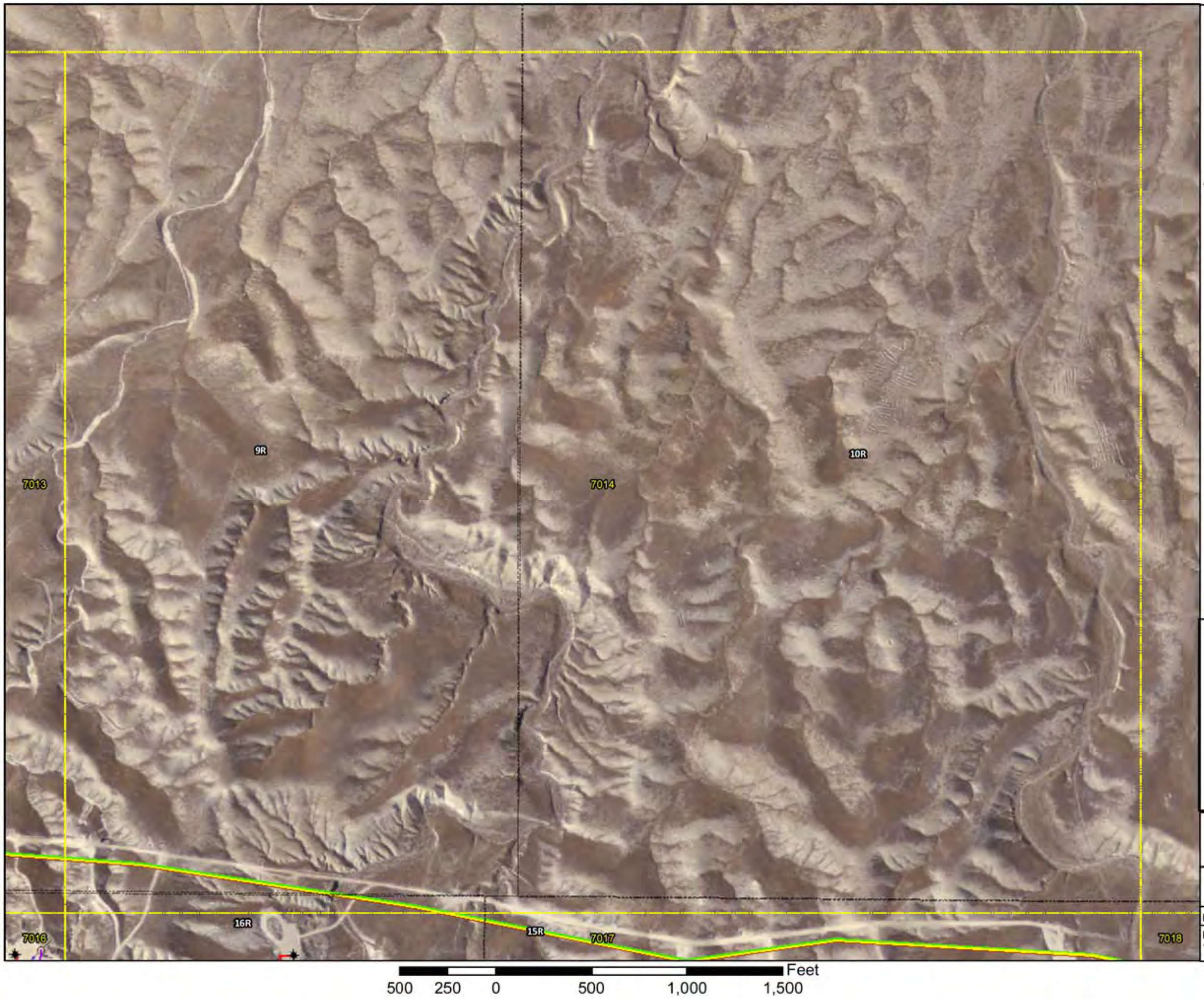
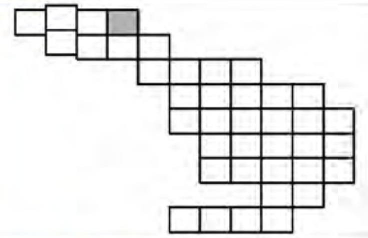


N

1 inch = 500 feet

Legend

- Water Wells
- Producing Wells
- Injection Wells
- Producing Lines
- Injection Lines
- Gathering Lines
- CO2 Trunk Line
- CO2 Lateral
- Residue Gas Line
- Fuel Gas Line
- Nitrogen Line
- Propane Line
- NGL
- Oil Line
- Water Line



Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010
Project Number: 16179

Area 7014
16179-MUS-PIP-DWG-10-7014

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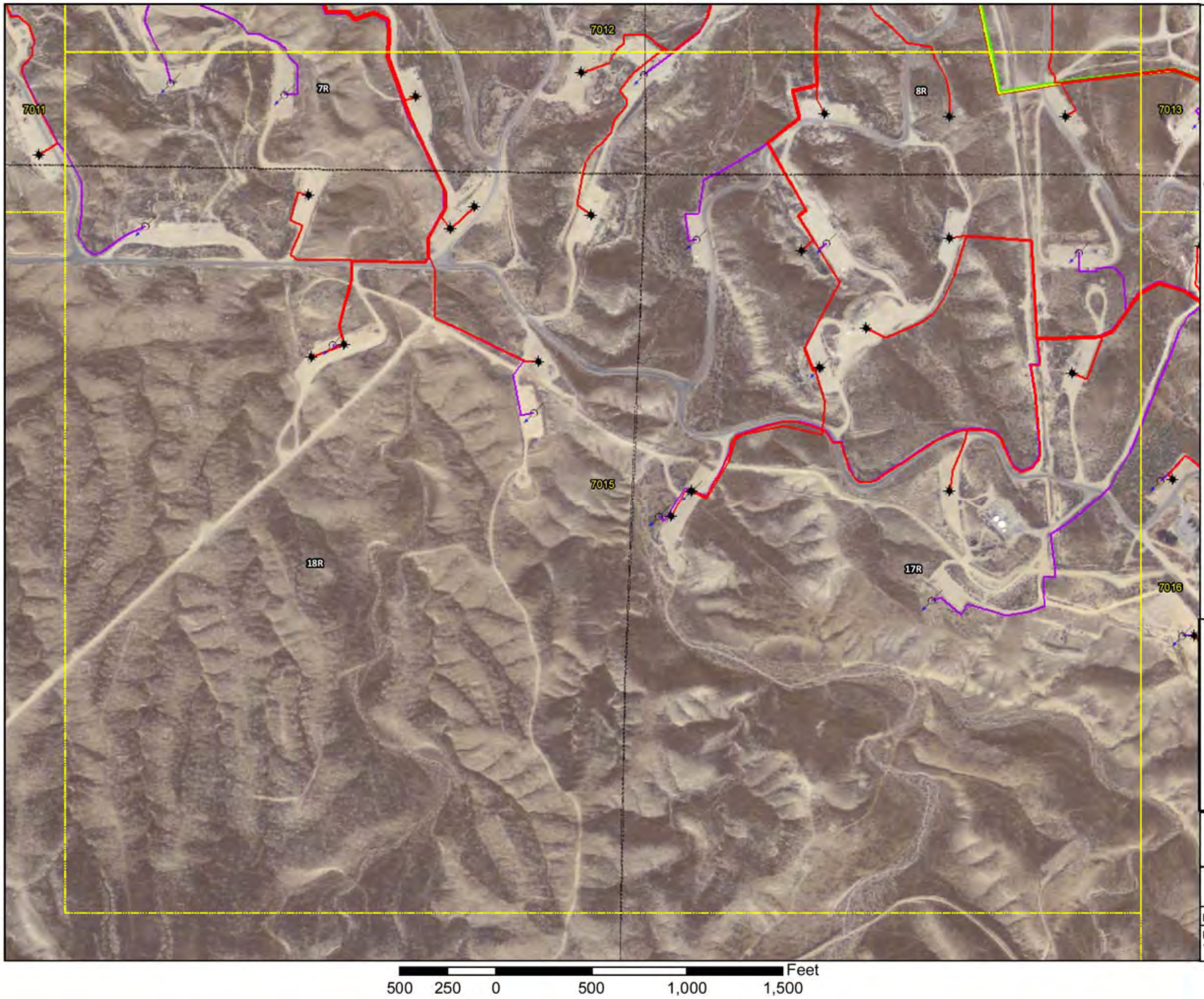
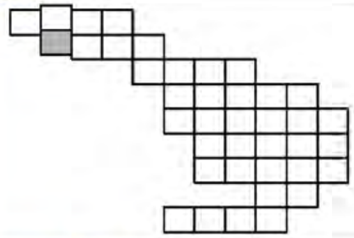


N

1 inch = 500 feet

Legend

- Water Wells
- Producing Wells
- Injection Wells
- Producing Lines
- Injection Lines
- Gathering Lines
- CO2 Trunk Line
- CO2 Lateral
- Residue Gas Line
- Fuel Gas Line
- Nitrogen Line
- Propane Line
- NGL
- Oil Line
- Water Line



Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010	Area 7015
Project Number: 16179	16179-MUS-PIP-DWG-10-7015

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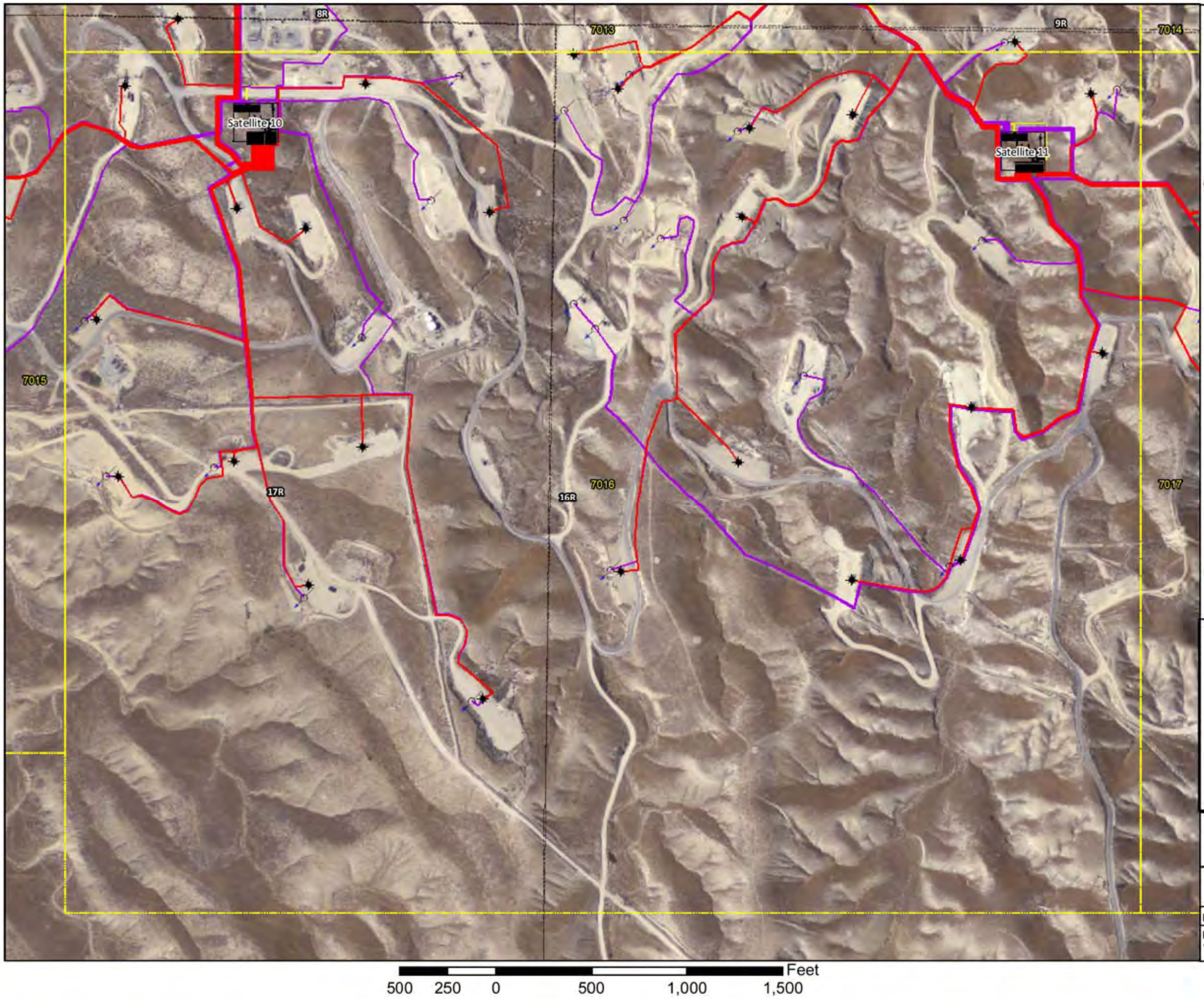

N

1 inch = 500 feet

Legend

- Water Wells
- ✱ Producing Wells
- Injection Wells
- 🟥 Producing Lines
- 🟪 Injection Lines
- 🟨 Gathering Lines
- 🟩 CO2 Trunk Line
- CO2 Lateral
- Residue Gas Line
- Fuel Gas Line
- Nitrogen Line
- Propane Line
- NGL
- Oil Line
- 🟦 Water Line

Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010
Project Number: 16179

Area 7016
16179-MUS-PIP-DWG-10-7016

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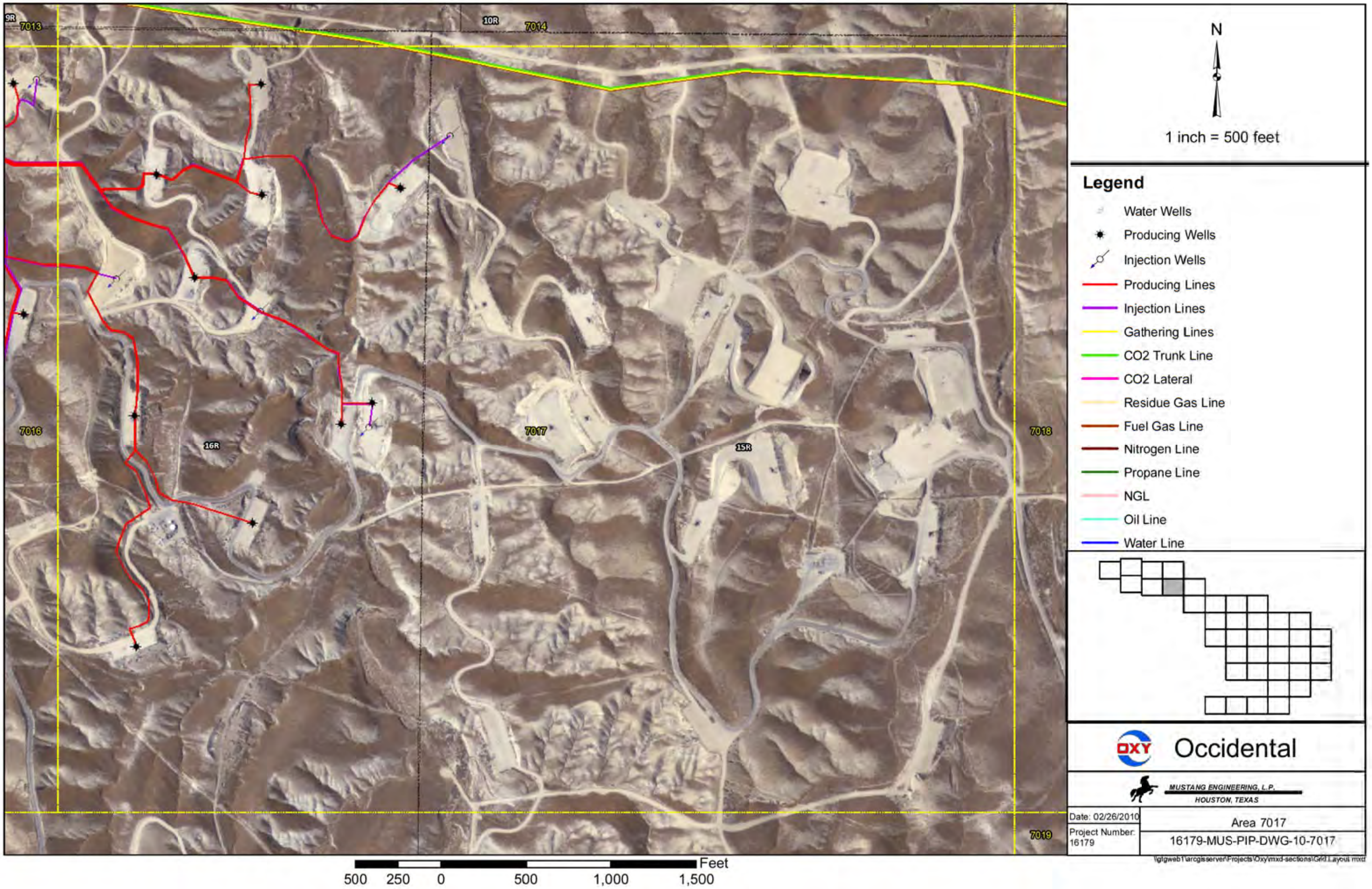

Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010	Area 7017
Project Number: 16179	16179-MUS-PIP-DWG-10-7017

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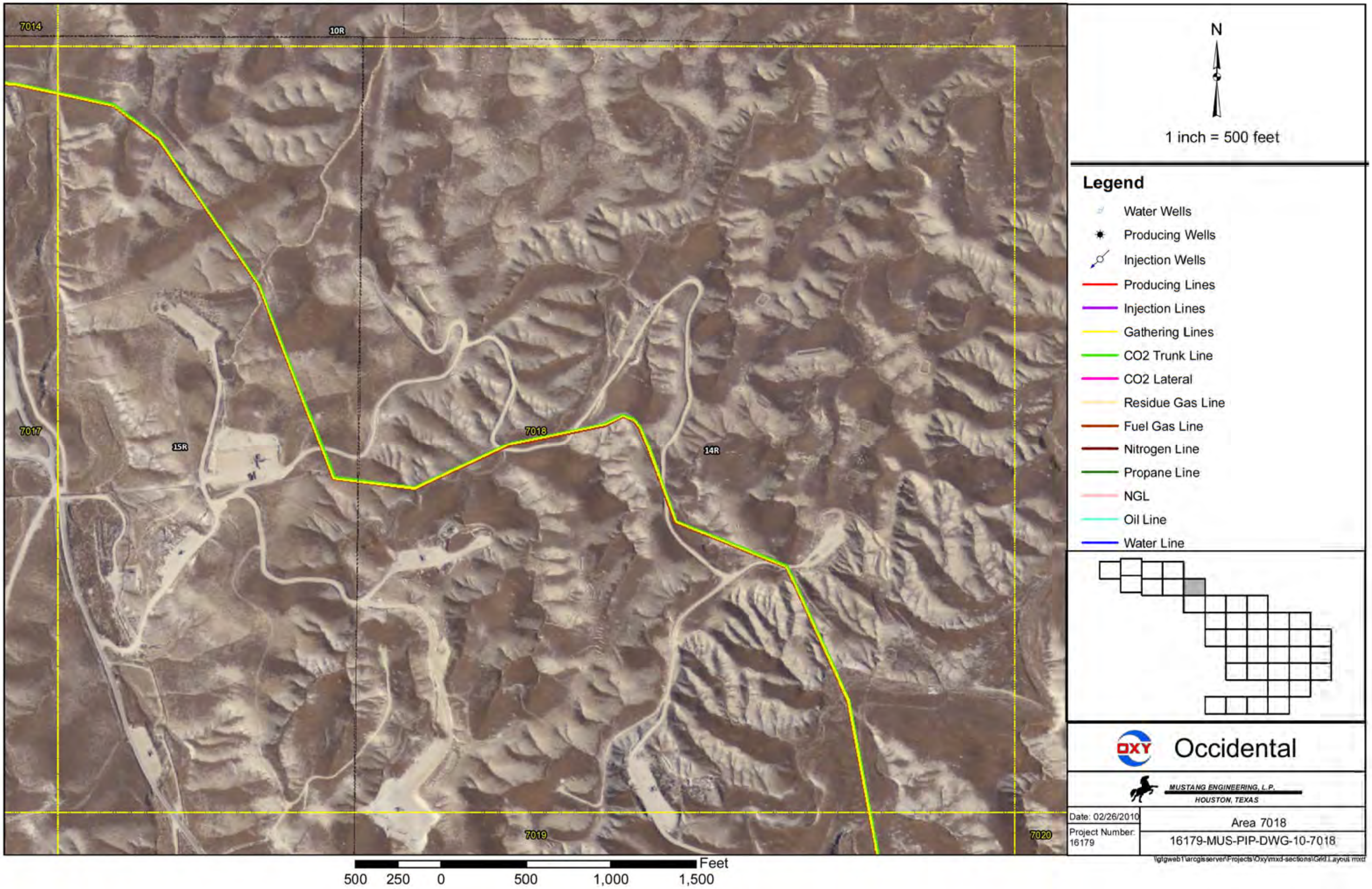

Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010

Project Number:
16179

Area 7018

16179-MUS-PIP-DWG-10-7018

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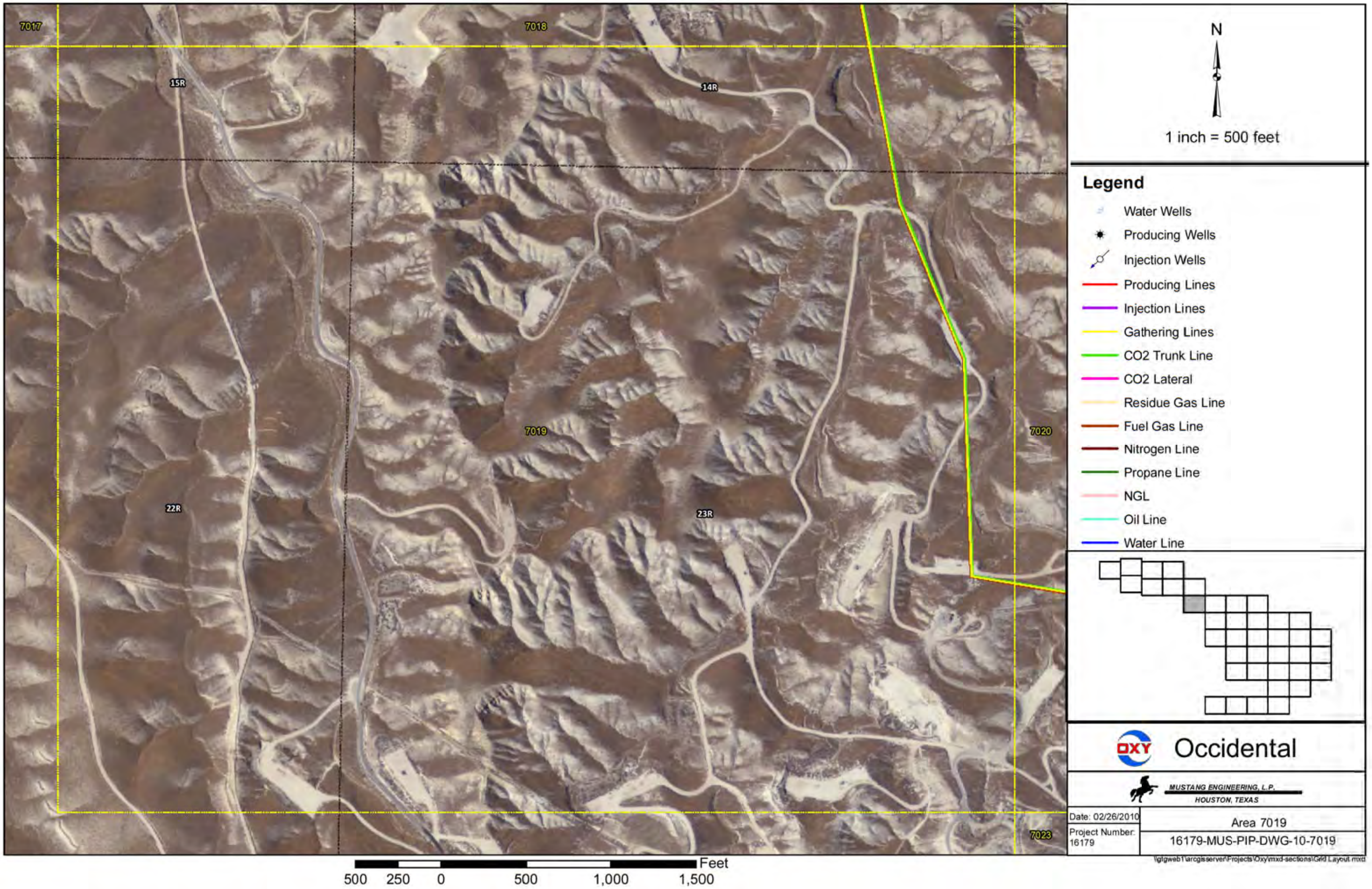

Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010
Project Number: 16179

Area 7019
16179-MUS-PIP-DWG-10-7019

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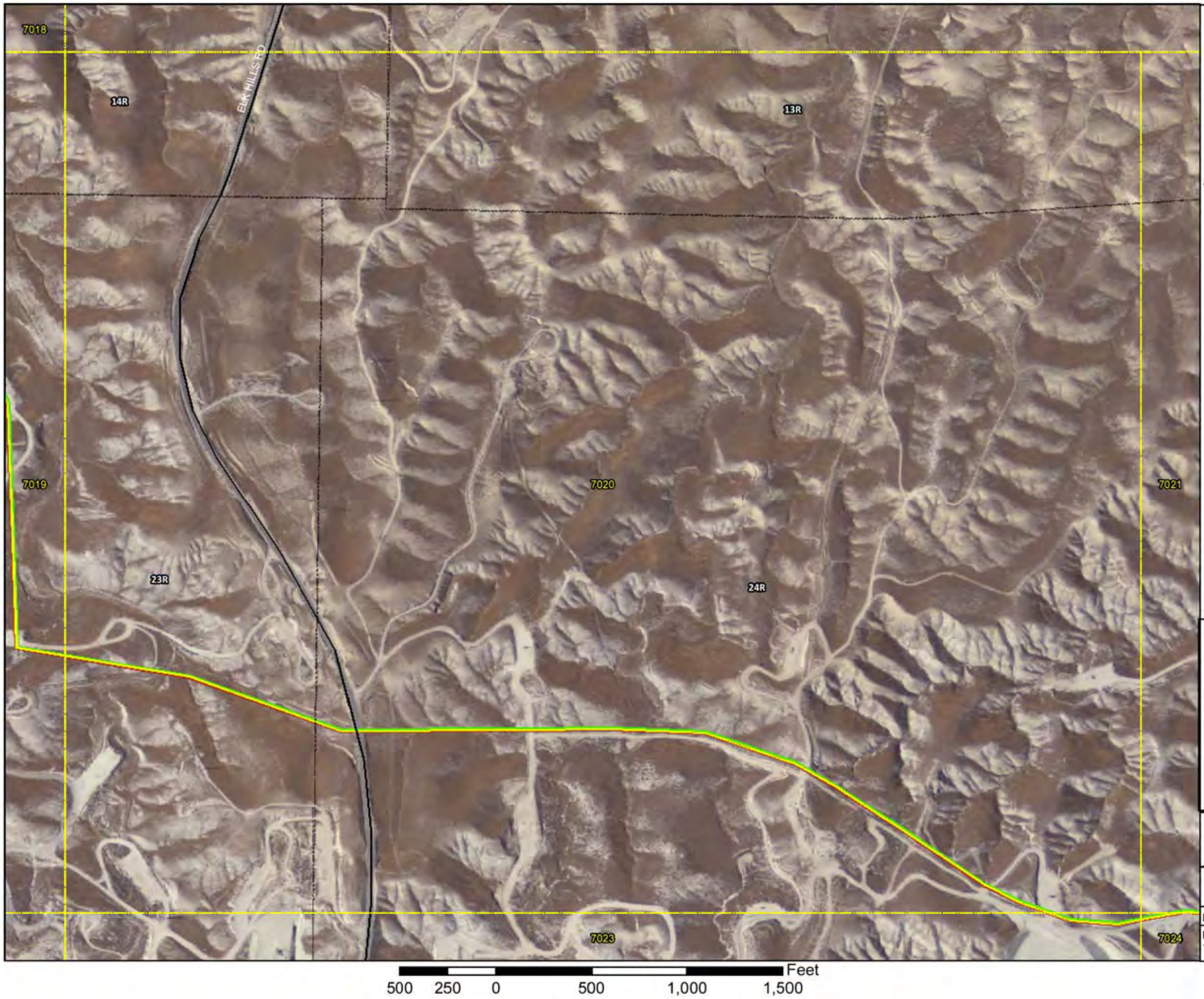
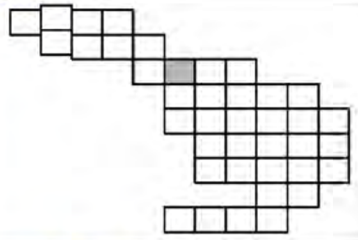


N

1 inch = 500 feet

Legend

◦	Water Wells
✸	Producing Wells
↙	Injection Wells
🟥	Producing Lines
🟪	Injection Lines
🟨	Gathering Lines
🟩	CO2 Trunk Line
🟪	CO2 Lateral
🟨	Residue Gas Line
🟧	Fuel Gas Line
🟫	Nitrogen Line
🟩	Propane Line
🟥	NGL
🟦	Oil Line
🟦	Water Line



OXY Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010
Project Number: 16179

Area 7020

16179-MUS-PIP-DWG-10-7020

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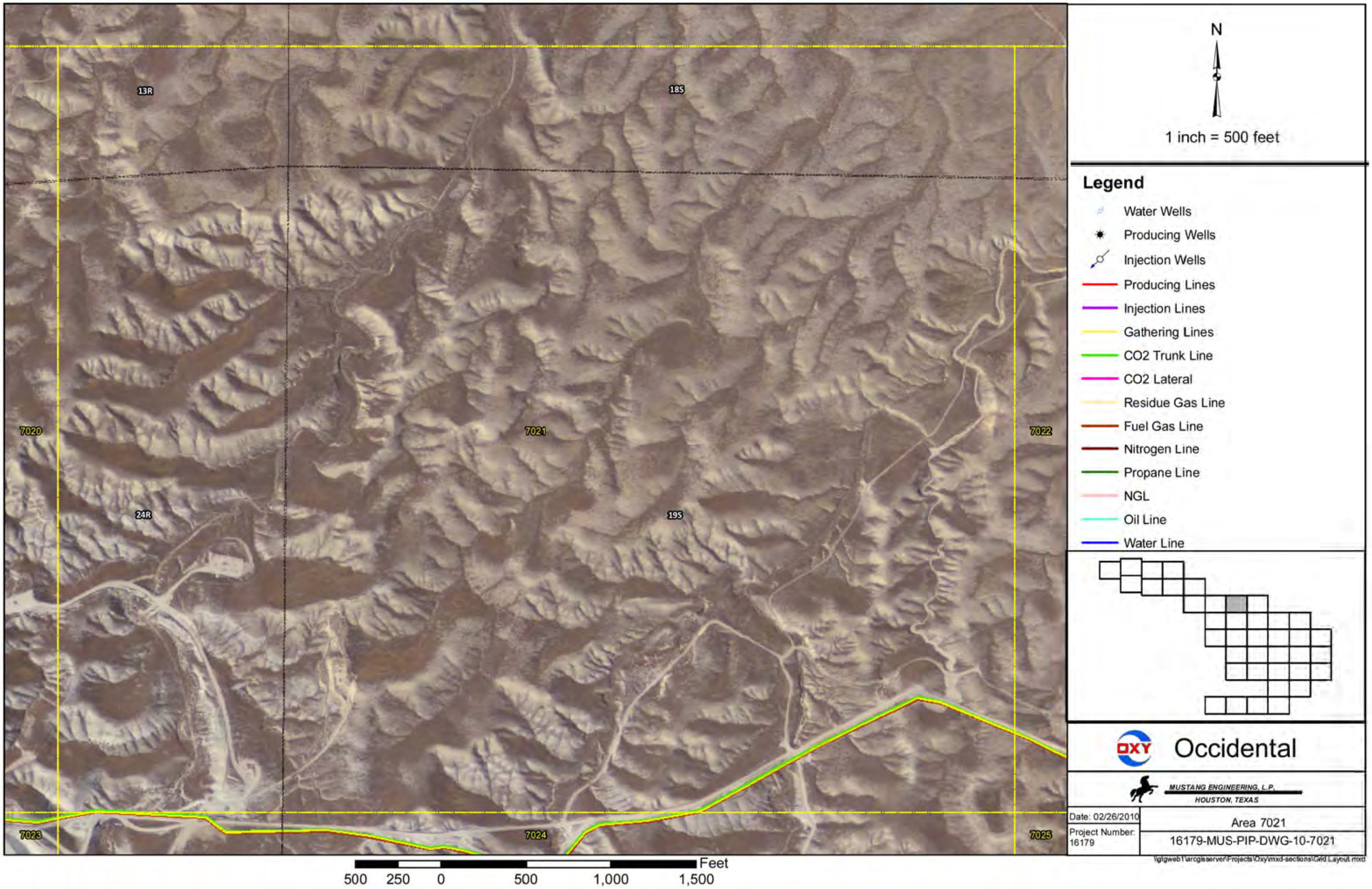

Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010	Area 7021
Project Number: 16179	16179-MUS-PIP-DWG-10-7021

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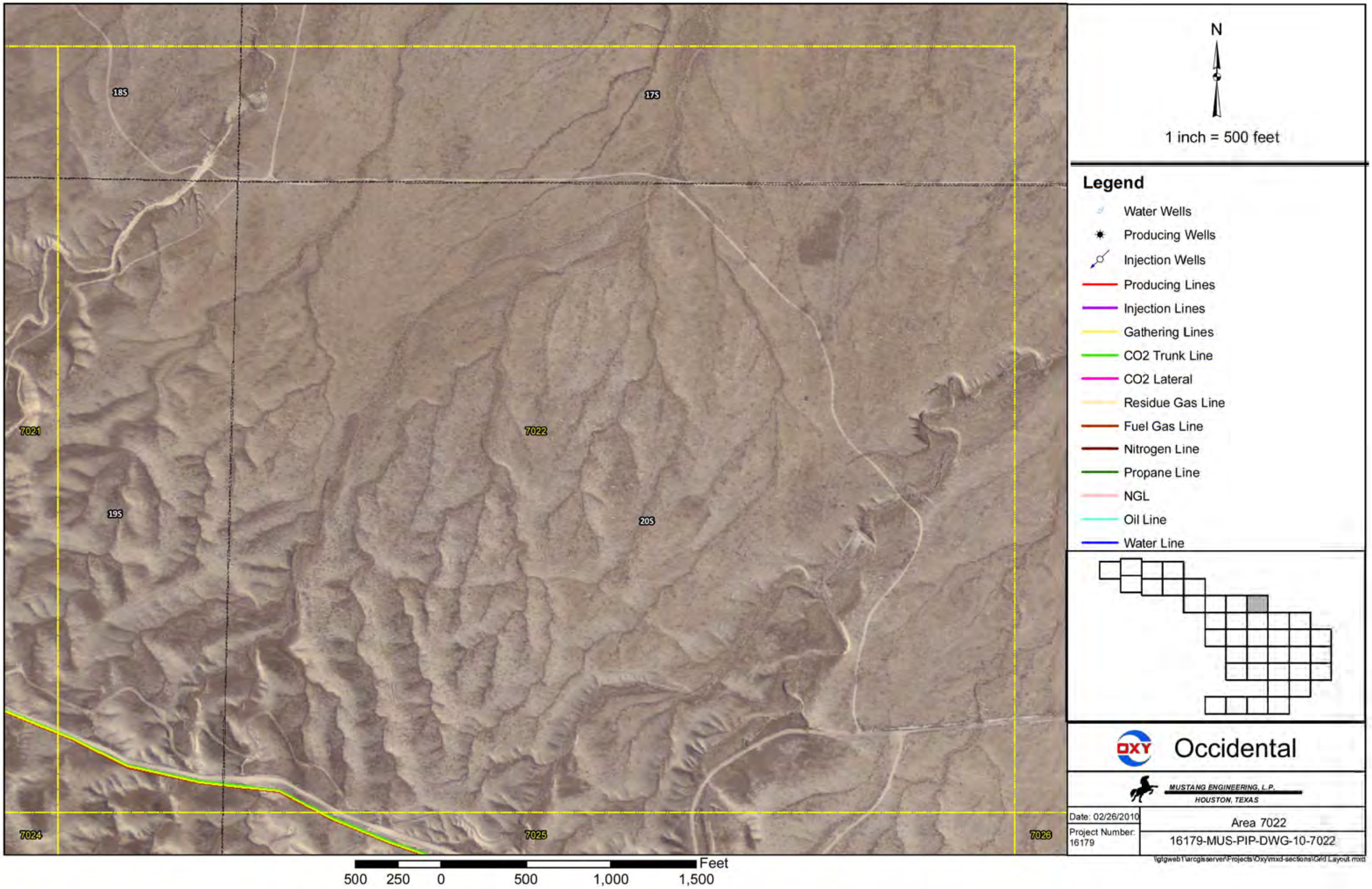

Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010

Project Number: 16179

Area 7022

16179-MUS-PIP-DWG-10-7022

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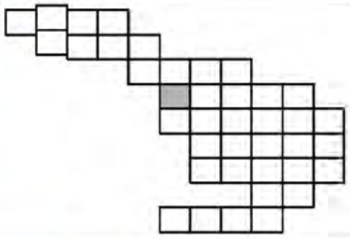
N

1 inch = 500 feet

Legend

- Water Wells
- ✱ Producing Wells
- Injection Wells
- Producing Lines
- Injection Lines
- Gathering Lines
- CO2 Trunk Line
- CO2 Lateral
- Residue Gas Line
- Fuel Gas Line
- Nitrogen Line
- Propane Line
- NGL
- Oil Line
- Water Line



Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010
Project Number: 16179

Area 7023
16179-MUS-PIP-DWG-10-7023

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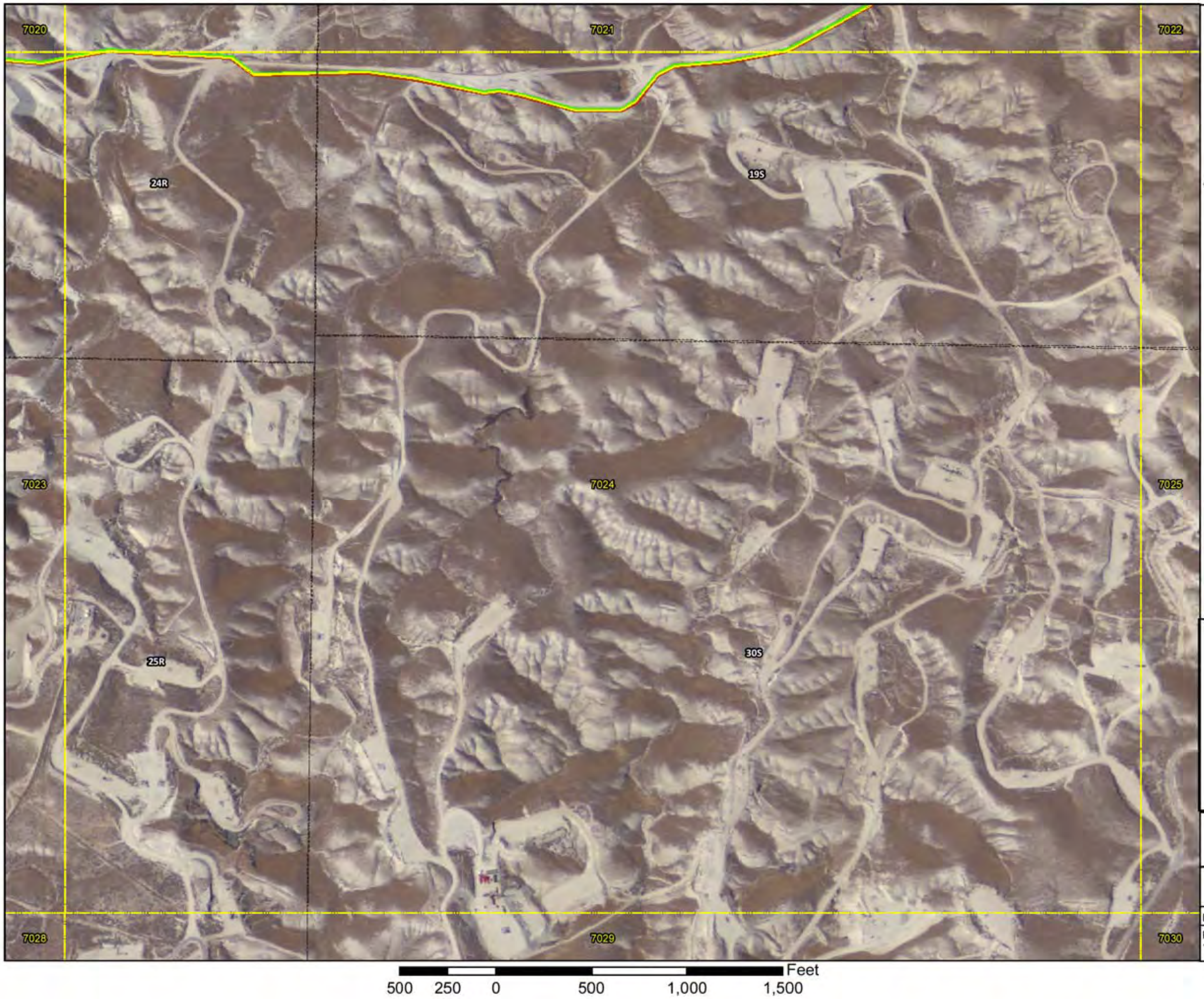

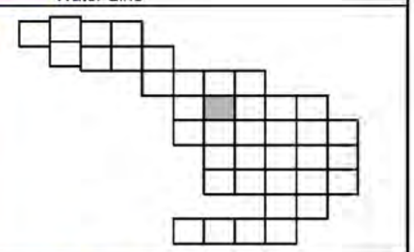

Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010
Project Number: 16179

Area 7024

16179-MUS-PIP-DWG-10-7024

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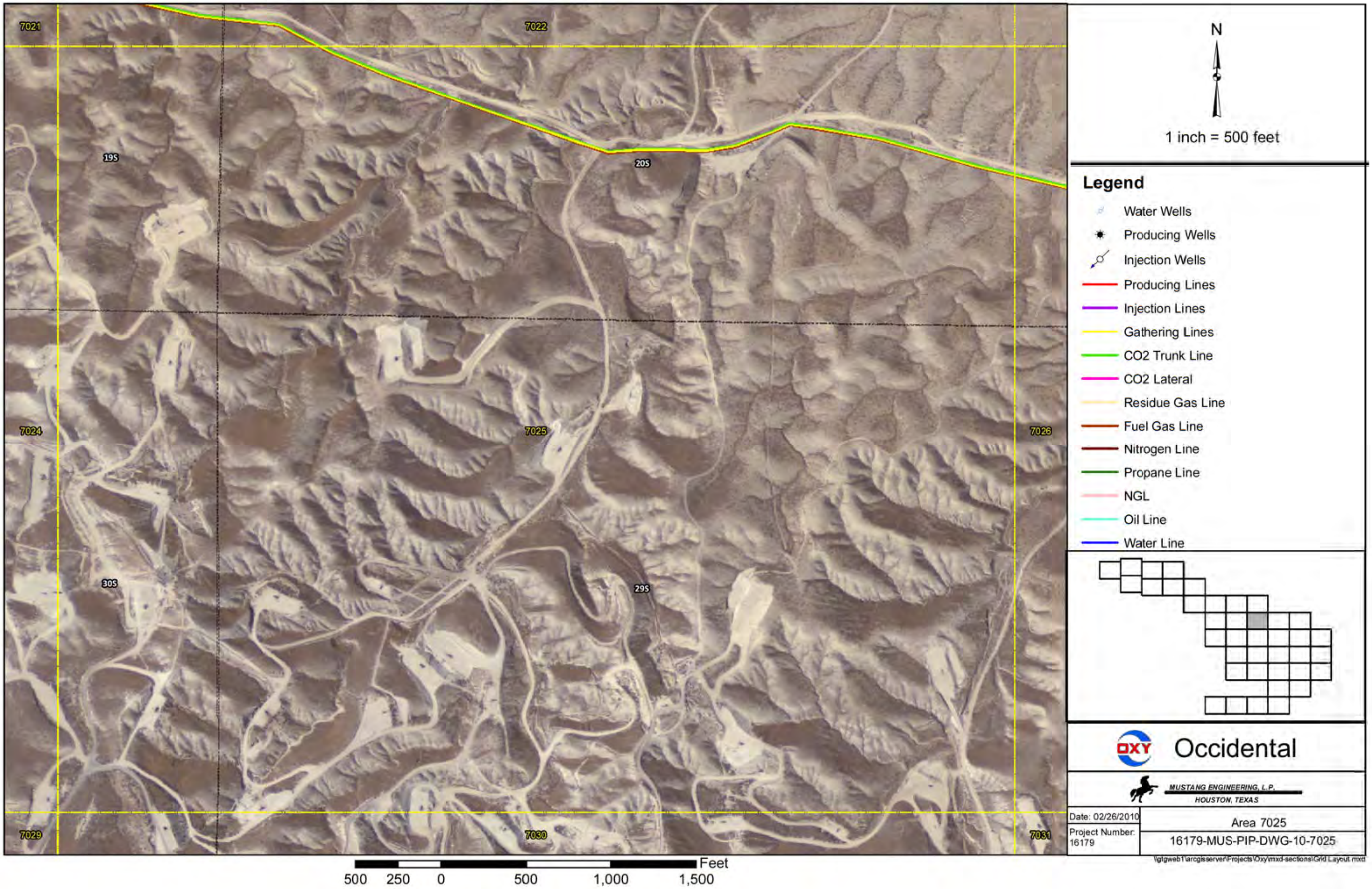

Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010	Area 7025
Project Number: 16179	16179-MUS-PIP-DWG-10-7025

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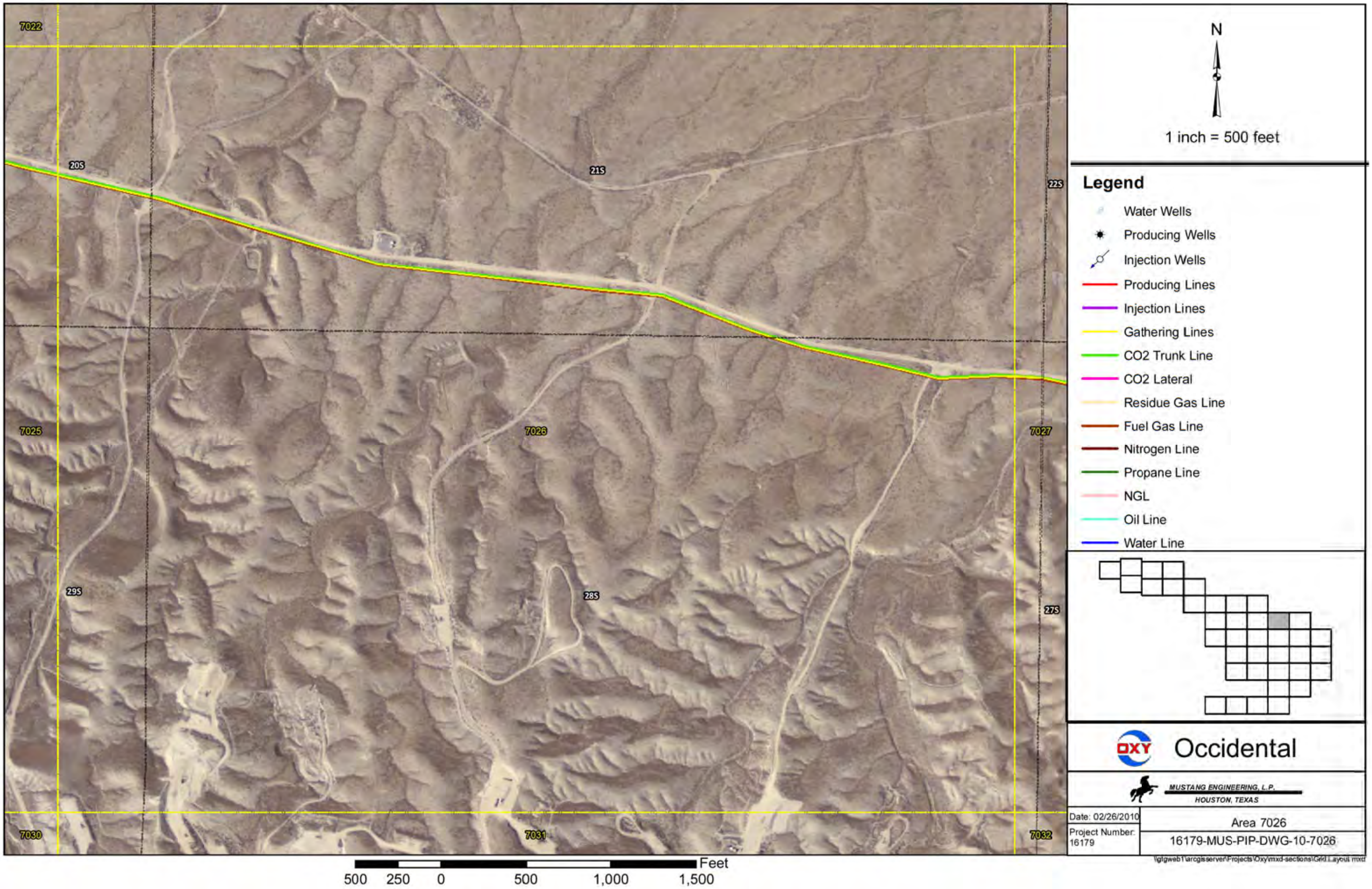

Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010
Project Number: 16179

Area 7026
16179-MUS-PIP-DWG-10-7026

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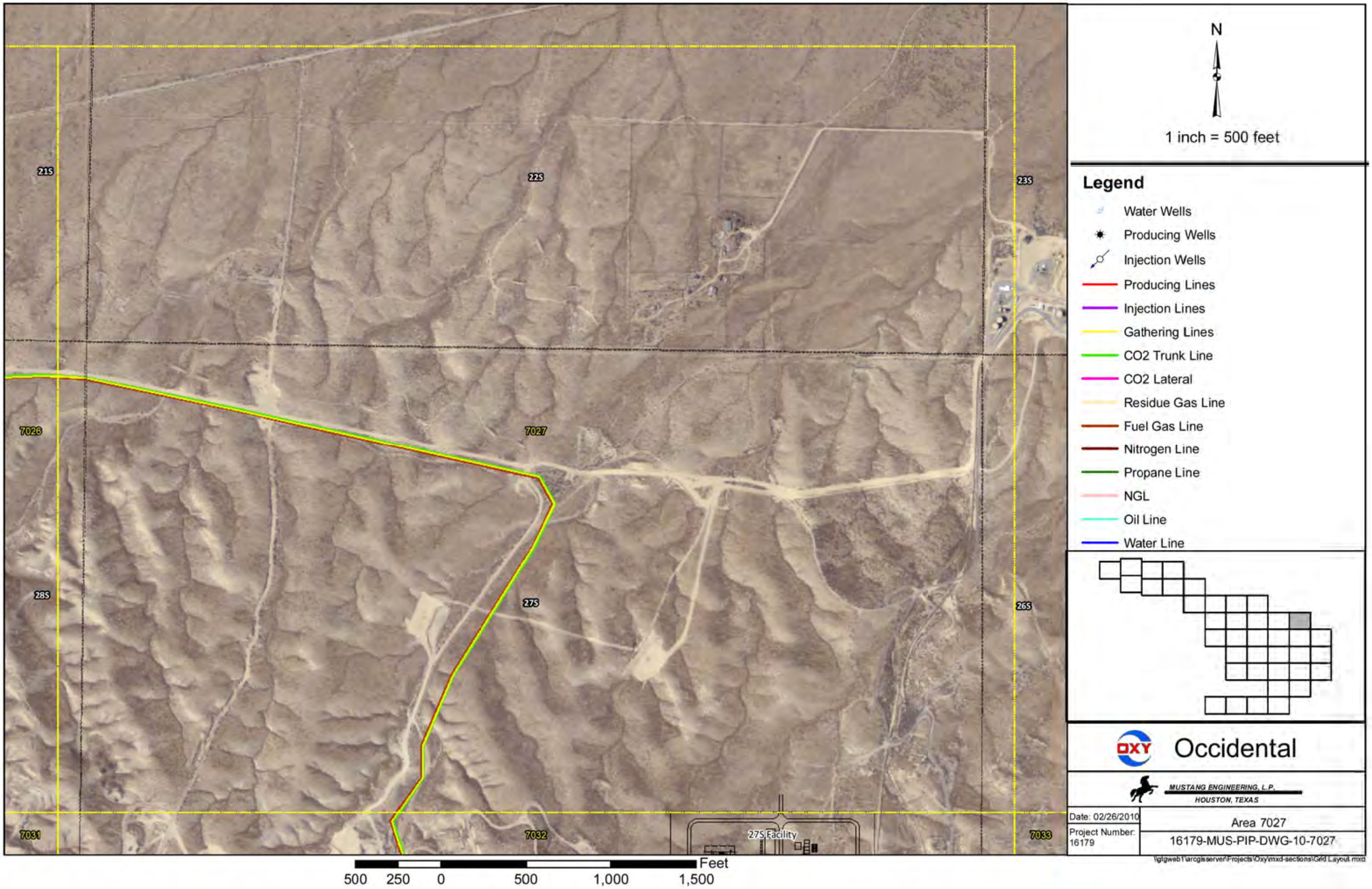

OXY Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010	Area 7027
Project Number: 16179	16179-MUS-PIP-DWG-10-7027

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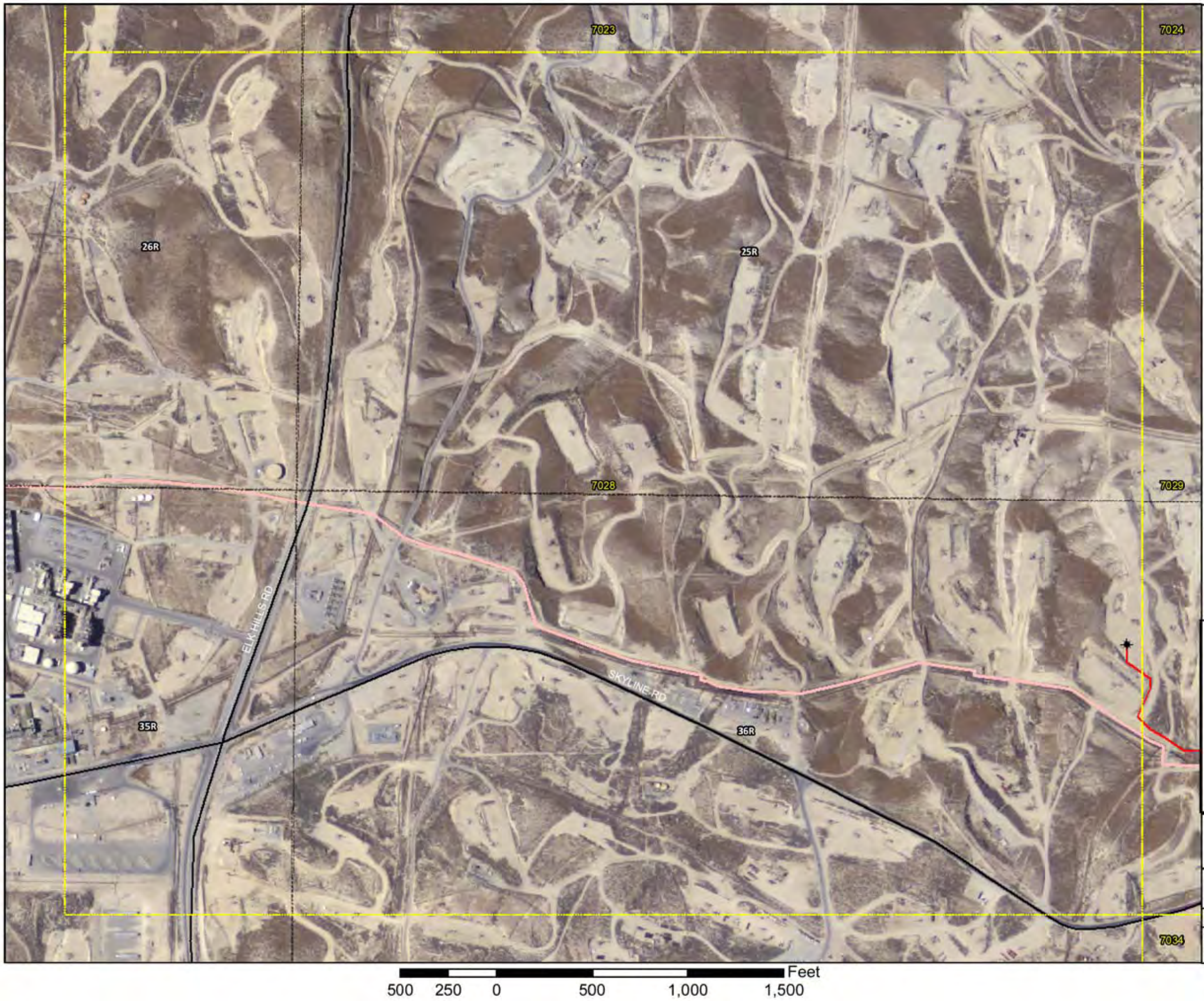
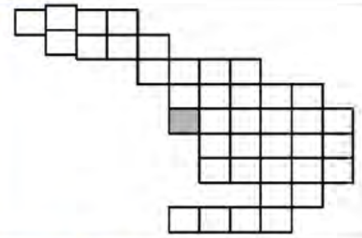


N

1 inch = 500 feet

Legend

- Water Wells
- Producing Wells
- Injection Wells
- Producing Lines
- Injection Lines
- Gathering Lines
- CO2 Trunk Line
- CO2 Lateral
- Residue Gas Line
- Fuel Gas Line
- Nitrogen Line
- Propane Line
- NGL
- Oil Line
- Water Line



Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010	Area 7028
Project Number: 16179	16179-MUS-PIP-DWG-10-7028

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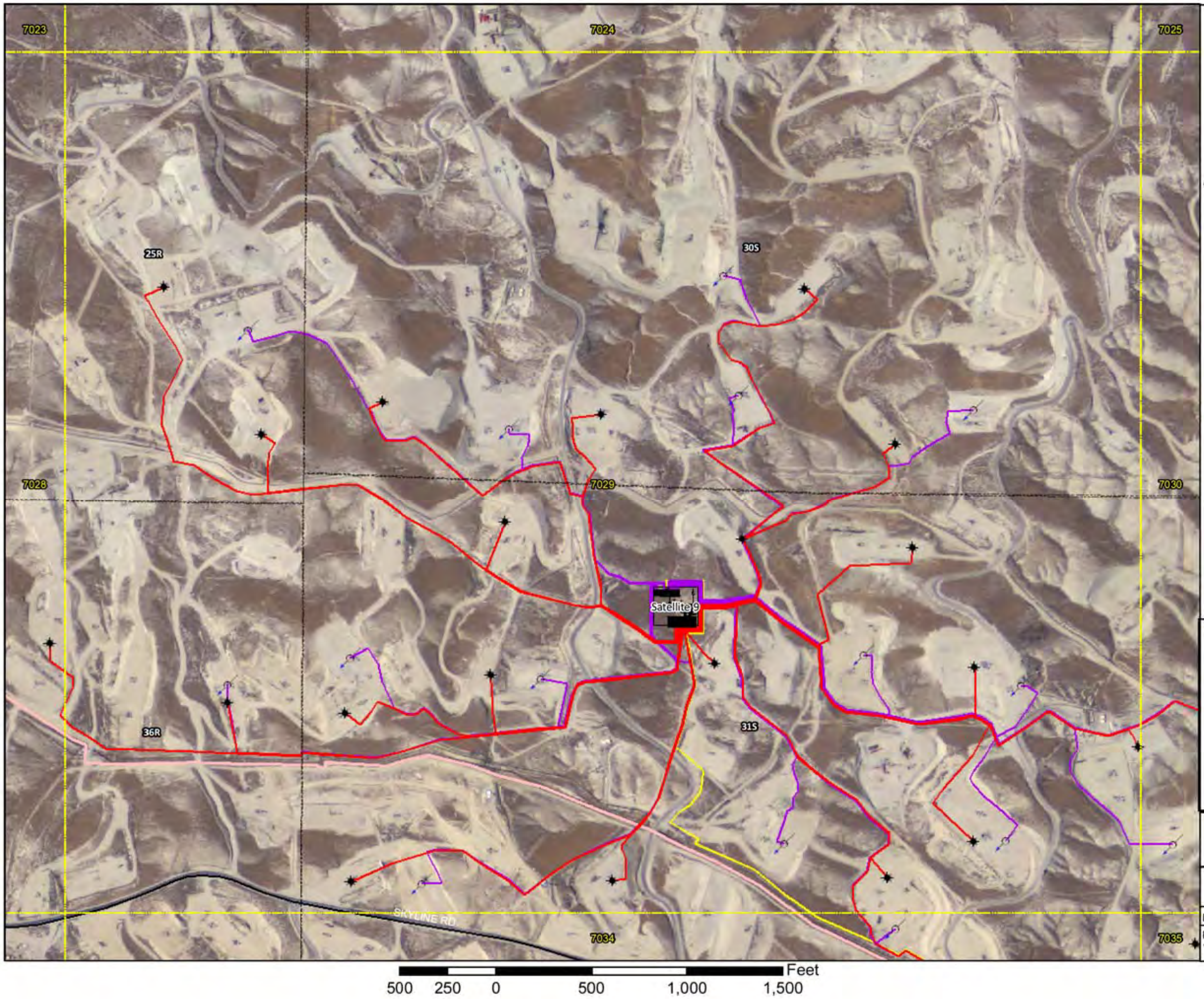
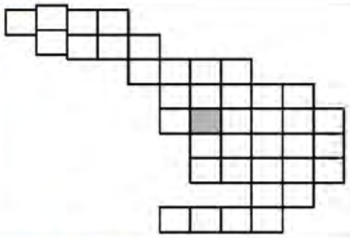


N

1 inch = 500 feet

Legend

- Water Wells
- ✱ Producing Wells
- Injection Wells
- Producing Lines
- Injection Lines
- Gathering Lines
- CO2 Trunk Line
- CO2 Lateral
- Residue Gas Line
- Fuel Gas Line
- Nitrogen Line
- Propane Line
- NGL
- Oil Line
- Water Line



OXY Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010	Area 7029
Project Number: 16179	16179-MUS-PIP-DWG-10-7029

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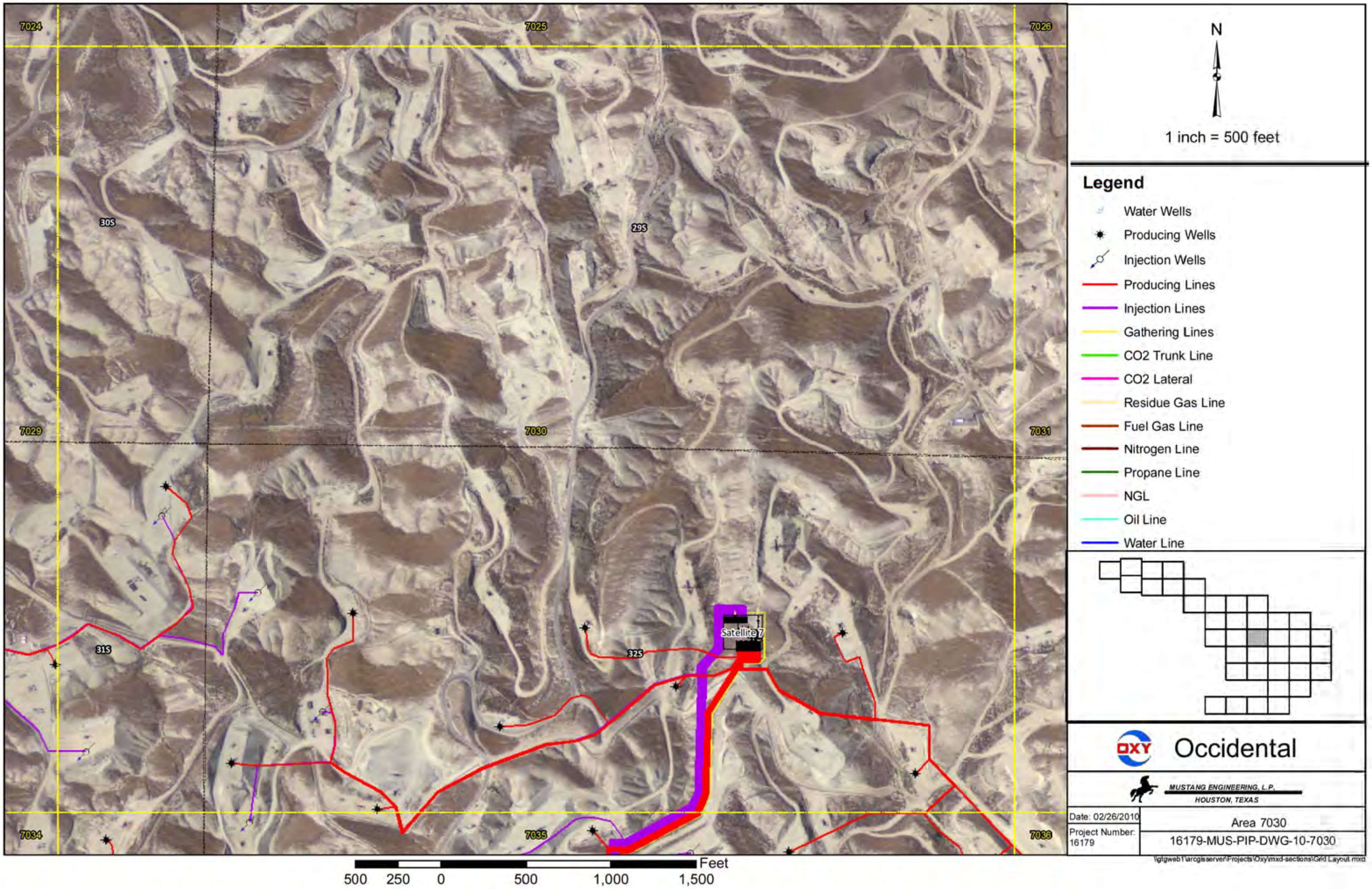

Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010

Project Number: 16179

Area 7030

16179-MUS-PIP-DWG-10-7030

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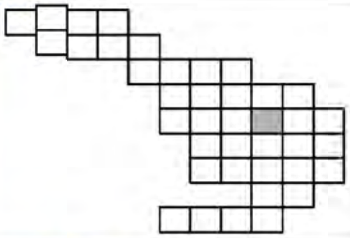
N

1 inch = 500 feet

Legend

- Water Wells
- Producing Wells
- Injection Wells
- Producing Lines
- Injection Lines
- Gathering Lines
- CO2 Trunk Line
- CO2 Lateral
- Residue Gas Line
- Fuel Gas Line
- Nitrogen Line
- Propane Line
- NGL
- Oil Line
- Water Line



Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010	Area 7031
Project Number: 16179	16179-MUS-PIP-DWG-10-7031

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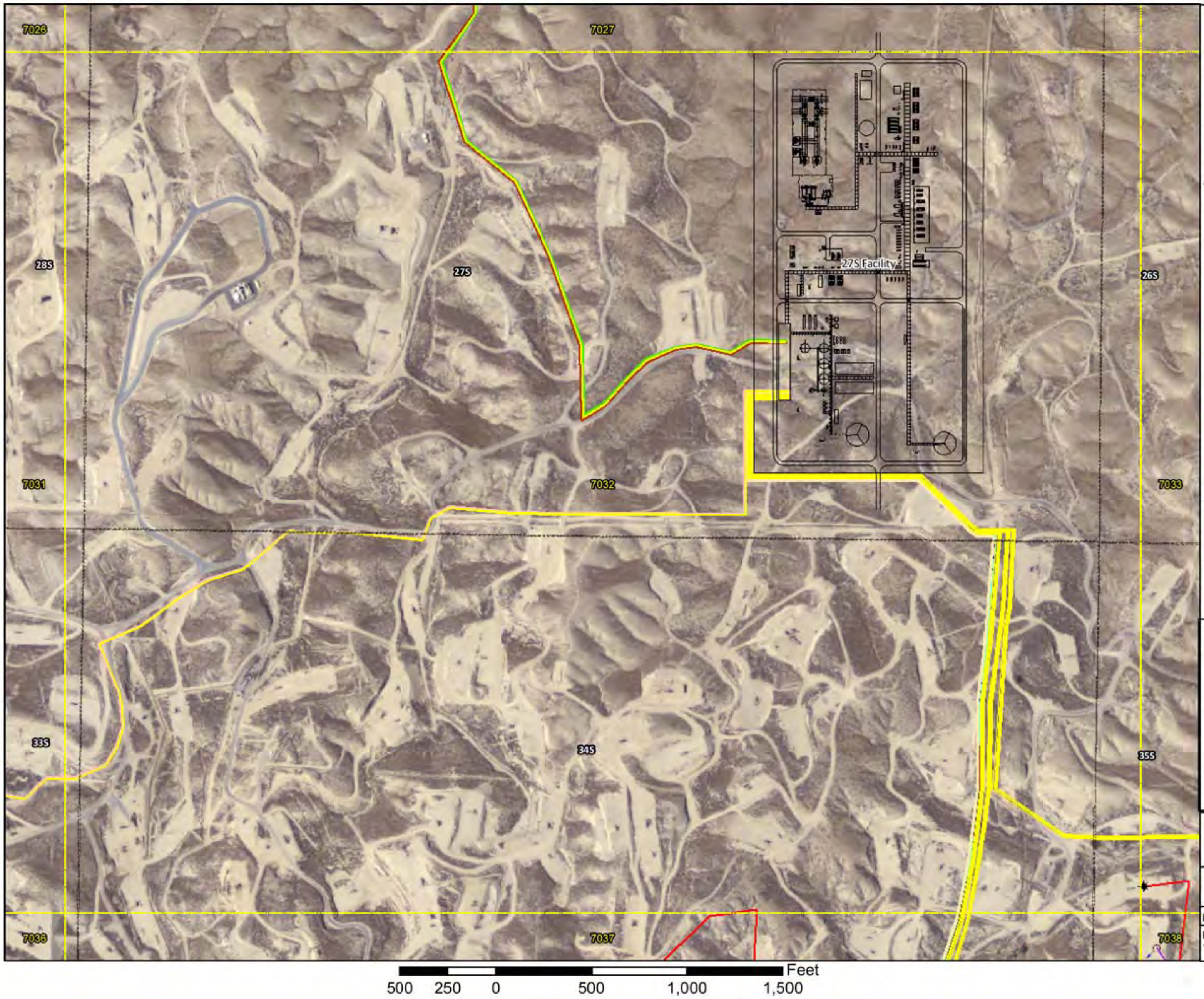

Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010
Project Number: 16179

Area 7032

16179-MUS-PIP-DWG-10-7032

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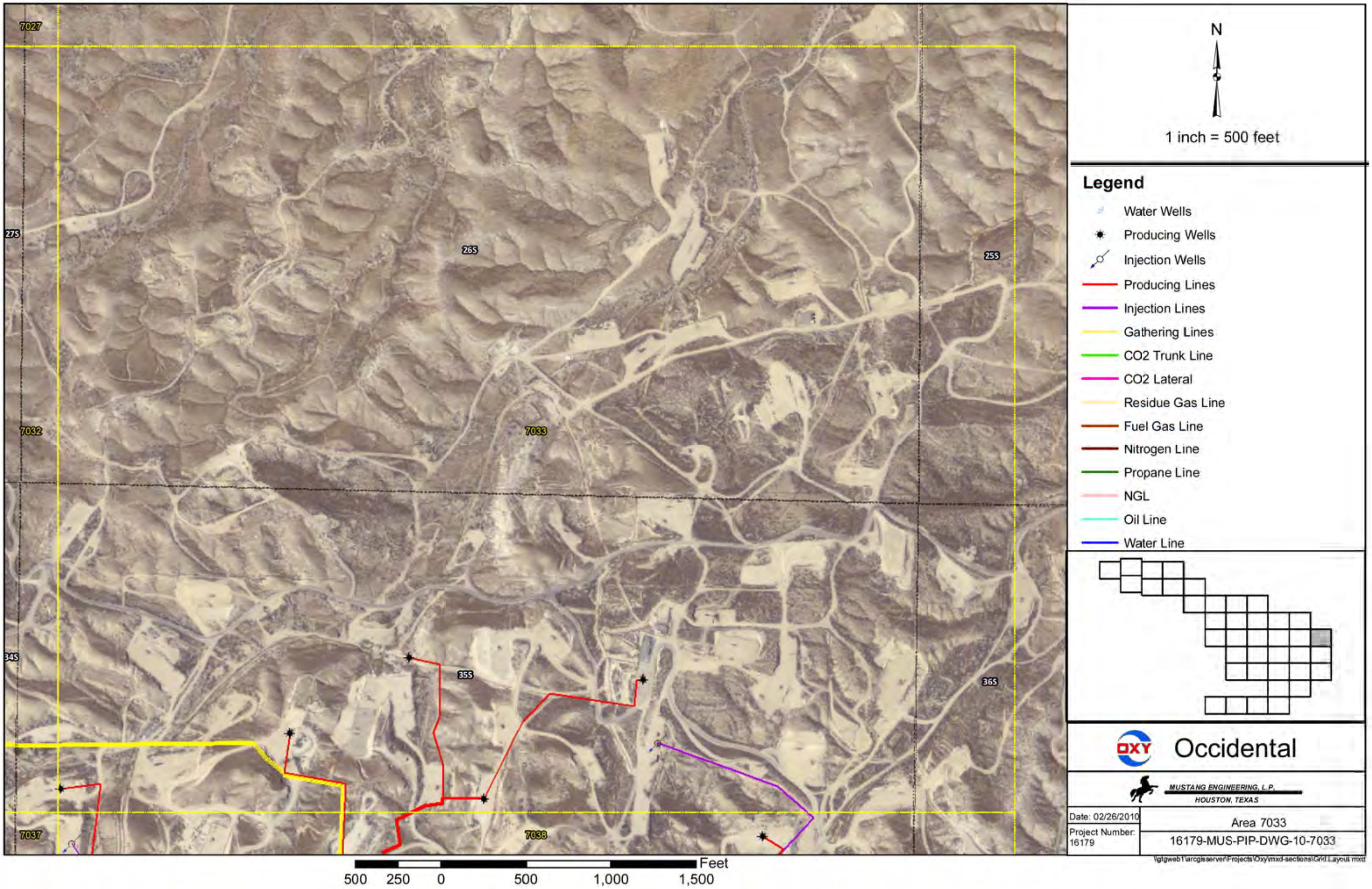

1 inch = 500 feet

Legend

✱	Water Wells
✱	Producing Wells
○	Injection Wells
🟥	Producing Lines
🟪	Injection Lines
🟨	Gathering Lines
🟩	CO2 Trunk Line
—	CO2 Lateral
—	Residue Gas Line
—	Fuel Gas Line
—	Nitrogen Line
—	Propane Line
—	NGL
—	Oil Line
🟦	Water Line

Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010
Project Number: 16179

Area 7033
16179-MUS-PIP-DWG-10-7033

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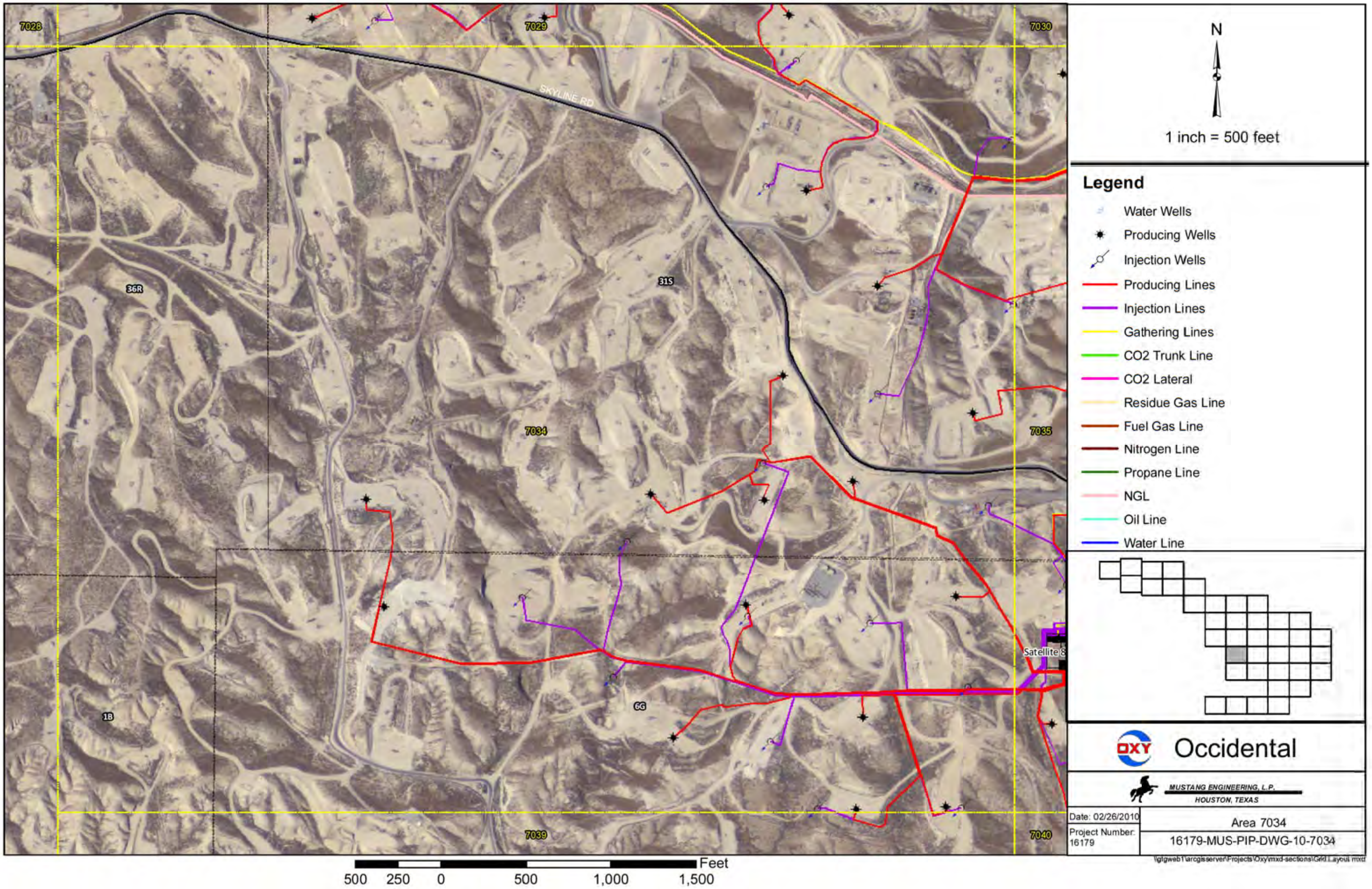

Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010
Project Number: 16179

Area 7034
16179-MUS-PIP-DWG-10-7034

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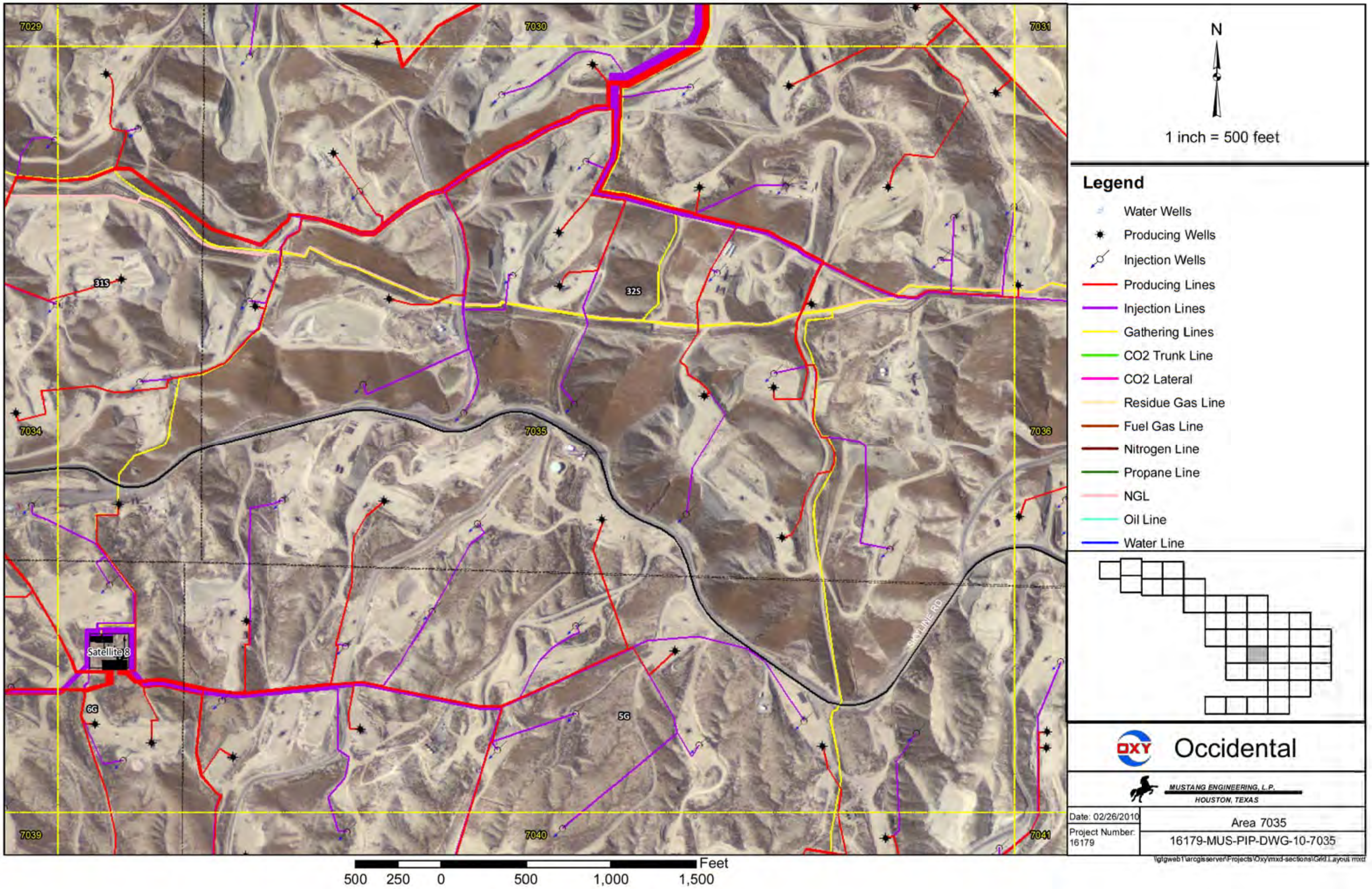

Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010	Area 7035
Project Number: 16179	16179-MUS-PIP-DWG-10-7035

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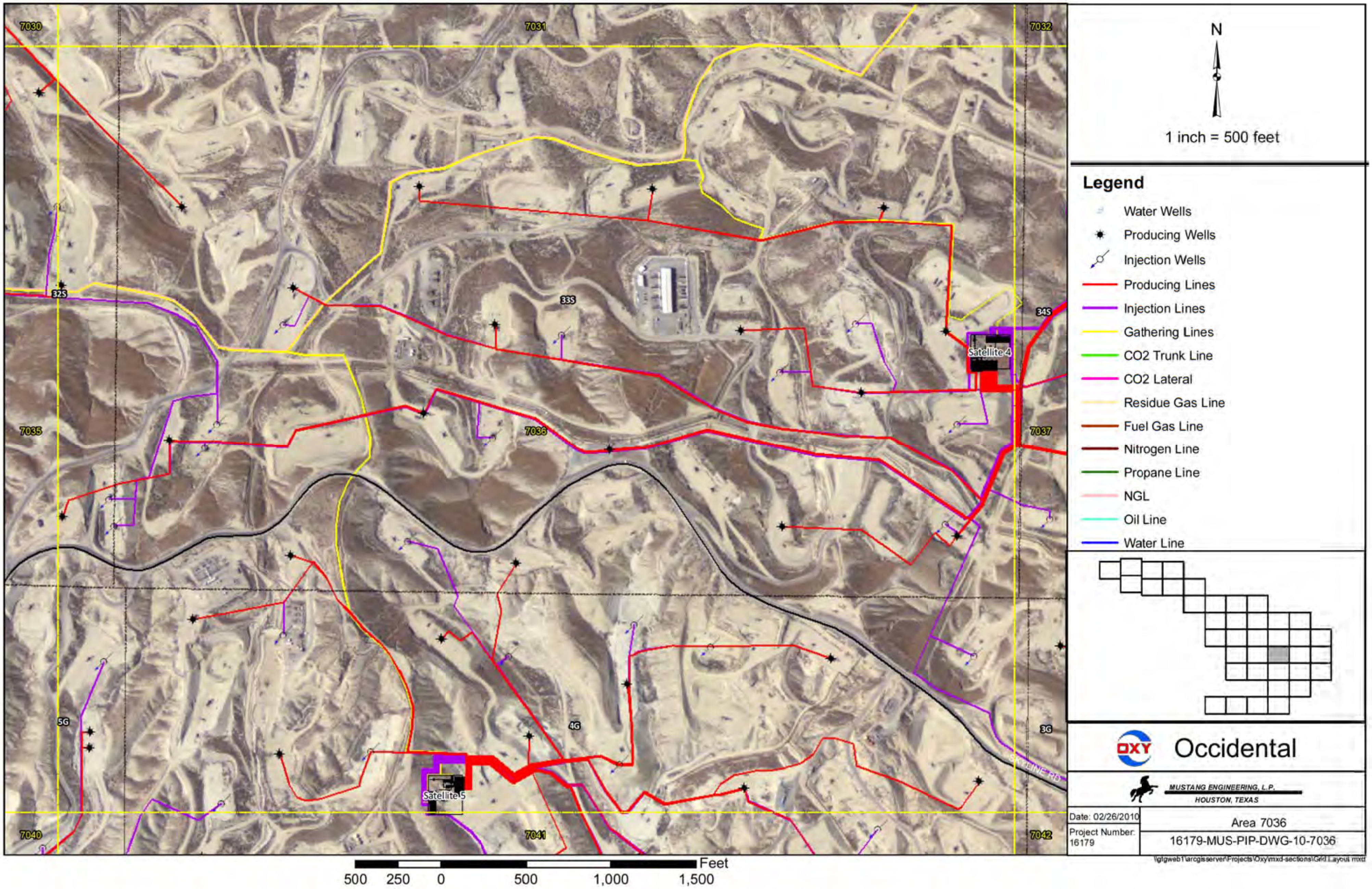

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010
Project Number: 16179

Area 7036
16179-MUS-PIP-DWG-10-7036

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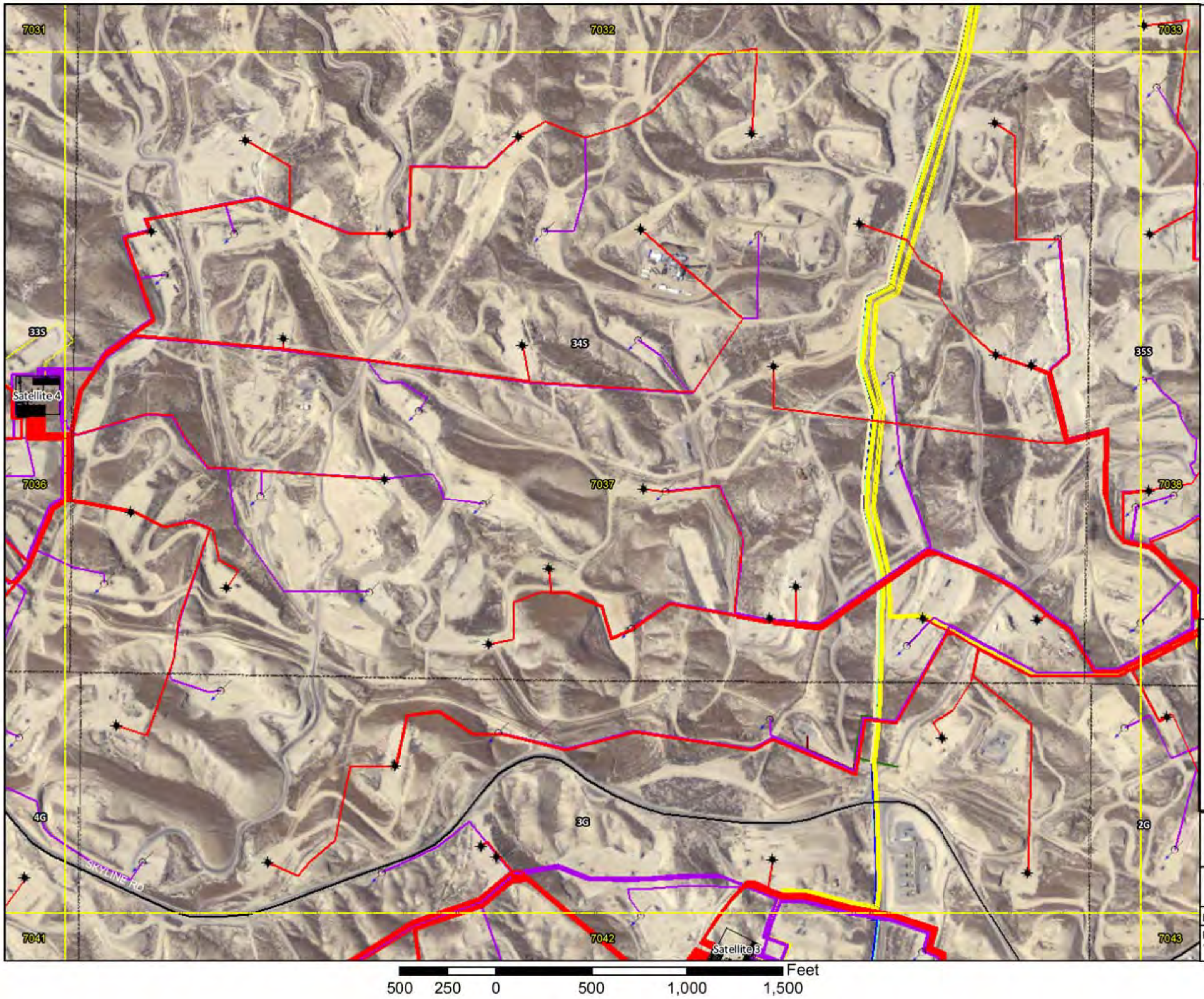
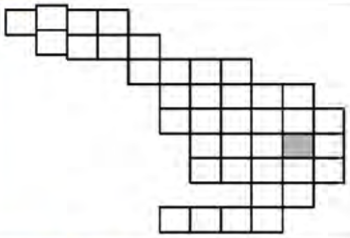


N

1 inch = 500 feet

Legend

- Water Wells
- Producing Wells
- Injection Wells
- Producing Lines
- Injection Lines
- Gathering Lines
- CO2 Trunk Line
- CO2 Lateral
- Residue Gas Line
- Fuel Gas Line
- Nitrogen Line
- Propane Line
- NGL
- Oil Line
- Water Line



Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010	Area 7037
Project Number: 16179	16179-MUS-PIP-DWG-10-7037

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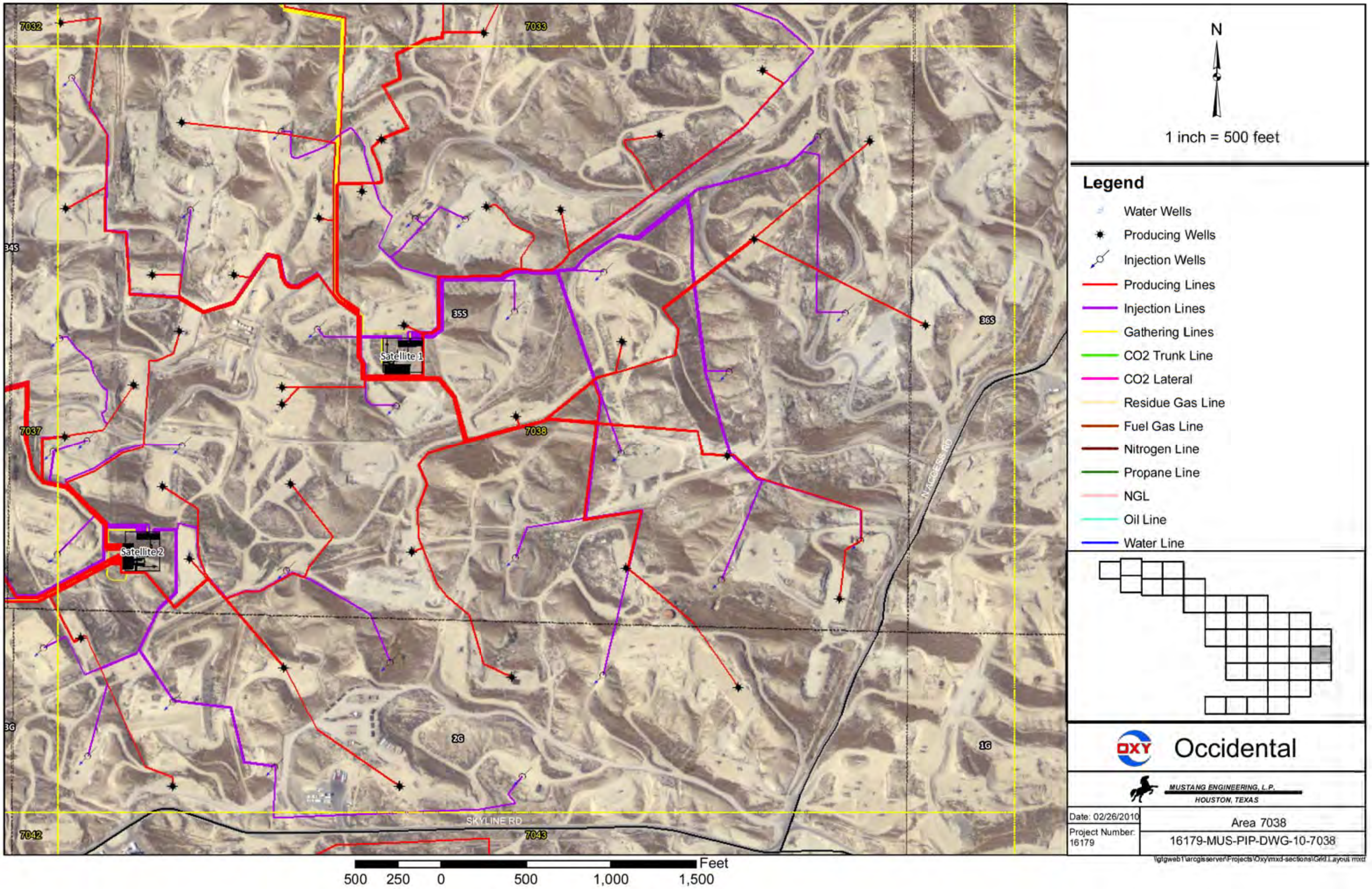

Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010

Project Number:
16179

Area 7038

16179-MUS-PIP-DWG-10-7038

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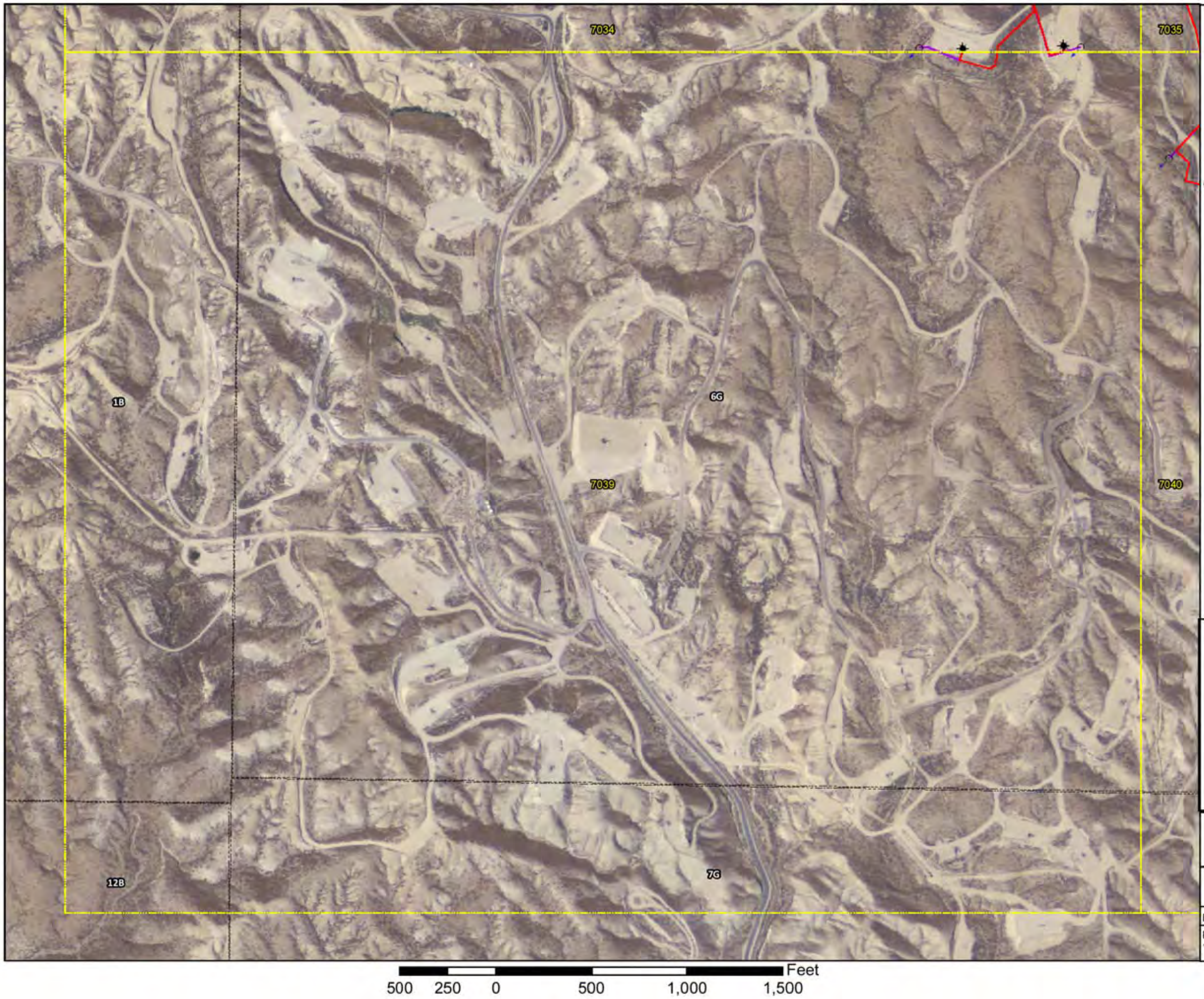
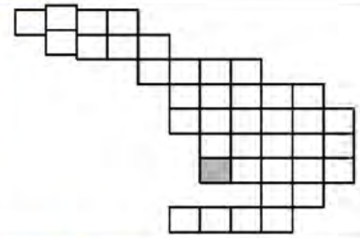


N

1 inch = 500 feet

Legend

- Water Wells
- ✱ Producing Wells
- Injection Wells
- Producing Lines
- Injection Lines
- Gathering Lines
- CO2 Trunk Line
- CO2 Lateral
- Residue Gas Line
- Fuel Gas Line
- Nitrogen Line
- Propane Line
- NGL
- Oil Line
- Water Line



Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010	Area 7039
Project Number: 16179	16179-MUS-PIP-DWG-10-7039

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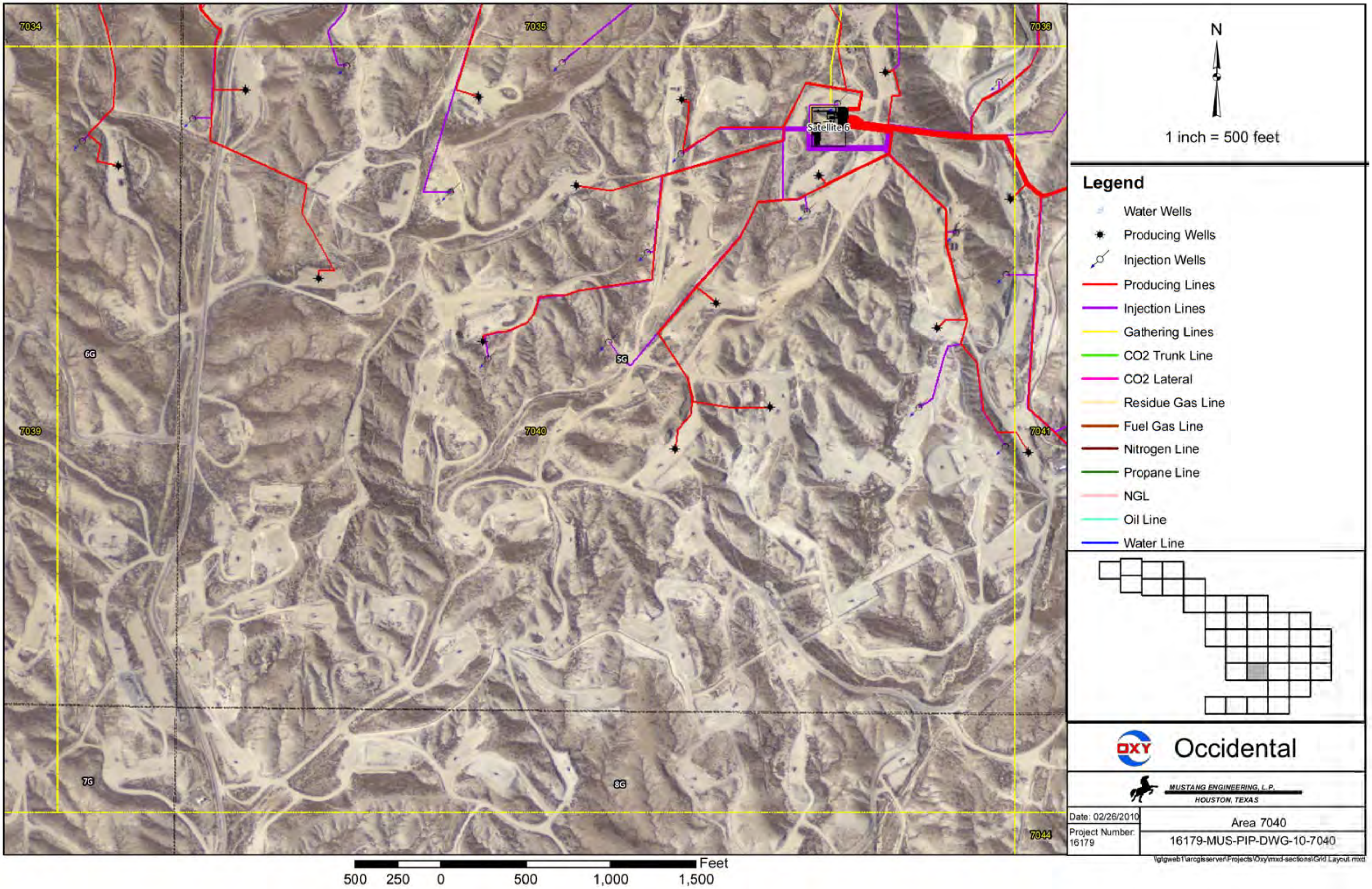

OXY Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010
Project Number: 16179

Area 7040
16179-MUS-PIP-DWG-10-7040

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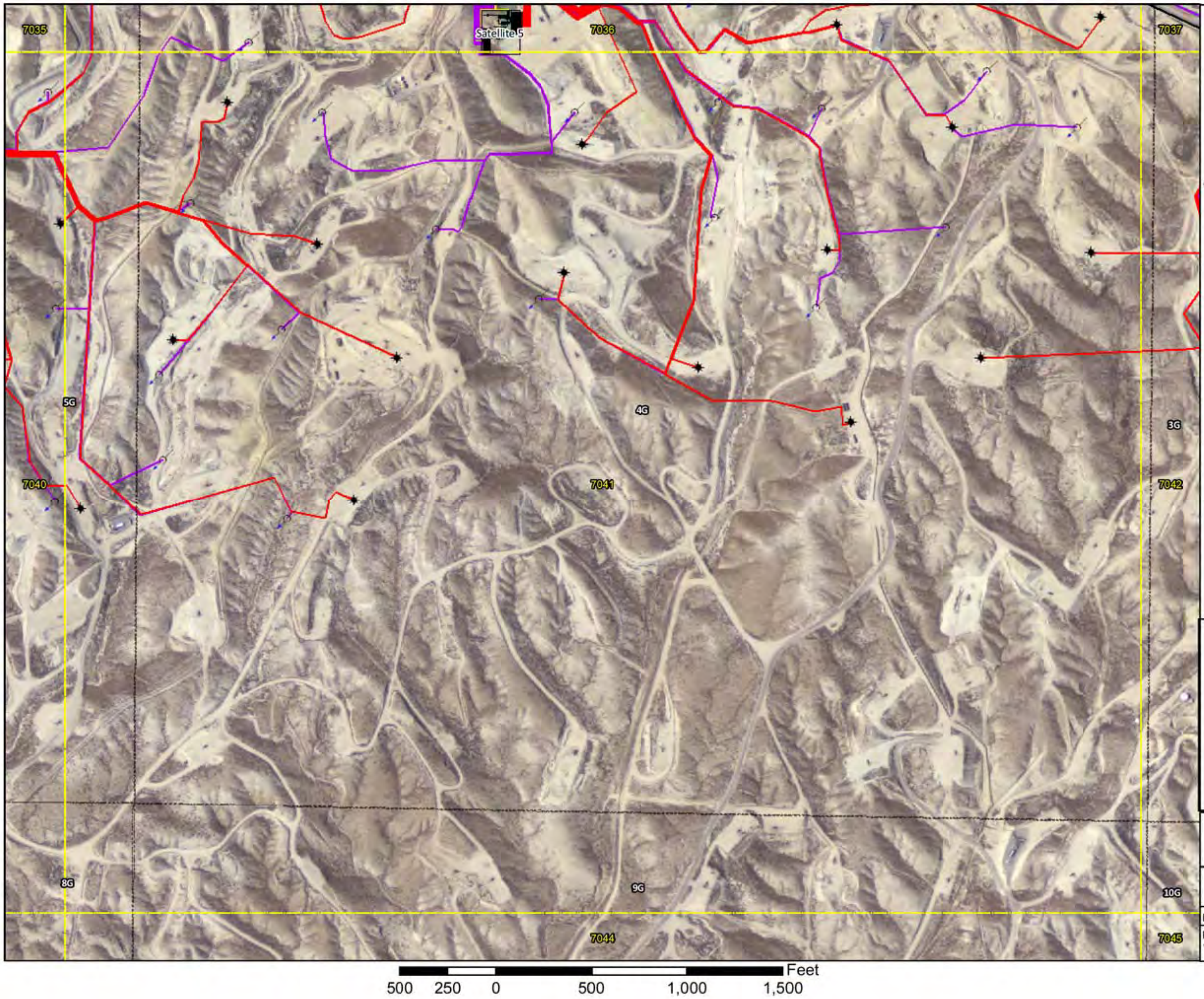
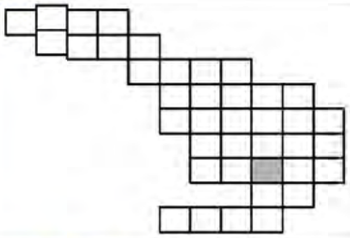


N

1 inch = 500 feet

Legend

- Water Wells
- Producing Wells
- Injection Wells
- Producing Lines
- Injection Lines
- Gathering Lines
- CO2 Trunk Line
- CO2 Lateral
- Residue Gas Line
- Fuel Gas Line
- Nitrogen Line
- Propane Line
- NGL
- Oil Line
- Water Line



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MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010

Project Number:
16179

Area 7041

16179-MUS-PIP-DWG-10-7041

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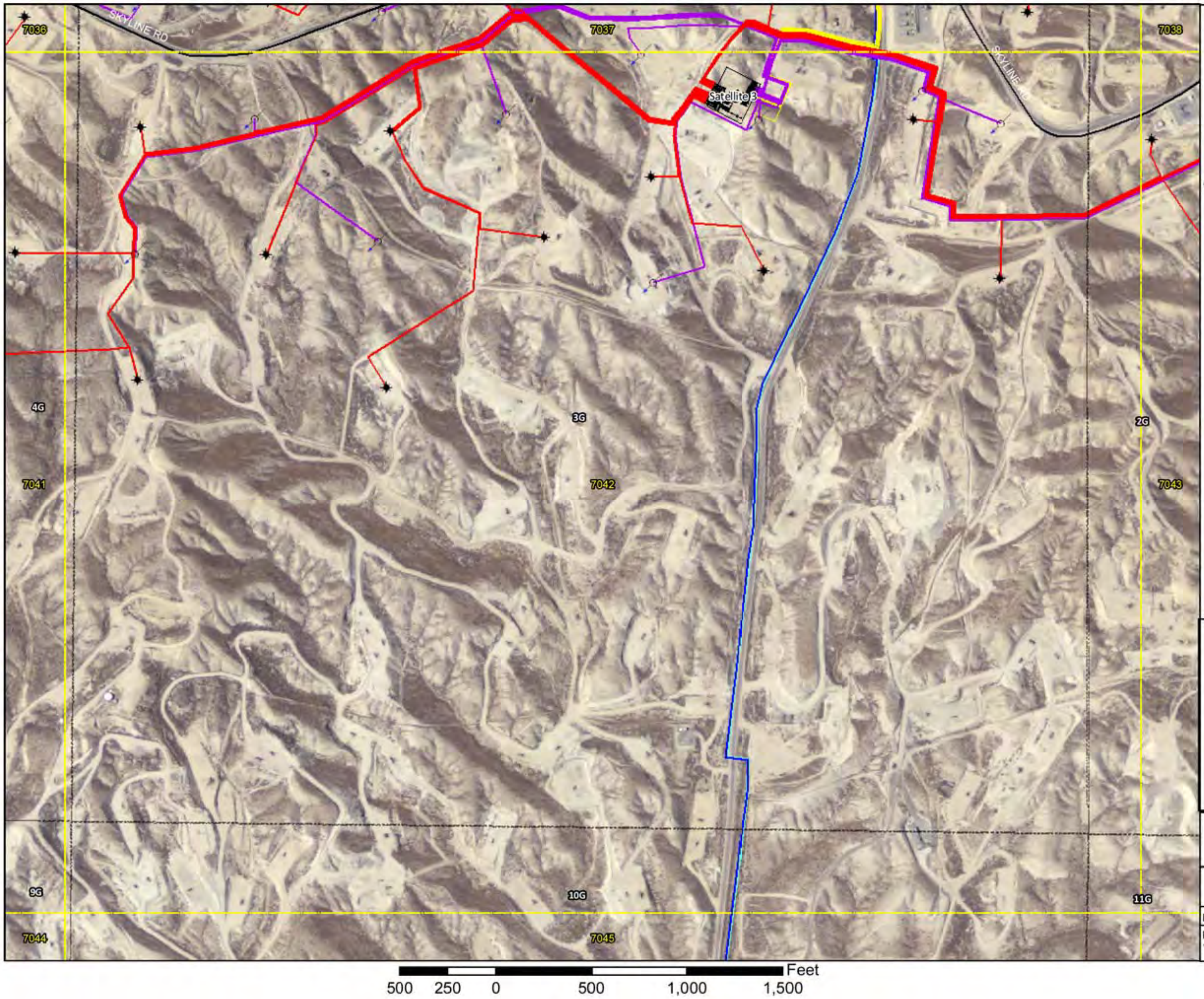
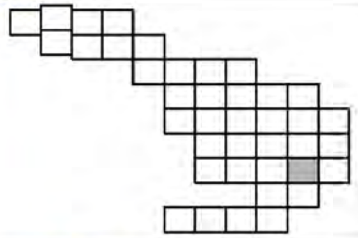


N

1 inch = 500 feet

Legend

- Water Wells
- ✱ Producing Wells
- Injection Wells
- Producing Lines
- Injection Lines
- Gathering Lines
- CO2 Trunk Line
- CO2 Lateral
- Residue Gas Line
- Fuel Gas Line
- Nitrogen Line
- Propane Line
- NGL
- Oil Line
- Water Line



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MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010
Project Number: 16179

Area 7042

16179-MUS-PIP-DWG-10-7042

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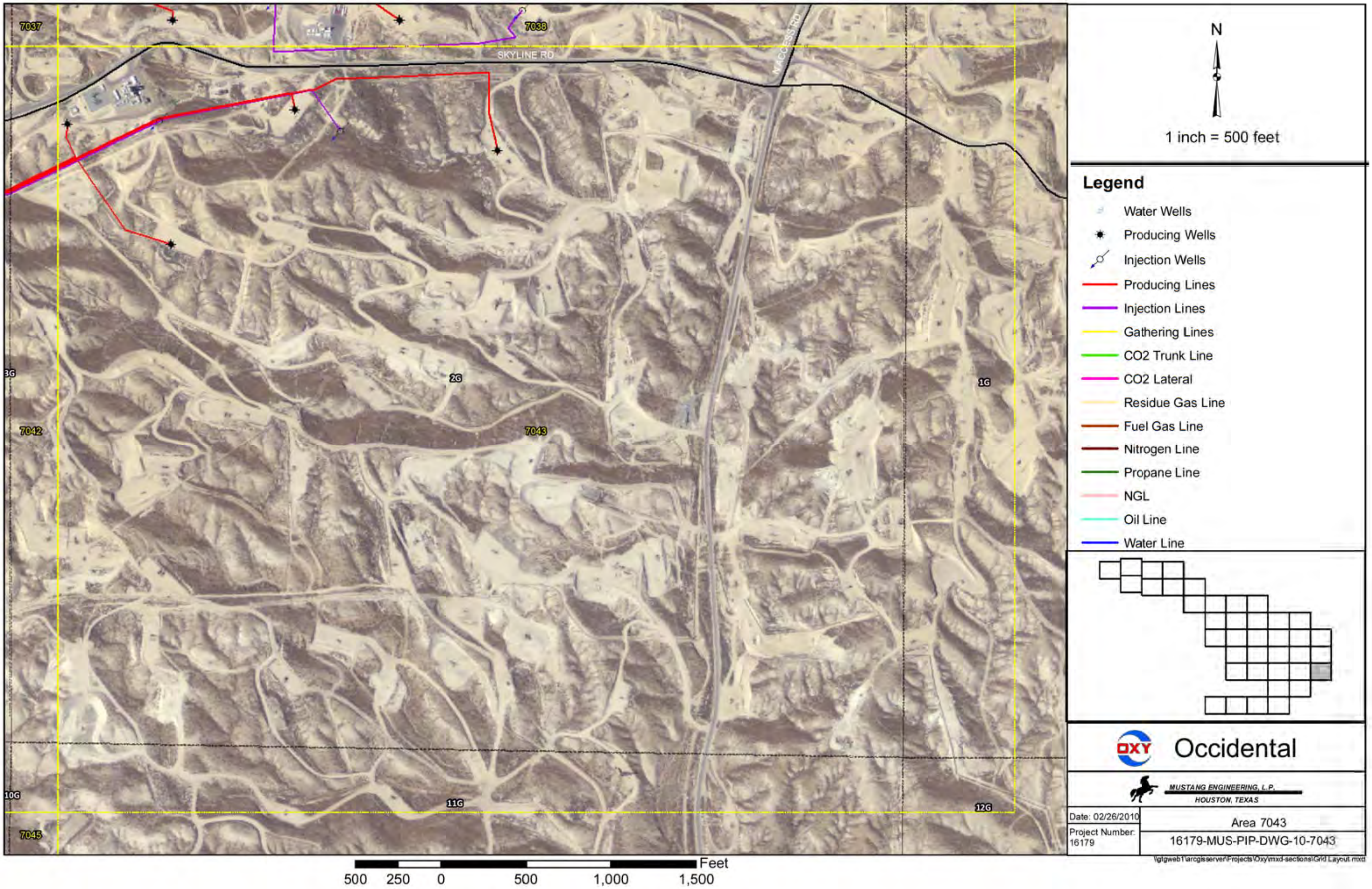

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MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010
Project Number: 16179

Area 7043
16179-MUS-PIP-DWG-10-7043

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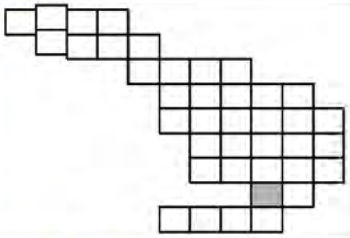
N

1 inch = 500 feet

Legend

- Water Wells
- ✸ Producing Wells
- Injection Wells
- Producing Lines
- Injection Lines
- Gathering Lines
- CO2 Trunk Line
- CO2 Lateral
- Residue Gas Line
- Fuel Gas Line
- Nitrogen Line
- Propane Line
- NGL
- Oil Line
- Water Line



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MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010
Project Number: 16179

Area 7044
16179-MUS-PIP-DWG-10-7044

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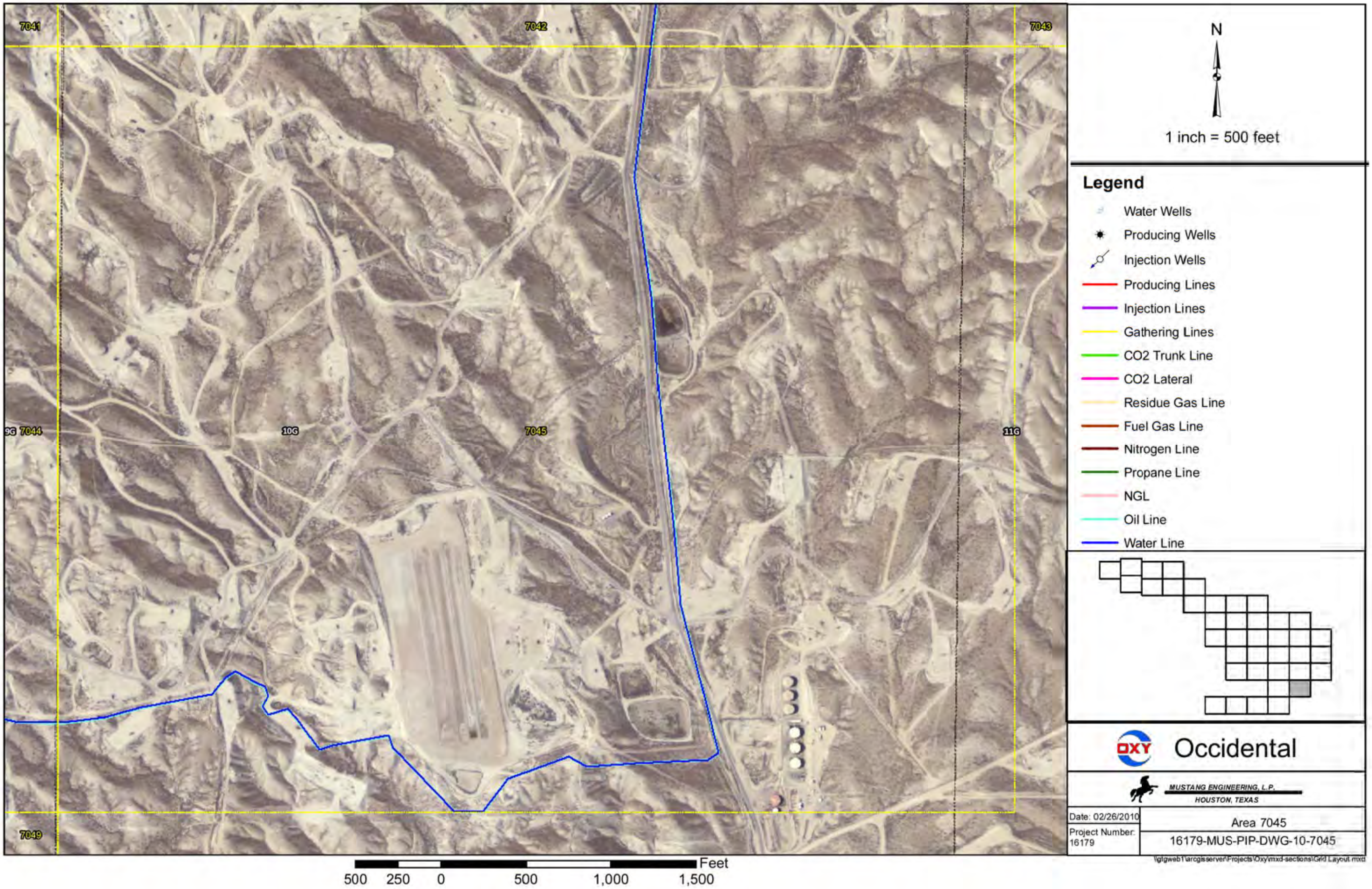

Legend

- Water Wells
- ✱ Producing Wells
- Injection Wells
- Producing Lines
- Injection Lines
- Gathering Lines
- CO2 Trunk Line
- CO2 Lateral
- Residue Gas Line
- Fuel Gas Line
- Nitrogen Line
- Propane Line
- NGL
- Oil Line
- Water Line

OXY Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010
Project Number: 16179

Area 7045
16179-MUS-PIP-DWG-10-7045

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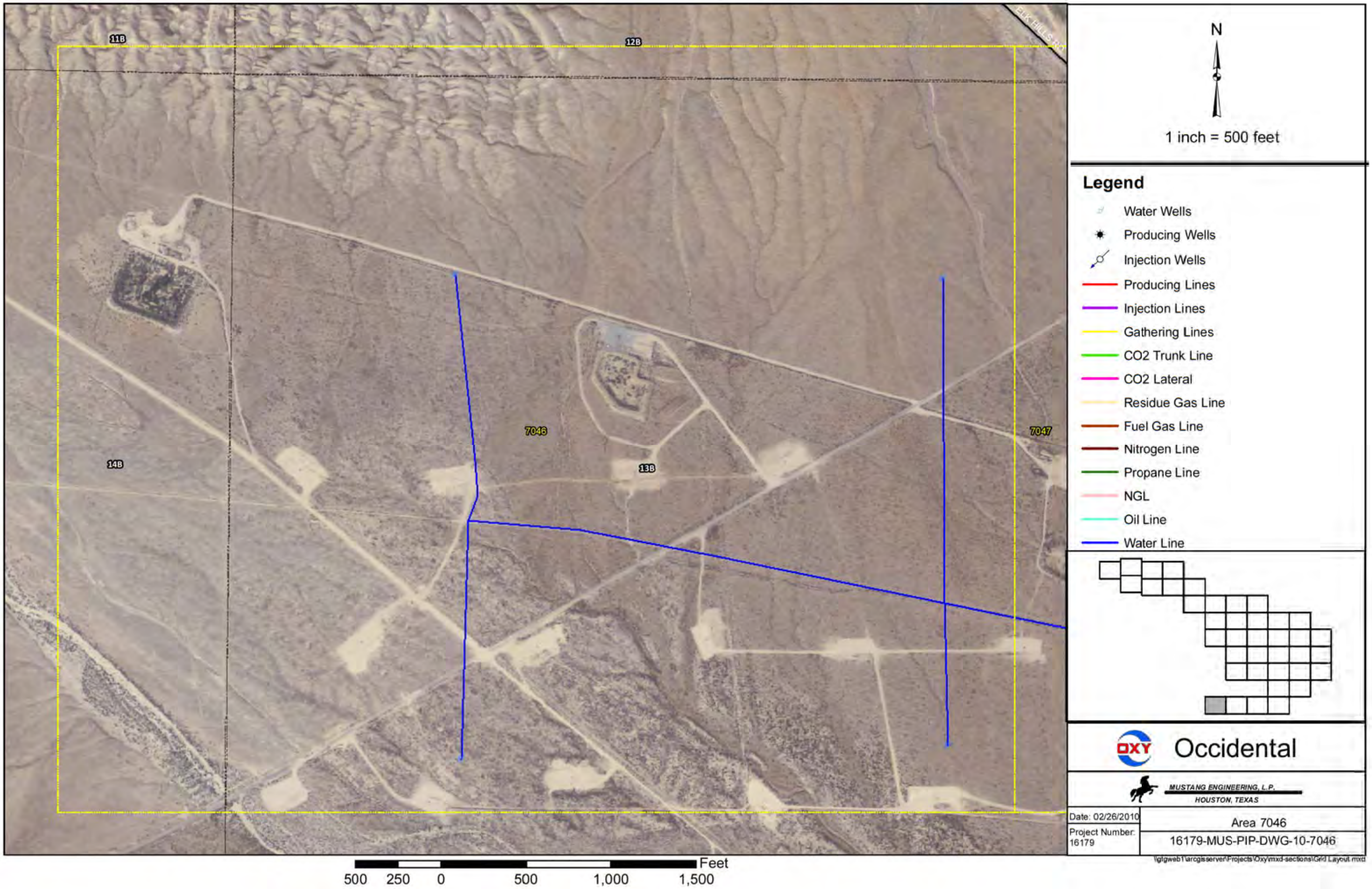

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MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010	Area 7046
Project Number: 16179	16179-MUS-PIP-DWG-10-7046

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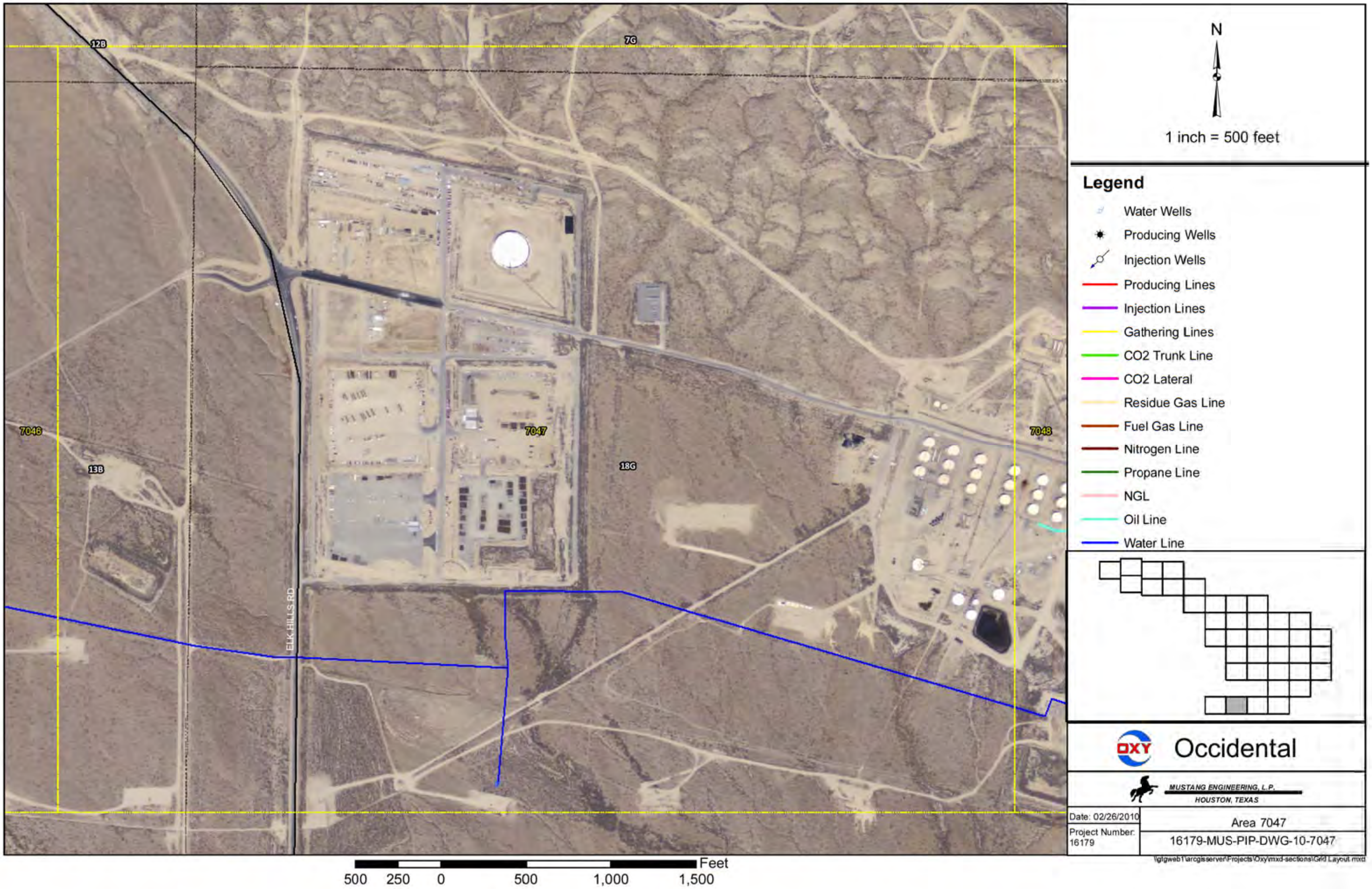

Date: 02/26/2010

Project Number: 16179

Area 7047

16179-MUS-PIP-DWG-10-7047

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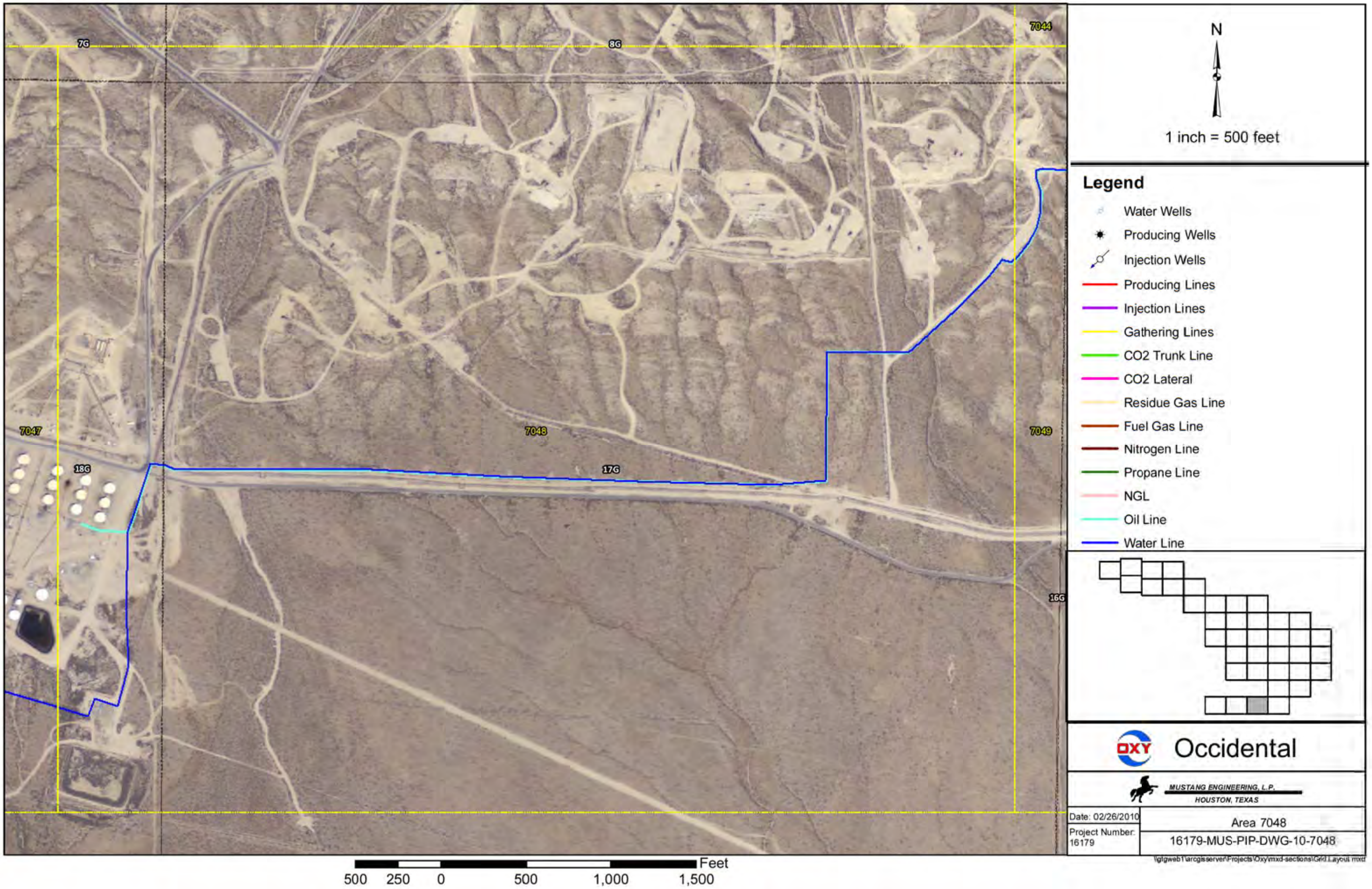

Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010
Project Number: 16179

Area 7048

16179-MUS-PIP-DWG-10-7048

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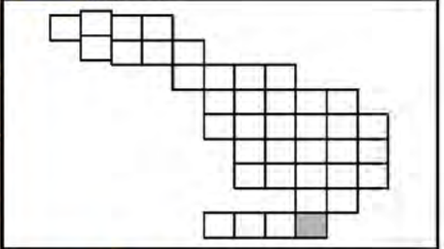
N

1 inch = 500 feet

Legend

- Water Wells
- Producing Wells
- Injection Wells
- Producing Lines
- Injection Lines
- Gathering Lines
- CO2 Trunk Line
- CO2 Lateral
- Residue Gas Line
- Fuel Gas Line
- Nitrogen Line
- Propane Line
- NGL
- Oil Line
- Water Line



OXY Occidental

MUSTANG ENGINEERING, L.P.
HOUSTON, TEXAS

Date: 02/26/2010	Area 7049
Project Number: 16179	16179-MUS-PIP-DWG-10-7049

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Attachment A177-3

Pre-FEED Engineering Study, Execution Schedule, Mustang Engineering, April 23, 2010.

Occidental of Elk Hills, Inc.

Elk Hills CO_2 Project
Pre-FEED Engineering Study

EPC Execution Schedule

Document No. 16179-MUS-PCO-PL-00-0002

A	23 Apr 10	Issued for FEED	MLS	KB	SCW
REVISION	**DATE**	**DESCRIPTION**	**ORIGINATOR**	**CHECKED**	**APPROVED**

Mustang Engineering L.P.
Project Number 16179

	Project	Originator	Discipline	Type	System No.	Sequence No.
Document No.	16179	MUS	PCO	PL	00	0002

TABLE OF CONTENTS

1. INTRODUCTION

This document contains the Level 2 EPC Execution schedules developed for the Elk Hills CO_2 Pre-FEED Engineering Study.

There is one high level schedule and six separate and more detailed schedules covering the full phasing of the development, and each of the schedules is explained in section 3.0.

Each schedule is included as Appendices 1 through 7.

A Project FEED schedule has been developed separately and is detailed in document 16179-MUS-PCO-PL-00-0003.

2. PROJECT SUMMARY

Hydrogen Energy California (HECA) is evaluating installing a hydrogen plant near the Elk Hills property of Occidental of Elk Hills, Inc. (OEHI). The hydrogen will be used to fuel an electrical generation plant to provide power to the California markets. A by-product of the process is a CO_2 rich stream that OEHI is considering injecting into various oil reservoirs for enhanced oil recovery. OEHI plans to implement a phased installation program to install CO_2 distribution and storage systems, satellite gathering and separation systems, and CO_2 recompression and processing facilities, in order to maximize the potential enhanced oil recovery in the southeast and northwest sections of Stephens reservoir. The facilities will consist of the following primary components:

- CO_2 Supply Pipeline (from HECA to the CO_2 Processing Plant) – By Others
- CO_2 & Water Distribution Pipelines
- Satellite Gathering Systems (a total of 13 Satellites)
- Infield Distribution Flowlines, Injection Lines and Gathering Pipelines
- Central Tank Battery (CTB) – installed in two phases
- Reinjection Compression Facility (RCF)
- CO_2 Recovery Plant (CRP)
- Backup Injection Facility
- Water Treating & Injection Unit
- Utilities, Tie-ins & Infrastructure
- Product Sales Pipelines

3. LEVEL 2 EPC SCHEDULES

The full development of the project is spread over more than 20 years which necessitates several schedules. The analysis of the field development timeline has been described in Appendix 5 of the Overall Design Basis document, 16179-MUS-GEN-BD-00-0001.

The seven schedules are identified as:

1. High Level Schedule Summary (summarizing Value Engineering, FEED and all EPC schedules)
2. RCF, CTB Phase I and Satellites 1, 2 and 3.
3. Typical Satellite for Satellites 4 through 13.
4. Trunk lines concurrent with Satellite 4
5. Trunk lines concurrent with Satellite 10
6. CRP
7. CTB Phase II.

3.1 High Level Schedule Summary (summarizing Value Engineering, FEED and all EPC schedules):

Schedule:	1. Start date – May 3, 2010 2. End date – Q4, 2035
Activities:	1. High level summary of all schedules
Scope:	1. Pre-FEED Phase 2 Value Engineering 2. FEED 3. RCF 4. CTB – Phases I and II 5. Utilities 6. Substation 7. Satellites 1 through 13 including all associated flow lines, trunk, production and injection lines 8. Power supply 9. CO_2 Line to A1A2 10. Tulare water lines from 13B and 18G 11. Oil line to 18G 12. Fuel and flare assist gas line from 35R 13. Fuel gas to A1A2 for heater

3.2 RCF, CTB Phase I and Satellites 1, 2 & 3 EPC Schedule:

Schedule:	1. End date - December 31, 2015 (Satellite 3 is to be completed by the end of Q2 2016.) 2. Assumes the following approximate durations: a. Total schedule - 48 months b. Engineering – 24 months c. Procurement – 18 months d. Construction – 18 months
Activities:	1. Let EPC contract 2. Detailed Engineering 3. Procurement 4. Permitting and Regulatory Support 5. Construction 6. Training 7. Commissioning and Startup
Scope:	1. RCF 2. CTB – Phase I 3. Utilities 4. Substation 5. Satellites 1, 2 and 3 including all associated flow, trunk, production and injection lines 6. Power supply 7. Fiber Optic Cables 8. Backup Injection Facility at A1A2 including CO_2 Line from 27R 9. Tulare water lines from 13B and 18G 10. Oil line to 18G 11. Fuel and flare assist gas line from 35R to 27 R and A1A2

3.3 Typical Satellite EPC Schedule for Satellites 4 through 13 EPC Schedule:

(See schedules 4 and 5 respectively for trunk lines concurrent with Satellites 4 and 10)

Time scale:	Satellite 4 – completed 1 March 2017 Satellite 5 – completed 1 March 2018 Satellite 6 – completed 1 March 2020 Satellite 7 – completed 1 December 2021 Satellite 8 – completed1 October 2024 Satellite 9 – completed 1 March 2027 Satellite 10 – completed 1 May 2028 Satellite 11 – completed 1 September 2029 Satellite 12 – completed 1 February 2031 Satellite 13 – completed 1 December 2033
Activities:	1. Bid and let EPC contract 2. Detailed Engineering 3. Procurement 4. Construction 5. Commissioning and Startup
Scope:	1. Satellite including all associated flow lines and laterals to trunk lines 2. Production and Injection Lines from, and to, Wells

3.4 Trunk Lines – concurrent with Satellite 4 EPC Schedule:

Time scale:	To be completed 1 March, 2017
Activities:	1. Bid and let EPC contract 2. Detailed Engineering 3. Procurement 4. Construction 5. Commissioning and Startup
Scope:	1. Gas and liquid gathering trunk lines between Satellite 4 and RCF/CTB/CRP

3.5 Trunk Lines – concurrent with Satellite 10 EPC Schedule:

Time scale:	To be completed 1 May, 2028
Activities:	1. Bid and let EPC contract 2. Detailed Engineering 3. Procurement 4. Construction 5. Commissioning and Startup
Scope:	1. Gas and liquid gathering trunk lines between Satellite 10 and RCF/CTB/CRP

3.6 CRP EPC Schedule:

Time scale:	To be completed Q3, 2019
Activities:	1. Bid and let EPC contract 2. Detailed Engineering 3. Procurement 4. Permitting and Regulatory Support 5. Construction 6. Training 7. Commissioning and Startup
Scope:	1. CRP (including NGL recovery and NRU) 2. Residue gas line to 3G 3. NGL line to 35R 4. Nitrogen line to 3G

3.7 CTB Phase II EPC Schedule:

Time scale:	1. Separator to be completed Q4, 2023 2. Rest of CTB Phase II to be completed Q2, 2025
Activities:	1. Let EPC contracts 2. Detailed Engineering 3. Procurement 4. Construction 5. Commissioning and Startup
Scope:	1. CTB – Additional Separator 2. CTB – phase 2

Appendices:

Appendix 1: High Level Schedule Summary (summarizing all Value Engineering, FEED and all EPC schedules).

Appendix 2: RCF, CTB Phase I and Satellites 1, 2 and 3.

Appendix 3: Typical Satellite for Satellites 4 through 13.

Appendix 4: Trunk lines concurrent with Satellite 4.

Appendix 5: Trunk lines concurrent with Satellite 10.

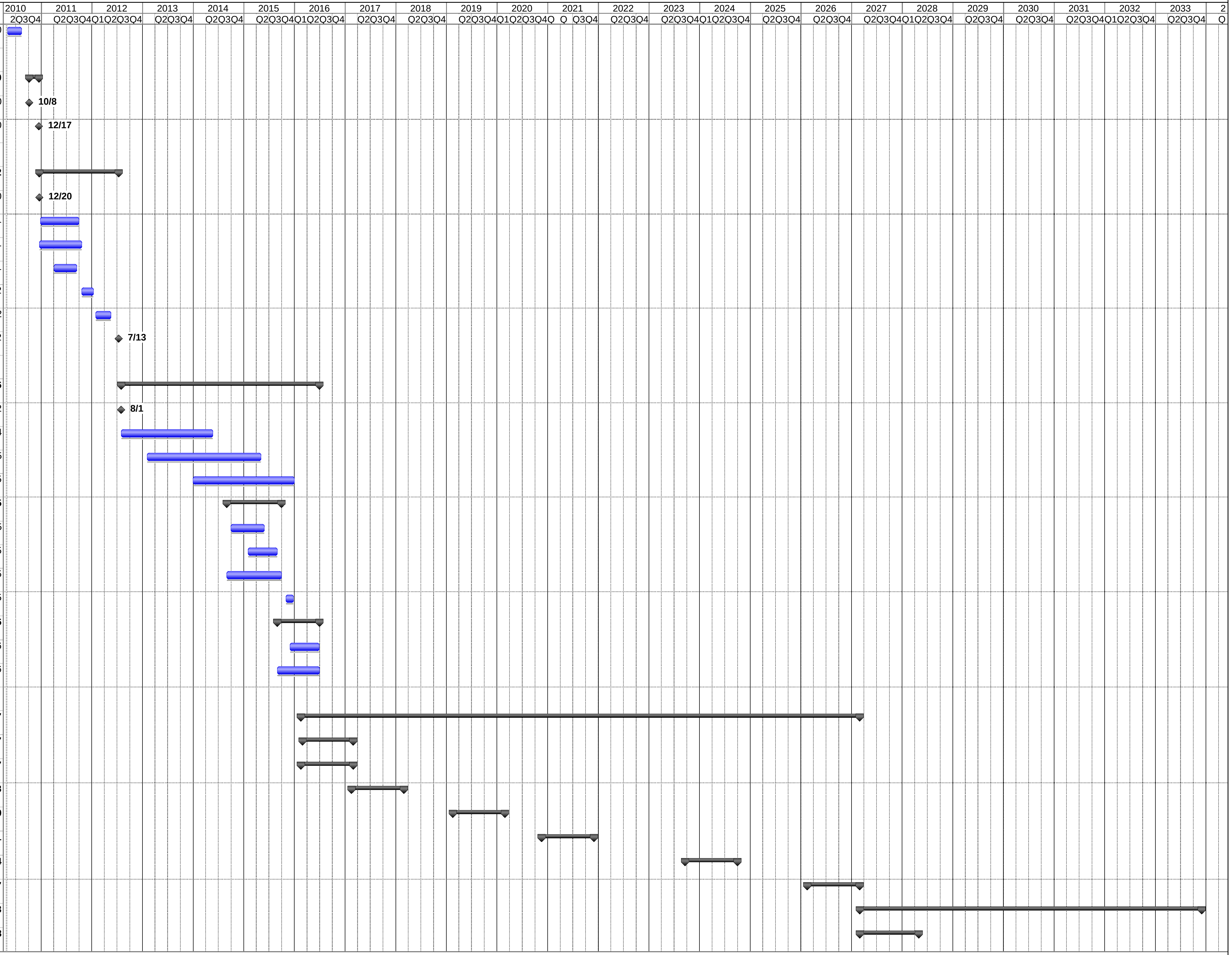
Appendix 6: CRP.

Appendix 7: CTB Phase II.

Occidental of Elk Hills, Inc.
Elk Hills CO2 Pre-FEED Engineering Study

Appendix 1 - High Level Summary Schedule
Rev A

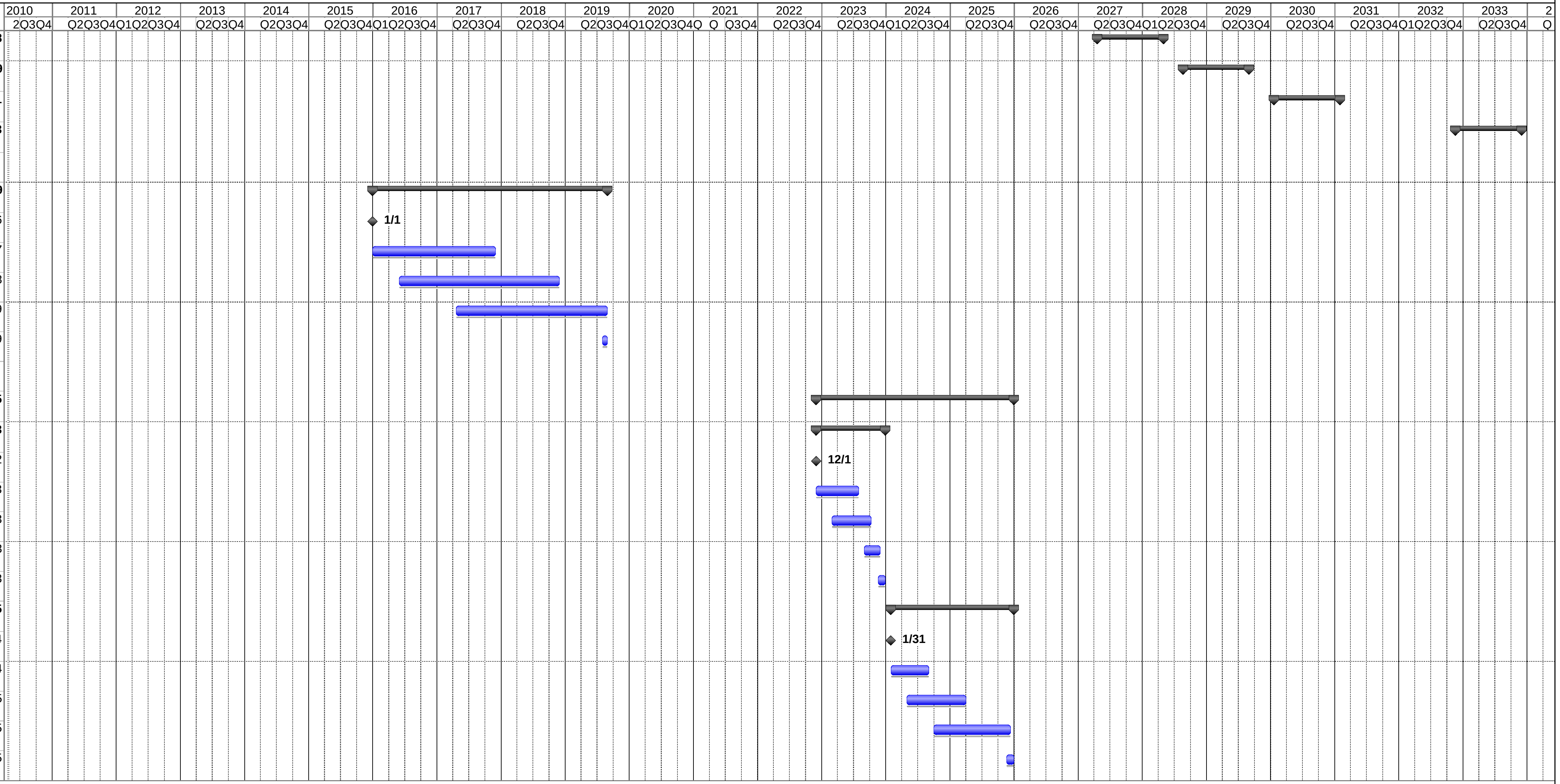
ID	Task Name	Duration	Start	Finish
1	**Pre-FEED PHASE 2 / VALUE ENGINEERING**	75 days?	May 3 '10	Aug 13 '10
2				
3	**Bid and Award FEED**	**50 days**	**Oct 8 '10**	**Dec 17 '10**
4	Bids received	0 days	Oct 8 '10	Oct 8 '10
5	Award FEED	0 days	Dec 17 '10	Dec 17 '10
6				
7	**FEED**	**410 days?**	**Dec 20 '10**	**Jul 13 '12**
8	Start FEED	0 days	Dec 20 '10	Dec 20 '10
9	Permitting and regulatory support	200 days?	Dec 27 '10	Sep 30 '11
10	FEED Egineering	220 days?	Dec 20 '10	Oct 21 '11
11	Environmental Surveys	118 days?	Apr 5 '11	Sep 15 '11
12	AFE Approval	61 days?	Oct 21 '11	Jan 13 '12
13	EPC Bid period	80 days?	Jan 30 '12	May 18 '12
14	Recommend EPC Contractor	0 days	Jul 13 '12	Jul 13 '12
15				
16	**EPC - RCF, CTB Phase I and Satellites 1-3**	**1022 days?**	**Aug 1 '12**	**Jun 30 '16**
17	Award EPC	0 days	Aug 1 '12	Aug 1 '12
18	Engineering	473 days?	Aug 1 '12	May 23 '14
19	Procurement	587 days?	Feb 4 '13	May 5 '15
20	Construction - RCF and CTB	522 days?	Jan 1 '14	Dec 31 '15
21	**Satellites 1 and 2 and trunklines**	**283 days?**	**Sep 1 '14**	**Sep 30 '15**
22	Construction Satellite 1	173 days?	Oct 1 '14	May 29 '15
23	Construction Satellite 2	151 days?	Feb 2 '15	Aug 31 '15
24	Satellite trunk and flowlines	283 days?	Sep 1 '14	Sep 30 '15
25	**Startup**	40 days?	Nov 2 '15	Dec 25 '15
26	**Satellite 3 and trunklines**	**218 days?**	**Sep 1 '15**	**Jun 30 '16**
27	Construction Satellite 3	151 days?	Dec 1 '15	Jun 28 '16
28	Satellite trunk and flowlines	218 days?	Sep 1 '15	Jun 30 '16
29				
30	**Satellites 4 to 9 with trunklines**	**2878 days?**	**Feb 18 '16**	**Mar 1 '27**
31	**Trunk lines for Satellites 4 to 9**	**262 days?**	**Mar 1 '16**	**Mar 1 '17**
33	**Satellite 4**	**270 days**	**Feb 18 '16**	**Mar 1 '17**
35	**Satellite 5**	**270 days**	**Feb 17 '17**	**Mar 1 '18**
37	**Satellite 6**	**270 days**	**Feb 18 '19**	**Feb 28 '20**
39	**Satellite 7**	**270 days**	**Nov 19 '20**	**Dec 1 '21**
41	**Satellite 8**	**270 days**	**Sep 20 '23**	**Oct 1 '24**
43	**Satellite 9**	**270 days**	**Feb 17 '26**	**Mar 1 '27**
45	**Satellites 10 to 13 with trunklines**	**1762 days?**	**Mar 3 '27**	**Dec 1 '33**
46	**Trunklines for Satellites 10 to 13**	**304 days?**	**Mar 3 '27**	**May 1 '28**



Project: Roll up of all schedules
Date: Apr 23 '10

Task	▬	Progress	▬	Summary	▬	External Tasks	▬	Deadline	⇩
Split	┈	Milestone	◆	Project Summary	▬	External Milestone	◆		

ID	Task Name	Duration	Start	Finish
48	**Satellite 10**	**270 days**	**Apr 20 '27**	**May 1 '28**
50	**Satellite 11**	**270 days**	**Aug 21 '28**	**Aug 31 '29**
52	**Satellite 12**	**270 days**	**Jan 21 '30**	**Jan 31 '31**
54	**Satellite 13**	**270 days**	**Nov 19 '32**	**Dec 1 '33**
56				
57	**EPC - CRP**	**955 days?**	**Jan 1 '16**	**Aug 29 '19**
58	Award EPC	0 days	Jan 1 '16	Jan 1 '16
59	Engineering	500 days?	Jan 1 '16	Nov 30 '17
60	Procurement	652 days?	Jun 1 '16	Nov 29 '18
61	Construction	615 days?	Apr 21 '17	Aug 29 '19
62	Startup	20 days?	Aug 2 '19	Aug 29 '19
63				
64	**CTB Phase 2**	**805 days?**	**Dec 1 '22**	**Dec 31 '25**
65	**Additional separator**	**282 days?**	**Dec 1 '22**	**Dec 29 '23**
66	Award EPC	0 days	Dec 1 '22	Dec 1 '22
67	Engineering	173 days?	Dec 1 '22	Jul 31 '23
68	Procurement	160 days?	Mar 1 '23	Oct 10 '23
69	Construction	65 days?	Sep 1 '23	Nov 30 '23
70	Startup	30 days	Nov 20 '23	Dec 29 '23
71	**Additional CTB tanks, pumps, etc.**	**501 days?**	**Jan 31 '24**	**Dec 31 '25**
72	Award EPC	0 days	Jan 31 '24	Jan 31 '24
73	Engineering	153 days?	Feb 1 '24	Sep 2 '24
74	Procurement	240 days?	May 1 '24	Apr 1 '25
75	Construction	313 days?	Oct 1 '24	Dec 11 '25
76	Startup	30 days	Nov 20 '25	Dec 31 '25



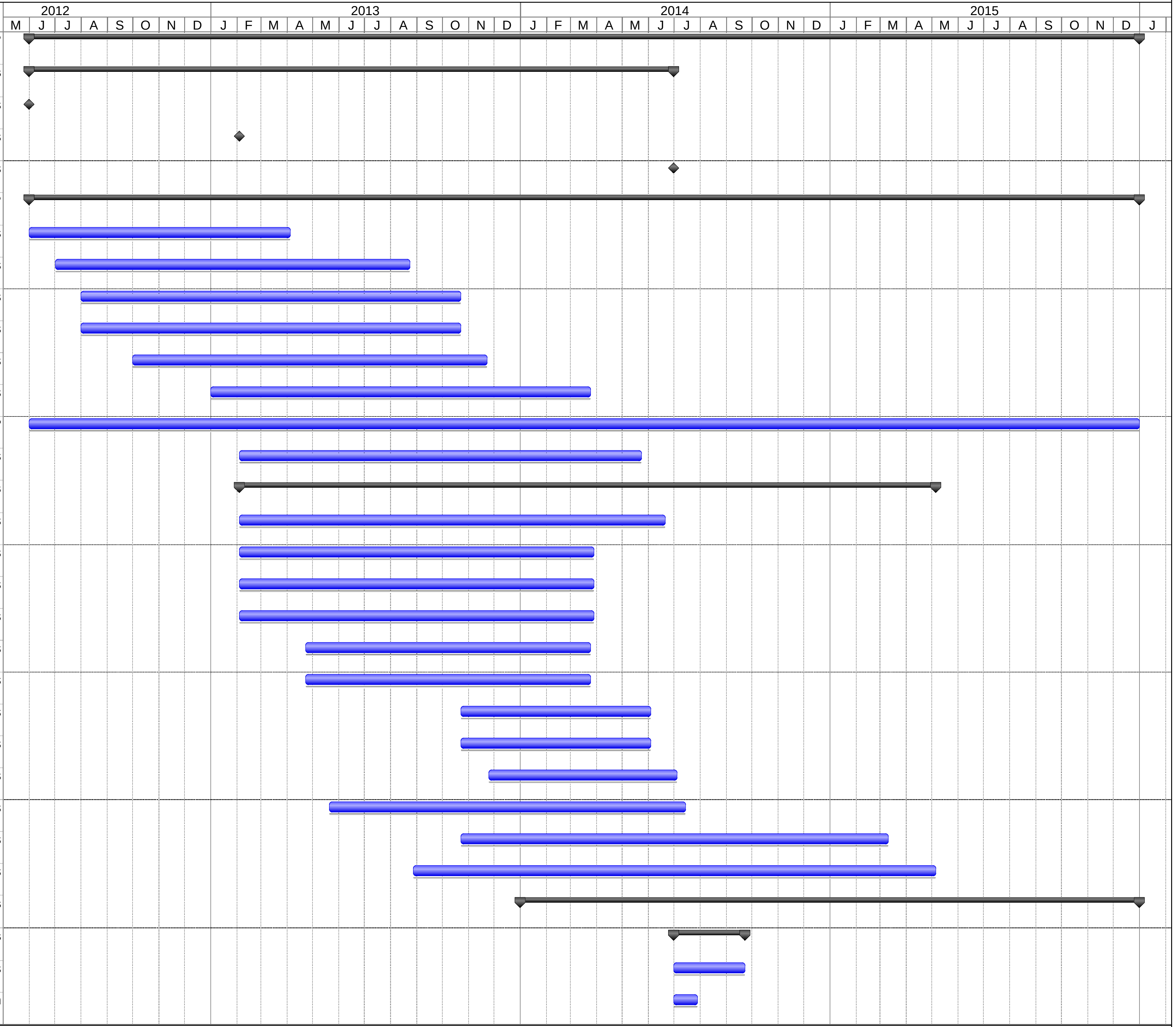
Project: Roll up of all schedules
Date: Apr 23 '10

Task
Split
Progress
Milestone ◆
Summary
Project Summary
External Tasks
External Milestone ◆
Deadline ⇩

Occidental of Elk Hills, Inc.
Elk Hills CO2 Pre-FEED Engineering Study

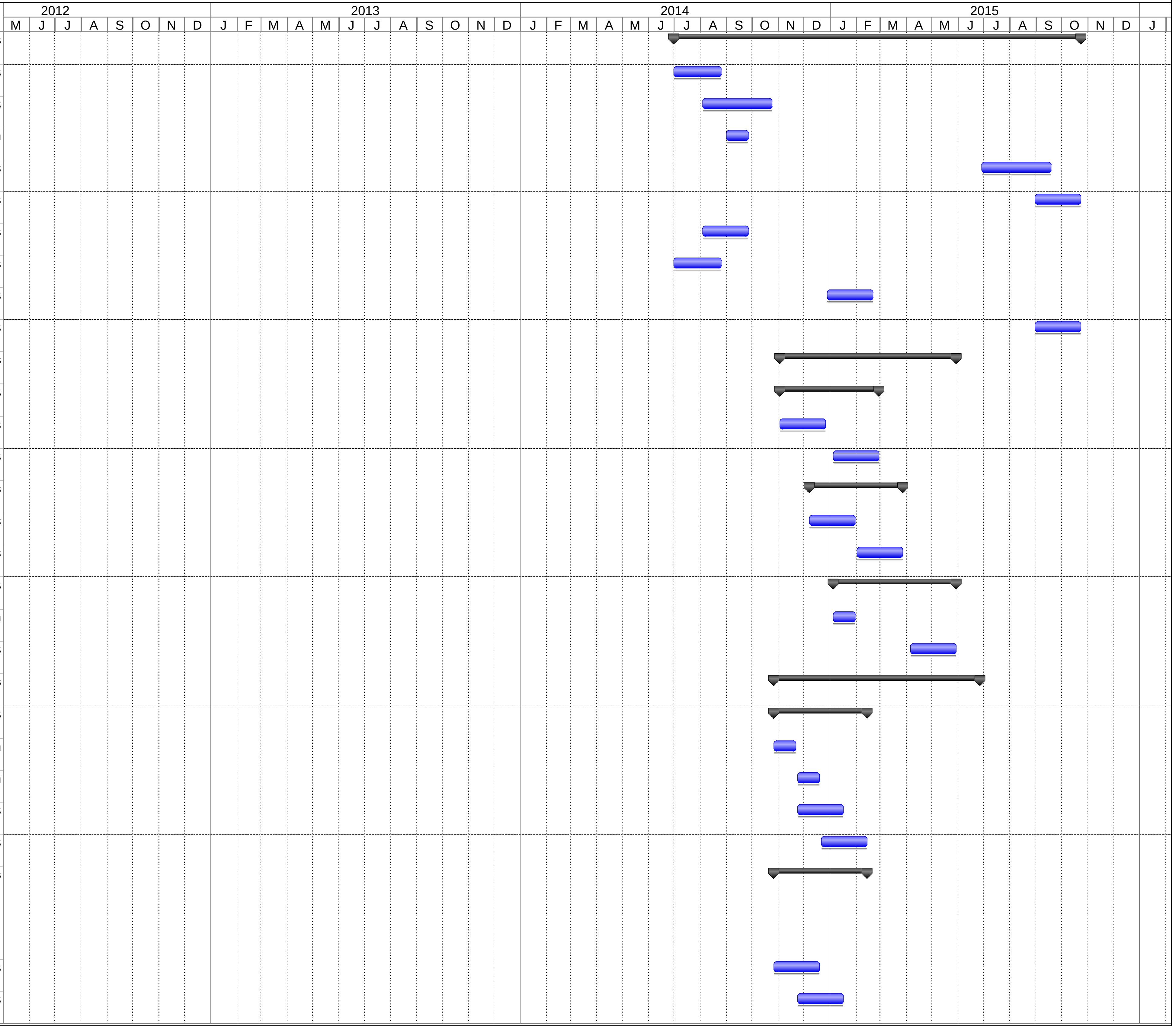
Appendix 2 - RCF, CTB Ph I & Satellites 1, 2 & 3 Schedule
Rev A

ID	Task Name	Duration
1	**RCF and CTB EPC Project**	**46.75 mons?**
2	**Milestones**	**27.1 mons**
3	Let EPC Contract	0 mons
4	Let Long-Lead RFQs	0 mons
5	Let Construction Contract	0 mons
6	**Detail Engineering**	**46.75 mons?**
7	Process Engineering	11 mons
8	Mech & Facilities Engineering	15 mons
9	Piping Eng & Design	16 mons
10	Pipeline Eng & Design	16 mons
11	Civil & Structural Eng & Design	15 mons
12	Electrical Eng & Design	16 mons
13	Permitting and Regulatory Support	46.75 mons?
14	Instrument & Automation Eng & Design	17 mons
15	**Procurement**	**29.35 mons**
16	Purch & Delv - Compressors	18 mons
17	Purch & Delv - Exchangers	15 mons
18	Purch & Delv - Vessels	15 mons
19	Purch & Delv - Pumps	15 mons
20	Purch & Delv - Buildings	12 mons
21	Purch & Delv - Electrical Equipment	12 mons
22	Purch & Delv - Rack Piping	8 mons
23	Purch & Delv - Fabricated Piping	8 mons
24	Purch & Delv - Steel	8 mons
25	Purch & Delv - Instruments & DCS	15 mons
26	Purch & Delv - Line Pipe, Valves, Fittings	18 mons
27	Purch & Delv - Misc. Equip & Bulks	22 mons
28	**Construction - RCF, CTB, Satellites & Utilities**	**26.1 mons**
29	**Mobilize Contractor**	**3 mons**
30	Set-up Onsite Construction Offices & Temp Warehouse	3 mons
31	Set Temporary Power	1 mon



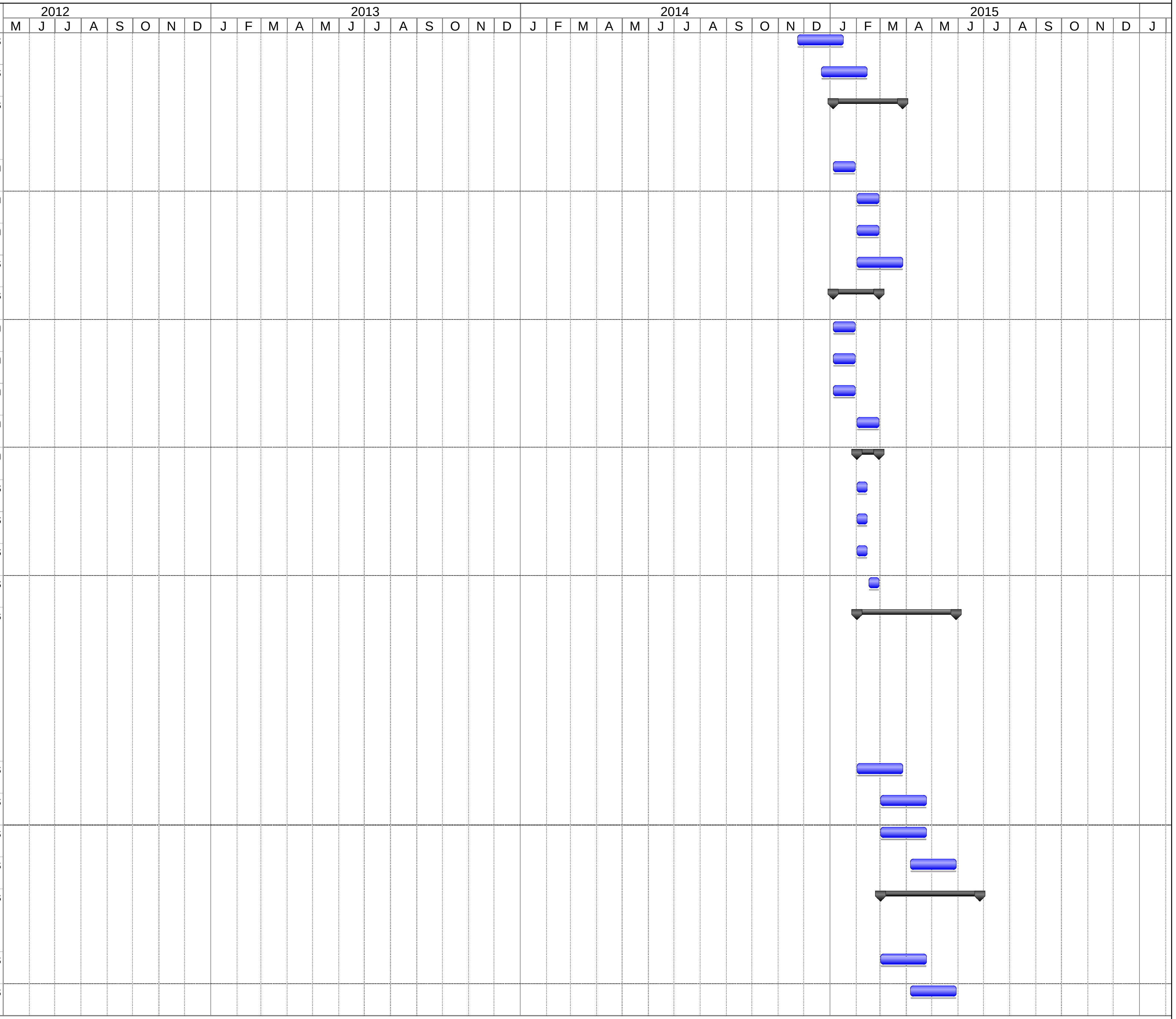
Task	▬	Milestone	◆	Rolled Up Task	▬	Rolled Up Progress	▬	External Tasks	▬	Group By Summary	▬
Progress	▬	Summary	▬	Rolled Up Milestone	◇	Split	┄	Project Summary	▬	Deadline	⇩

ID	Task Name	Duration
32	**Site Excavation Activities**	**17.2 mons**
33	Clear and Grubbing Surface	2 mons
34	Cut, Fill, & Compaction	3 mons
35	Temporary Site Drainage	1 mon
36	Permanent Site drainage	3 mons
37	Final Grade	2 mons
38	Install Perimeter Fence	2 mons
39	Build Main Entrance Road	2 mons
40	Build In-Plant Roads - Initial	2 mons
41	Build In-Plant Roads - Final	2 mons
42	**Construct Buildings**	**7.5 mons**
43	**Admin/Control Room/MCC**	**4.25 mons**
44	Excavate, Form, Steel , Pour Concrete, Cure	2 mons
45	Set Building & Finish Out	2 mons
46	**Maintenance/Warehouse**	**4 mons**
47	Excavate, Form, Steel, Pour Concrete, Cure	2 mons
48	Erect Building & Finish Out	2 mons
49	**Compressor Shelter**	**5.25 mons**
50	Excavate, Form, Steel, Pour Concrete, Cure	1 mon
51	Erect Building & Finish Out	2 mons
52	**Equipment Foundations**	**8.75 mons**
53	**Main Compressors #1 #2 & #3**	**4 mons**
54	Excavate	1 mon
55	Set Forms	1 mon
56	Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	2 mons
57	Pour Concrete & Cure (28 days)	2 mons
58	**1st & 2nd Stage KO Drum, Coalescer, Inlet Gas Separator, Inlet Gas Filter, Inlet Gas Separator, 1st & 2nd Stage Aftercoolers (4)**	**4 mons**
59	Excavate	2 mons
60	Set Forms	2 mons



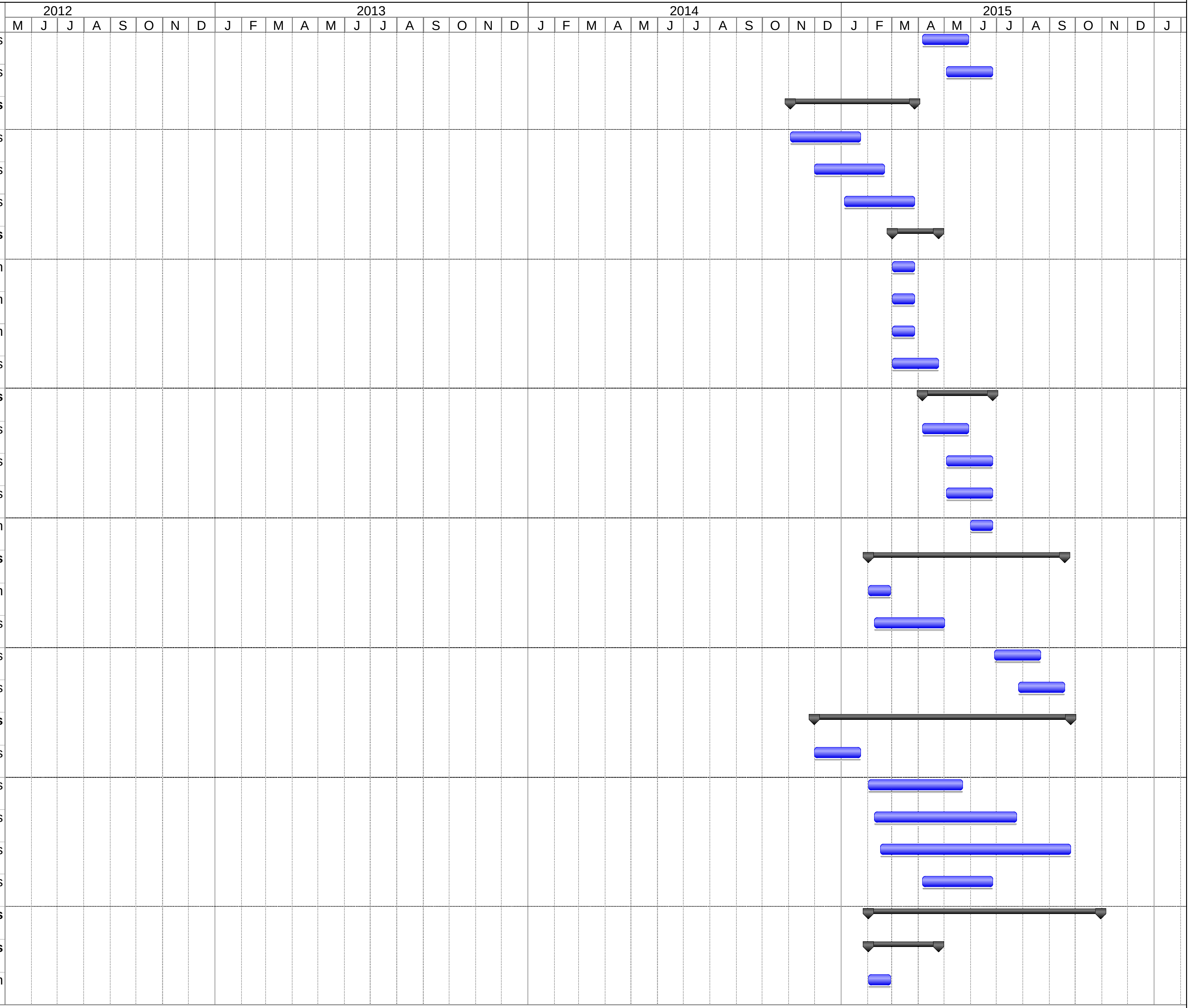
Task		Milestone	◆	Rolled Up Task		Rolled Up Progress		External Tasks		Group By Summary	
Progress		Summary		Rolled Up Milestone	◇	Split		Project Summary		Deadline	⇩

ID	Task Name	Duration
61	Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	2 mons
62	Pour Concrete & Cure	2 mons
63	**Gas/Glycol Exchanger, TEG Regeneration Package, TEG Contactor**	**3 mons**
64	Excavate	1 mon
65	Set Forms	1 mon
66	Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	1 mon
67	Pour Concrete & Cure	2 mons
68	**LP Compressor (2) & VRU (2),**	**2 mons**
69	Excavate	1 mon
70	Set Forms	1 mon
71	Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	1 mon
72	Pour Concrete & Cure	1 mon
73	**Firewater Pumps & Tanks**	**1 mon**
74	Excavate	2 wks
75	Set Forms	2 wks
76	Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	2 wks
77	Pour Concrete & Cure	2 wks
78	**Flare, Flare Scrubber & Pump, Water Injection Pumps (3), Water Recirculation Pump, LACT Unit Pumps (2), Booster Pumps (3), Filter Charge Pumps (Filter), Filter Charge Pumps, Backwash/Cone Barrel Tank, Walnut Shell Filters, Flotation Cell (3), Water Inject**	**4.25 mons**
79	Excavate	2 mons
80	Set Forms	2 mons
81	Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	2 mons
82	Pour Concrete & Cure	2 mons
83	**Solids Removal Package, Free Water Knock Out (2), Flume & Blanket Gas Scrubber, Oil Tanks (2), Water Tanks (2)**	**4.25 mons**
84	Excavate	2 mons
85	Set Forms	2 mons



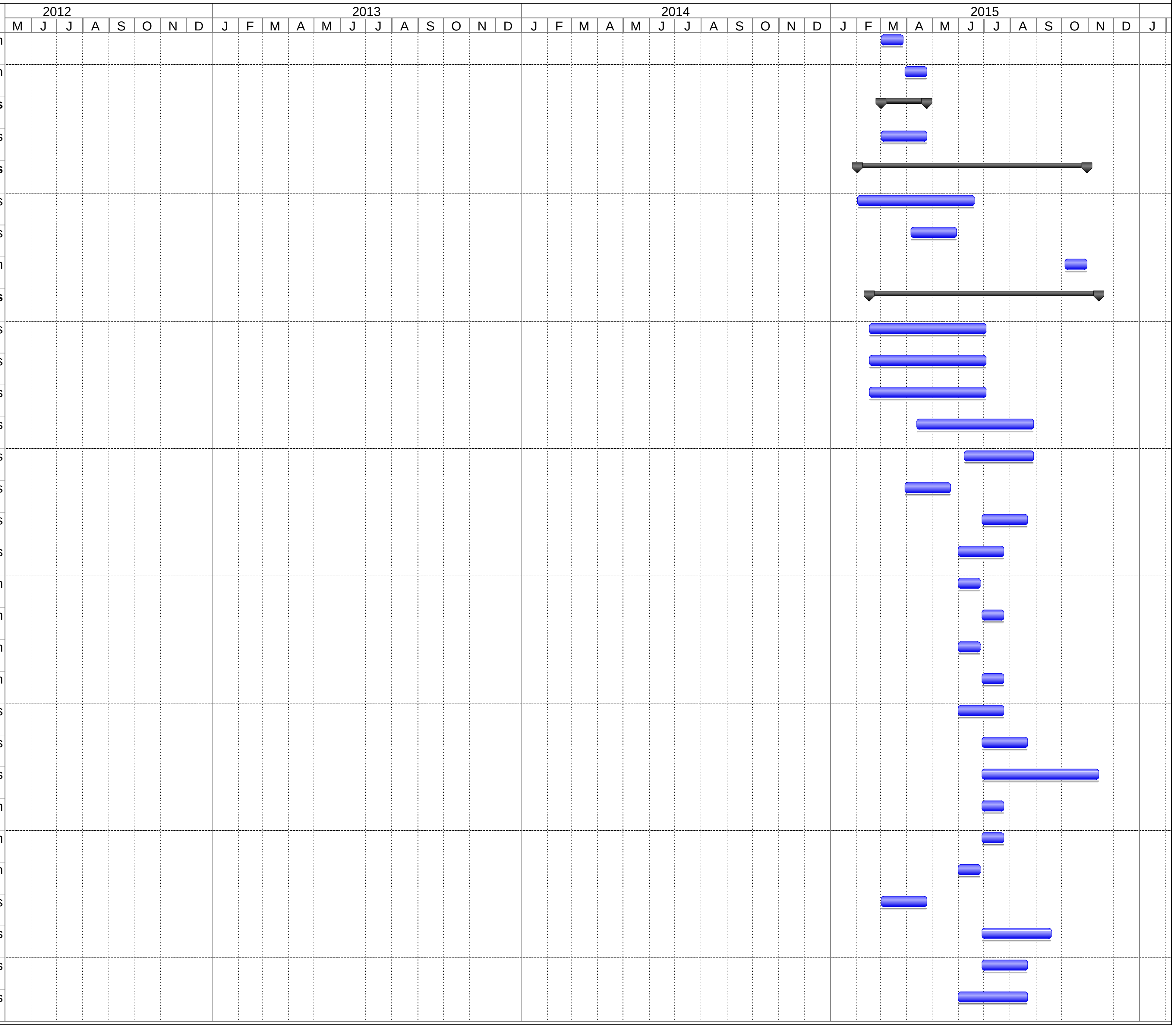
Task		Milestone	◆	Rolled Up Task		Rolled Up Progress		External Tasks		Group By Summary	
Progress		Summary		Rolled Up Milestone	◇	Split		Project Summary		Deadline	⇩

ID	Task Name	Duration
86	Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	2 mons
87	Pour Concrete & Cure	2 mons
88	**Pipe Sleepers & Light Poles**	**5.25 mons**
89	Drill Piers	3 mons
90	Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	3 mons
91	Pour Concrete & Cure	3 mons
92	**Utilities/Air Compressor**	**2 mons**
93	Excavate	1 mon
94	Set Forms	1 mon
95	Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	1 mon
96	Pour Concrete & Cure	2 mons
97	**Electrical Transmission Yard & Transformer Pads**	**3 mons**
98	Excavate	2 mons
99	Set Forms	2 mons
100	Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	2 mons
101	Pour Concrete & Cure	1 mon
102	**Underground Piping**	**8.25 mons**
103	Excavation Ditch for Underground Pipe	1 mon
104	Fabricate and Install Underground Drains	3 mons
105	Tie-in Underground Drains	2 mons
106	Backfill	2 mons
107	**Pipe Racks & Piping**	**10.75 mons**
108	Receive Racks Onsite	2 mons
109	Assemble Racks & Install	4 mons
110	Receive Fabricated Spools & Install Piping	6 mons
111	Install Equipment Interconnect Piping	8 mons
112	Install Cable Tray	3 mons
113	**Electrical Scope**	**9.75 mons**
114	**Transmission Yard**	**3 mons**
115	Assemble & Set Structure	1 mon



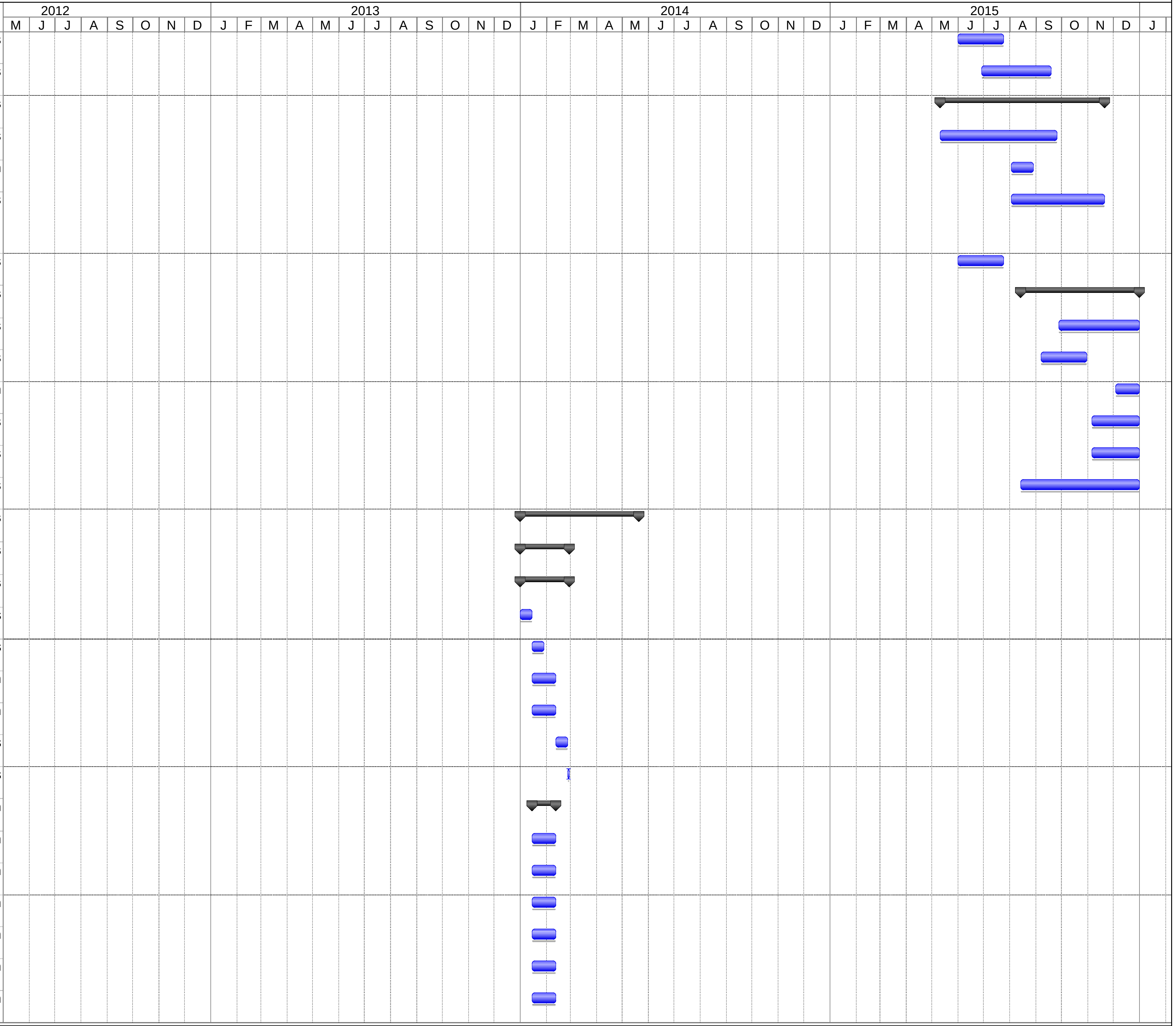
Task	▬	Milestone	◆	Rolled Up Task	▬	Rolled Up Progress	▬	External Tasks	▬	Group By Summary	▬
Progress	▬	Summary	▬	Rolled Up Milestone ◇		Split	┈	Project Summary	▬	Deadline	⇩

ID	Task Name	Duration
116	Install Supports & Cable	1 mon
117	Install Security Fence	1 mon
118	**Transformers**	**2 mons**
119	Set Transformers	2 mons
120	**Grounding Grid**	**9.75 mons**
121	Excavate, Install Grounding Cable, Backfill & Connect to Equip.	5 mons
122	Drill Ground Wells	2 mons
123	Connect to Equipment	1 mon
124	**Equipment Installation, Tie-in Piping**	**9.75 mons**
125	Set #1 Compressor, Grout & Tie-in	5 mons
126	Set #2 Compressor, Grout & Tie-in	5 mons
127	Set #3 Compressor, Grout & Tie-in	5 mons
128	Set Aftercoolers & Tie-in Piping	5 mons
129	Set & Tie-in Inlet Gas Separator, Coalescer, Gas Filter & KO Drums	3 mons
130	Set TEG System & Tie-in Piping	2 mons
131	Set Lube Oil Storage Tank & Lube Oil Transfer Pump	2 mons
132	Set Oil Pumps (Booster & LACT Unit Pumps)	2 mons
133	Set Water Injection & Recirculation Pumps	1 mon
134	Set Firewater Pumps (2)	1 mon
135	Set Closed & Open Drain Pumps	1 mon
136	Set Potable Water System (Pumps & Tank) & Tie-in	1 mon
137	Set Filter Charge Pumps (3) & Filter Charge Pumps Filter	2 mons
138	Set Gunbarrel Tank, Backwash / Cone Barrel Tank & Tie-in	2 mons
139	Construct Tanks on Site (Oil & Water) and Tie-in	5 mons
140	Firewater Storage Tanks	1 mon
141	Set Prefabricated Tanks	1 mon
142	Set Flare, Scrubber & Pump	1 mon
143	Set VRU & LP Compressor	2 mons
144	Set Free Water Knock Out Vessel & Tie-in	3 mons
145	Set Free Water Knock Out	2 mons
146	Set Flotation Cells	3 mons



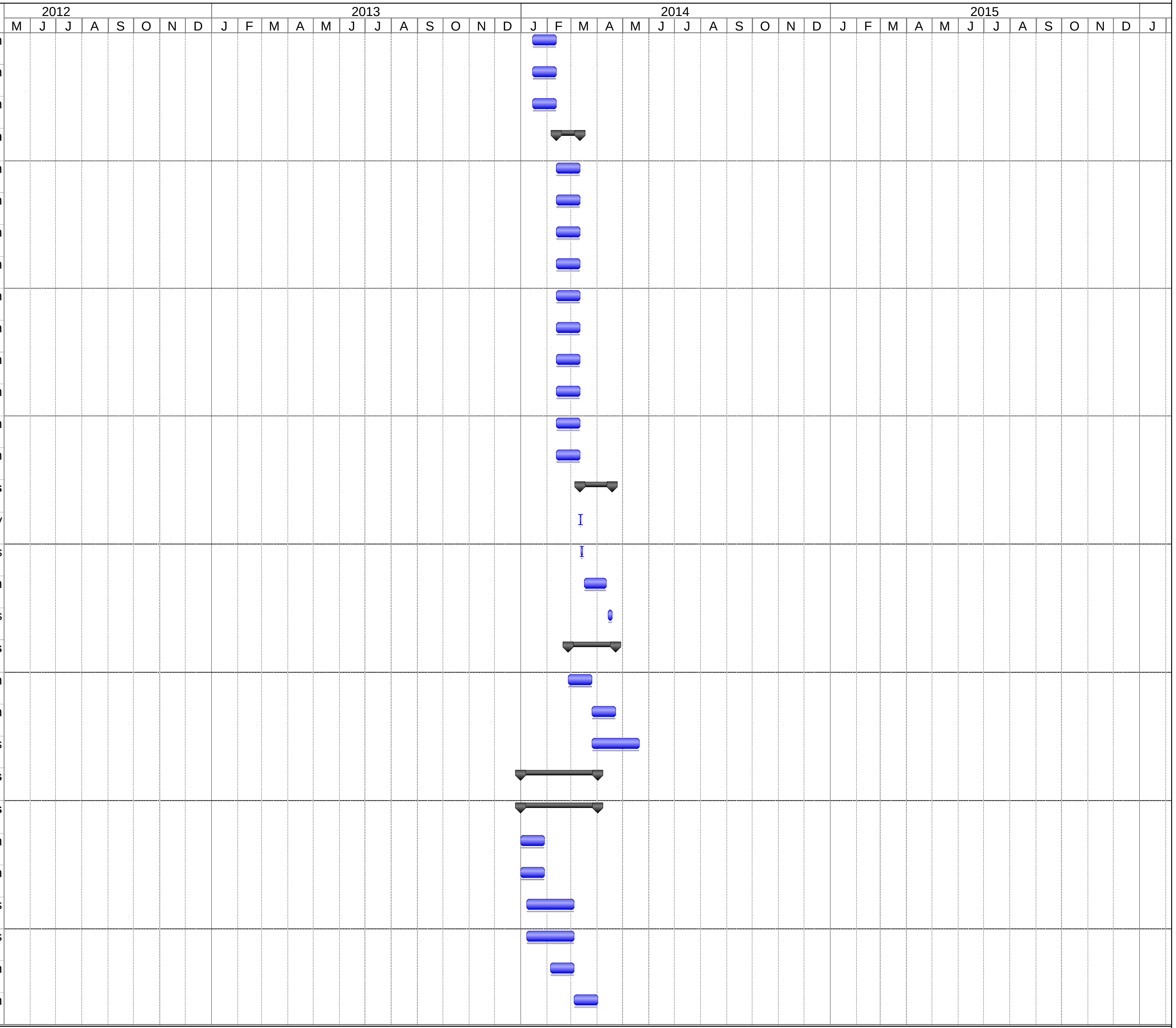
Task	Milestone ◆	Rolled Up Task	Rolled Up Progress	External Tasks	Group By Summary
Progress	Summary	Rolled Up Milestone ◇	Split	Project Summary	Deadline ⇩

ID	Task Name	Duration
147	Set Walnut Shell Filters & Tie-in	2 mons
148	Solids Removal Package	3 mons
149	**Install Electrical & Control Cables**	**7 mons**
150	Place all Cables Into Tray	5 mons
151	Megger HV Cables	1 mon
152	Connect Electrical Cables to Switchgear & Equipment, Check Rotation of Motors	4 mons
153	Install Light Poles and Tie-in Power	2 mons
154	**Pre-Commission / Commission Facility**	**5 mons**
155	Flush Piping, Connect to Equip, Install Strainers	3.45 mons
156	Loop Check Control Cables & Function Test End Devices	2 mons
157	Purge Piping	1 mon
158	Final Equipment Check-out	2 mons
159	Introduce Co2 to Facility	2 mons
160	Punch List & Start-up Activities	5 mons
161	**Satellite #1**	**5 mons**
162	**Civil**	**2.1 mons**
163	**Site Excavation Activities**	**2.1 mons**
164	Clear and Grubbing Surface	10 days
165	Cut/Fill/Compaction	10 days
166	Perimeter Fence	1 mon
167	Entrance Road - initial	1 mon
168	Entrance Road - final	10 days
169	Build Plant Roads	2 days
170	**Equipment Foundations**	**1 mon**
171	Vent Stack / Vent Tank	1 mon
172	Production Separator	1 mon
173	Test Separator	1 mon
174	Instrument Air Skid	1 mon
175	Chemical Injection Skid	1 mon
176	Producing Wells Manifold	1 mon



Task		Milestone	◆	Rolled Up Task		Rolled Up Progress		External Tasks		Group By Summary	
Progress		Summary		Rolled Up Milestone	◇	Split		Project Summary		Deadline	⇩

ID	Task Name	Duration
177	Injection Wells Manifold	1 mon
178	Control Building	1 mon
179	Perimeter Lighting	1 mon
180	**Set Equipment**	**1 mon**
181	Vent Stack / Vent Tank	1 mon
182	Production Separator	1 mon
183	Test Separator	1 mon
184	Instrument Air Skid	1 mon
185	Chemical Injection Skid	1 mon
186	Producing Wells Manifold	1 mon
187	Injection Wells Manifold	1 mon
188	Control Building	1 mon
189	Transformer	1 mon
190	Perimeter Lighting Poles	1 mon
191	**Inst & Elect**	**1.4 mons**
192	Set Feeder Poles	1 day
193	Install Feeder to Electrical Rack	2 days
194	Install Control Cable &Loop Check/Function test End Devices	1 mon
195	Install Perimeter Lighting Cable	5 days
196	**Piping**	**2 mons**
197	Fabricate Piping Spools Offsite	1 mon
198	Receive Piping Spools & Install	1 mon
199	Pre-commission / Commission	2 mons
200	**Pipelines**	**3.25 mons**
201	**Flowlines from Producing Wells**	**3.25 mons**
202	Clear ROW	1 mon
203	Road Bore / Cut Road Install Section	1 mon
204	Ditching & String Pipe	2 mons
205	Weld, Backfill & Test	2 mons
206	Tie-in's	1 mon
207	Commission	1 mon



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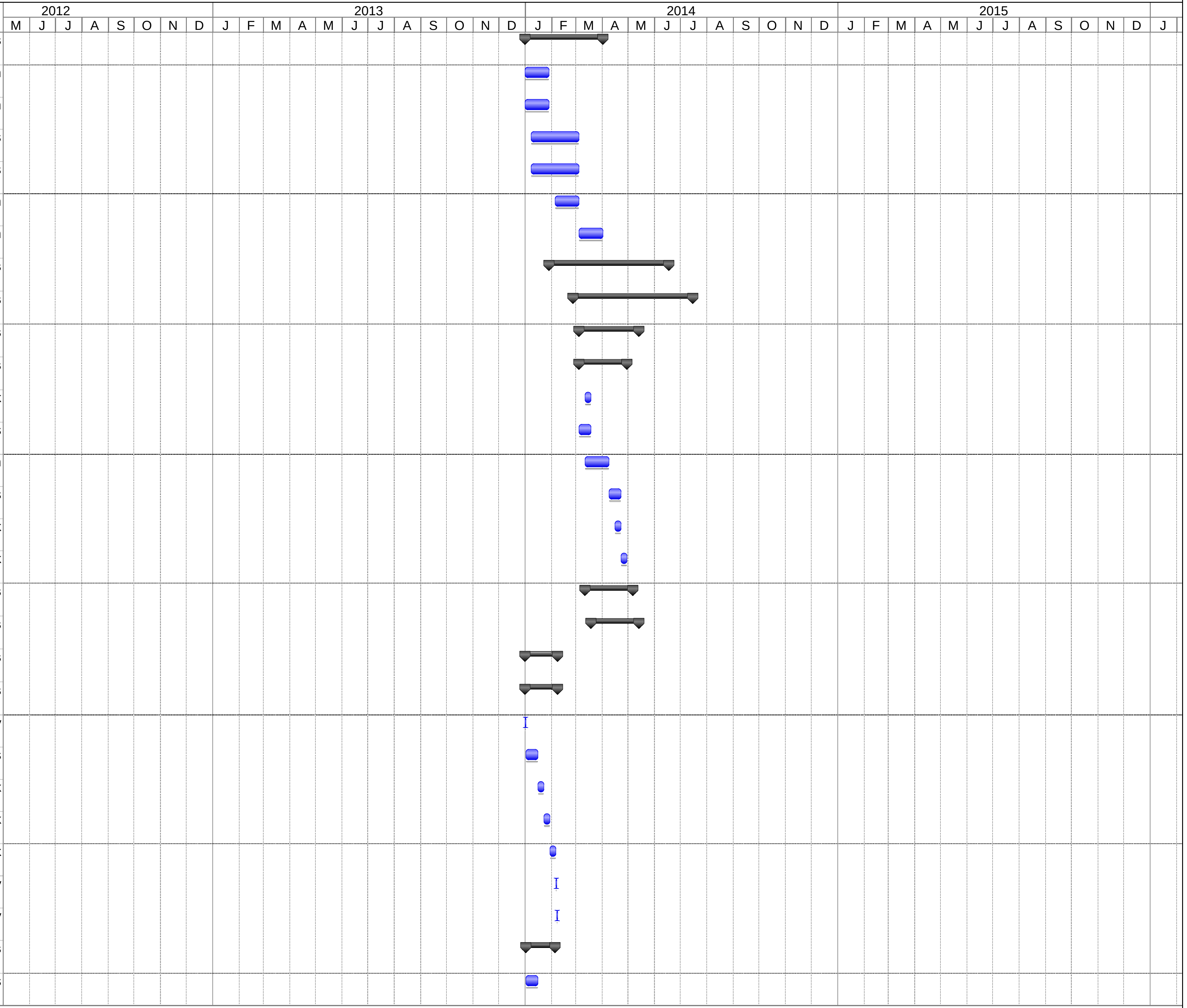
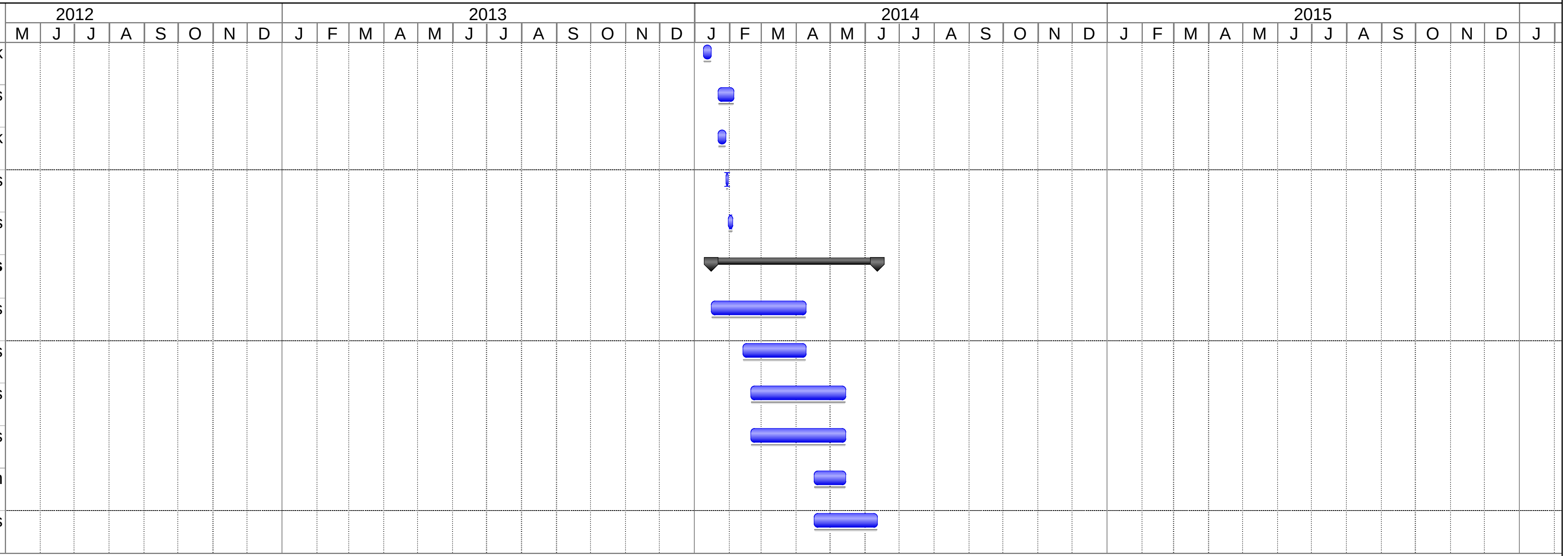
External Tasks
Project Summary
Group By Summary
Deadline ⇩

ID	Task Name	Duration
208	**Flowlines to Injection Wells**	**3.25 mons**
209	Clear ROW	1 mon
210	Road Bore / Cut Road Install Section	1 mon
211	Ditching & String Pipe	2 mons
212	Weld, Backfill & Test	2 mons
213	Tie-in's	1 mon
214	Commission	1 mon
215	**Satellite #2 - See Satellite 1 for details**	**5 mons**
269	**Satellite #3 - See Satellite 1 for details**	**5 mons**
323	**Construction - Satellite 1,2,3 Trunklines & Flowlines**	**2.5 mons**
324	**Satellite #1 Pipelines to and From RCF & CTB**	**2 mons**
325	Clear ROW & Cut Fence Gaps	1 wk
326	Road Bore / Cut Road Install Section	2 wks
327	Ditching & String Pipe	1 mon
328	Weld, Backfill & Test	2 wks
329	Tie-in's	1 wk
330	Commission	1 wk
331	**Satellite #2 Pipelines to and From RCF & CTB - See Satellite 1 for details**	**2 mons**
338	**Satellite #3 Pipelines to and From RCF & CTB - See Satellite 1 for details**	**2 mons**
345	**Construction - CO2 & Fuel Gas Pipelines to A1A2**	**1.4 mons**
346	**CO2 Pipeline to A1A2 Storage**	**1.4 mons**
347	Moblize Contractor	1 day
348	Clear ROW & Cut Fence Gaps	2 wks
349	Road Bore / Cut Road Install Section	1 wk
350	Ditching & String Pipe	1 wk
351	Weld, Backfill & Test	1 wk
352	Tie-in's	1 day
353	Commission	1 day
354	**Fuel Gas to A1A2**	**1.2 mons**
355	Clear ROW & Cut Fence Gaps	2 wks



Task	▬	Milestone	◆	Rolled Up Task	▬	Rolled Up Progress	▬	External Tasks	▬	Group By Summary	▬
Progress	▬	Summary	▬	Rolled Up Milestone	◇	Split	┈	Project Summary	▬	Deadline	⇩

ID	Task Name	Duration
356	Road Bore / Cut Road Install Section	1 wk
357	Ditching & String Pipe	2 wks
358	Weld, Backfill & Test	1 wk
359	Tie-in's	2 days
360	Commission	2 days
361	**Construction - Fiber Optics**	**5.25 mons**
362	Clear ROW & Cut Fence Gaps	3 mons
363	Road Bore / Cut Road Install Section	2 mons
364	Ditching & String Pipe	3 mons
365	Weld, Backfill & Test	3 mons
366	Tie-in's	1 mon
367	Commission	2 mons



Task	Milestone ◆	Rolled Up Task	Rolled Up Progress	External Tasks	Group By Summary
Progress	Summary	Rolled Up Milestone ◇	Split	Project Summary	Deadline ⇩

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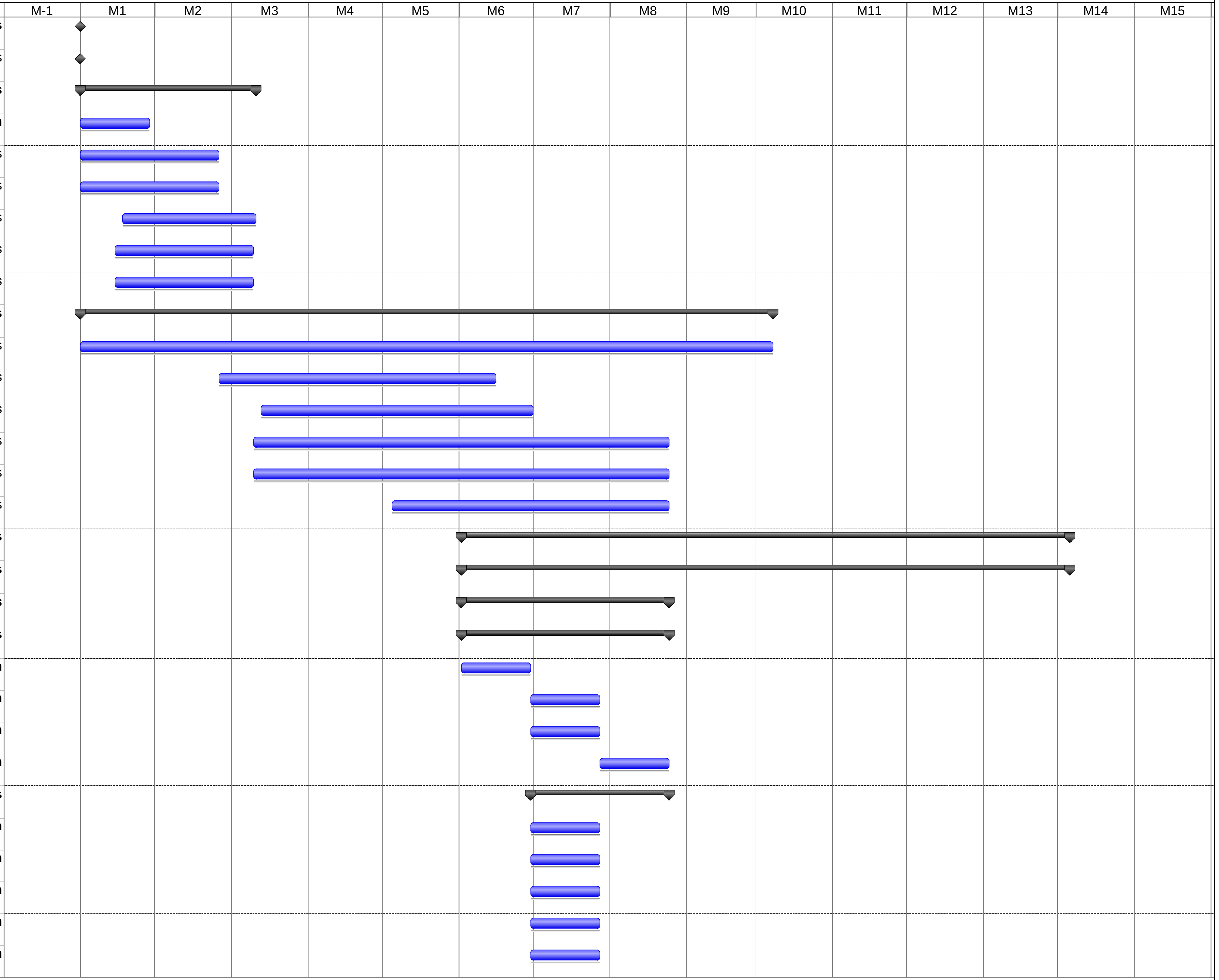
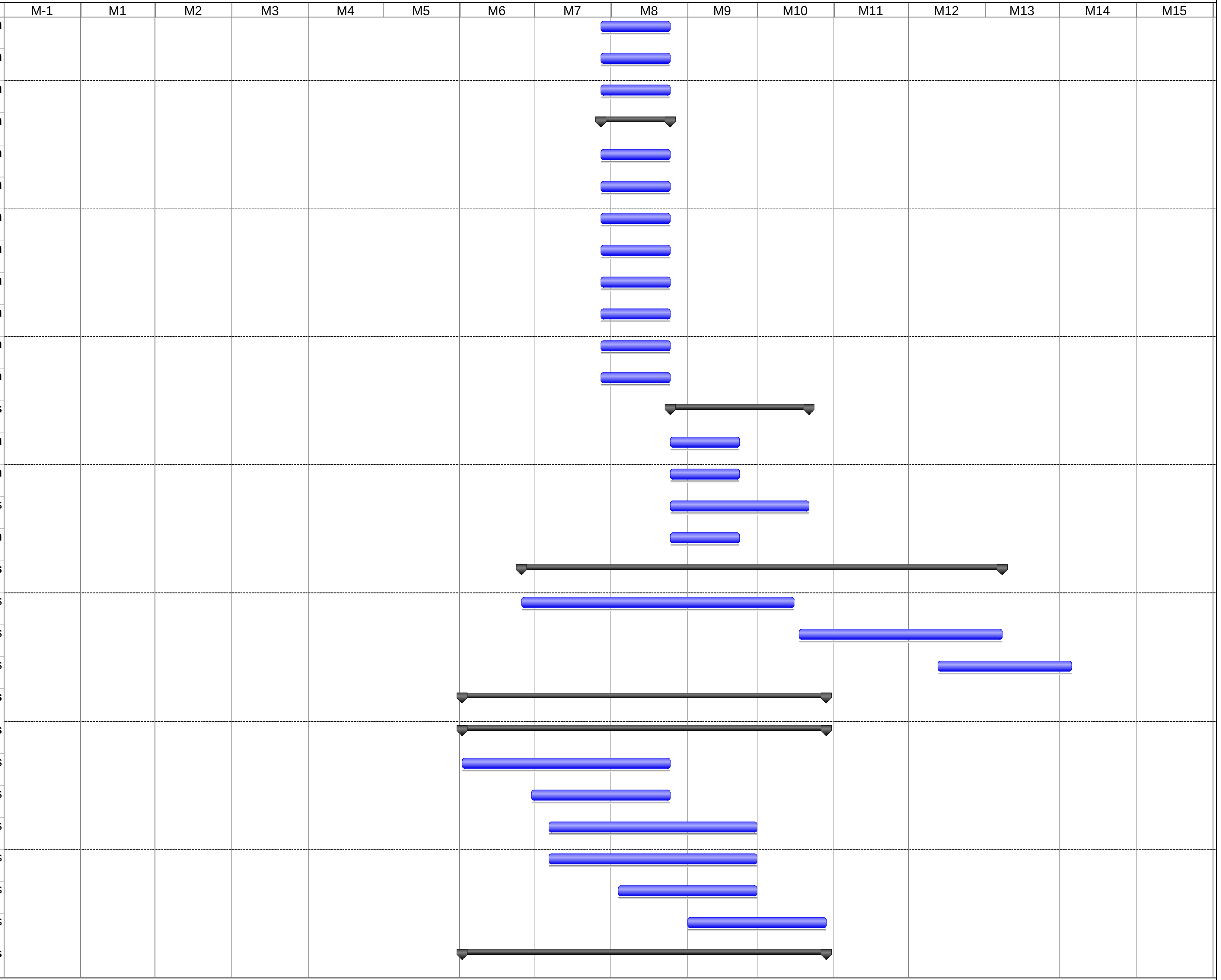
Appendix 3 - Typical Satellite for Satellites 4 to 13
Rev A

ID	Task Name	Duration
1	**Milestones**	**0 mons**
2	Bid & Let EPC Contract	0 mons
3	**Detail Engineering**	**2.55 mons**
4	Process Engineering	1 mon
5	Mech & Facilities Engineering	2 mons
6	Piping Eng & Design	2 mons
7	Civil/Structural Eng & Design	2 mons
8	Electrical Eng & Design	2 mons
9	Instrument & Automation Eng & Design	2 mons
10	**Procurement**	**10 mons**
11	Purch & Delv - Vessels	10 mons
12	Purch & Delv - Fabricated Piping	4 mons
13	Purch & Delv - Steel	4 mons
14	Purch & Delv - Electrical Equipment	6 mons
15	Purch & Delv - Instruments	6 mons
16	Purch & Delv - Bulks	4 mons
17	**Construction**	**8.8 mons**
18	**Satellite**	**8.8 mons**
19	**Civil**	**3 mons**
20	**Site Excavation Activities**	**3 mons**
21	Clear and Grubbing Surface	1 mon
22	Cut/Fill/Compaction	1 mon
23	Entrance Road - initial	1 mon
24	Entrance Road - final	1 mon
25	**Equipment Foundations**	**2 mons**
26	Vent Stack / Vent Tank	1 mon
27	Production Separator	1 mon
28	Test Separator	1 mon
29	Instrument Air Skid	1 mon
30	Chemical Injection Skid	1 mon



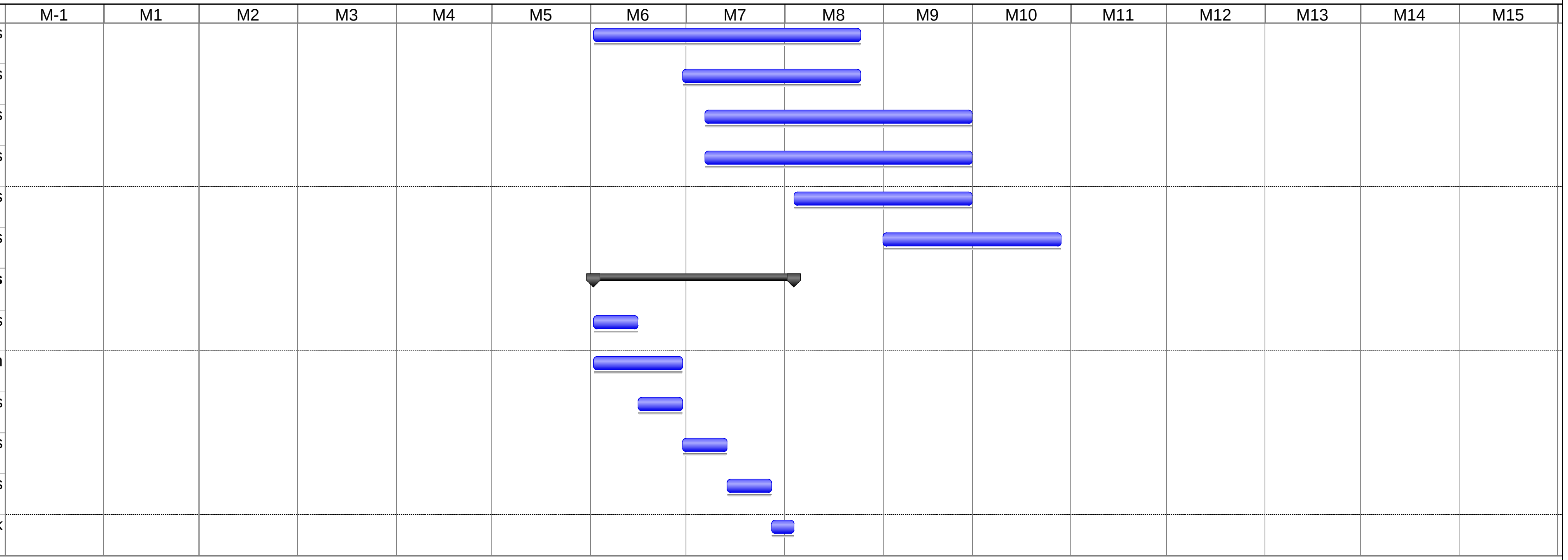
Task	▬	Progress	▬	Summary	▬	External Tasks	▬	Deadline	⇩
Split	┈	Milestone	◆	Project Summary	▬	External Milestone	◆		

ID	Task Name	Duration
31	Producing Wells Manifold	1 mon
32	Injection Wells Manifold	1 mon
33	Perimeter Lighting	1 mon
34	**Set Equipment**	**1 mon**
35	Vent Stack / Vent Tank	1 mon
36	Production Separator	1 mon
37	Test Separator	1 mon
38	Instrument Air Skid	1 mon
39	Chemical Injection Skid	1 mon
40	Producing Wells Manifold	1 mon
41	Injection Wells Manifold	1 mon
42	Perimeter Lighting Poles	1 mon
43	**Inst & Elect**	**2 mons**
44	Set Feeder Poles	1 mon
45	Install Feeder to Switchrack	1 mon
46	Install Control Cable, Loop Check, & Function Test End Devices	2 mons
47	Install Perimeter Lighting Cable	1 mon
48	**Piping**	**7 mons**
49	Fabricate Piping Spools Offsite	4 mons
50	Receive Piping Spools & Install	3 mons
51	Pre-commission / Commission	2 mons
52	**Pipelines**	**5.25 mons**
53	**Flowlines from Producing Wells**	**5.25 mons**
54	Clear ROW	3 mons
55	Road Bore / Cut Road Install Section	2 mons
56	Ditching & String Pipe	3 mons
57	Weld, Backfill & Test	3 mons
58	Tie-in's	2 mons
59	Commission	2 mons
60	**Flowlines to Injection Wells**	**5.25 mons**



Task	▬	Progress	▬	Summary	▬	External Tasks	▬	Deadline	⇩
Split	⋯	Milestone	◆	Project Summary	▬	External Milestone	◇		

ID	Task Name	Duration
61	Clear ROW & Cut Fence Gaps	3 mons
62	Road Bore / Cut Road Install Section	2 mons
63	Ditching & String Pipe	3 mons
64	Weld, Backfill & Test	3 mons
65	Tie-in's	2 mons
66	Commission	2 mons
67	**Satellite Laterals to Trunklines**	**2.25 mons**
68	Clear ROW & Cut Fence Gaps	2 wks
69	Road Bore / Cut Road Install Section	1 mon
70	Ditching & String Pipe	2 wks
71	Weld, Backfill & Test	2 wks
72	Tie-in's	2 wks
73	Commission	1 wk



Task
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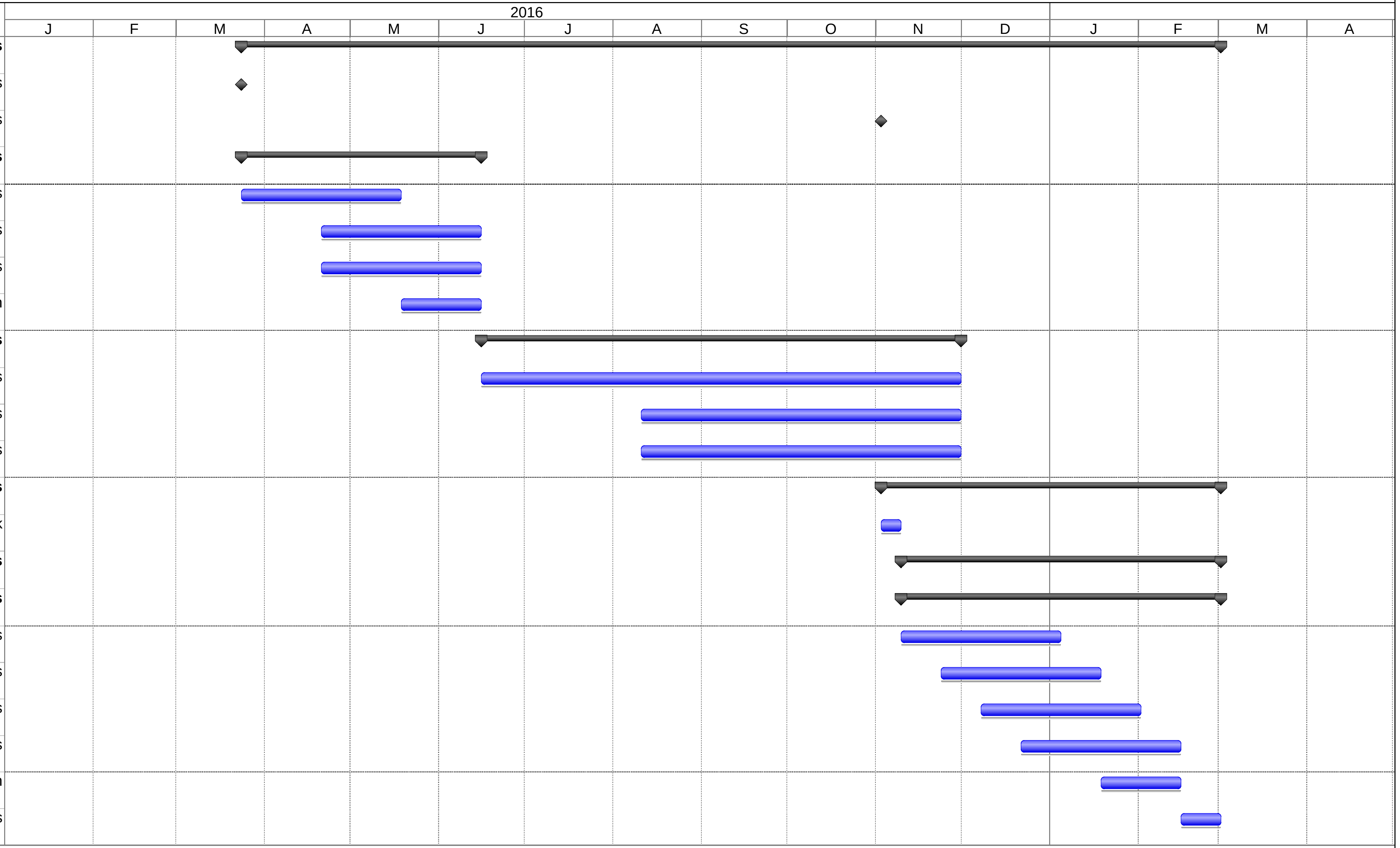
Project Summary
External Tasks
External Milestone ◆
Deadline ⇩

ID	Task Name	Duration
1	**Milestones**	**12.25 mons**
2	Bid & Let EPC Contract	0 mons
3	Let Construction Subcontract	0 mons
4	**Detail Engineering**	**3 mons**
5	Pipeline Engineering	2 mons
6	Pipeline Design	2 mons
7	Civil & Structural Eng & Design	2 mons
8	Electrical & Instrumentation Eng & Design	1 mon
9	**Procurement**	**6 mons**
10	Purch & Delv - Piping & Valves	6 mons
11	Purch & Delv - Steel	4 mons
12	Purch & Delv - Bulks	4 mons
13	**Construction**	**4.25 mons**
14	Mobilize Contractor	1 wk
15	**Pipelines**	**4 mons**
16	**Trunk Lines**	**4 mons**
17	Clear ROW & Cut Fence Gaps	2 mons
18	Road Bore / Cut Road Install Section	2 mons
19	Ditching & String Pipe	2 mons
20	Weld, Backfill & Test	2 mons
21	Tie-in's	1 mon
22	Commission	2 wks



Task	▬	Progress	▬	Summary	▬	External Tasks	▬	Deadline	⇩
Split	┈	Milestone	◆	Project Summary	▬	External Milestone	◆		

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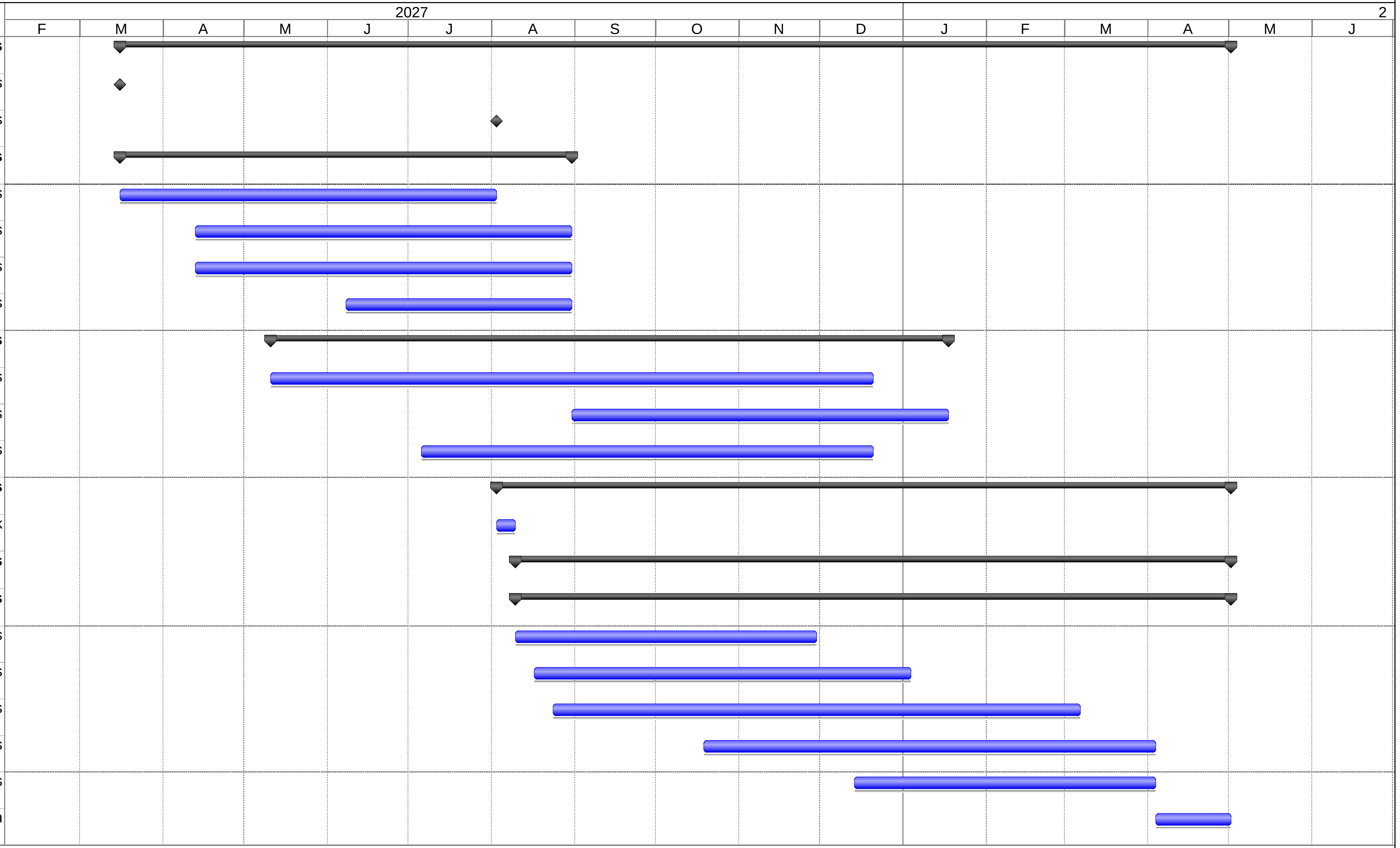
Elk Hills CO2 Project Pre-FEED Engineering Study

Appendix 5 - Trunklines for Satellite 10 to 13 (concurrent with Satellite 10)
Rev A

ID	Task Name	Duration
1	**Milestones**	**14.75 mons**
2	Bid & Let EPC Contract	0 mons
3	Let Construction Subcontract	0 mons
4	**Detail Engineering**	**6 mons**
5	Pipeline Engineering	5 mons
6	Pipeline Design	5 mons
7	Civil & Structural Eng & Design	5 mons
8	Electrical & Instrumentation Eng & Design	3 mons
9	**Procurement**	**9 mons**
10	Purch & Delv - Piping & Valves	8 mons
11	Purch & Delv - Steel	5 mons
12	Purch & Delv - Bulks	6 mons
13	**Construction**	**9.75 mons**
14	Mobilize Contractor	1 wk
15	**Pipelines**	**9.5 mons**
16	**Trunk Lines**	**9.5 mons**
17	Clear ROW & Cut Fence Gaps	4 mons
18	Road Bore / Cut Road Install Section	5 mons
19	Ditching & String Pipe	7 mons
20	Weld, Backfill & Test	6 mons
21	Tie-in's	4 mons
22	Commission	1 mon



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Project Summary
External Tasks
External Milestone ◇
Deadline ⇩

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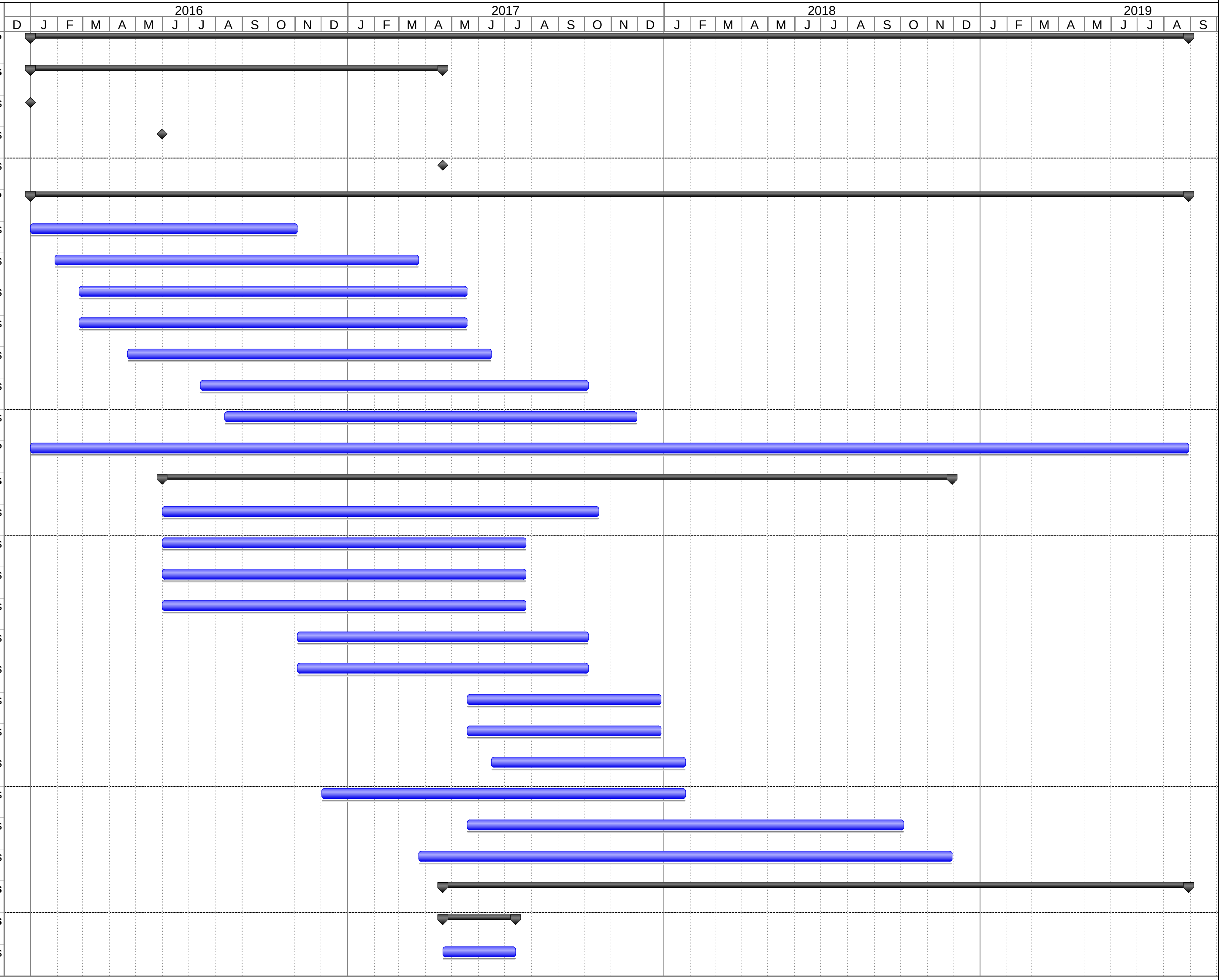
Elk Hills CO2 Pre-FEED Engineering Study

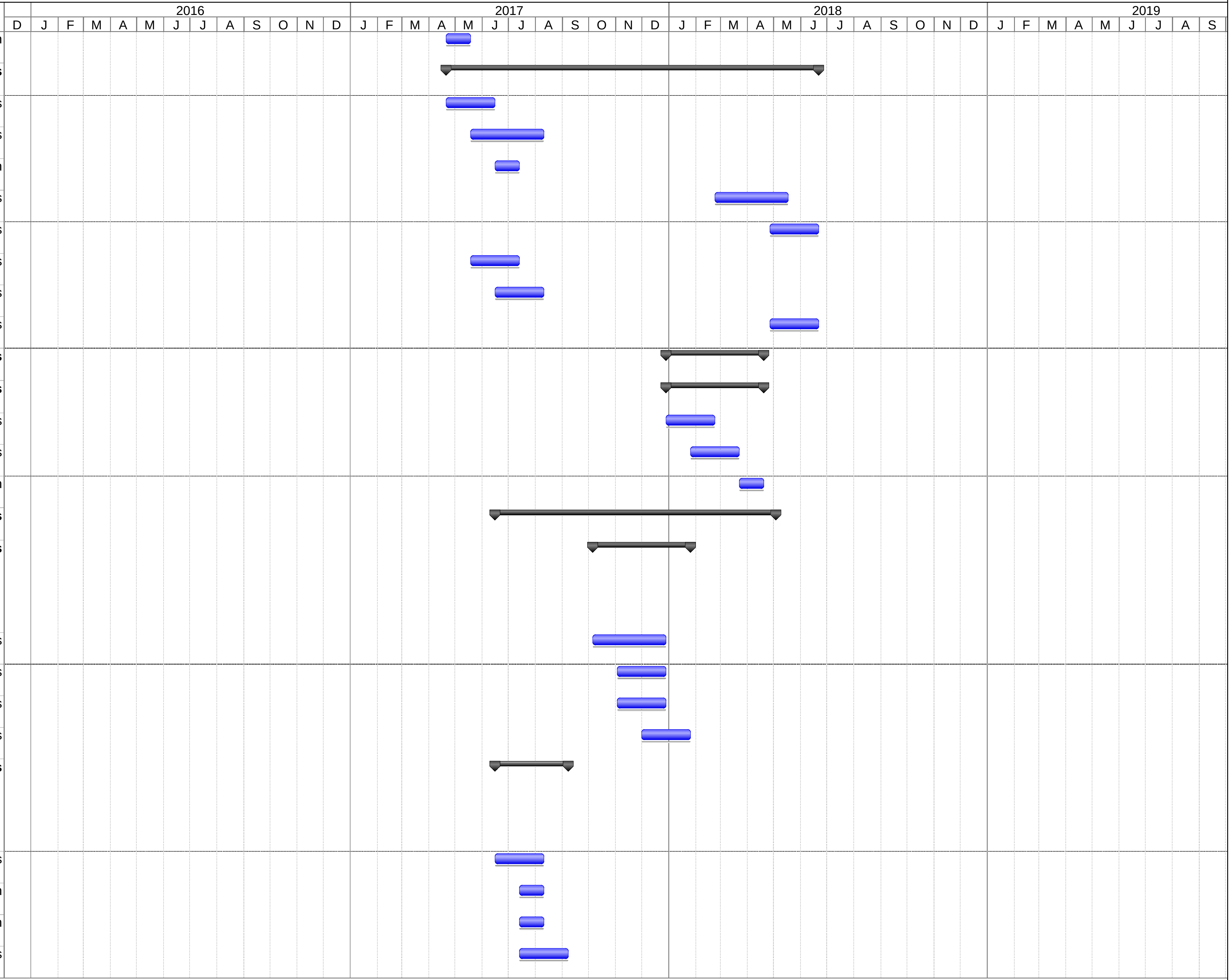
Appendix 6 - CRP Schedule
Rev A

ID	Task Name	Duration
1	**CO2 Recovery Plant**	**47.75 mons?**
2	**Milestones**	**17 mons**
3	Let EPC Contract	0 mons
4	Let Long-Lead RFQs	0 mons
5	Let Construction Contract	0 mons
6	**Detail Engineering**	**47.75 mons?**
7	Process Engineering	11 mons
8	Mech & Facilities Engineering	15 mons
9	Piping Eng & Design	16 mons
10	Pipeline Eng & Design	16 mons
11	Civil/Structural Eng & Design	15 mons
12	Electrical Eng & Design	16 mons
13	Instrument & Automation Eng & Design	17 mons
14	Permitting and Regulatory Support	47.75 mons?
15	**Procurement**	**32.6 mons**
16	Purch & Delv - Compressors	18 mons
17	Purch & Delv - Exchangers	15 mons
18	Purch & Delv - Vessels	15 mons
19	Purch & Delv - Pumps	15 mons
20	Purch & Delv - Buildings	12 mons
21	Purch & Delv - Electrical Equipment	12 mons
22	Purch & Delv - Rack Piping	8 mons
23	Purch & Delv - Fabricated Piping	8 mons
24	Purch & Delv - Steel	8 mons
25	Purch & Delv - Instruments & DCS	15 mons
26	Purch & Delv - Line Pipe, Valves, Fittings	18 mons
27	Purch & Delv - Misc. Equip & Bulks	22 mons
28	**Construction - CRP**	**30.75 mons**
29	**Mobilize Contractor**	**3 mons**
30	Set-up Onsite Construction Offices & Temp Warehouse	3 mons



Task	▬	Milestone	◆	Rolled Up Task	▬	Rolled Up Progress	▬	External Tasks	▬	Group By Summary	▬
Progress	▬	Summary	▬	Rolled Up Milestone ◇		Split	┈	Project Summary	▬	Deadline	⇩

ID	Task Name	Duration
31	Set Temporary Power	1 mon
32	**Site Excavation Activities**	**15.25 mons**
33	Clear and Grubbing Surface	2 mons
34	Cut/Fill/Compaction	3 mons
35	Temporary Site Drainage	1 mon
36	Permanent Site drainage	3 mons
37	Final Grade	2 mons
38	Install Perimeter Fence	2 mons
39	Build In-Plant Roads - Initial	2 mons
40	Build In-Plant Roads - Final	2 mons
41	**Site Buildings**	**4 mons**
42	**Compressor Shelter**	**4 mons**
43	Excavate, Form, Steel , Pour Concrete, Cure	2 mons
44	Erect Building	2 mons
45	Finish out	1 mon
46	**Equipment Foundations**	**11.5 mons**
47	**CO2 Product Compressor, Propane Compressor, Recycle Flash Gas Compressors, Booster Compressors**	**4 mons**
48	Excavate	3 mons
49	Set Forms	2 mons
50	Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	2 mons
51	Pour Concrete & Cure (28 days)	2 mons
52	**1st & 2nd Stage KO Drum, Coalescer, Inlet Gas Separator, Inlet Gas Filter, Inlet Gas Separator, 1st & 2nd Stage Aftercoolers (4)**	**3 mons**
53	Excavate	2 mons
54	Set Forms	1 mon
55	Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	1 mon
56	Pour Concrete & Cure	2 mons



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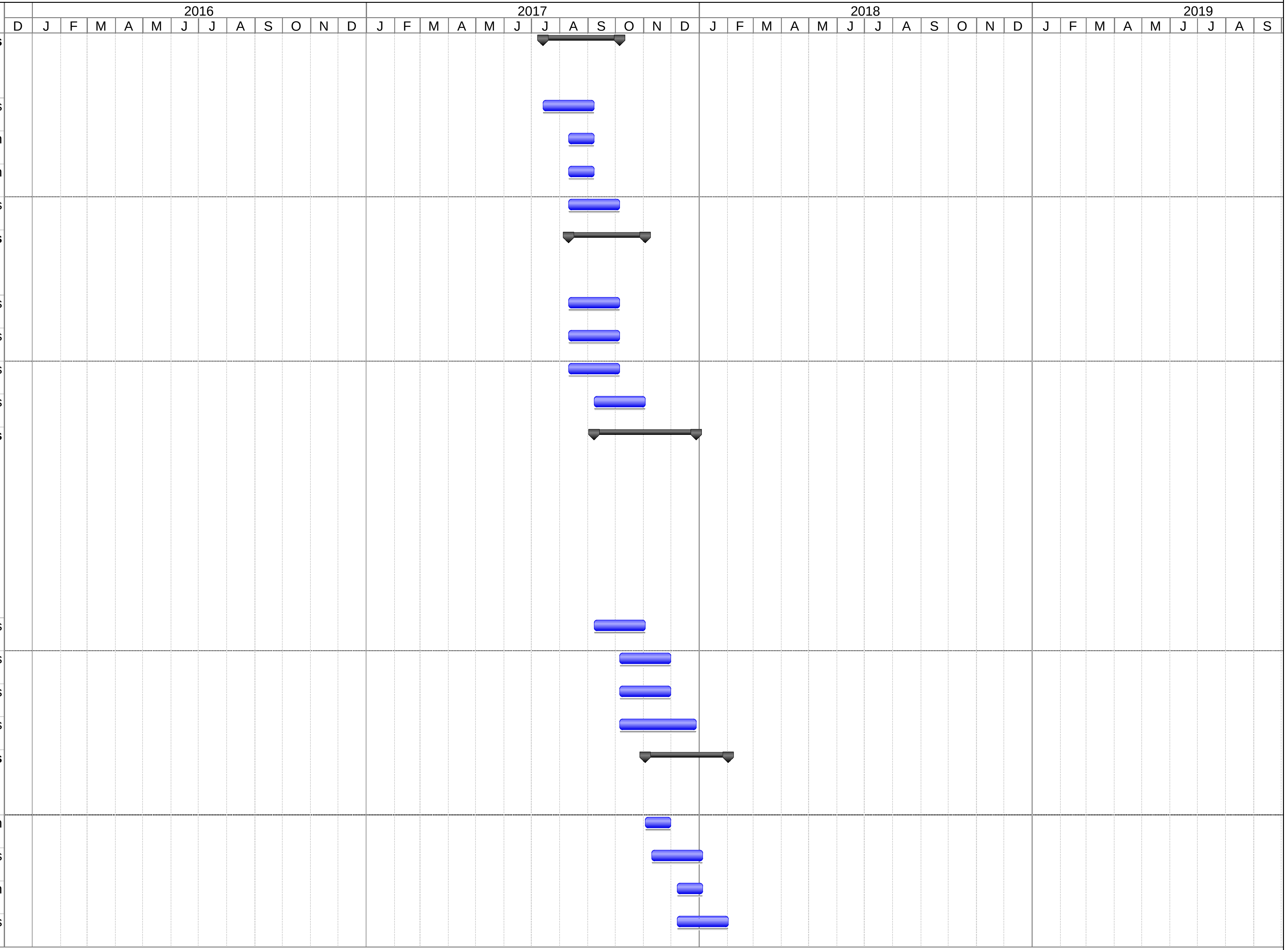
Project Summary
Group By Summary
Deadline ⇩

ID	Task Name	Duration
57	**Recycle Gas Coalescer, Inlet Gas Coalescer, Inlet Gas Filter, Inlet Gas Separator**	**3 mons**
58	Excavate	2 mons
59	Set Forms	1 mon
60	Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	1 mon
61	Pour Concrete & Cure	2 mons
62	**Booster Compressor Discharge Coolers, Regen Gas Cooler,Booster Compressor Suction Scrubber**	**3 mons**
63	Excavate	2 mons
64	Set Forms	2 mons
65	Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	2 mons
66	Pour Concrete & Cure	2 mons
67	**Propane Surge Drum, Propane High-Level Economizer, Propane MP Economizer, Propane MP Economizer, Propane Dryer, Propane Suction Scrubber, Propane Accumulator , Propane Low Level Economizer, Propane MP Economizer, Propane Low Level Economizer, Propane Drye**	**4 mons**
68	Excavate	2 mons
69	Set Forms	2 mons
70	Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	2 mons
71	Pour Concrete & Cure	3 mons
72	**Dehydrator Beds (3) , Dust Filter, Regen Gas Separator, Regen Gas Separator, Stabilizer Scrubber**	**3.25 mons**
73	Excavate	1 mon
74	Set Forms	2 mons
75	Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	1 mon
76	Pour Concrete & Cure	2 mons



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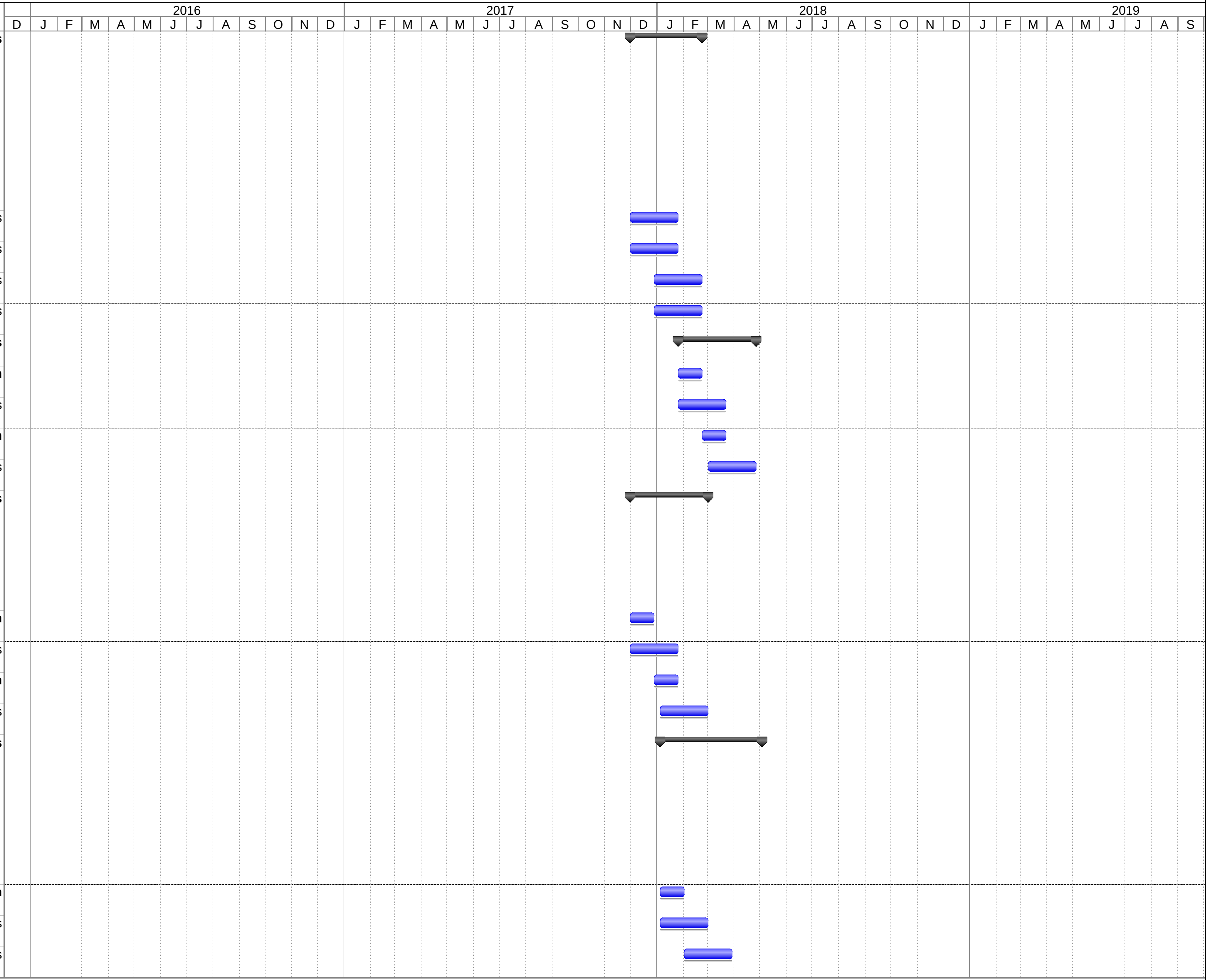
Progress	▬	Summary	▼▬▼	Rolled Up Milestone ◇		Split	┈	Project Summary	▼▬▼	Deadline	⇩

ID	Task Name	Duration
77	**Feed/Overhead Exchanger Gas Chiller, Demethanizer Feed Gas Chiller, Demethanizer Side Reboiler, Demethanizer Reboiler, Demethanizer Reflux Condenser, Stabilizer Reboiler, Demethanizer Bottoms Surge Drum, Demethanizer Reflux Accumulator, Demethanizer, Co2**	**3 mons**
78	Excavate	2 mons
79	Set Forms	2 mons
80	Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	2 mons
81	Pour Concrete & Cure	2 mons
82	**CO2 Product Pumps, CO2 Product Booster Pumps**	**3.25 mons**
83	Excavate	1 mon
84	Set Forms	2 mons
85	Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	1 mon
86	Pour Concrete & Cure	2 mons
87	**Booster Compressor Discharge Cooler, Regen Gas Cooler, CO2 Product Compressor Coolers, Recycle Compressor Aftercooler, Regen Gas Heater, Regen Gas Compressors**	**3.25 mons**
88	Excavate	1 mon
89	Set Forms	2 mons
90	Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	1 mon
91	Pour Concrete & Cure	2 mons
92	**Nitrogen Recovery Unit , HP Recycle Flash Drum, Lube Oil Coalescer, HP CO2 Flash Drum, MP CO2 Flash Drum, LP CO2 Flash Drum, Lean Selexol Filter, Propane Surge Drum, CO2 Absorber, Lean Selexol Pumps, Lean Selexol Booster Pumps, Propane Dryer, Propane Accu**	**4.25 mons**
93	Excavate	1 mon
94	Set Forms	2 mons
95	Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	2 mons



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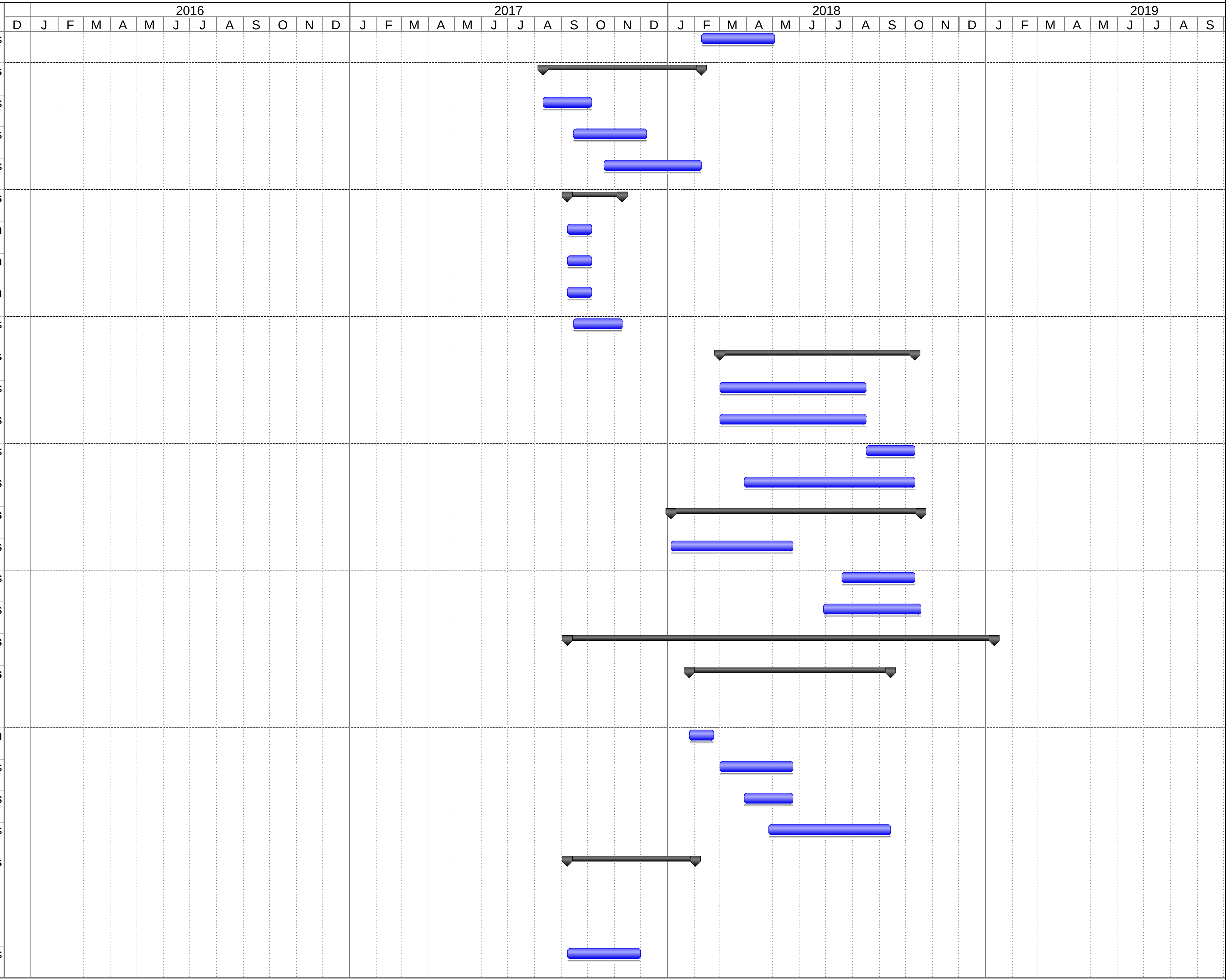
Progress		Summary		Rolled Up Milestone	◇	Split		Project Summary		Deadline	⇩

ID	Task Name	Duration
96	Pour Concrete & Cure	3 mons
97	**Pipe Rack & Light Poles**	**6.5 mons**
98	Drill Piers	2 mons
99	Form, Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	3 mons
100	Pour Concrete & Cure	4 mons
101	**Electrical MCC Buildings & Transformers**	**2.25 mons**
102	Excavate	1 mon
103	Set Forms	1 mon
104	Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	1 mon
105	Pour Concrete & Cure	2 mons
106	**Underground Piping**	**8 mons**
107	Excavation Ditch for Underground Pipe	6 mons
108	Fabricate and Install Underground Pipe & Drains	6 mons
109	Tie-in Underground Pipe & Drains	2 mons
110	Backfill	7 mons
111	**Grounding Grid**	**10.25 mons**
112	Excavate, Install Grounding Cable and Backfill	5 mons
113	Install Grounding Rods	3 mons
114	Connect to Equipment	4 mons
115	**Equipment Installation, Install & Tie-in Piping**	**17.5 mons**
116	**CO2 Product Compressor, Propane Compressor, Recycle Flash Gas Compressors, Booster Compressors**	**8.25 mons**
117	Chip Foundation	1 mon
118	Set Units, Torque Anchor Bolts, Align Couplings	3 mons
119	Grout Unit	2 mons
120	Install Piping	5 mons
121	**1st & 2nd Stage KO Drum, Coalescer, Inlet Gas Separator, Inlet Gas Filter, Inlet Gas Separator, 1st & 2nd Stage Aftercoolers (4)**	**5.25 mons**
122	Set Equipment	3 mons



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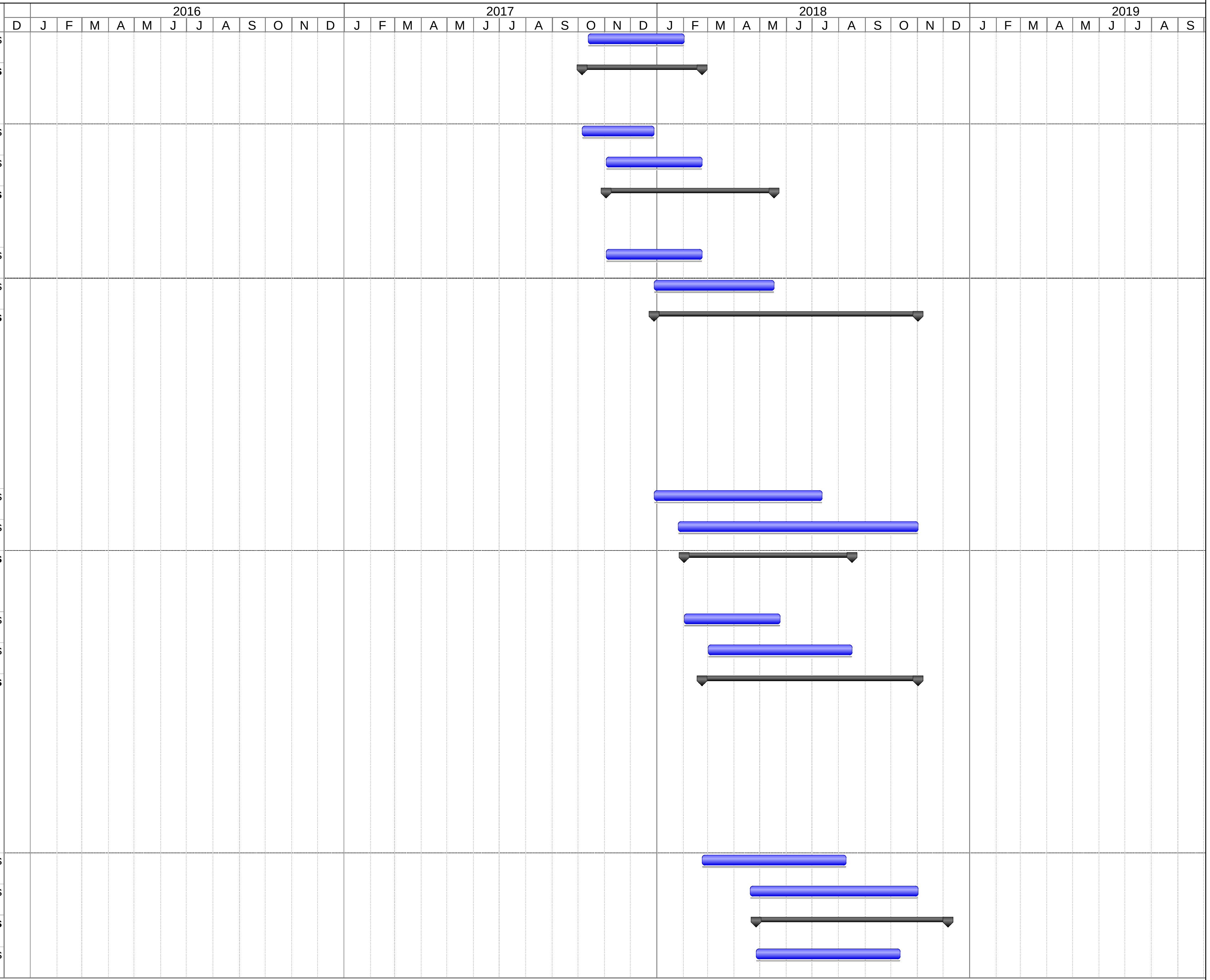
Progress	▬	Summary	▬	Rolled Up Milestone	◇	Split	┈	Project Summary	▬	Deadline	⇩

ID	Task Name	Duration
123	Install piping	4 mons
124	**Recycle Gas Coalescer, Inlet Gas Coalescer, Inlet Gas Filter, Inlet Gas Separator**	**5 mons**
125	Set Equipment	3 mons
126	Install piping	4 mons
127	**Booster Compressor Discharge Coolers, Regen Gas Cooler,Booster Compressor Suction Scrubber**	**7 mons**
128	Set Equipment	4 mons
129	Install piping	5 mons
130	**Propane Surge Drum, Propane High-Level Economizer, Propane MP Economizer, Propane MP Economizer, Propane Dryer, Propane Suction Scrubber, Propane Accumulator , Propane Low Level Economizer, Propane MP Economizer, Propane Low Level Economizer, Propane Drye**	**11 mons**
131	Set Equipment	7 mons
132	Install piping	10 mons
133	**Dehydrator Beds (3) , Dust Filter, Regen Gas Separator, Regen Gas Separator, Stabilizer Scrubber**	**7 mons**
134	Set Equipment	4 mons
135	Install piping	6 mons
136	**Feed/Overhead Exchanger Gas Chiller, Demethanizer Feed Gas Chiller, Demethanizer Side Reboiler, Demethanizer Reboiler, Demethanizer Reflux Condenser, Stabilizer Reboiler, Demethanizer Bottoms Surge Drum, Demethanizer Reflux Accumulator, Demethanizer, Co2**	**9 mons**
137	Set Equipment	6 mons
138	Install piping	7 mons
139	**CO2 Product Pumps, CO2 Product Booster Pumps**	**8 mons**
140	Set Equipment	6 mons



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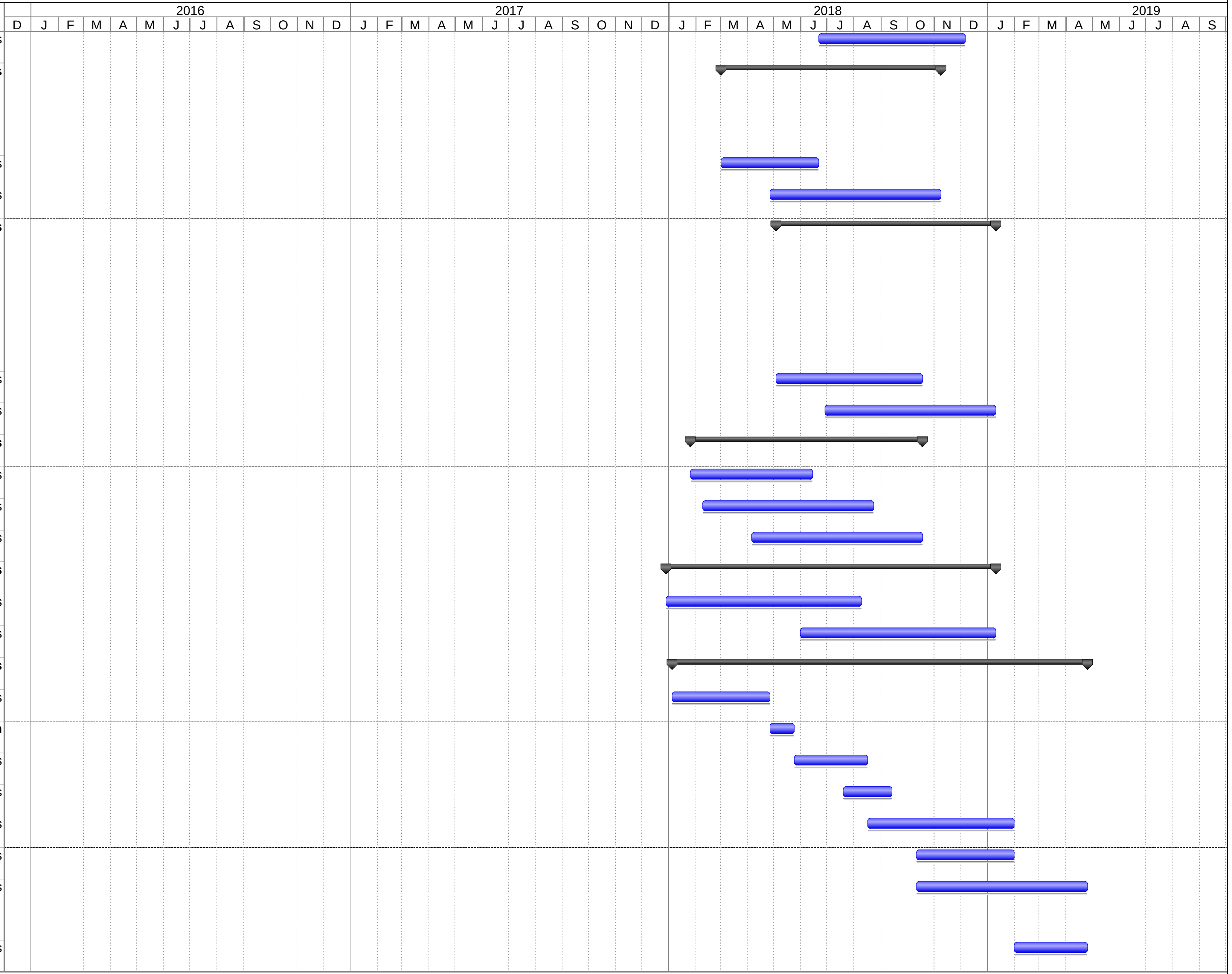
Progress	▬	Summary	▬	Rolled Up Milestone	◇	Split	┈	Project Summary	▬	Deadline	⇩

ID	Task Name	Duration
141	Install piping	6 mons
142	**CO2 Product Compressor Coolers, Recycle Compressor Aftercooler, Regen Gas Heater, Regen Gas Compressors**	**9 mons**
143	Set Equipment	4 mons
144	Install piping	7 mons
145	**Nitrogen Recovery Unit , HP Recycle Flash Drum, Lube Oil Coalescer, HP CO2 Flash Drum, MP CO2 Flash Drum, LP CO2 Flash Drum, Lean Selexol Filter, Propane Surge Drum, CO2 Absorber, Lean Selexol Pumps, Lean Selexol Booster Pumps, Propane Dryer, Propane Accu**	**9 mons**
146	Set Equipment	6 mons
147	Install Piping	7 mons
148	**Pipe Racks**	**9.5 mons**
149	Receive Fabricated Racks Onsite	5 mons
150	Assemble Racks/Structure & Install Pipe Rack	7 mons
151	Install Cable Tray	7 mons
152	**Piping Installation in Racks**	**13.5 mons**
153	Receive Fabricated Spools & Install Piping	8 mons
154	Install Equipment Interconnect Piping	8 mons
155	**Install Electrical Equipment & Control Cables**	**17 mons**
156	Modify Esixting Substation	4 mons
157	Set MCC Buildings	1 mon
158	Main Feeder Cable to MCC's	3 mons
159	Set Transformers	2 mons
160	Place all Cables Into Tray	6 mons
161	Megger HV Cables	4 mons
162	Connect Electrical Cables to Switchgear & Equipment, Check Rotation of Motors	7 mons
163	Install Light Poles and Tie-in Power	3 mons



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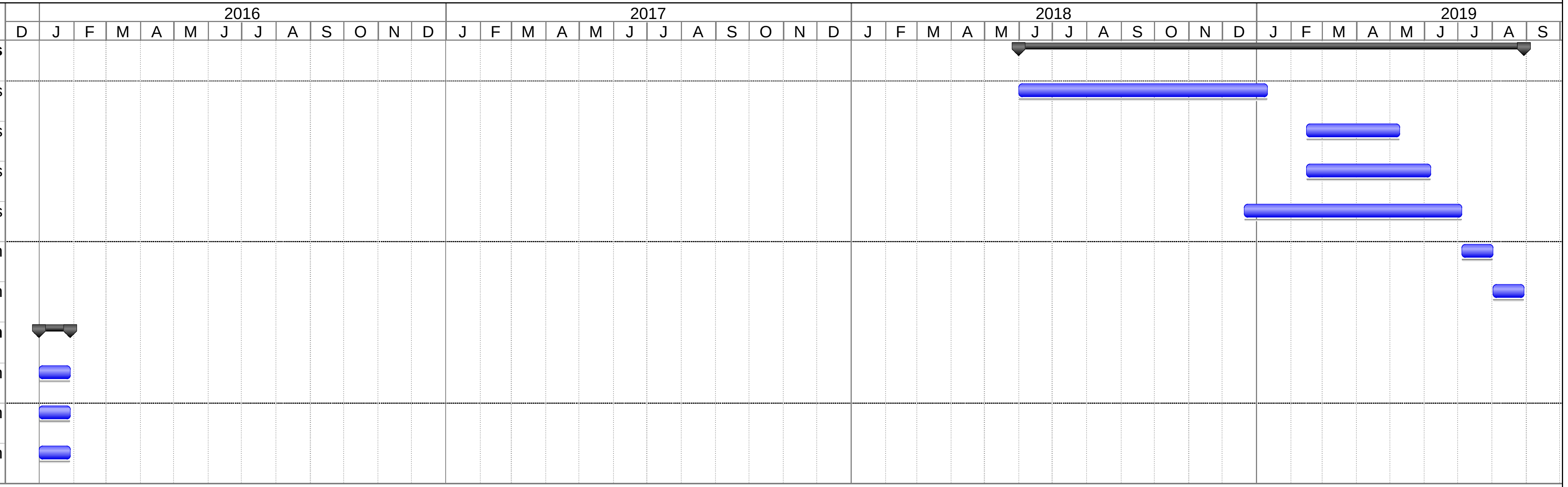
Progress	▬	Summary	▬	Rolled Up Milestone ◇		Split	┈	Project Summary	▬	Deadline	⇩

ID	Task Name	Duration
164	**Pre-Commission / Commission Facility**	**16.25 mons**
165	Flush Piping, Connect to Equipment, Install Strainers	8 mons
166	Loop Check Control Cables & Function Test End Devices	3 mons
167	Final Equipment Check-out	4 mons
168	Punch List & Start-up Activities	7 mons
169	Purge Piping	1 mon
170	Introduce Product to Facility	1 mon
171	**Construction - Product Lines to Tie-Ins**	**1 mon**
172	Residue Gas Line to 3G	1 mon
173	NGL Line to 35R	1 mon
174	Nitrogen Line to 3G	1 mon



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Progress	▬	Summary	▬	Rolled Up Milestone	◇	Split	┈	Project Summary	▬	Deadline	⇩

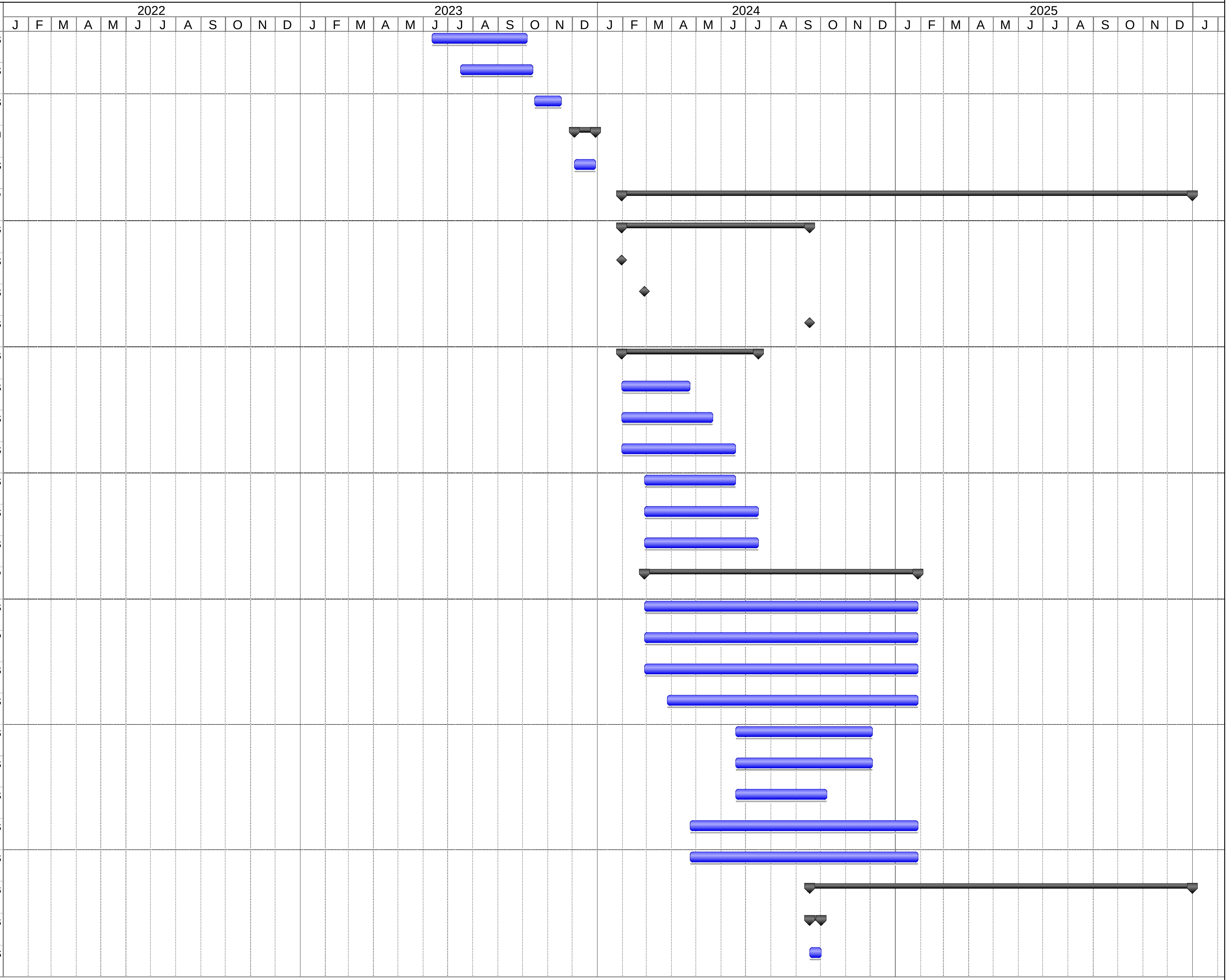
Occidental of Elk Hills, Inc.
Elk Hills CO2 Pre-FEED Engineering Study

Appendix 7 - CTB Phase II
Rev A

ID	Task Name	Duration
1	**Central Tank Battery - Phase II**	**51.15 mons?**
2	**2023 Schedule - Gas Separator**	**25 mons**
3	**Milestones**	**7.75 mons**
4	Let EPC Contract	0 mons
5	Let Long-Lead RFQs	0 mons
6	Let Construction Contract	0 mons
7	**Detail Engineering**	**4 mons**
8	Process Engineering	1 mon
9	Mech & Facilities Engineering	2 mons
10	Piping Eng & Design	2 mons
11	Civil & Structural Eng & Design	2 mons
12	Electrical Eng & Design	3 mons
13	Instrument & Automation Eng & Design	3 mons
14	**Procurement**	**8 mons**
15	Purch & Delv - Vessels	8 mons
16	Purch & Delv - Rack Piping	3 mons
17	Purch & Delv - Fabricated Piping	3 mons
18	Purch & Delv - Steel	3 mons
19	Purch & Delv - Instruments	3 mons
20	Purch & Delv - Misc. Equip & Bulks	3 mons
21	**Construction**	**17.25 mons**
22	**Mobilize Contractor**	**1.25 mons**
23	Set-up Onsite Construction Offices & Temp Warehouse	5 wks
24	**Equipment & Pipe Rack Foundations**	**9 mons**
25	Break Concrete & Excavate	8 wks
26	Set Forms	13 wks
27	Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	13 wks
28	Pour Concrete & Cure	17 wks
29	**Equipment Installation & Hookup**	**8.75 mons**
30	Set Vessel	15 wks

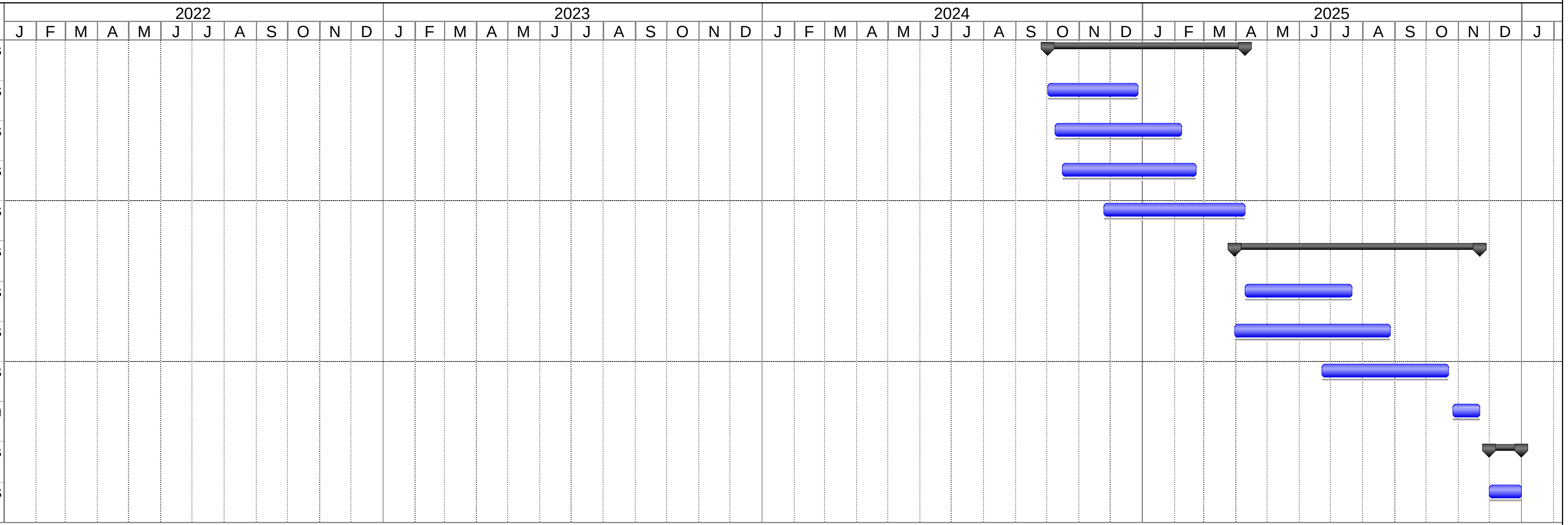
Task	Milestone ◆	Rolled Up Task	Rolled Up Progress	External Tasks	Group By Summary
Progress	Summary	Rolled Up Milestone ◇	Split	Project Summary	Deadline ⇩

ID	Task Name	Duration
31	Install Steel & Piping	4.25 mons
32	Install Instrument & Electrical	3.25 mons
33	Testing	5 wks
34	**Start-Up**	**1 mon**
35	Punch List and Start-Up	4 wks
36	**2025 Schedule - All Remaining Equipment**	**25.05 mons?**
37	**Milestones**	**8.25 mons**
38	Let EPC Contract	0 mons
39	Let Long-Lead RFQs	0 mons
40	Let Construction Contract	0 mons
41	**Detail Engineering**	**6 mons**
42	Process Engineering	3 mons
43	Mech & Facilities Engineering	4 mons
44	Piping Eng & Design	5 mons
45	Civil & Structural Eng & Design	4 mons
46	Electrical Eng & Design	5 mons
47	Instrument & Automation Eng & Design	5 mons
48	**Procurement**	**12 mons?**
49	Purch & Delv - Vessels	12 mons
50	Purch & Delv - Tanks	12 mons?
51	Purch & Delv - Pumps	12 mons
52	Purch & Delv - Electrical Equipment	11 mons
53	Purch & Delv - Rack Piping	6 mons
54	Purch & Delv - Fabricated Piping	6 mons
55	Purch & Delv - Steel	4 mons
56	Purch & Delv - Instruments	10 mons
57	Purch & Delv - Misc. Equip & Bulks	10 mons
58	**Construction**	**16.8 mons**
59	**Mobilize Contractor**	**0.5 mons**
60	Set-up Onsite Construction Offices & Temp Warehouse	2 wks



Task	Milestone ◆	Rolled Up Task	Rolled Up Progress	External Tasks	Group By Summary
Progress	Summary	Rolled Up Milestone ◇	Split	Project Summary	Deadline ⇩

ID	Task Name	Duration
61	**Equipment Foundations**	**6.8 mons**
62	Break Concrete & Excavate	3.15 mons
63	Set Forms	4.4 mons
64	Cut, Bend, Install Reinforcement Steel, Set Anchor Bolts	4.65 mons
65	Pour Concrete & Cure	4.9 mons
66	**Equipment Installation & Hookup**	**8.5 mons**
67	Set Equipment	3.65 mons
68	Install Steel & Piping	5.4 mons
69	Install Instrument & Electrical	4.4 mons
70	Testing	1 mon
71	**Start-Up**	**1.15 mons**
72	Punch List and Start-Up	4.6 wks



Task
Progress
Milestone
Summary
Rolled Up Task
Rolled Up Milestone ◇
Rolled Up Progress
Split
External Tasks
Project Summary
Group By Summary
Deadline ⇩

Attachment A177-4

Pre-FEED Engineering Study, Overall Design Basis, Mustang Engineering, April 28, 2010.

Occidental of Elk Hills, Inc.

Elk Hills CO_2 Project

Pre-FEED Engineering Study

Overall Design Basis

Document 16179-MUS-GEN-BD-00-0001

E	28 Apr 10	Re-Issued for FEED w/minor changes	KML	MLS	SCW
D	1 Apr 10	Re-Issued for FEED	KML	MLS	SCW
C	11 Mar 10	Issued for FEED	KML	MLS	SCW
B	15 Feb 10	Issued for Client Review	MLS	LAS	SCW
A	5 Feb 10	Issued for Internal Review	MLS	LAS	SCW
REVISION	**DATE**	**DESCRIPTION**	**ORIGINATOR**	**CHECKED**	**APPROVED**

Mustang Engineering LP
Project Number 16179

	Project	Originator	Discipline	Type	Area	Sequence
Document Control Number	16179	MUS	GEN	BD	00	0001

TABLE OF CONTENTS

1.0 INTRODUCTION

Hydrogen Energy (HECA), a joint venture between BP Alternative Energy, and Rio Tinto, is planning to install an Integrated Gasification Combined Cycle (IGCC) power generating facility near Occidental's Elk Hills property. The IGCC plant will gasify petroleum coke and/or coal to produce hydrogen to fuel a combustion turbine operating in combined cycle mode and produce a net electrical generation output of approximately 250 MW. The gasification process will also capture approximately 90% of the CO_2, from where 130 MMSCFD of compressed CO_2 will be transported by pipeline to the Elk Hills oil field for injection into various oil reservoirs for CO_2 Enhanced Oil Recovery and Sequestration.

This Design Basis provides specific requirements and design data for use in the design of the Elk Hills CO_2 Project facilities.

Occidental of Elk Hills Inc. (OEHI) is planning to develop the existing Elk Hills oil field located 25 miles southwest of Bakersfield, in Kern County, California, by converting certain areas of existing operations from water flooding to CO_2 flooding for Enhanced Oil Recovery (EOR). The CO_2 development is planned to be incrementally developed over a 20 year period, with initial operations commencing 4th Quarter 2015.

2.0 PROJECT DESCRIPTION

2.1 CO_2 Project Overview

OEHI plans to implement a phased installation program to install CO_2 distribution & storage systems, satellite gathering and separation systems, and CO_2 recompression and processing facilities, in order to maximize the potential of enhanced oil recovery in the southeast and northwest sections of the Stevens reservoir. The facilities will consist of the following primary components:

- CO_2 Supply Pipeline (from HECA to the CO_2 Processing Plant) – By Others
- CO_2 & Water Distribution Pipelines
- Satellite Gathering Systems (a total of 13 Satellites)
- Satellite Water Alternating Gas (WAG) Injection System (co-located with Satellite Gathering Systems)
- Infield Distribution Flowlines, Injection Lines and Gathering Pipelines
- CO_2 Backup Injection Facility (A1/A2)
- Central Tank Battery (CTB) including Water Treating and Injection
- Reinjection Compression Facility (RCF)
- CO_2 Recovery Plant (CRP)
- Utilities & Infrastructure, including tie-in Pipelines
- Product Sales Pipelines

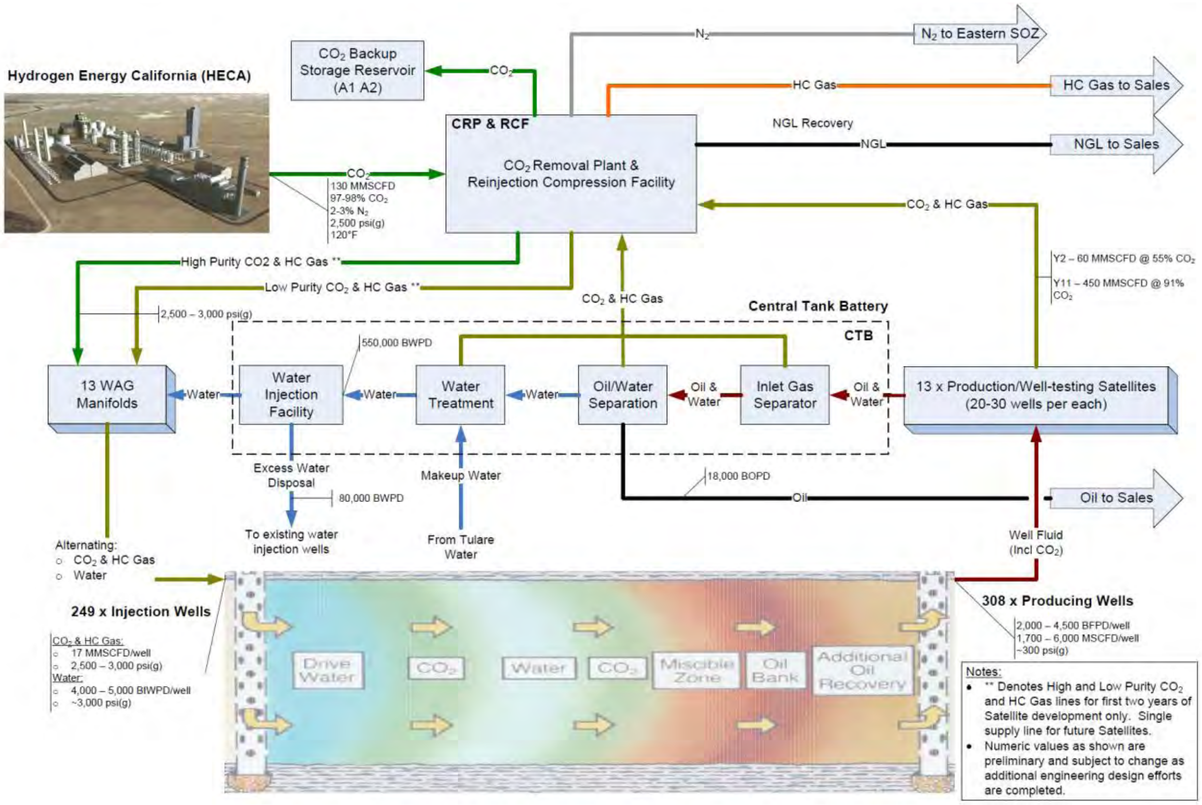
OEHI provided preliminary reservoir performance information indicating typical CO_2 Enhanced Oil Recovery (EOR) injector well patterns and production profiles for water and gas production from the Stevens formation (provided in Excel spreadsheet file ―*Forecast*

Revised 5_21_09 CO2 implementation gantt chart - base1 TC.xls”). This information was based on a progressive CO_2 injection well development program spanning from 2015 to 2034. The data provided was on a month-by-month basis, however for this analysis the monthly flows have been adjusted to an average for each calendar year. Averaging removed short term spikes in flows and prevents equipment sizing based on potentially spurious short term data.

The full development will be capable of handling 422 MMSCFD of gas with the nominal capacities of the RCF and CRP being 222 MMSCFD and 200 MMSCFD respectively. It is expected the gas volume will rise from virtually nil to 380 MMSCFD over the period of 2016 to 2024. After this time, it is expected the flow will decrease and then rise to peak again at around 365 MMSCFD approximately nine years later in 2033.

The development will proceed with the construction of the RCF and between 2016 and 2019 gas throughput will rise to the nominal capacity RCF of 222 MMSCFD. The CRP is planned to be operational at this point in time and will take approximately 112 MMSCFD of the gas and leave 100 MMSCFD for the RCF to continue processing. The CRP will absorb the increased gas flows through 2022 at which time it will have reached capacity. The RCF will then be ramped from 50% capacity throughput to 100% to meet the peak gas flows of 380 MMSCFD around 2024. The phasing for the completion of the full development is detailed in Appendix 5.

Figure 1 below provides an overview of the proposed facilities.



Notes:
- ** Denotes High and Low Purity CO_2 and HC Gas lines for first two years of Satellite development only. Single supply line for future Satellites.
- Numeric values as shown are preliminary and subject to change as additional engineering design efforts are completed.

Figure 1 – Facility Overview

3.0 GENERAL

3.1 Facility Location

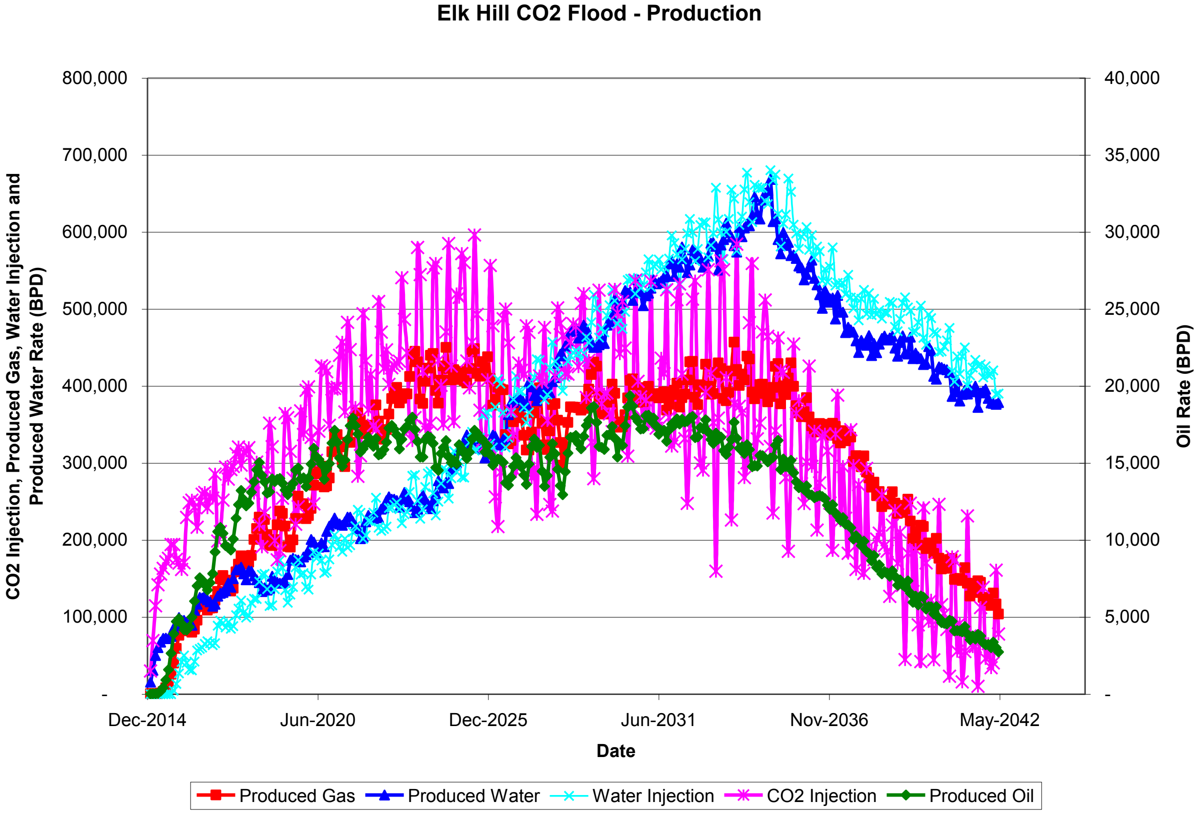
The Elk Hills CO_2 Project is located 25 miles southwest of Bakersfield, in Kern County, California.

3.2 Design Life

The new facility shall be designed to provide a minimum design life of thirty years.

3.3 Reservoir Forecast

The below graph is the forecast performance of the Elk Hills CO_2 Flood. Tabular results of this data are also available.



3.4 Turndown Requirements

The design basis for the operational turndown for the facility (RCF, CRP and CTB) shall be set at 25% of nominal total plant capacity. Initial start-up requirements during low flow periods as CO_2 begins to break through will be handled in the RCF by a combination of speed reduction of the compressor motor and recycle of the gas to the inlet of the compressor. Due to turndown limitations of the CO_2 injection pumps, operational constraints should be handled by HECA flow rate being maintained above minimum flow of the pump(s). As net feed gas increases above minimum flow for the injection pumps the operational constraint discussed above for HECA flow can be relaxed and still maintain proper operation of the system.

3.5 Systems of Measurement

Engineering and design shall be performed using the English systems of measurement. Figure 3.4 indicates units of common properties to be used in engineering and design.

Description	**Units**
Temperature	°F
Pressure	PSIG, inches H_2O
Vacuum	PSIA, inches Hg absolute
Weight (mass)	LB
Length	FT, inches
Volume, Liquids	US Gallons, BBL
Volume, Standard	FT^3, SCF, 14.696 PSIA @ 60 °F
Flow, Liquids	GPM, BPD
Flow, Gases	FT^3/s, MMSCFD, ACFM
Flow, Mass	LB / HR
Density, Relative	Specific Gravity T °F / 60°, API°
Density, Absolute	LB / GAL @ 60 °F
Density, Flowing	LB / FT^3
Viscosity, Absolute	Centipoise
Heat, Energy	BTU
Enthalpy	BTU / LB
Heat Capacity, Cp	BTU / LB -°F
Thermal Conductivity	BTU / HR-FT -°F
Heat Rate	10^6 BTU / HR
Power – Mechanical/Electrical	HP / kW
Sound Pressure / Power	dBA
Molecular Weight	LB / mol
x 10^3 (thousands)	M
x 10^6 (millions)	MM

Table 3.4 - Systems of Measurement

4.0 SITE CONDITIONS

Climate	Semi-arid, seasonal; dust storms are frequent.
Elevation	250' to 1325' above sea level
Main Plant Facilities	~675' above sea level
Barometric pressure	14.34 PSIA
Design dry-bulb temperature	105° F
Maximum dry-bulb temperature	110° F (for air cooler design)
Design Maximum Wet bulb temperature	72° F (33% relative humidity at 95.6°F
Design Minimum Dry bulb temperature	40° F
Annual Average Temperature	65° F
January average	48° F
July average	84° F
Relative humidity	20% Summer / 82% Winter
Average annual rainfall	6.49 inches
Twenty-five year maximum in one hour	2.29 inches
Design Snow load	Zero Ground Snow Load Area
Design Wind load, maximum	3-second gust is 85 MPH per CBC 2007
Average Velocity:	6.0/5.4 MPH summer/winter
Wind Rose data	See Appendix 4
Prevailing wind direction	From Northwest (See Appendix 4)
Frost line depth	Not applicable
Earthquake coefficients	Seismic Zone 4 per CBC 2007
Foundation design bearing capacity	2,000 psf* *pending Geotechnical investigation results

5.0 PROCESS DESCRIPTION

5.1 Reinjection Compression Facility (RCF)

The produced CO_2 and hydrocarbon gas from the Satellites will initially flow to the Reinjection Compression Facility (RCF) where the gas will be dehydrated, compressed and mixed with makeup CO_2 from HECA. The nominal capacity of the RCF is 222 MMSCFD. The CO_2 will be pumped to the required injection pressure using a high pressure (HP) pump and distributed back to the Satellites via the CO_2 injection lines for re-injection at the injection wells.

The nominal flow rate of the HECA gas is 130 MMSCFD and could contain as much as 100 ppmw of H_2S. In the initial stages of this project, this should not affect the operation of the main facilities as this gas will bypass the plant and be injected into the reservoir. However, over time this concentration of reinjection H_2S will migrate through the reservoir and be assimilated in the production stream.

For the first few years of CO_2 injection, the HECA CO_2 and the RCF discharge gases will be maintained as separate high and low purity streams respectively. When the RCF stream is rich enough in CO_2 to be miscible, the streams will be co-mingled.

Further design details are provided in Process Description document no. 16179-MUS-PRO-RP-00-0001, and PFD's.

5.2 CO_2 Recovery Plant (CRP)

As the gas flowrate increases over time, a CO_2 Recovery Plant (CRP) will be added to allow for recovery and concentration of the CO_2. The CRP will consist of several processing units for the recovery of CO_2 from the produced gas and removal of NGL's, water and Nitrogen. Nominal capacity of the CRP is 200 MMSCFD.

The gas will be dehydrated, compressed and cooled, and bulk CO_2 recovery will be provided in the Demethanizer unit. There will be a separator on the inlet section of the Demethanizer to allow for recovery of some of the NGLs in the inlet associated gas. The condensed liquid will be processed in a cold feed stabilizer to remove excess light ends, including $CO_{2,}$ which will be recycled to the Inlet Booster Compressor.

The partially treated gas will then flow to the Selexol unit for further treating of the associated gas to meet the export hydrocarbon gas specification. A recovered CO_2 stream from the Selexol unit will be recycled to the plant inlet for recovery of CO_2.

The gas from the Selexol will then be sent to the Nitrogen Rejection unit (NRU) to remove excess nitrogen from the gas prior to sales. Nitrogen will transported via a new pipeline for disposal via injection. The NRU will also include an amine CO_2 removal system to reduce the level of CO_2 in the gas going to the NRU.

The CO_2 from the Demethanizer will be combined with the compressed CO_2 rich gas from the RCF and will then be combined with the relatively pure CO_2 received via pipeline from the HECA power plant. The net CO_2 for injection will then be pumped up to the required injection pressure using high pressure (HP) pumps and distributed back to the Satellites via the CO_2 injection lines. The CO_2 and the injection water will be routed via the Water Alternating Gas (WAG) manifolds where the injection fluids will be alternately injected downhole as needed. The WAG manifolds will be co-located at the satellites.

As stated in the previous section regarding H_2S content in the production stream, over time H_2S will show up in the processing facilities both in the RCF and the CRP. Preliminary calculations indicate that some H_2S could become present in the NGL product stream. During the FEED phase of the project an evaluation will be necessary as to whether additional equipment will be required to remove the H_2S in order to meet product specifications.

Further design details are provided in Process Description document no. 16179-MUS-PRO-RP-00-0001, and PFD's.

5.3 Central Tank Battery (CTB)

The produced liquids from the Satellites will go to the Central Tank Battery (CTB). Two-phase separators will remove the gas, which will be compressed and sent to the RCF, and the liquid will be sent to flumes and vortex tanks where the oil and water will be separated. The oil will be sent for sales to the existing LACT facilities at 18G. The water will be treated and boosted to injection pressure at the water injection portion of the CTB and distributed to the Satellites via the water injection trunklines.

Equipment required includes:

- Gas Separators (three x 33% of maximum capacity with two installed initially)
- Flumes (four x 25% of maximum capacity with two installed initially)
- Vortex Tanks (four x 25% of maximum capacity with two installed initially)
- Vapor Recovery Units
- LP Compressor
- Oil Tank
- Water and oil transfer pumps
- Water cleanup equipment such as flotation unit, filters, pumps, etc.
- Flare system

Further design details are provided in Process Description document no. 16179-MUS-PRO-RP-00-0001 and PFD's.

5.4 CO_2 Backup Injection Facility (A1/A2 Area)

The CO_2 storage (A1/A2 Area), in Block 7R, is used in the event injection of CO_2 into the injection wells could not be done for any reason. The CO_2 gas stream from HECA, and / or the recovered CO_2 from the CRP or RCF is diverted for injection at the low pressure CO_2 Storage Reservoirs (A1/A2). The CO_2 stream from HECA is approximately 2400 PSIG but the injection pressure into the energy reservoir can be as low as 250 PSIG. This pressure drop results in a decrease of the temperature of approximately -12° F which presents a risk for hydrate formation in the line or freezing in the wellbores. In order to avoid hydrates, a gas-fired heater will be installed to keep the gas temperature above 50° F. Further injectivity work will be needed by the reservoir engineers to complete the facility design during FEED.

During FEED, the feasibility of sending small maintenance blowndown volumes of gas to the A1/A2 area should be considered. This would require the addition of a vent collection system and a small compressor but would remove the need to vent or flare maintenance gas.

5.5 Satellites

CO_2 and injection water from the main process units will be distributed via pipeline to a Water Alternating Gas (WAG) manifold at each of a total 13 Satellites, from where CO_2 and injection water will be directed to injection wellheads served by each Satellite.

Production from the production wellheads will flow to the Satellites where the associated gas will be separated from the oil and water. The gas and liquid will flow separately to the main facility for further processing via gas and liquid infield gathering lines.

The construction of the 13 Satellites will be incrementally phased over a 20 year period. See Appendix 5.

In the early operation of the EOR, the first three satellites will require two streams of CO_2. One stream will be high purity and the other low purity. This will permit operations to selectively direct high or low purity CO_2 on a well by well basis. High purity CO_2 will have miscible properties whereas low purity CO_2 will not.

5.6 Pipelines

Pipelines will be designed in accordance with the ANSI B31.4 “Liquid Transportation Systems for Hydrocarbons”, and ANSI B31.8 “Gas Transmission and Distribution Piping Systems” and will be constructed in accordance with API 1104 “Welding of Pipelines and Related Facilities” and ASME Section IX “Boiler and Pressure Code”. The base case of cost estimate preparation is for all pipelines to be below grade. Alternate costs for above grade configuration will be prepared for comparison.

It is anticipated that any above ground CO_2 lines will have to be insulated in order to maintain miscible properties.

Below are the anticipated sizes for the various services, as well as the intended materials of construction.

Service	Size	Material
Gas Gathering	12”, 16”, and 26”	CS - HDPE
Liquid Gathering	10”, 12” and 16”	CS - HDPE
Water Injection	10”, 12” and 16”	CS - HDPE
CO_2 Injection	4”, 6”, and 12”	CS
Residue Sales Gas	6”	CS
Heater Fuel Gas	3” and 6”	CS
NGLs	3”	CS
Oil Sales	8”	CS
Make-Up Water	10”	CS - HDPE
Nitrogen to Injection	8”	CS
Production Lines	4”	CS - IPC
Injection Lines	4”	SS

CS	Carbon Steel
CS - IPC	Carbon Steel, Internally Plastic Coated
CS - HDPE	Carbon Steel, High-Density Polyethylene Lined
SS	316 Stainless Steel

The design flow rates for the field pipelines are to be reviewed and agreed with OEHI after completion of the reservoir analyses. Pipe size determination is expected to be somewhat conservative to accommodate possible changes in future reservoir development and performance. These changes could relate to pressure, and flow rates.

The field layout drawings done during the Pre-FEED depict a design based on satellite images and have not been checked in the field. The satellite locations, pipeline layouts and tire-ins could change in FEED and in detailed engineering after the completion of field surveys. Pipeline layouts need to take account of the requirement to minimize land disturbance and also to avoid contaminated areas.

5.7 Utility Area

Utilities required for the new facilities (RCF, CRP and CTB) will include instrument air, fuel gas, potable water, firewater, closed and open drain systems, chemical and lube oil storage and a septic tank.

5.7.1 Instrument Air System

The instrument air system will include two 100% compressors. Each compressor will have an associated dryer system and filter skid to accommodate 500 SCFM of air. The compressor units will be designed for a lead-lag operation to provide instrument air for the new facility. This preliminary design will be finalized during the FEED phase of the project.

5.7.2 Fuel Gas

Fuel gas will be provided at the new facilities (RCF, CRP and CTB) for the Triethylene Glycol (TEG) Regeneration Package, the Regeneration Gas Heater, tank blanket gas, and as pilot and assist gas for each flare. During emergency conditions when the plant will shut down and the total gas will be sent to the flares, assist gas (fuel) will be required to mix with the high CO_2 content flare gas to provide a combustible product. It has been estimated that each flare will require approximately 49 MMSCFD of assist gas. This preliminary design will be finalized during the FEED phase of the project.

5.7.3 Potable Water

Potable water for plant use will be provided by a Reverse Osmosis (RO) unit and stored for distribution to users throughout the plant. The water source is discussed in section 5.5. Preliminary design will be finalized during the FEED phase of the project. In FEED stage an alternate source of potable water from the West Kern Water District will be evaluated.

5.7.4 Firewater

Preliminary design of the firewater system for the facilities will provide a storage tank to handle a volume equivalent to 4 hours of water disbursed by one of the two firewater pumps. Oxy Engineering Guide (EG-307) calls for 4 hours of storage, more than 4 hours of storage would not be necessary unless the isolation/shutoff of the fuel source or the de-pressurization and shutdown of the plant takes longer than 4 hours.

The two pumps, one electric-motor driven and the other diesel-motor driven, will provide 1,500 gpm minimum each through the firewater network, which is to be designed in FEED. The firewater system design will be finalized during the FEED phase of the project. The water in the firewater tank is to be sourced from the RO unit. A firewater jockey pump is also required.

5.7.5 Drain Systems

Open and closed drain systems will be provided in each area of the plant. Initial design provides for an open and closed drain tank in the RCF, CRP and CTB, with a common open and common closed drain tank and associated pump. Drain tanks to be located above grade, but at low level, by utilizing the slope of the OEHI facilities.

5.7.6 Chemical and Lube Oil Storage and Septic Facilities

Design Basis to be developed in FEED.

5.8 Tulare Water Well (TWW)

Five wells will be drilled and equipped as make-up water wells. They are located in Blocks 13B and 18G, producing nominally 10,000 bpd each. Makeup Water pumps transport water to main facility in Block 27S for use in the potable water system, as an initial fill for the Firewater Tank, and as make-up injection water for the reservoirs when the HECA CO_2 gas is unavailable. Refer to sections 5.4.3 and 5.4.4 for further information on water treating and usage.

6.0 PROCESS FLUID DATA

The initial source of the CO_2 will be from the Hydrogen Energy California (HECA) site located adjacent to the Elk Hills Property. The tie-in point is to be confirmed, but assumed to be in block 27S adjacent to the proposed new OEHI CO_2 Processing Plant. OEHI will install a spur to the CO_2 backup injection facility in the A1/A2 (Block 7R) region of the Elk Hills facility.

6.1 Inlet Gas

6.1.1 CO_2 Design Parameters

- Supply Rate from HECA:
  - Normal 130 MMSCFD
  - Minimum 115 MMSCFD
  - Maximum 145 MMSCFD
  - Average per month on annual basis 170 MMSCFD. (See note below regarding HGCA availability)
- Pressure:
  - 2500 PSIG from compressor supplied by HECA. Project to assume 2500 PSIG at the discharge flange of the compressor.
- Temperature:
  - Assume 120° F at the discharge flange of the HECA compressor.
- Availability of HECA CO_2
  - Project assumes HECA CO_2 will be available for 82% of any one year, i.e. HECA downtime is assumed to be 9 weeks per year.

6.1.2 HECA CO_2 Feed Gas Composition

Component	Expected Operating Conditions [Volume %]	Operational Excursions [Volume %]
Carbon Dioxide, CO_2	>97	>96
Nitrogen, N_2	< 2	2
Total Sulfur (H_2S & COS)	<65 ppmv	<220 ppmv
Hydrocarbons, (C_1-C_4)	<1	—
Hydrogen Sulfide (H_2S)	<10 ppmv	100 ppmv (max)
Oxygen (O_2)	< 10 ppmv	—
SO_2	<10 ppmv	—
Ammonia	<1 ppmv	—
Particulate Matter (dust, sand, iron oxide, catalyst fines, silicates)	<1 ppmv	—
Carbon Monoxide	<800 ppmv	—
Solvent (Methanol)	<200 ppmv	—
Water, H_2O	0.61 lb/MMCF 13 ppmv Dew point 11°F	1 lb/MMCF (max) 20 ppmv (max)

Further detailed composition information is provided in the Process Design Basis: 16179-MUS-PRO-BD-00-0001.

6.1.3 Hydrogen Sulfide (H_2S)

One of the components that could impact the design of the facilities is the amount of hydrogen sulfide (H_2S) in the various streams. Oxy is still working with HECA to determine the exact composition of the CO_2 supply, potential excursions and lengths of duration. However for this design basis, the H_2S in the HECA supply is assumed to be <10ppm for expected operating conditions but could have excursions as high as 100 ppm. In the well/satellite production streams, the process simulation work assumes 0 ppm H_2S as a base case. Several alternate cases of 10 ppm and 100 ppm are being conceptually evaluated to determine the impact.

6.2 Producing Wells

- Normal Operating Pressure – 300 - 400 psig
- Maximum Allowable Working Pressure - 2200 psig – flowlines
- Average Well Flow Rate (at peak water rate) - 8 BOPD x 4,550 BWPD x 59 MCFD
- Average Well Flow Rate (at peak oil rate) - 300 BOPD x 2,270 BWPD x 5057 MCFD
- Average Well Flow Rate (at peak gas rate) - 149 BOPD x 2,234 BWPD x 5956 MCFD
- High Well Flow Rate - Assume surge capacity of 30% for above cases
- Produced fluid - 1.02 sp. gr. produced water, 37-38 API oil

6.3 Injection Well WAG Metering and Control

The WAG manifolds will provide manual double block and bleed valves in the CO_2 and water piping to allow switching from water to CO_2 injection, a wafer style wedge meter and multivariable transmitter for flow measurement and an actuated flow control choke. A pressure transmitter will also be installed on the skid downstream of the flow control valve to provide tubing pressure. A pressure transmitter will also be installed near the wellhead to measure well annulus pressure. An RTU will be used for metering and control; the RTU will include NIST 14 for CO_2 measurement calculation. If the bottom-hole pressure control algorithm has been developed in the RTU when the order is placed, that will be specified. A radio, solar panel and antenna will be needed to communicate with the host automation system.

Facility work will also include installation of stainless steel piping from the WAG manifolds to the well, flow tee (with check valve), lubricator valve, flow transmitter for casing pressure, rupture disk and blowout control piping.

Design conditions for WAG skids are 17.1 MMCFD, 3000 psig supply pressure and 2000-3000 psig discharge pressure. The 17.1 MMCFD rate will be used for upper end of choke and wedge meter sizing but they must also be able to turn down by approximately 8:1 range. Maximum drop across the skid (assuming a wide open choke) is less than 50 psig. Use ASME B31.4 piping code and OEHI Piping Specifications.

6.4 Fuel Gas (Plant supplied)

Fuel gas is available at the tailgate of the exiting Elk Hills processing plants.

- Pressure 1,200 PSIG
- Temperature 120° F

Component	Mol %
H_20	0.000
N_2	3.750
O2	0.000
CO_2	0.004
H_2S	0.000
C_1	94.362
C_2	1.878
C_3	0.006
iC_4	0.000
nC_4	0.000
iC_5	0.000
nC_5	0.000
C_{6+}	0.000
C_7+	0.000
Total	**100.000**
Molecular Weight	**16.758**

6.5 Fuel Gas (Pipeline supplied)

If applicable (HOLD)

Component	**Mol %**
H_20	
N_2	
O2	
CO_2	
H_2S	
C_1	
C_2	
C_3	
iC_4	
nC_4	
iC_5	
nC_5	
C_{6+}	
C_7+	
Total	
Molecular Weight	

7.0 PRODUCT SPECIFICATIONS

7.1 Pipeline Gas Specification Requirements

Pipeline Specification Gas		
Delivery Pressure	PSIG	1,200
Temperature	°F	120
HHV, max	BTU/SCF	1100
HHV, min	BTU/SCF	995
CO_2, max	mol%	3
Inerts, max	mol%	4
Water, max	LB/MMSCF	7
H_2S, max	gr/100 SCF	0.25
Non-ethane, max	mol%	12
Hydrocarbon dewpoint at 600 PSIG	°F	20

7.2 NGL to Pipeline

- Vapor Pressure @ 100 °F 208 PSIG **(HOLD)**
- Delivery Pressure 365 PSIG
- Temperature ° F **(HOLD)**

8.0 HES REQUIREMENTS

The Elk Hills CO_2 Project will be designed to comply with all applicable industry and corporate codes and standards.

8.1 Safety In Design

Where codes and standards are lacking, and a risk assessment indicates that significant residual risks remain, the following approach will be provided, in order of priority:

- Inherently Safe Design - Application of such measures as substituting benign chemicals for hazardous ones, modifying equipment layout to eliminate hazards, minimize storage requirements for unstable intermediate products, leak detection and containment, eliminate the requirement for personnel to be in high risk areas, are examples that lead to an inherently safe design.
- Instrumented Safety - Risks that cannot be -designed out”, may be amenable to the application of instrumentation for monitoring risk precursors and automatically responding to bring the process to a safe state.
- Safety Procedures - For remaining residual risk, implement procedures that address these risks. The objective of these procedures is to monitor the safety state of the plant (e.g. corrosion, leak potential, etc.) and to promote safe behaviors of plant personnel.

8.2 Equipment Spacing Guidelines

The following Oxy Spacing Guidelines are to be considered when laying out equipment. These guidelines may be modified by the results of a Facility Siting Study.

- EG 301 Facility Siting
- EG 302 Facility Layout and Spacing
- EG 303 Process-Related Buildings

8.3 Emissions - Sources, Limits, Monitoring, Control

The Elk Hills CO_2 Project will be designed to comply with all permit requirements for toxic and priority pollutant emissions. Fired heaters will have ladders and platforms to access ports and platforms to allow sampling for compliance assurance.

Combustible gas detectors will be incorporated in the facilities design.

8.4 Noise

The Elk Hills CO_2 Project will be designed to comply with the OSHA noise requirements of 29 CFR 1910.95. Specifically, the facilities will comply with the limits shown below:

FACILITY WORK AREA/LOCATION	NOISE LEVEL
General Work Areas/Process Operations	85 dBA (2)
Workshops, General Stores, Food Service Facilities (galley/dishwashing/food preparation area)	70 dBA
Note 1: Noise levels are in units of decibels measured on an "A"-weighted, slow response scale. Note 2: Any facility work area/location with a continuous noise source exceeding 85 dBA will be designated as a "High Noise Level Area". These areas shall be adequately posted with warning signs stating that hearing protection is mandatory when working in the area. This Permissible Exposure Limit (PEL) of 87 dBA is based on twelve hour per day work shifts.	

8.5 Flare Radiation Limits

The flare system will be designed to meet the requirements in API 521 and all other applicable codes and standards. The flare will be designed to meet the thermal radiation and noise limits shown below in Table 8.5.1.

Table 8.5.1 Flare Thermal Radiation and Noise Limits	
Emergency Flare Operations (excludes solar radiation)	
Normally manned areas	1500 BTU / FT^2-HR
Property Line	1500 BTU / FT^2-HR
Emergency Stations(areas manned during emergencies)	500 BTU / FT^2-HR
Noise Level (at base of flare stack)	105 dBA
Add 220 BTU / FT^2-HR for solar radiation to express limits inclusive of solar radiation.	

The flare will be designed for smokeless operation, and will not exceed a Ringleman #1 smoke emissions level.

In this regard, the process design effort will strive to eliminate continuous flaring operations.

8.6 Regulatory Requirements / Permitting Support

Regulatory and Permitting will be by others. Project shall provide support as required.

8.7 Environmental Impacts

Design to include Best Available Control Technology (BACT) such that the project will meet California certification requirements for all environmental impacts. Environmental survey and California Energy Commission (CEC), Department of Oil, Gas and Geothermal Resources (DOGGR) and California Environmental Quality Act (CEQA) applications will be performed by a third party contractor.

8.8 Risk Analysis

The Elk Hills CO_2 Project will be designed to comply with all applicable codes, regulations, and standards which will be identified as part of the design philosophy and design basis documents for specific types of equipment. Often these reference documents are not prescriptive but require that a risk analysis be conducted to determine the significance of a potential risk issue. In such cases the frequency and severity of the risk issue can be evaluated through the following types of risk studies or analytical methods.

Consequence Analysis Studies - these studies are conducted to identify the credible release scenarios and assess the severity of the consequences of a credible release using various consequence modeling software tools.

Quantitative Risk Assessments - QRAs are studies directed toward understanding the likelihood that the credible release scenarios and the consequences will occur. The results of the QRA can be applied to the regulatory and corporate cost vs risk requirements to decide whether the risks are tolerable. These studies are typically conducted early in the design phase after preliminary equipment sizing and a preliminary facilities layout have been developed.

Process Hazard Analyses - PHAs include –hazardous identification” reviews (HAZID’s) and hazardous operations reviews (HAZOP’s) with the objective of identifying potential hazards so they can be addressed early in the design.

Dispersion Modeling Analysis - Dispersion Modeling is conducted to determine the extent of a flammable gas plume, before it disperses to safe concentrations. The PHAST software suite (by det Norsk Veritas, version 6.54) for example, is used to model flammable plumes. Should the flammable gas plume encounter an ignition source, the software models the resultant blast overpressures.

The thermal radiation from the resulting jet fire shall be modeled using the Flaresim software (by Softbits). This software uses the API calculation method as described in Appendix C of the API Std 521.

Facility Siting / Equipment Location - Layout design is an iterative process and involves trade-offs between economics and incident severity versus incident frequency before a layout is finalized. Fire, explosion and toxicity risks exert the largest effects on a plant layout. To the degree possible these risks will be identified and evaluated using recognized industry tools such as the Dow Fire and Explosion Hazards index and/or credible release scenarios.

A Facility Siting Study shall be done to API 752 and 753, Facility Siting Regulations and Compliance requirements. This study shall meet a 2” release scenario requirement, as a minimum. At the conclusion of the study, the equipment spacing may be modified to conform to the results. Also, API 752 may require specific building design requirements for over-pressure protection.

8.9 Fire Safety

Preliminary design of the firewater system has allowed for two firewater pumps at a minimum of 1,500 gpm each. One pump will be powered by an electric motor, while the second will have a diesel driver. A firewater storage tank has also been provided in the initial design with a capacity of 4 hours with one pump running continuously. This design will be verified and finalized during the FEED phase including location of monitors, hydrants foam system and deluge where required by Oxy EG-307. Fire Extinguishers of appropriate quantity and type shall be provided in accordance with Oxy EG-307.

The requirements for fireproofing to be developed during FEED in accordance with Oxy EG-308.

8.10 Site Security and Fencing

The main processing facility shall be fenced and secure access provided adjacent to the administration/control building. No site specific security provisions have been addressed for the Satellites and Pipelines. However, these facilities are located within the boundary limits of the Elk Hills preserve, and fences with manned gates provides secure access to the entire site.

9.0 EQUIPMENT RELIABILITY, SIZING AND SPARING PHILOSOPHY

Preliminary design has included a 50% spare train for the CO_2 Re-injection Compression system in the RCF. This is to provide continuity of service during the early years of the facility to ensure maximum injection gas availability. Additionally, the early design of the CTB allows for two of the three Gas Separators to be installed to allow maximum water production availability during that same time period. This preliminary design will be finalized during the FEED phase of the project. A Reliability, Availability and Maintainability Study (RAM) shall be performed during FEED.

Equipment size selection and sparing at the processing facility shall be:

- CO_2 Plant – 2 x 50% trains
- Tower – 1 only, no sparing
- Centrifugal compressors – 2 x 50%, except for CO_2 Re-injection Compressors at the RCF which will be 3 x 50%.
- Pumps – N+1

10.0 CIVIL / STRUCTURAL DESIGN REQUIREMENTS

All Civil and Structural design shall comply with California State design codes and with the requirements of Kern county.

10.1 Site Layout

The Elk Hills CO_2 Project site will be located within the existing Occidental of Elk Hills facilities.

10.2 Storm Water Drainage

The storm water drainage system design will be designed to meet site permitting requirements.

10.3 Roadway and Pavement

Roadway and pavement design for the CO_2 project will be compatible with the existing plant construction.

10.4 Foundations

Specific type of foundations for major equipment will be selected according to the recommendations of the project geotechnical report including seismic zone 4 requirements. The preliminary design assumes spread footings.

10.5 Soil Conditions

Soils data from four projects in other areas at Elk Hills, and this data was summarized and used for the Pre-FEED work. The summarized information is recorded in document 16179-MUS-CVS-RP-00-0001. Anticipated soils conditions were bearing pressures of around 2,000 psf, and for excavated material being suitable for reuse as fill.

Site-specific soils investigations and geotechnical requirements shall be developed during FEED and civil designs determined accordingly.

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10.6 Piperacks and Steel Structures

Piperacks and steel structures supporting process equipment, air coolers, and cable trays will be provided. Steel walkways and platforms will be provided for maintenance access.

Fireproofing of piperacks and other steel structures may be required for the Elk Hills CO_2 Project. Criteria for the fireproofing placement to be established during FEED according to the plant operating requirement and risk analysis.

All structural steel to be hot dipped galvanized. Follow Oxy specification on painting, coating, etc.

11.0 MECHANICAL DESIGN REQUIREMENTS

11.1 Equipment Design and Sizing Requirements

Equipment design will be based off material and energy balance information calculated from the HYSYS and PROMAX process simulation programs.

Exchangers shall be sized using a 110% design margin on the flow and duty.

The system design pressure shall be calculated to be operating pressure plus 50 PSI or operating pressure plus 10%, whichever is greater. In cases where liquid would dump to a downstream vessel, the downstream vessel would have a minimum design of the upstream operating pressure. The system design temperature calculated to be the maximum operating temperature plus 50°F.

Internal corrosion allowance to be used in the vessel design shall be as designated on the pressure vessel data sheets. The internal corrosion allowance shall be applied to all pressure bearing members including the shell, heads, nozzles, closures and all members contained within the pressure vessel.

Equipment and piping materials shall be in accordance with the Material Selection Philosophy 16179-MUS-MEC-PH-00-0001.

No ―yellow” (copper, brass, bronze, etc.) materials are allowed to contact the process fluids.

11.2 Pressure Vessels

All pressure vessels shall be designed, fabricated, inspected, tested and stamped in accordance with ASME Code, Section VIII, Division 1, unless noted otherwise. All vessels shall be registered with Nation Board Inspection Code (NBIC).

All low pressure vessels operating below 15 PSIG and requiring no ASME Code stamp, shall conform to the requirements of code and project specifications with regard to design, materials, welding and fabrication. NDE is not required for these vessels or drums but hydrostatic test shall be performed at 40 PSIG and shall be maintained for minimum for 1 hour without leak.

Pressure vessels shall have only flanged connections, minimum 2” in size (exception for compressor pulsation bottles).

All vessels or tower over 4 feet in diameter shall have 24-inch nominal manway.

All vessels less than 4 feet in diameter shall have 18 inch (nominal) manway unless stated otherwise.

Level control dump valves shall be off the bottom head through the skirt opening.

Vane pack mist eliminators can be used in lieu of mesh pad mist eliminators reciprocating compressor –skid” scrubbers to reduce vessel diameter.

Suction pulsation bottles will be furnished with 1” NPT connections for installation of vents, drains, pressure instrument taps and thermowells. Small NPT connections are preferred, in reciprocating compressor service, from a vibration standpoint due to the lower combined weight of connection and valve.

Likewise discharge pulsation bottles will be furnished with 1” NPT connections for installation of vents, drains, pressure instrument taps and thermowells. Since these vessels normally operate above the water dewpoint, no corrosion is expected.

11.2.1 Test Separators

- Design Information
  - Rate – 500 BOPD x 4,000 BWPD x 3 MMSCFD
  - Minimum oil pad thickness of 6” or retention time of 5 minutes
  - Water retention time 5 minutes
  - Total liquid height approx 60% of vessel diameter
  - Bucket and weir design
  - Include Burgess Manning type gas dome
  - Include wave breakers, inlet diverters and gas coalescers (vane mist extractor)
  - Internal coating for corrosion prevention

11.2.2 Production Separator

- Design Information
  - Rate: 20 well unit - 2,820 BOPD x 66,340 BWPD x 71.42 MMSCFD
  - Rate: 30 well unit – 4,230 BOPD x 99,510 BWPD x 107.13 MMSCFD
  - Retention time of 3 minutes plus 12” of surge capacity
  - Total liquid height approx 50% of vessel diameter
  - Low-low in vessel to close SDV on header.
  - Include Burgess Manning type gas dome
  - Include wave breakers, inlet diverters and gas coalescers (vane mist extractor)
  - Internal coating for corrosion prevention

11.2.3 LP Gas Separators (or called Inlet Separator)

- Design Information
  - Liquid retention time 3 minutes
  - Total liquid height approx 40% of vessel diameter
  - Include Burgess Manning type gas dome
  - Include inlet diverter, wave breakers and gas coalescing
  - Internal coating for corrosion prevention

11.2.4 Flume - (elevated atmospheric separator to remove gas before going to the skim tanks)

- Flume (n+1) – Design Information
  - Design pressure 50 psig; however vessel is non ASME sec VIII code since it will be made out of pipe and plate.
  - 100% X-ray (where accessible)
  - 24” Manway on bottom
  - Include inlet diverter
  - Access manway or flanged connection on top for access for coating.
  - Internal coating for corrosion prevention

11.3 Compressors

The following large compressors have been included in the preliminary design:

- K-6000/6001 – Two propane refrigeration compressors (2 x 50%) are to be skid mounted motor driven multistage centrifugal compressors. Approximate horsepower is 10,400 hp each.
- K-3110/3220/3310 – Three Re-injection Compressors (3 x 50%) which are two stage, single body, centrifugal compressors. Approximate horsepower is 15,350 hp each.
- K-4170/4180 – Two Booster Gas Compressors (2 x 50%) which are single stage, centrifugal compressors. Approximate horsepower is 7,050 hp each.
- K-2210/2260 – Two LP Gas Compressors (2 x 50%) which will be oil-flooded screw compressors. Approximate horsepower is 1,000 hp each.
- K-4800/4810 – CO_2 Product Compressors (2 x 50%) which is are 5-stage reciprocating compressors. Approximate horsepower is 450 hp each.

- K-5110/5120 – Two NRU sales gas compressors (2 x 50%). Approximate horsepower is 1,000 hp each.

A preliminary cost analysis was performed on the three large compression services, in order to determine the relative cost difference between motor driven centrifugal compressors versus motor driven API-618 slow speed reciprocating compressors. From this analysis it became apparent that centrifugal compressors would be 50% or less of the total installed cost of reciprocating compressors.

The project team directed the decision to use two 50% units for these services. We recommended these centrifugal compressors be driven by a variable speed method and have included the cost of the Voith Vorecon variable speed planetary gearbox as the most economical was of obtaining this control. A preliminary cost analysis has put the incremental costs of the Vorecon variable speed gearbox at about half the total installed cost of a variable frequency drive and associated components. Efficiency of either method is about the same.

With two 50% centrifugal compressors it is recommended to include a spare modular bundle for each pair of compressors. The modular bundle is more expensive but it comes ready for installation into the case. The modular bundle comes complete with heads, seals, bearings housings, and bearings. It results in a quick change-out.

The selected LP Compressors are Howden oil flooded screw compressors. This brand and type of screw compressor has been used very successfully by Oxy Permian in the North Hobbs unit. The 8.5 compression ratios can be handled by just one compression stage. We have sized these units as two x 50% units.

The small flow and high overall compression ration limits the CO_2 Product compressor to only a reciprocating compressor. We obtained a performance and cost estimate from Dresser-Rand for 12” stroke 5HHE-VB-5 operating at 321 rpm. The total brake horsepower for this service is 379 hp, hence the 450 hp recommended motor size. Due to the small size here and the five throws needed to handle five stages of compression, we have sized these units at two x 50%.

In the case of the Reinjection compressor at the RCF, 3 x 50% units were selected to provide full CO_2 compression volume should one of the RCF or CRP 50% compressors be down.

Reciprocating compressors will have double distance pieces to reduce the risk of contaminating the compressor frame crankcases with process gases. The inboard and outboard distance piece drains can be shared between compressors when each drain is equipped with a liquid seal leg. Inboard distance piece vents are to be vented locally to the atmosphere. Outboard vents and packing vent/drain connections will be tied into a vacuum system, to be routed to the flare.

All compressors are to have temporary inlet strainers.

11.4 Exchangers

11.4.1 Air Coolers

Ambient design temperature (dry bulb) for air coolers shall be 110 °F.

All air coolers shall comply with API 661. In addition to normal design loads, main process nozzles shall be designed for moments and loads which are at least THREE times the values shown in Table 4 of API-661. All motors shall be rated for variable frequency drive (VFD).

Fans shall be driven with high torque type belt.

Each fan shall be equipped with a vibration transmitter, Metrix ST5481E.

All coolers shall have header walkways on each header end, with access via a single caged ladder at each end of cooler.

Structural steel shall be galvanized and headers shall be hot metallized sprayed.

All coolers shall be located at minimum heights to provide adequate airflow to fans.

Air coolers shall not exceed the noise limits 85 dBA @ 3 feet (measured three feet below the forced draft fan).

11.4.2 Shell and Tube

Shell and Tube Heat Exchangers shall be per API 660 and TEMA. Refer to Pressure Vessel section 11.2 for additional requirements.

11.5 Centrifugal Pumps

Pumps in hydrocarbon service shall comply with API Standards. Pumps that are considered to be in critical service shall have an operating spare whereas pumps in non-critical service will have single pump.

<u>FOR FIELD FACILITIES AND PLANT (EXCLUDES FIELD PIPING SYSTEMS)</u>
The available NPSH for pumps taking suction from vertical towers and drums shall be determined from the bottom tangent line. Pumps taking suction from horizontal vessels shall be determined from the bottom of the vessel. In all cases, the available NPSH shall provide for a minimum margin (safety factor) of two feet or maximum 6 ft/sec. In all cases, the pump suction line and block valve shall be at least as large as the pump suction nozzle.

Where pressure drop consideration permits the discharge block and check valves at pumps may be smaller (reduced bore valves) than the discharge line size, but not smaller than the pump nozzles.

Particular required features are:

- Mechanical seals for the 5000 hp Produced Water Injection pumps shall be a John Crane API-682 cartridge type mechanical seal. For many of the CO_2 pumps the vendors have recommended and proposed Champion seals due to the long time satisfactory performance in CO_2 services in West Texas. Design and materials of seals shall be per pump or seal manufacturer recommendations. When seal pots for tandem seals are necessary the flush plans shall be equipped with a pressure transmitter and a welded level gauge on the seal pot.
- Centrifugal pumps shall have a Y-strainer or basket strainers.
- Minimum Flow Bypass for Centrifugal Pumps
- Vertical pumps may be used up to 75 HP.
- Cast or ductile iron may be used for pressure containing utility pumps.
- Pumps and drivers (50 HP and above) shall be doweled to structural skids or foundation after final alignment.
- Certificate of Conformance (C of C) for materials shall be required.
- NPSH test shall be required for margins of 3 feet or less between NPSHA and NPSHR.
- Hydrostatic pressure test shall be required for all units.
- Performance test shall be required for first of the service, with option for testing all.

11.6 Piping

The following should be used for pressure drop design in all the facilities.

The determination basis of frictional pressure drop in piping conveying single phase liquids other than waste and drainage shall be the Darcy equation using friction factors based on Moody's correlation, except for certain extremely viscous (non-Newtonian) fluids requiring special techniques.

An absolute roughness value of 0.0005 shall be used for all piping except a value of 0.00015 shall be used for stainless steel piping in low temperature service.

The determination of frictional pressure drop in sewers and drains shall be on the basis of the Manning equation using roughness coefficients (n) of 0.015 for clean coated or uncoated cast iron and vitrified clay pipe, 0.015 – 0.035 for dirty or corroded cast iron or steel pipe, 0.012 – 0.017 for concrete pipe, and 0.013 for steel pipe.

Piping in intermittent service (such as start-up, pump-out, and bypass lines) shall be sized on the basis of the available pressure differentials.

Utility air lines shall be sized to keep the pressure drop between the air receiver and the last point of use, including the pressure drop in the air hose, under 10% of the initial pressure.

Unless otherwise noted, maximum allowable pressure drop will be as noted below:

Liquids:

Pump suction – Liquids within 50 degrees F of their boiling point 0.04 to 0.20 psi/100 ft
Pump suctions – Other liquids 0.20 to 0.4 psi/100 ft
Pump discharge – Liquids within 50 degrees F of their boiling point 0.4 to 1.6 psi/100 ft
Pump discharge – Other liquids 0.8 to 2.0 psi/100 ft

Gases, Vapors and Steam:

Vacuum – 0.016 to 0.20 psi/100 ft
0 to 50 PSIG – 0.08 to 0.20 psi/100 ft
51 to 300 PSIG – 0.08 to 0.60 psi/100 ft
Over 300 PSIG – 0.08 to 1.2 psi/100 ft

Reboilers
Inlet and outlets on the process side of each reboiler shall be sized to handle 125 percent of the design flow rate without exceeding 80 percent of the available pressure differential.

Two-Phase Mixtures
Size shall be based on available differential, flow regime, and recognized methods to predict two-phase flow properties. When slugging or pressure fluctuations may adversely affect operations, piping that will handle mixtures of liquids and vapors should be sized to produce an average fluid flowing velocity of 25 to 40 feet per second. If the available pressure drop is insufficient to size the entire pipe length for higher velocities, than only the vertical pipe sections for upward flow should be reduced to obtain 25 to 40 feet per second velocities. The reduced size should begin in the horizontal line with an eccentric reducer, flat side down, than a reduced size elbow to start the rise.

Vmax = 100/(density of process fluid)^0.5, where density is in lb/ft^3; there might be some instance where it would go with a 150 or higher in the numerator, but these could be on a case by case basis.

Flare Header – 200 to 300 fps
Flare Stack – 180 fps (also discuss with Flare manufacturers)
Flare Tip – 60 fps (also discuss with Flare manufacturers)

11.7 Valves

All valves shall have metal seats unless otherwise approved. Soft seats are allowed if fire exposure is minimal; however, the valves must meet API-607.

Gate valves are to be used predominantly unless the process requires other types of valves. This includes block, isolation, and root connection valves. Vanessa trunnion rotary disc valves may be considered for some services. All heat medium valves are to be gate valves with removable bonnets, even for socket welded valves.

Make a reasonable effort to locate frequently used valves accessible near grade or a platform.

Use chain operator on frequently used valves that are located over 8’ above grade or platform.

ESD and isolation valves shall be meet the requirements of API 6F.

11.8 Pressure Safety Valves (PSV)

A block valve is to be provided upstream of all PSV's with a bleed valve located between the block valve and the PSV, unless the equipment can be independently isolated for testing without loss of process operations. A 1½" gate bypass will be provided on certain PSVs. Globe valves are not required on by-passes. A downstream block will be provided for each unit's PSV.

In general, bellows type PSV's shall be used. However, pilot operated PSV will be used when one or more of the following conditions are matched:

- The normal operating pressure is within top 10% of the relief setpoint
- The relief capacity requires PSV of 4" or larger inlet
- Low operating pressure (15 PSIG or less)
- Inlet flange rating is ANSI 900 or higher
- When bellows type PSV requires larger size than pilot type due to capacity requirement and high backpressure

Pulsation dampeners are to be provided if pilots are used where pulsation service is expected, such as compressor discharges.

12.0 ELECTRICAL DESIGN REQUIREMENTS

OEHI has plans to install a new 320/115 kV electrical substation and electrical distribution lines in the Elk Hills field. This new substation is expected to provide 500 MW of power from PG&E (Pacific Gas & Electric, the utility company). It is to be assumed the power distribution upgrade will be completed in time for the CO_2 Project, and that sufficient power can be made available. The electrical loads from the CO_2 Project need to be incorporated with the current OEHI electrical forecast to adequately size the substation.

No power is required to be provided to HECA.

Power will be required at the main CO_2 processing facility in Block 27S, each of the 13 satellites and also at the heater area at the A1/A2 Backup Injection Facility in Bock 7R.

12.1 General Requirements

The design will ensure:

- Safety to personnel during operation and maintenance
- Reliability and continuity of service
- Easy maintenance, convenience of operation
- Interchangeability of equipment
- Adequate space available for future expansion and modifications

12.2 Voltage Levels

High Voltage	115 kV / 12.47 kV, 3 Ø, 60 Hz, Low – Resistance Grounded

Medium Voltage	4.16 kV, 3 Ø, 60 Hz, Low – Resistance Grounded
Low Voltage	480 VAC, 3 Ø, 60 Hz, High – Resistance Grounded
Lighting / Small Load	208 / 120 VAC, 3Ø, 60 Hz, 4-wire
Control	120 VAC, 1 Ø, 60 Hz, two-wire
Direct Current	125 VDC

12.3 Short Circuit Requirements

Switchgear, motor control centers, and circuit breakers shall be engineered based on the following short circuit levels:

15 kV systems	63 kA
4160 V systems	50 kA
480 V systems	85 kA

12.4 Spare Capacity Requirements

Feeders to switchgear and transformers shall be designed with 20 % spare capacity.

Transformers sizing shall include 20 % spare capacity

Switchgear and MCCs shall include 10 % spare capacity.

12.5 Area Classification

Classification of areas and installations shall be in accordance with API-RP 500, 1997. Equipment and materials shall be suitable for the area classification.

12.6 Power Supply Requirements

Power will be supplied from a new 115 kV transmission line. A new substation will be designed and constructed containing the following equipment:

- One incoming steel —Dead End” structure supporting the tap line from new 115 kV line
- 9 - 115 kV Outdoor Main Power Circuit Breakers (Type SF6)
- 24 – 115 kV Outdoor Disconnect Switches
- 4 – 30/40 MVA Liquid-Filled Power Transformers with Load Tap Changers
- Four 1000 A, Ten-Second Neutral Grounding Resistors
- Pre-Fabricated Switchyard & Substation Switchgear Building to house substation related switchgear, 125 volt batteries and charger, switchgear motor control center, relaying panels.
- Two 125 VDC Battery Systems with Battery Chargers and substation relaying and control equipment.

The secondary side of the substation transformers will interface with the switchgear utilizing 12.47 kV, 2000 A copper bus duct. A pre-fabricated Switchgear and Control Building will be located at the main substation area.

12.7 Medium Voltage Switchgear

Medium voltage switchgear shall be suitable for indoor installation; ambient rated to the site maximum temperature. Expandable from both ends, free standing assembly, single height vertical sections, arc resistant structures (Type 2), front and rear access, main-tie-main configuration.

12.8 Medium Voltage Motor Control Centers

Medium voltage MCCs shall be suitable for indoor installation; ambient rated to the site maximum temperature. Expandable from both ends, insulated bus, tin plated, 50 kA bracing, main-tie-main configuration, Type 2 arc-resistant structures, front access only. Starters shall be full voltage across-the-line starting, two contactors per vertical section with current limiting fuses, voltage transformers and relay protection in the side compartment.

12.9 Low Voltage Motor Control Centers

Low voltage MCCs shall be suitable for indoor installation; ambient rated to the site maximum temperature. Expandable from both ends, insulated bus, tin plated, 85 kA bracing, main-tie-main configuration, back to back line-up. Starters shall be full voltage across-the-line starting, motor circuit protector - contactor configuration.

12.10 DC Power Supply Systems

DC power supply system shall supply continuous 125 VDC power to switchgear and relays.

The unit will consist of one 110% Lead Selenium battery bank, one 110% rectifier charger with 150 % loading capability. Backup time shall be eight hours. AC input to the DC system shall be 240 V, single-phase, 60 Hz.

12.11 Uninterruptible Power Supply System

Total of four uninterruptible power supply UPS systems, three for BPCS & SIS systems and one for F&G system, located in three MCC buildings in the plant. Each UPS consists of 125% nickel cadmium battery bank, static & automatic transfer switch. AC input 480 VAC, three-phase, 60 Hz AC output 120 VAC, single phase, 60 Hz. Battery backup time is one hour for BPCS / SIS, and eight hours for F&G.

12.12 Illumination Levels

Levels of illumination for the design of lighting systems shall be based on the illumination intensities indicated below. These are in-service values after applying a maintenance factor of 0.7 and a utilization factor depending on the type of the fixture. These figures are the minimum vertical component values for the locations described on a horizontal plane being 0.75m from the floor levels in buildings and the ground or platform levels in other areas:

Area Description	Lux
Outdoor Area	20
Walkways, Platforms, Stairs	50
Control Rooms	300
Compressor & Utility Shelters	150
Electrical Rooms	200

12.13 Cable Tray

Cable trays shall be aluminum ladder-type, 9” rung spacing, with 6” minimum side rails.

Cable tray widths, load bearing requirements and maximum spans will be determined during detailed design. Separate cable tray systems shall be provided for the following:

- Medium voltage cables
- Low voltage power and control cables (power and control cables shall be separated)
- DC control, instrumentation, fire and gas and communications

  Barriers shall be installed separating fire and gas signal cables. If intrinsically safe circuits are required, they will be separated from all other circuits by use of barriers and shall be labeled accordingly.

Cables in Tray Arrangement:

- Medium voltage cables will be arranged in a single layer per NEC 392.12 and with respect to allowable ampacity requirements.
- Low voltage cables will be arranged per NEC 392.9(a).
- Control and instrumentation cables will be arranged per NEC 392.9(b).

12.14 Cabling

All medium voltage and direct burial cables will be copper multi-conductor, armored, with a PVC outer jacket suitable for ladder style cable tray and direct burial. Cables will be flame retardant and UV resistant. Medium voltage cables in addition to the above will be shielded, XLPE insulated, PVC sheathed. Control cables will be Type TC.

13.0 CONTROL SYSTEMS & INSTRUMENTATION REQUIREMENTS

13.1 General Instrumentation Requirements

Project specifications define general field instrumentation requirements. OEHI has existing field communications, automation and Central Control Facility (CCF). Each site will need appropriate automation and telecommunications to communicate to the existing system.

A control room is to be included at the main CO_2 processing plant in 27S to cover the operation of the RCF, CTB and CRP. The Satellites are to be unmanned.

13.2 Control and Safety Systems

The Design Basis shall be revisited, and may be revised during the FEED or Detail Design to match the latest technology options at the current time.

13.2.1 CO_2 Gas Plant Facility

The plant Integrated Control and Safety System (ICSS) shall be a Distributed Control System (DCS) with monitoring, control, and shutdown capabilities. The ICSS shall consist of an Emerson DeltaV as the facility's Process Control System (PCS), and an Emerson DeltaV SIS as the facility's Safety Instrumented System (SIS). There will not be a separate process area Fire and Gas System (FGS). All process area Fire and Gas detectors shall be wired to the SIS when used for a shutdown, and to the PCS when used for alarming only. The PCS and SIS shall be seamlessly integrated with each other at the common operator interface. The configuration, maintenance, and operating environment for these systems shall be achieved from the same Human Machine Interface (HMI) / Engineering station. There will be several HMIs that can view and monitor the entire facility. Each HMI shall be capable of achieving the same functionality in case one HMI fails. Each system shall be physically (hardware & I/O) and functionally separated from each other; such that each system shall operate independently regardless of the status of any other system. The benefits of having an integrated system are lower engineering, configuration, training, and maintenance cost due to the reduced complexity of system interfaces.

Note: *The Fire and Gas System for the process areas shall be incorporated into the SIS; the Fire and Gas Control Panel for the occupied buildings shall be a separate system supplied by the Building Manufacturer.*

The CO_2 Plant will be controlled from a new CO_2 control building with-in the plant area. The new control room will contain Operator Workstations (OWS) and Engineering Workstations (EWS) to provide operators a means of interfacing and controlling the CO_2 Plant's process, and injection and production wells. The new CO_2 control equipment will be added to the existing Oxy Elk Hills control system, and will be connected via fiber optic ring from the CO_2 control building to the existing Central Control Facility. With the correct security access, the operators in the Central Control Facility will have the ability to view, or even control (depending on OEHI requirements), the new CO_2 Plant.

For ease of maintenance and a preferred environment for electronic equipment, the control panels for the Control and Safety System shall be located in non-hazardous air-conditioned buildings inside the CO_2 Plant area. Control panels containing Controllers and there respective I/O modules, or Logic Solvers, will be strategically placed in MCC and Switchgear buildings throughout the plant area. This will allow panels to be closer to the process and electrical equipment that will be controlled by the ICSS, and reduce homerun cable lengths.

The DeltaV control network shall be extended with fiber optic cables from the CO_2 Plant's Control Room to all the MCC and Switchgear buildings that contain control cabinets.

The ICSS shall have the ability to operate the CO_2 Plant as a minimally manned facility and provide all process control, safety shutdowns, and interlocks required within the design. For more details, please see 16179-MUS-AUT-DWG-00-0001, ~~"C~~Control & Safety System Architecture Diagram".

Note: *The general philosophy of Oxy Elk Hills is to control the overall Elk Hills area from the Central Control Facility (CCF), and put all new controller and I/O cards on the existing DeltaV Pro Plus system. Due to the constant expansion and future projects of Oxy Elk Hills, the existing Pro Plus will need to be looked at closely during detail design to see if it can handle an addition of this size of project. If the existing system cannot handle the new addition of this project, it is recommended that the scope of the CO_2 Project be placed on a new DeltaV Pro Plus and be connected to the existing DeltaV Pro Plus via a Zone architecture. This decision has a negligible impact on the project cost and risk.*

13.2.2 Satellite Gathering Sites

Each satellite site will have a DeltaV panel with a controller and I/O cards. The DeltaV controller will communicate back to the DeltaV network in the CO_2 Plant via a fiber optic cable. This control panel will be used for controlling any local satellite site processes.

A radio antenna, located on a pole, is required at each satellite site. The radio pole will be used to communicate to all the related production and injection well control panels. The radio signal will be converted to fiber at the satellite site and communicated back by fiber optic cable to the CO_2 Plant for operator interaction. A Mynah VIM card will be used as the DeltaV interface module to communicate to all of the production and injection wells control panels. Detail Design shall determine if the VIM card will reside at each of the satellite sites, or at the CO_2 Plant.

Note: *Due to the terrain of hills, radio antennas will have to be strategically placed in some cases to ensure a good signal and communication to each well site. There is minimal risk using radio, but the minimal risk outweighs the cost of fiber to each well site. Radio shall be further evaluated in the FEED.*

13.2.3 Production and Injection Well Sites (Verify in FEED)

Each well site will have a control panel containing a MicroLogix 1100 PLC, Radio, and Beijer HMI. The MicroLogix PLC will interface directly to the wells for data collection or control. The MicroLogix will then communicate via radio to the corresponding satellite site's radio antenna. From the satellite site, well data will then be transmitted via fiber optic to the CO_2 Plant.

13.2.4 Fiber Optic Backbone

The project will run a fiber optic backbone cable from 17R to 35R at Skyline Road, and from 35R to 2G down Skyline Road. This will allow OEHI to complete a fiber loop through the entire Oxy Elk Hills area. From the main backbone fiber cable, fiber homerun cables would be run to each satellite site in a ~~"S~~Spur" type fashion.

Note: *Currently there is a fiber backbone from 35R to 2G down Skyline Road. This fiber belongs to Oxy Elk Hills IT Department and does not have enough capacity for this project. Therefore, it is being proposed to run new fiber down the same route to increase capacity. This new fiber will allow OEHI to create a fiber loop. During the FEED, satellite communication shall be evaluated as a back-up. Satellite cost as a back-up has negligible impact on the CAPEX of the project.*

13.2.5 Process Control System (PCS)

The PCS shall be designed to:

- The entire system shall be redundant accept for the I/O cards. This includes, but is not limited to, redundancy for all control modules, power feeds, power supplies, communications, HMIs, etc.
- Provide information to Operators and enable them to operate the process plant from the control room.
- Log and archive operating parameters
- Interface with other systems such as PLC's for packaged equipment.
- The PCS shall be an Emerson DeltaV based system that consists of:
- Redundant control processors
- Input and Output (I/O) modules to interface with field devices.
- Redundant 12 V and 24 V power supplies for the control processors, I/O modules, and loop power.
- Redundant Ethernet / Fiber-optic switches
- Fiber-optic modems for serial communication
- NEMA 12 Rittal Enclosures (cabinets) to house the above
- Control Processors
- Shall be Redundant MD Controllers version 10.3 or higher
- Shall be sized to handle control loops, computation algorithms with a minimum of 40 % spare capacity
- Control loops such as Cascade, ratio loops shall be processed in the same control processor. Processing information across the network shall be minimized.
- I/O Modules
- Shall be able to handle 4-20 mA Input and Output signals with HART communication, Thermocouple inputs, RTD inputs, Discrete In (Dry Contact), Discrete Out (24 Vdc), and Serial communications
- Analog Input and Output modules associated with control loops shall be Redundant.
- Enclosures
- Control Processors, I/O Modules and Marshalling shall be located in the same cabinet

- Homerun cables shall be landed and marshaled inside the cabinet
- Homerun cables shall be marshaled before being landed on I/O modules
- DeltaV Pro Station
- The Professional Station shall contain Control Studio, DeltaV Operate, DeltaV Tune, Diagnostics, and OSI Pi History View
- The Pro Station shall provide the Operator process graphics, point information, trends and event information, and alarm management tools
- The look and feel of the graphics and control configuration shall match those existing at OEHI as close as possible
- Power Supplies
- The systems shall have two 100% DC power supplies. The DC power supplies shall handle DC loads such as the control processor, I/O modules, and field instruments. The power supplies shall be fed by the UPS power source. See Section 12.11 for more UPS details.

13.2.6 Safety Instrumented System

The SIS shall be designed to:

- The entire system shall be redundant accept for the Logic Solvers. This includes, but is not limited to, redundancy for all control modules, power feeds, power supplies, communications, HMIs, etc.
- Provide an additional layer of protection for the plant.
- Perform Process Critical Safety Functions and Shutdowns.
- Implement Safety Functions with dedicated hardware, software, and networks that are separate from the PCS.
- Seamlessly be integrated with the PCS at the workstation level so the configuration, maintenance, and operations environment are consistent with the PCS
- Be configured and programmed through the same HMI stations as the PCS

The SIS shall be a DeltaV SIS based safety system consisting of:

- Redundant MD Control Processors version 10.3 or higher
- DeltaV SIS Logic Solvers (SLS 1508) to interface with field devices
- Redundant 12 V and 24 V power supplies for the control processors and Logic Solvers. Logic Solvers use separate power supplies.
- NEMA 12 Rittal Enclosures (cabinets) to house the above

The manual ESD pushbutton stations shall be strategically located throughout the plant, and be hard-wired to the SIS.

13.2.7 Fire and Gas Detectors

The PCS and SIS shall be used to monitor the fire, H_2S and combustible gas throughout the plant.

The FEED will need to determine the voting scheme of the detectors to perform a shutdown. For example, it may be desired to need 2 or 3 detectors in one area before initiating a shutdown to minimize spurious trips do to false readings or detectors failures.

Operations will have the ability to perform maintenance bypasses on failed fiels devices to perform maintenance. Refer to the Control and Safety System Philosophy for more details.

Field Detectors

- Fire Detectors – UV/IR flame detectors shall be installed in the combustible gas and flammable liquids processing facilities.
- Smoke Detectors - Ionization type smoke detectors shall be installed in the MCC buildings, substation building, and other buildings facilitate electrical equipment.
- H_2S Detectors (If necessary) - Semiconductor type H_2S detectors shall be installed in the compressor building and throughout facilities with high-risk H_2S leak.
- Combustible Gas Detectors - Infrared type combustible gas detectors shall be installed in the compressor building and other combustible gas and flammable liquids processing facilities.
- Manual Fire Alarm Stations to be provided in important areas in accordance with Oxy EG-306.

13.3 Unit Control Panels

Each UCP shall be a PLC based panel and be equipped with a panel mounted Human-Man Interface. The panel shall be a NEMA 4X metal enclosure and be located by the skid. All skid related indications and alarms shall reside on the UCP and be shared with the PCS as required. Only the ESD signals shall be routed to the SIS.

The UCP will communicate with the PCS via the Ethernet based fiber-optic LAN. The UCP will be hard wired to the SIS for the emergency shutdown signals.

Refer to OXY Automation Technology Group ~~–S~~tandard PLC Specification” Revision 1.41 for more Vendor-provided PLC information.

13.4 Process Shutdown and Emergency Shutdown Philosophy

13.4.1 Basic Process Control System

PCS responds to process upsets, such as loss of liquid level shutting down a pump, without any signal automatically triggering an emergency shutdown event. Several process shutdowns may occur simultaneously within a system, each being triggered by its own means. A process related shutdown is limited to a single function in a process unit, although in certain cases other selected process functions may also be shutdown. A process shutdown may also indirectly respond to an safety shutdown event, as in the case of loss of feed to or from an area isolated by an safety shutdown event.

In essence, the objective of the process shutdown is to contain the upset by isolating the affected system while causing the least disturbance to the other systems, enabling a rapid and straight forward re-start when the cause of the process shutdown has been rectified.

13.4.2 Safety Instrumented System

SIS responds to one or more of the following events:

- The PCS does not control a process upset, and the safe limits of operation are exceeded.
- Upon the fire and gas detection system actuation.
- Upon manual actuation (initiation by push button action).

Once activated, the system should initiate the isolation, shutdown, and depressurization and/or blowdown of the appropriate section of the process or facility, before the situation becomes "unsafe". The equipment to monitor the shutdown parameters should be provided in addition to, and independent of, that provided for normal facility control.

13.5 Field Instruments (Verify in FEED)

PCS and SIS systems shall have independent field instrumentation, including independent taps and unique bridals.

In general, all transmitters (pressure, differential pressure, temperature, level) will have the following options:

- Local LCD display
- Explosion proof for Class I, Division 2, Group D hazardous area

13.5.1 Temperature Instruments

All RTDs and thermocouples will be accompanied by temperature transmitters for PCS and SIS inputs. All transmitters to be Rosemount 3144P with HART protocol.

13.5.2 Flow Instruments

- Honed meter runs with senior orifice holders will be used for custody transfer applications (ultrasonic is also ok if preferred by the client). Orifice plates or liquid turbine meters may used for non-custody applications. Wedge meters should be used for liquid and gas applications on widely varying flows (flows requiring turndowns up to 10:1).
- All multi-variable flow transmitters will be Rosemount 3095FB communicating with RS-485 Modbus protocol. Temperature for flow compensation will be provided by a RTD wired to the 3095FB.
- All ΔP flow transmitters will be Rosemount 3051C with HART protocol.
- Senior orifice fittings to be used for meter skid. Others to be tapped flange-type orifice meters.

- Flow meter body material shall be carbon steel or stainless steel as governed by piping specification.

13.5.3 Level Instruments

- Sight glass level gauges to be used on all vessels - no magnetic level gauges - except where vessel is below grade, then a top mounted float magnetic level gauge and switches may be used.
- Interface level control to utilize two pressure differential controllers. Density of fluids to be operator set, and level of each interface can then be calculated.
- ΔP level transmitters will be Rosemount 3051L with HART protocol.
- Rosemount 1199 diaphragm seal system will be used with all differential pressure transmitters. A 3" seal diaphragm with direct-mount connection - transmitter welded on flange - will be used on high pressure side. A 3" seal diaphragm and 0.03" PVC coated, 316 SS armored capillary will be used on the low pressure side.
- Displacer type level transmitters, if used, will be external cage type with 1½" connections installed on bridles (no direct connections to vessels).
- Mechanical level switches are not allowed.

13.5.4 Pressure Instruments

- Pressure and ΔP transmitters will be Rosemount 3051C with HART protocol.
- Pressure transmitters will be equipped with integral two-valve manifolds
- ΔP transmitters will be equipped with integral five-valve manifolds

13.5.5 Analyzers

- CO_2 analyzers will be be provided at the production separators (tank settings) to monitor CO_2 breakout.
- Other process analyzers are to include:
  - H_2S analyzer (Del Mar Scientific Sulfur Smart series)
  - O_2 analyzer.
  - Moisture analyzer
  - Gas chromatograph (Emerson / Daniel) 500 series)

13.5.6 Control Valves - Level, Pressure, Shutdown

- Provide Block valves up and downstream with bleed on upstream side of Control valve. Provide for globe or V-notch ball valve by-pass around block valves (V-notch balls to be used where cost effective versus globe valves). Bypasses will one pipe diameter bigger than the control valve ports.

- Control valves will be equipped with Fisher DVC 6000 digital controller with HART communications. Control valves shall be PCS controlled.
- Shutdown valves will be trunnion type ball valves with pneumatic actuators. Preferred vendors will be Orbit, Cameron, WKM. Orbit valves to be used on high pressure (ANSI 900 and above) applications. ESD and Isolation valves shall have fire test certification to 6FA.
- Solenoid valves to be 24 VDC, low wattage type.

14.0 BUILDING REQUIREMENTS

All occupied buildings are to be located outside of hazardous areas and the locations will be reviewed per the Facilities Siting Study to determine any over-pressure design requirements. All buildings will comply with applicable California building codes including any requirements to incorporate irrigated landscaping around new buildings. The building functional requirements are set out in document 16179-MUS-ARC-SP-00-0001.

Five new buildings are required at the main CO_2 processing facilities:

14.1 Administration / Control Building

Preliminary design has allowed for an Admin/Control Building of approximately 1,400 square feet. It will be air-conditioned, heated and pressurized. It will include an entry way, control room, conference room, break/kitchen room, two offices, an electrical/equipment room, a locker room and men's and women's restrooms. The building frame shall be constructed as a rigid, self-supporting steel structure. Structural steel design and fabrication shall be in accordance with AISC Specification for Structural Steel Buildings and welding shall be in accordance with AWS D1.1.

14.2 Maintenance / Warehouse Building

Preliminary design has allowed for a single story, pre-engineered metal Maintenance/Warehouse Building of approximately 6,000 square feet. It shall be located at a close distance to the main gate and adjacent to the Admin/Control Building inside the plant in an unclassified, non-hazardous area. There will be truck and equipment access, with parking in the front of the building, and a secured access to a lay-down yard. It will include a workshop, spare equipment store room, chemical storage room and restroom.

14.3 Compressor Shelters

Preliminary design has allowed for a compressor shelter (two required, one each) in the RCF and in the CRP. Each shall be a pre-engineered steel structure, with metal roof and partial sided skirting. Design of the shelter shall allow for compressor blocs and pad to be elevated approximately 9 feet above the building slab. Each shelter shall be naturally ventilated, with continuous ridge ventilator. Each shelter shall be equipped with an overhead bridge crane. The design shall allow for truck and equipment access.

14.4 Electrical Substation and MCC Building

Refer to Section 12.0 of this document.

15.0 TIE-INS TO EXISTING OEHI FACILITIES AND UTILITIES

The following tie-ins **to** the project are expected:

Commodity	Size	Tie-in Location	Design conditions
CO_2 from HECA	12”	Nominally at main plant boundary in 27S	2500 PSI @ 120 °F, 97% CO_2,100 PPM H_2S
Fuel Gas to Heater at A1/A2	3”	In 35R adjacent to existing gas plants	
Makeup Water	10”	Tulare water in 13B and 18G (HOLD)	Not potable quality
Propane	N/A	Trucked to main plant	HD5 propane
Electric power		In the SW corner of 28S	115kV, assume required power is available

The following tie-ins **from** the project are expected:

Commodity	Size	Tie-in Location	Design conditions
Nitrogen to injection	8”	Eastern SOZ compressor suction in NE corner of 3G	30 PSIG
Residue Gas to Sales	6”	Sales gas line in NE corner of 3G	
NGLs to Sales	3”	In 35R adjacent to existing gas plants	
Oil to sales	8”	LACT in 18G	
Oil for treating (off spec)	8”	Treating facility in 18G	
CO_2 to future users	12” HOLD	Blind flange inside main plant in 27S	High purity CO_2 after injection pumps

16.0 REGULATIONS, CODES, STANDARDS & SPECIFICATIONS

16.1 Industry Codes & Standards

Applicable Industry Codes & Standards as identified in Appendix 1 shall be used, modified as necessary to meet project specific requirements.

16.2 Occidental Engineering Guides

Oxy Engineering Guides as listed in Appendix 2 shall be used as a guide in engineering & design development.

16.3 Project Specifications & Standards

Refer to Appendix 1 for a list of Industry Codes and Standards and Appendix 3 for a list of project specifications to be developed.

17.0 NUMBERING REQUIREMENTS

17.1 Document Numbering Requirements

Project documents developed in Pre-FEED have been numbered in accordance with Document Numbering Procedure 16179-MUS-GEN-PR-00-0001.

17.2 Equipment Numbering Requirements

Project equipment developed in the Pre_FEED has been numbered in accordance with Equipment Numbering Procedure 16179-MUS-GEN-PR-00-0002.

17.3 Instrument Numbering Requirements

To be defined in FEED.

17.4 Piping Line Numbering Requirements

To be defined in FEED.

APPENDIX 1 - INDUSTRY CODES & STANDARDS

Application	National / International Codes & Standards
Pressure Vessels	ASME VIII
Boilers	ASME I
Buildings	ANSI, API, ASCE, IBC
Structural	AISC, API, IBC
Electrical	NEC (2005 Edition), NEMA, ANSI, API
Electrical Area Classification	API RP500 1997
Instrumentation	ANSI, ISA, NACE
Sanitary	EPA
Aircraft Warning	FAA
Safety	OSHA, NFPA, API
Water Pollution Standards	EPA, API
Air Pollution Standards	EPA, API
Noise Pollution Standards	OSHA
Fire Protection	UL, NFPA, API
Piping	ANSI/ASME, API
Concrete	ACI, API, PCA, IBC
Roads	AI, AASHTO
Materials	ASTM, ASME, API
Mechanical Equipment	NEMA, API
Welding	ASME IX, API
Heat Exchangers	TEMA, ASME, API
Tanks, Storage	API, NFPA
Package Boilers-Burner Controls	FM
Process Heaters–Burner Controls	API, RP 550 Part III

APPENDIX 2 - OXY ENGINEERING GUIDES

Guide No.	Engineering Guide Title
EG-300	General
EG-301	Facility Siting
EG-302	Facility Layout and Spacing
EG-303	Process-Related Buildings
EG-304	Electrical Area Classification
EG-305	Process Isolation and Emergency Shutdown
EG-306	Fire & Gas Detection and Alarm Systems
EG-307	Fire Protection Systems
EG-308	Fireproofing
EG-309	Facility Drainage and Sewer Systems
EG-310	Pressure Relief Systems
EG-311	Atmospheric Storage Tanks
EG-312	Oil Field Tank Batteries
EG-313	Gas Compression Facilities
EG-314	Gas Treating
EG-315	Natural Gas Dehydration Facilities
EG-316	Gas Plants
EG-319	Piping, Valves and Fittings
EG-320	Hydrocarbon Transmission Pipelines
EG-321	Pressure Vessel and Boilers
EG-322	Welding, Inspection & Testing
EG-323	Emergency Power Systems
EG-350	Environmental Impact Analysis
EG-351	Air Emissions Control Design
EG-352	Environmental Considerations for Water Quality Protection
EG-353	Considerations for Waste Management
EG-354	Environmental Considerations for Civil Design and Construction Projects

APPENDIX 3 – PROJECT SPECIFICATIONS

To be developed during FEED; including:

Specification List
Process Design Basis (each facility)
Centrifugal Compressor Specification
Reciprocating Compressor Specification
Centrifugal Pump Specification
Positive Displacement Pump Specification
Shell & Tube Heat Exchanger Specification
Air Cooled Heat Exchanger Specification
General Pressure Vessel Specification
Vessel Tray Mechanical Design Specification
Storage Tank Specification
Vessel Welding, Fabrication and Inspection Requirements Specification
Vents, Flare Stacks, Tips and Igniters Specifications
Fired Heater Specification
Instrument Air Compressor Package Specification
Packaged Equipment Specifications
Firewater System Specification
Protection & Packaging Requirements for Vessels Specification
Equipment Preservation Specification
Equipment & Piping Insulation Specification
Painting & Coating System Specification
Piping Specifications
Pipeline Material & Installation Specifications
Structural Design Specification
Geotechnical Investigation Specification
Asphalt & Concrete Surface Roads Specification
Concrete Roads and Paving Design Specification
Earthwork & Subgrade Preparation Specification
Chain Link Fencing Specification
Concrete Construction Specification
Concrete Materials & Testing Specification
Concrete Reinforcing Specification

Specification List
Structural Steel Fabrication & Erection Specification
Concrete Fireproofing Specification
Pre-Engineered Steel Building Specification
Switchyard and Substation Specification
Substation Power Transformer Specification
SF6 Gas Power Circuit Breakers Specification
Liquid Filled Sub-Station Class Transformer Specification
Transformer Bushings Specification
Medium Voltage Arc-Resistant Switchgear Specification
Low Voltage Switchgear Specification
Medium Voltage MCC Specification
Low Voltage MCC Specification
Prefabricated Electrical Building Specification
Medium Voltage Induction Motor 300 H.P. and Larger Specification
Low Voltage Induction Motor Specification
Uninterruptible Power Systems Specification
Electrical Requirements for Packaged Equipment Specification
Basic Process Control System Specification
Safety Instrumented System Specification
Fire & Gas Detection System Specification
Instrument Design Specification
Instrument Installation Specification

APPENDIX 4 – WIND ROSE DATA

This information was sourced from the Hydrogen Energy California application for certification to CEC, dated May, 2009. This information is in the public domain. This information relates to the Bakersfield Airport and needs to be replaced with OEHI site-specific data in FEED.

Annual Summary:

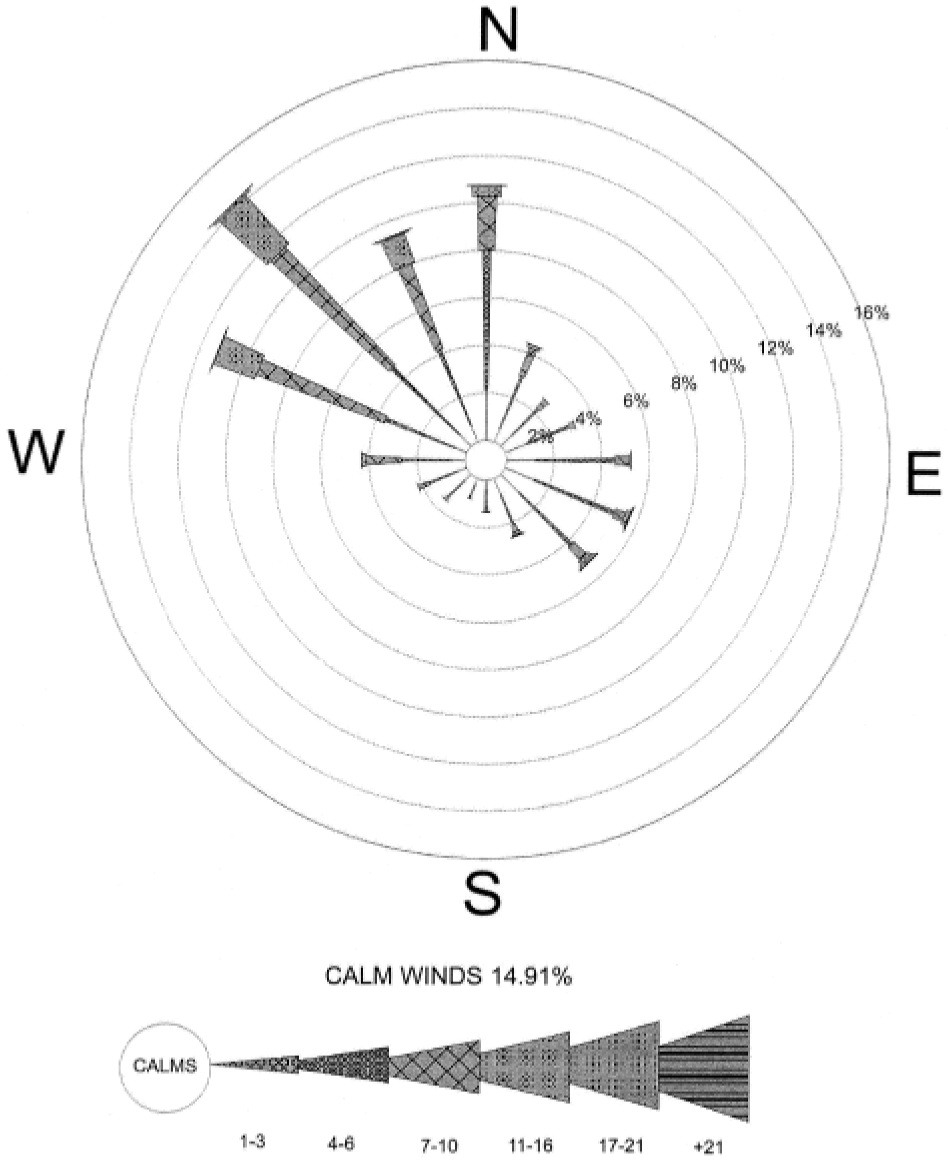

Figure A-1 Annual Windrose for Bakersfield Airport based on Surface Data for 2000-2004

Winter:

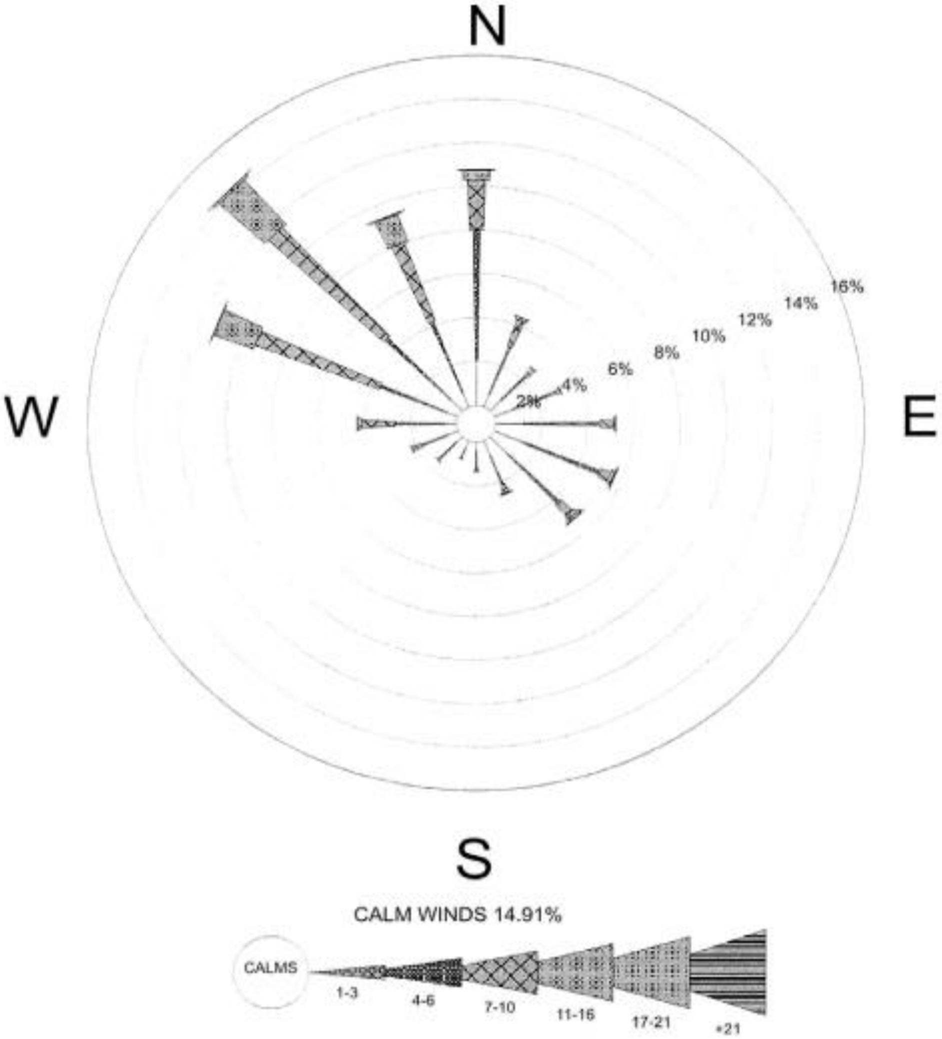

Figure A-5 Winter Season Windrose for Bakersfield Airport based on Surface Data for 2000-2004

Spring:

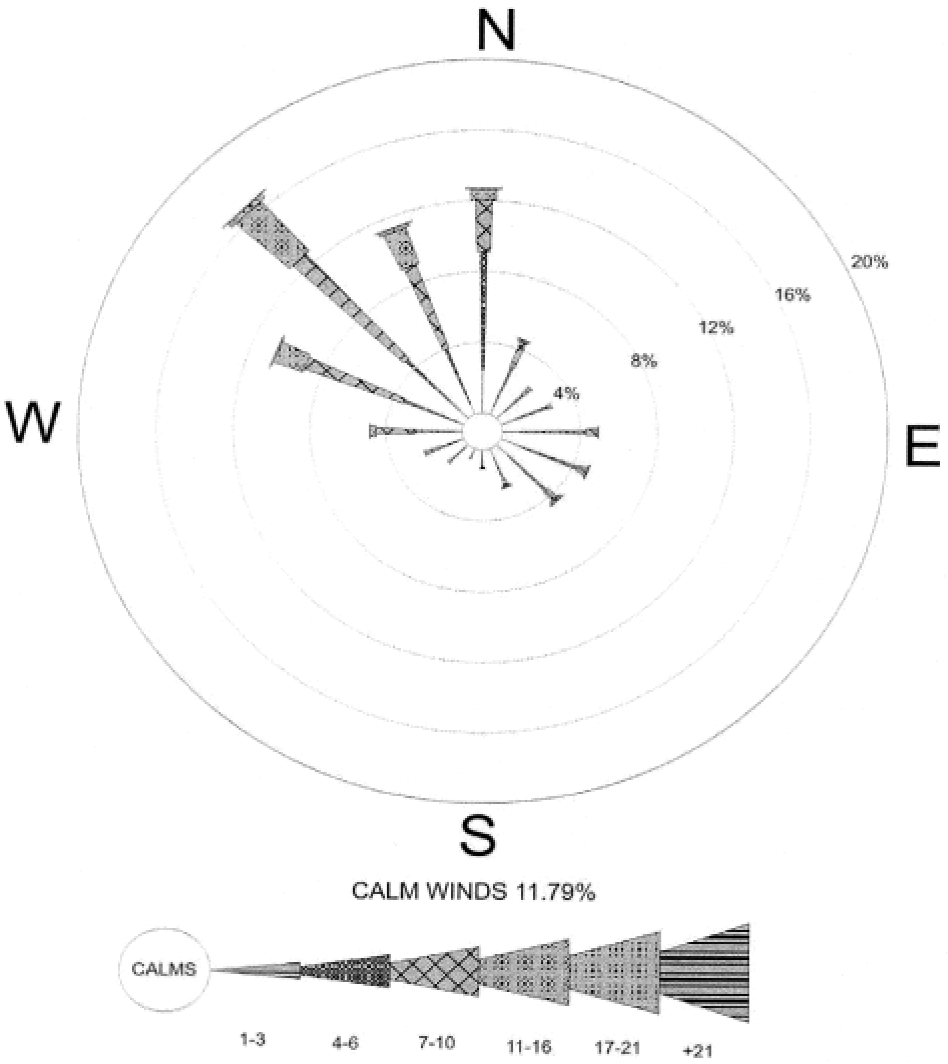

Figure A-2 Spring Season Windrose for Bakersfield Airport based on Surface Data for 2000-2004

Summer:

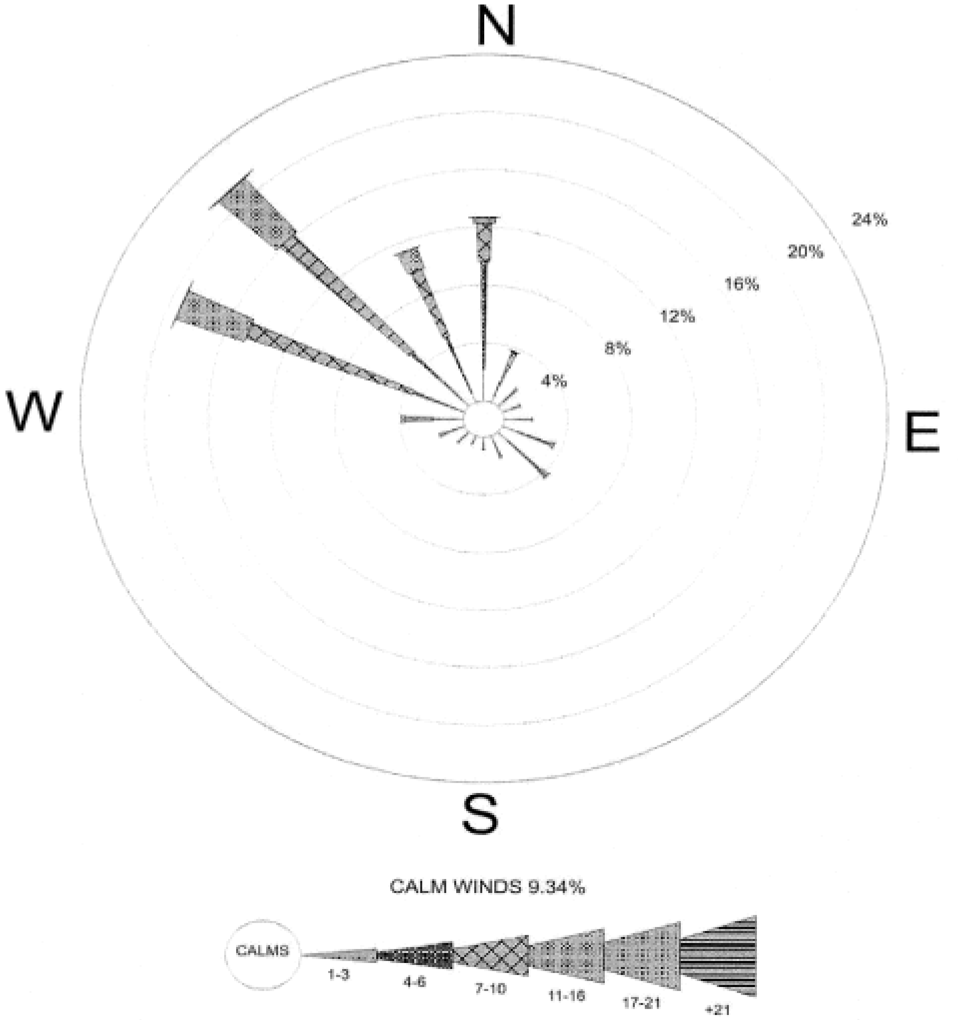

Figure A-3 Summer Season Windrose for Bakersfield Airport based on Surface Data for 2000-2004

Fall:

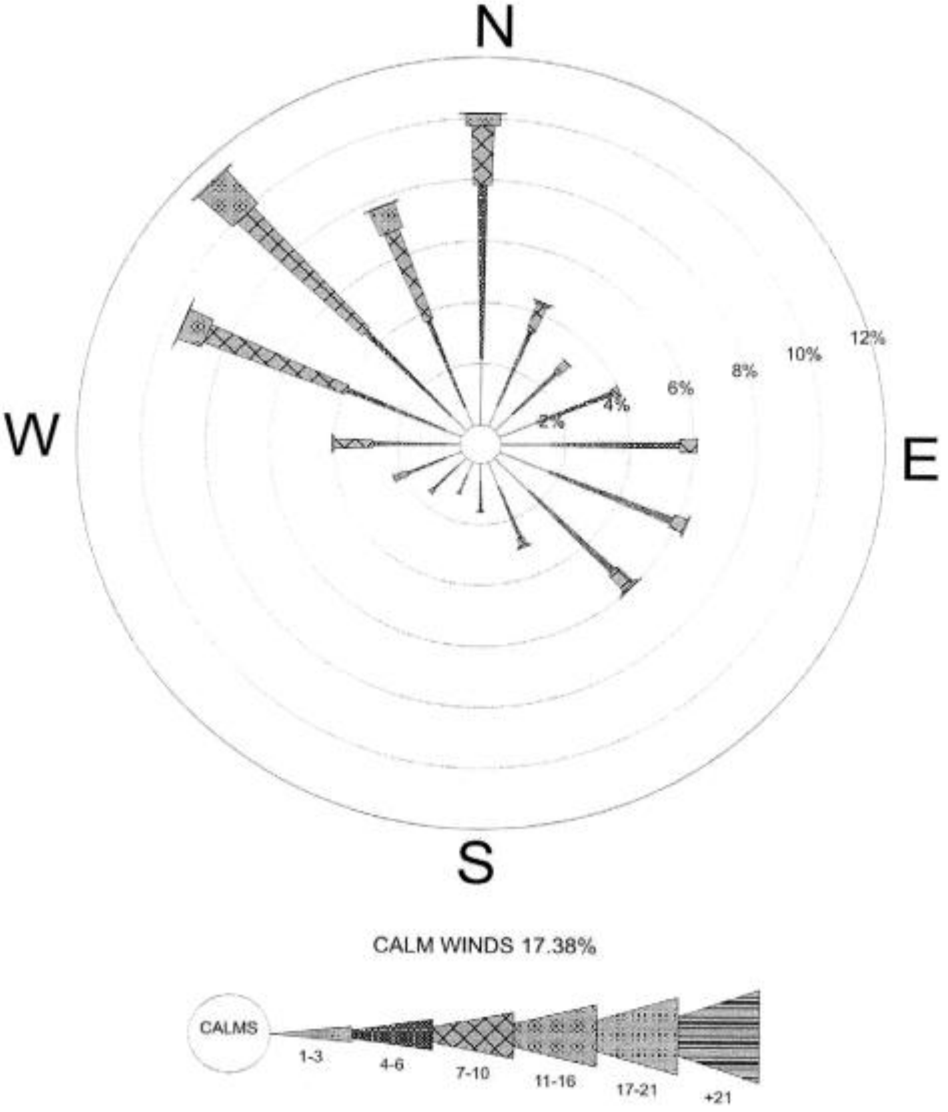

Figure A-4 Fall Season Windrose for Bakersfield Airport based on Surface Data for 2000-2004

APPENDIX 5 – CO_2 PROJECT PHASING

Project Phasing Overview

OEHI provided preliminary reservoir performance information indicating typical CO_2 Enhanced Oil Recovery (EOR) injector well patterns and production profiles for water and gas production from the Stevens formation (provided in Excel spreadsheet file ―*Forecast Revised 5_21_09 CO2 implementation gantt chart - base1 TC.xls*”). This information was based on a progressive CO_2 injection well development program spanning from 2015 to 2034. The data provided was on a month-by-month basis, however for this analysis the monthly flows have been adjusted to an average for each calendar year. Averaging removed short term spikes in flows and prevents equipment sizing based on potentially spurious short term data.

A well pattern constitutes an injection well surrounded by approximately four producing wells. Producing wells can be part of the pattern for adjacent injection wells. The injection well density is approximately one well per 23 acres, and this density corresponds to approximately one producing well per 19 acres. The entire development reviewed in the Pre-FEED assumes the following well count per the field development plan provided by OEHI (Table 1).

Well Location **Type of Well**	**South East Stevens**	**North West Stevens**	**Total Wells per Type**
Injector	181	68	**249**
Producer	211	97	**308**
Total Wells per Area	**392**	**165**	**557**

Table 1: Well Count per Field Development Plan (OEHI)

Per the field development plan provided by OEHI, the anticipated wells drilled, wellhead gas and water production profiles are as per Chart 1.

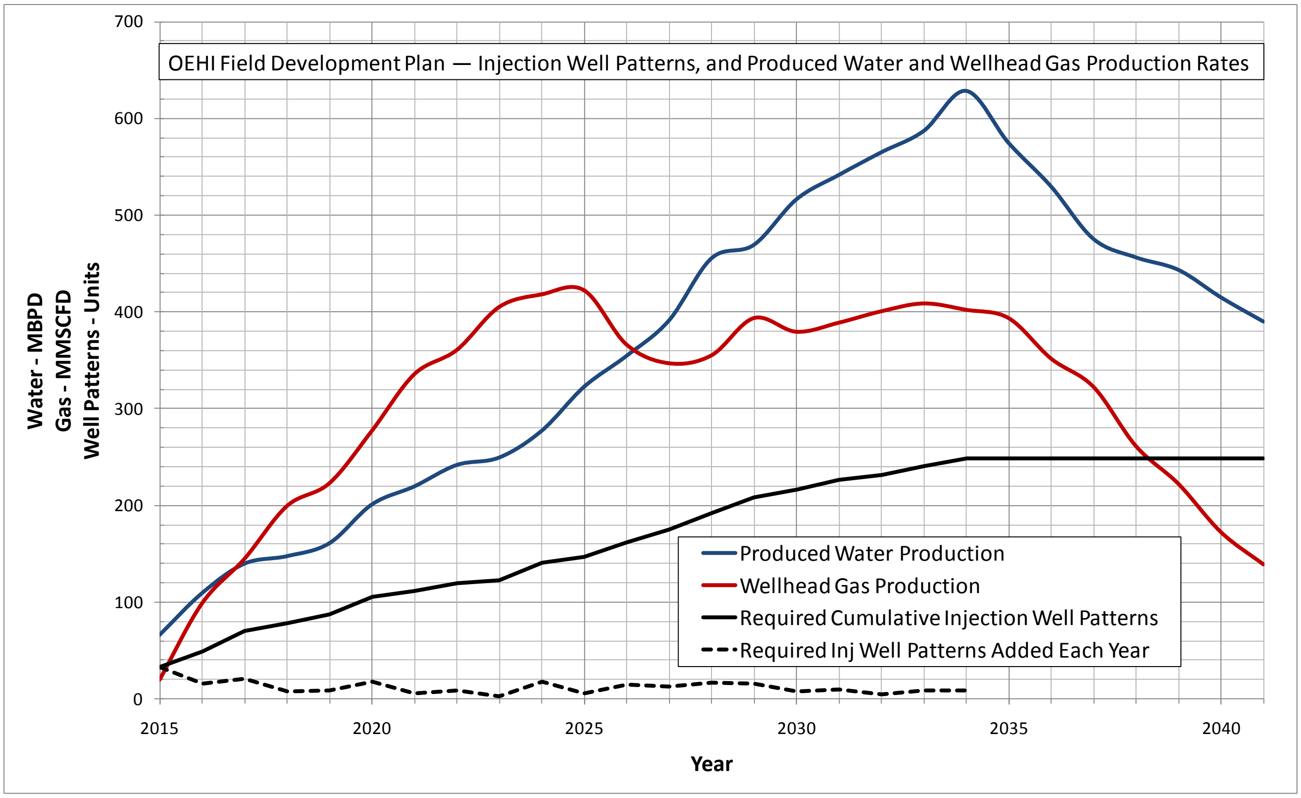

Chart 1: OEHI Field Development Plan –
Injection Well Patterns, Produced Water and Wellhead Gas Production Rates

The information in Chart 1 shows:

- Peak wellhead gas production of 422.4 MMSCFD and 408.8 MMSCFD occur in 2024 and 2033 respectively.
- Peak produced water flow of 628.4 MBWPD in 2034.
- Injection well pattern requirements are required each year until 2035 when there will be a total of 249 injection wells. (There will be 308 producing wells associated with this number of injection wells.)

Satellite and Well Development Phasing

Standard satellite designs were developed, with each satellite providing Water Alternating Gas (WAG) injection manifolds, and each also receiving liquids from producing wells. Two standard WAG designs were developed; one with capacity for 20 injectors and the other with capacity for 30 injectors.

The field layout drawings were developed and the satellite WAG configuration selected that best suited the field layout. The scheduling of the construction of the satellites was derived by considering the project requirements for injection patterns, and laying out of the field facilities.

Table 2 lists the satellite development schedule and indicates installed capacity in terms of modular size (20 or 30) for WAG and production separation designs, and also lists the actual number of wells connected. The date the satellite is required to be available is also listed. This date must be met in order for installed injector patterns to meet the CO_2 EOR field development requirements:

Satellite		**Installed Capacity**		**Actual Wells**		**Required Date**
		Injectors	**Producers**	**Injectors**	**Producers**	
SE Stevens	1	20	30	18	30	12/31/2015
	2	20	30	20	26	12/31/2015
	3	20	20	12	19	6/1/2016
	4	30	30	22	26	3/1/2017
	5	20	20	18	16	3/1/2018
	6	20	20	19	19	3/1/2020
	7	30	30	26	28	12/1/2021
	8	30	30	28	25	10/1/2024
	9	20	30	18	22	3/1/2027
NW Stevens	10	20	30	18	25	5/1/2028
	11	20	30	18	25	9/1/2029
	12	20	30	19	26	2/1/2031
	13	20	30	13	21	12/1/2033
		290	**360**	**249**	**308**	

Table 2: Satellite Development Schedule

Chart 2 shows the timing and actual number of injectors in graphical form – the number of required injector patterns per Chart 1 is also included. The corresponding satellite phasing from Table 2 ensures that the number of planned injectors precedes the requirement per the field development plan.

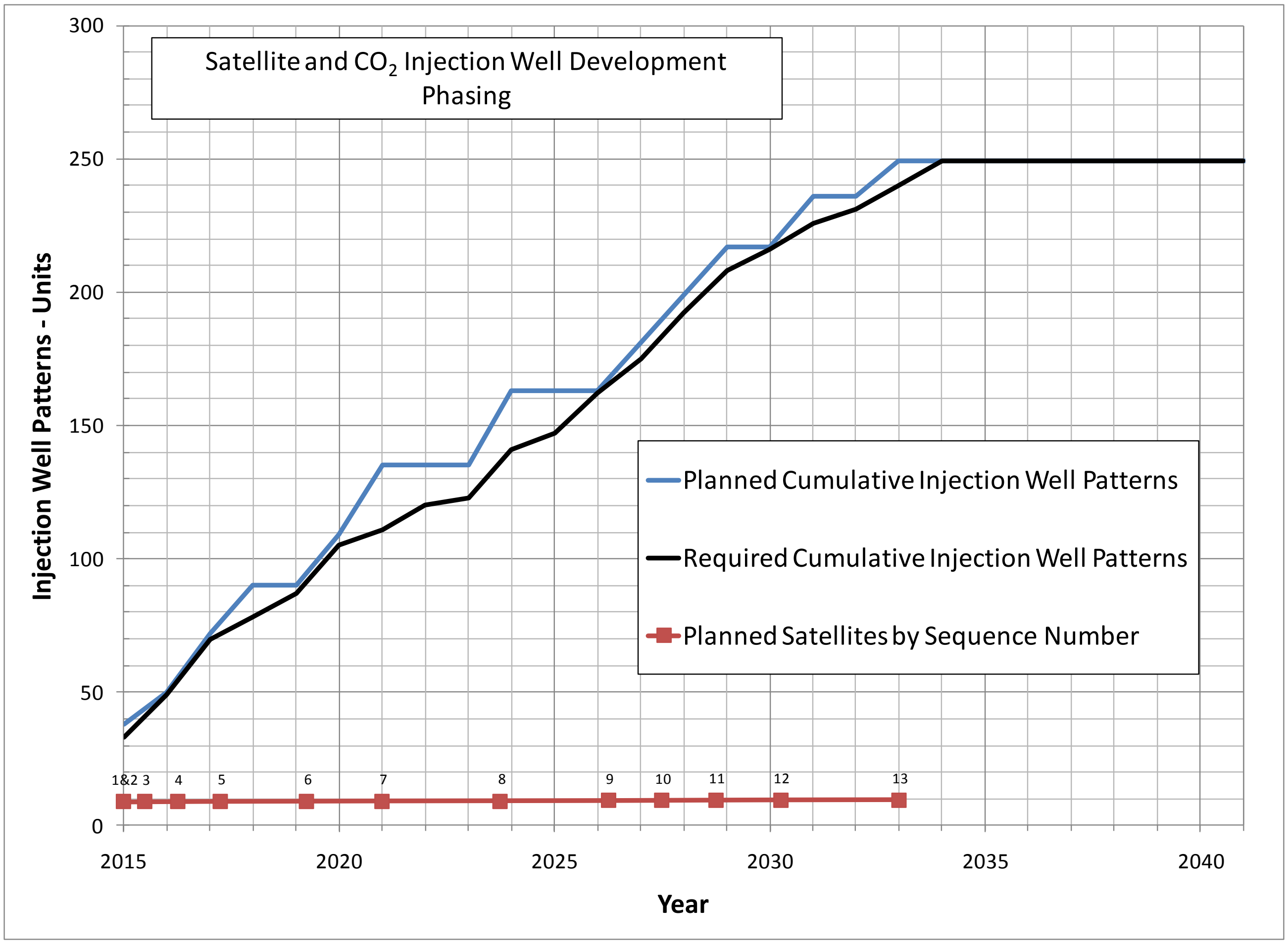

Chart 2: Satellite and CO_2 Injection Well Development Phasing

RCF, CTB Phase I,CRP and CTB Phase II Development Phasing

Chart 1 shows the buildup of wellhead gas and produced water flows over the life of the CO_2 EOR development. The same wellhead gas and produced water production curves are included in Chart 3, and the timing of the RCF, CRP, CTB Phase I, and CTB Phase II are overlaid on the planned production curves.

The capacities each facility are:

- RCF – 222 MMSCFD
- CRP – 200 MMSCFD
- CTB Phase I – 330 MBWPD
- CTB Phase II – 330 MBWPD

These give final combined facility capacities of:

- Combined RCF and CRP – 422 MMSCFD
- CTB Phases I & II – 660 MBWPD

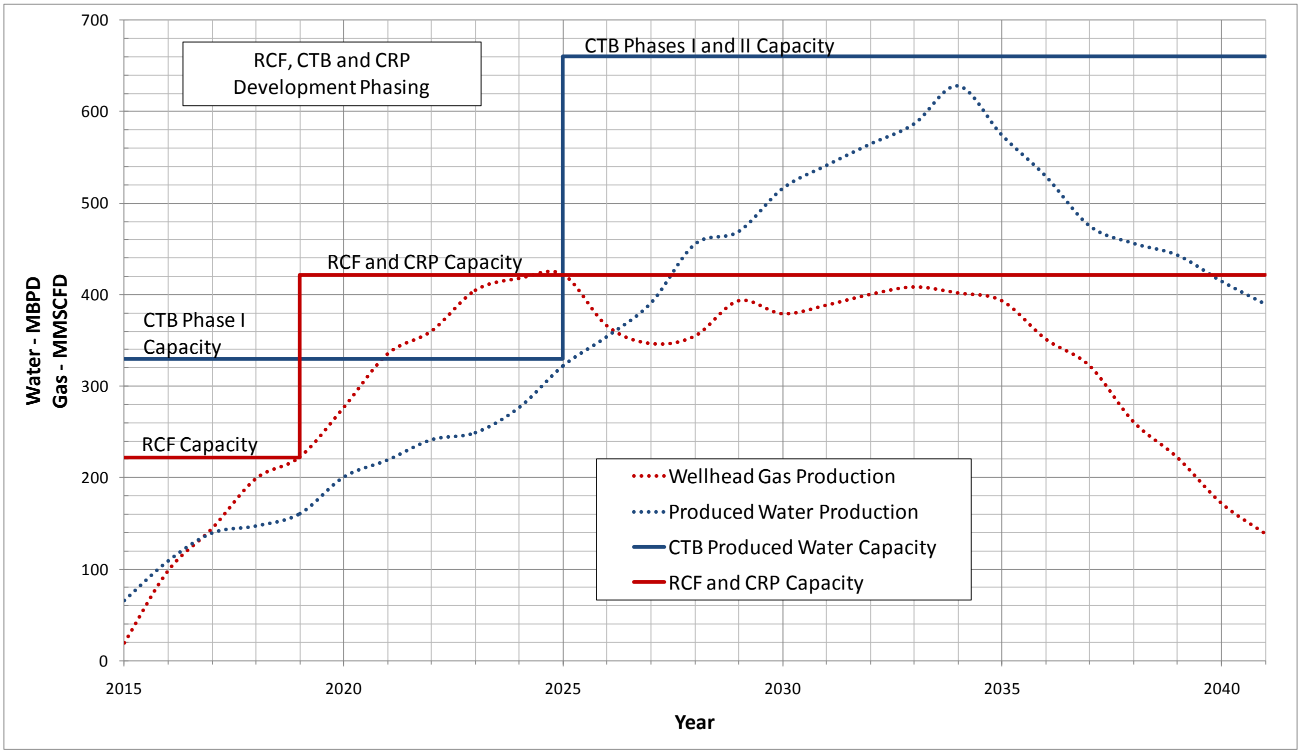

Chart 3: RCF, CTB Phase I, CRP and CTB Phase II Development Phasing

Chart 3 indicates the required timing for the completion of each facility in order to meet the development requirements in terms of expected wellhead gas and produced water flows. The timing for the completion of each facility is summarized in Table 3.

SUMMARY SCHEDULE	
Facility	**Date required to be operational**
RCF	31 December 2015
CTB – Phase I	31 December 2015
CRP	31 December 2019
CTB – Phase II	31 December 2025
Satellite 1	31 December 2015
Satellite 2	31 December 2015
Satellite 3	1 June 2016
Satellite 4	1 March 2017
Satellite 5	1 March 2018
Satellite 6	1 March 2020
Satellite 7	1 December 2021
Satellite 8	1 October 2024
Satellite 9	1 March 2027
Satellite 10	1 May 2028
Satellite 11	1 September 2029
Satellite 12	1 February 2031
Satellite 13	1 December 2033

Table 3: Summary Schedule

RCF, CRP Operating Phasing

In 2019 the CRP comes online to augment the wellhead gas capacity of the RCF. As the CRP could possibly make extra revenue from NGL and HC Gas sales, OEHI would likely want to operate the CRP at, or near, full capacity immediately, and scale back the throughput at the RCF. Chart 4 shows the ramping of the RCF throughput from 2016 to 2019, then scaling back to allow as much of the wellhead gas to be handled by the CRP. OEHI would operate the CRP are close as possible to the nominal maximum throughput of 200 MMSCFD, then pick up future increased wellhead gas flows by re-ramping up the RCF. Future declines would be handled by reducing the flow through the RCF.

OEHI may choose to not reduce the RCF production to zero in 2019 and maintain a minimum flow, if this is the case the CRP throughput will be correspondingly reduced from 200 MMSCFD until wellhead gas production increases to take the CRP up to full capacity.

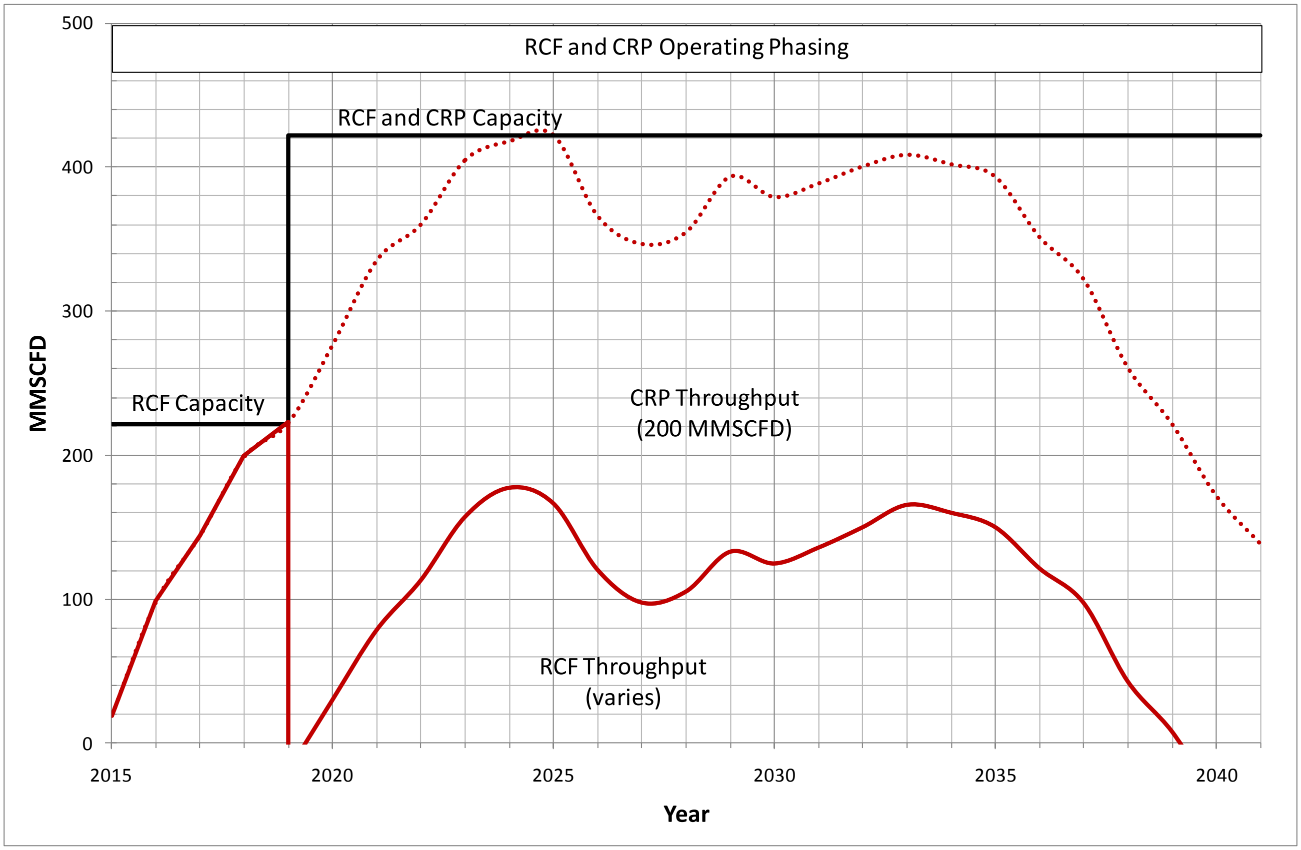

Chart 4: RCF and CRP Operating Phasing

Attachment A177-5

Pre-FEED Engineering Study, Project design drawings, Mustang Engineering, miscellaneous dates.

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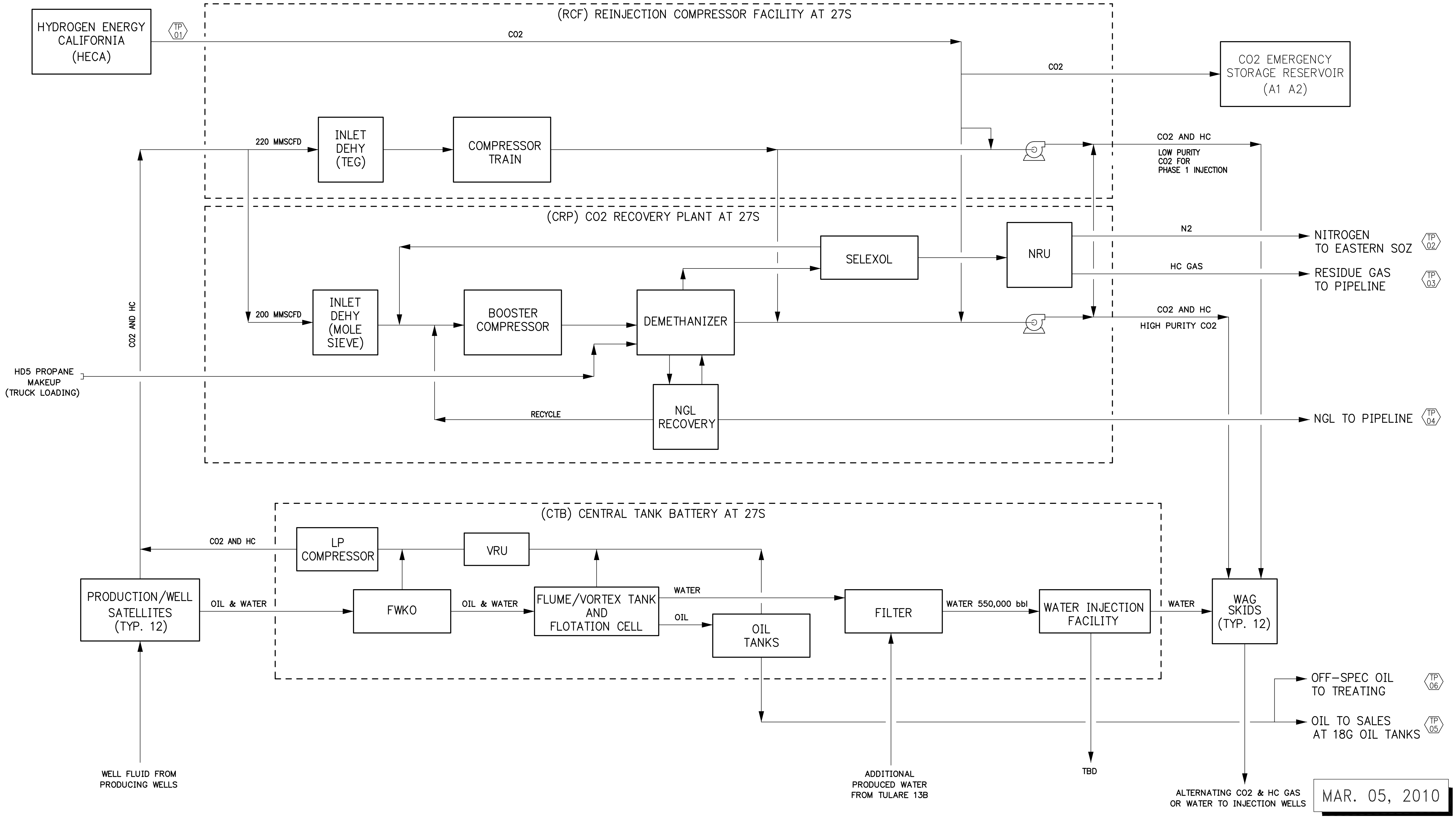

MAR. 05, 2010

NOTES:

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	14DEC09	ISSUED FOR CLIENT REVIEW	JOL	BHG	MS	
B	18DEC09	ISSUED FOR REVIEW	TWR	BHG	MS	
C	13JAN10	ISSUED FOR HAZID	JOL	BHG	MS	
D	29JAN10	ISSUED FOR REVIEW	NT	BHG	MS	
E	26FEB10	ISSUED FOR FEED	NT	BHG	LS	
F	05MAR10	RE-ISSUED FOR FEED	NT	BHG	MS	

ENGINEERING CONSULTANT:

MUSTANG ENGINEERING, L . P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	04DEC09
DRAWN	J. LOGAN	04DEC09
CHECKED	B. GOODWIN	04DEC09
APPROVED	M. SOMERS	04DEC09

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
BLOCK FLOW DIAGRAM
ELK HILLS CO2 PROJECT

SCALE	OCCIDENTAL DOCUMENT NUMBER							
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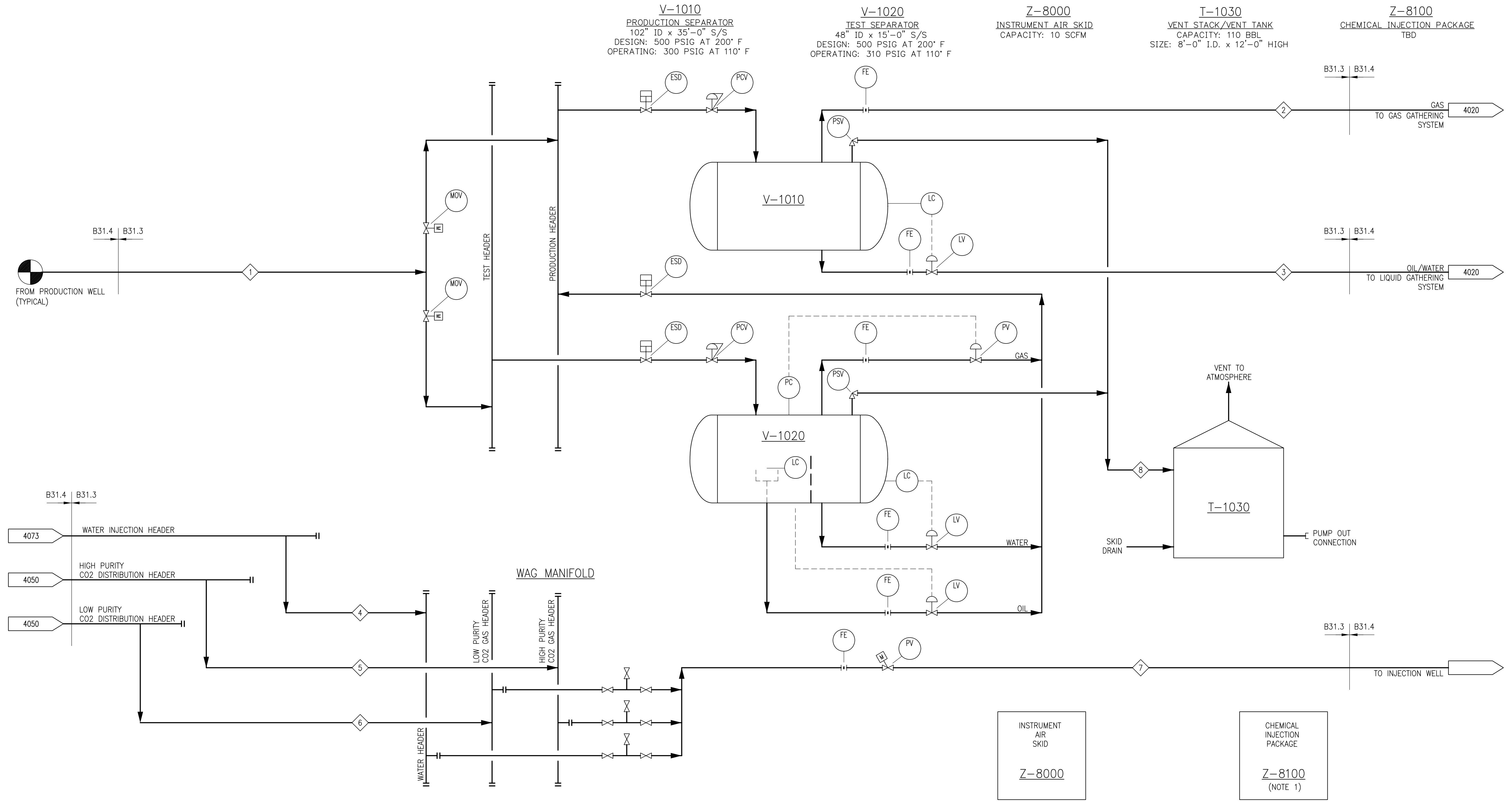

FEB. 26, 2010

NOTES:

1. PROVISION FOR SITE PAD FOR TOTE TANKS AND PUMP.

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	18DEC09	ISSUED FOR REVIEW	TWR	BHG	MS	
B	13JAN10	ISSUED FOR HAZID	JOL	BHG	MS	
C	29JAN10	ISSUED FOR REVIEW	NT	BHG	MS	
D	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:

MUSTANG ENGINEERING, L. P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	04DEC09
DRAWN	W. ROE	04DEC09
CHECKED	B. GOODWIN	04DEC09
APPROVED	M. SOMERS	04DEC09

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
PRODUCTION AND TEST SEPARATOR
SATELLITE (20 WELLS)

SCALE	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
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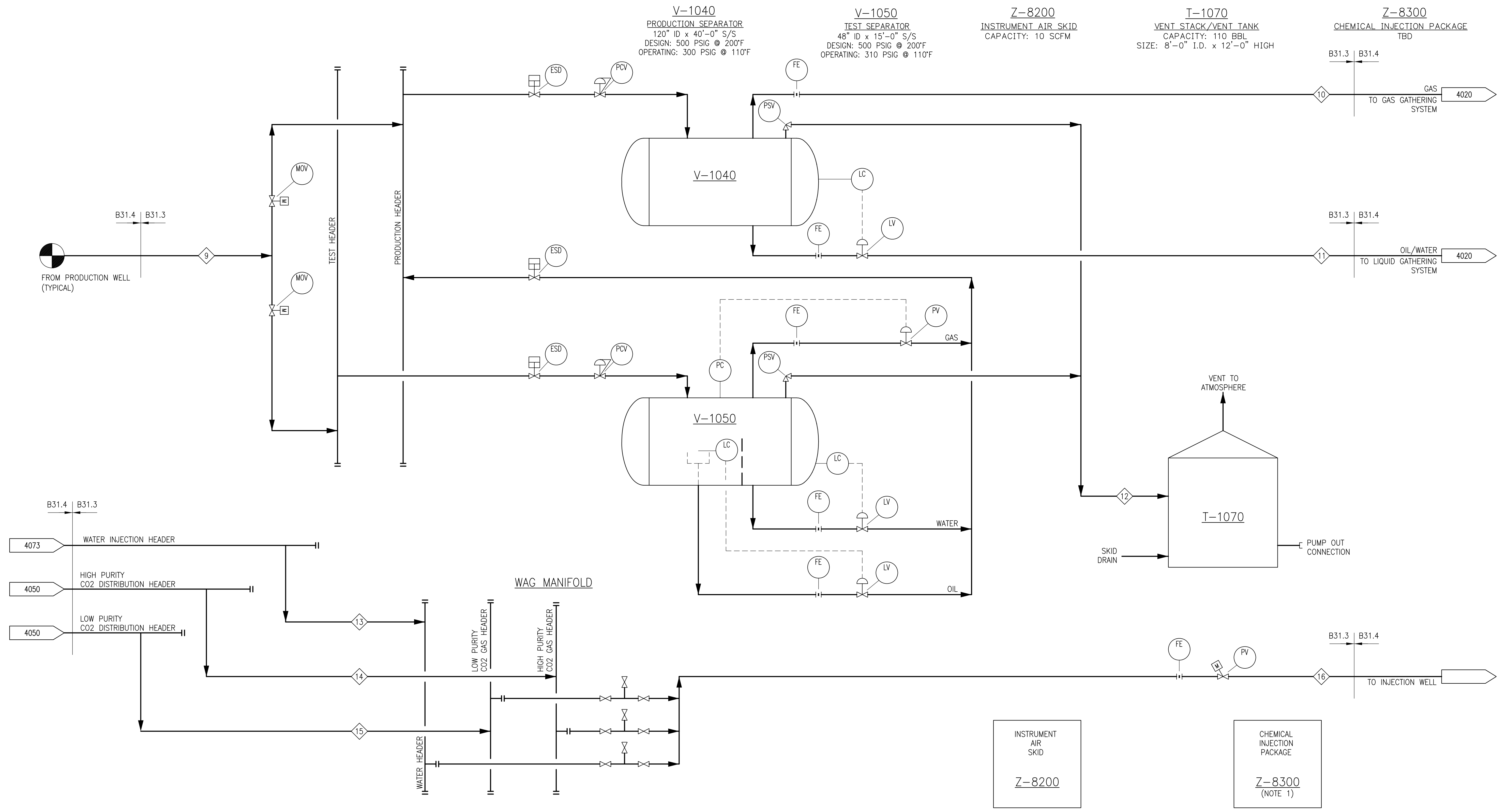
OCCIDENTAL DOCUMENT NUMBER



FEB. 26, 2010

NOTES:

1. PROVISION FOR SITE PAD FOR TOTE TANKS AND PUMP.

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	18DEC09	ISSUED FOR REVIEW	TWR	BHG	MS	
B	13JAN10	ISSUED FOR HAZID	JOL	BHG	MS	
C	29JAN10	ISSUED FOR REVIEW	NT	BHG	MS	
D	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:

MUSTANG ENGINEERING, L . P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	04DEC09
DRAWN	W. ROE	04DEC09
CHECKED	B. GOODWIN	04DEC09
APPROVED	M. SOMERS	04DEC09

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
PRODUCTION AND TEST SEPARATOR
SATELLITE (30 WELLS)

SCALE	OCCIDENTAL DOCUMENT NUMBER							
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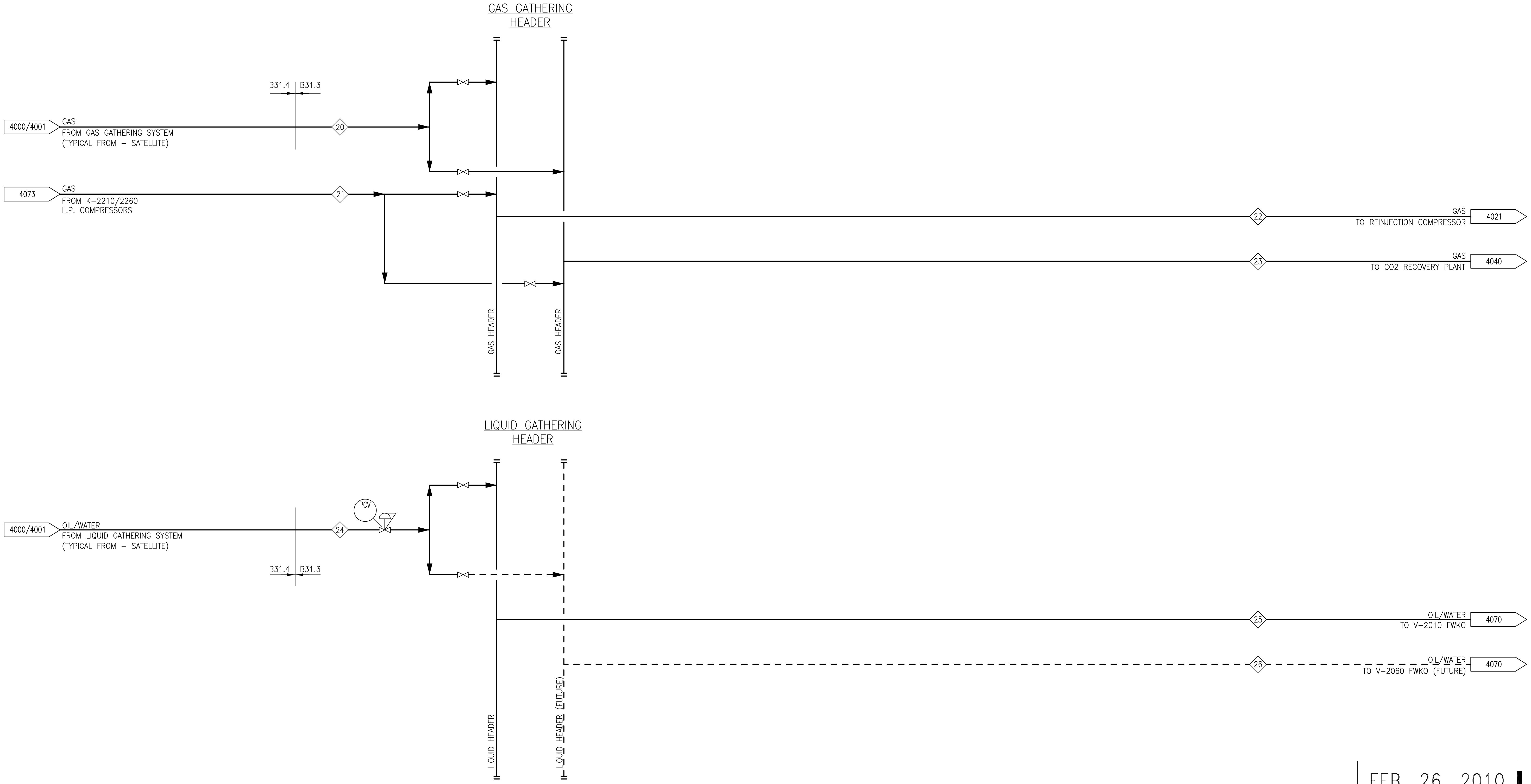

FEB. 26, 2010

NOTES:

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
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B	13JAN10	ISSUED FOR HAZID	JOL	BHG	MS	
C	29JAN10	ISSUED FOR REVIEW	NT	BHG	MS	
D	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:

MUSTANG ENGINEERING, L. P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	10DEC09
DRAWN	C. SOTO	10DEC09
CHECKED	B. GOODWIN	10DEC09
APPROVED	M. SOMERS	10DEC09

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
GAS & LIQUID GATHERING HEADER
(RCF) RE-INJECTION COMPRESSOR FACILITY

SCALE	OCCIDENTAL DOCUMENT NUMBER							
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MEI Project: 16179 – I:\16179\PROCESS\16179-MUS-PRO-PFD-20-4021.DWG 03MAR10 1038 SF 1.00 IMP CMCOATS

V–3000
INLET GAS SEPARATOR
120" ID x 40'–0" S/S
DESIGN: 500 PSIG @ 200°F
OPERATING: 300 PSIG @ 102°F

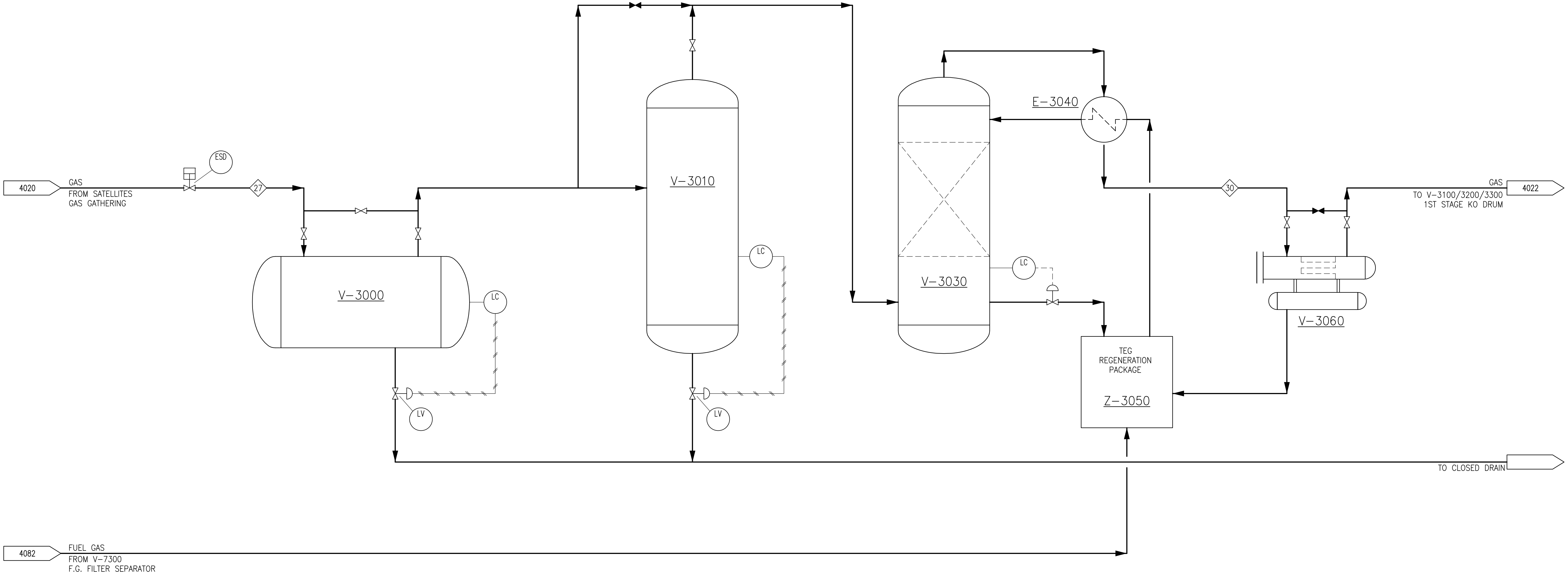
V–3010
INLET GAS FILTER
XX" ID x X' S/S
DESIGN: 500 PSIG @ 200°F
OPERATING: 300 PSIG @ 102°F

V–3030
TEG CONTACTOR
74" ID x 26'–0" S/S
DESIGN: 500 PSIG @ 200°F
OPERATING: 300 PSIG @ 102°F

Z–3050
TEG REGENERATION PACKAGE
60 GPM

E–3040
GAS/GLYCOL EXCHANGER
DUTY: 0.522 MMBTU/hr

V–3060
COALSCER
DESIGN: 500 PSIG @ 200°F
OPERATING: 300 PSIG @ 102°F



MAR. 05, 2010

NOTES:

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	18DEC09	ISSUED FOR REVIEW	CCS	BHG	MS	
B	13JAN10	ISSUED FOR HAZID	JOL	BHG	MS	
C	29JAN10	ISSUED FOR REVIEW	NT	BHG	MS	
D	26FEB10	ISSUED FOR FEED	NT	BHG	LS	
E	05MAR10	RE–ISSUED FOR FEED	CMC	BHG	LS	

ENGINEERING CONSULTANT:
MUSTANG ENGINEERING, L . P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	04DEC09
DRAWN	C. SOTO	04DEC09
CHECKED	B. GOODWIN	04DEC09
APPROVED	M. SOMERS	04DEC09

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
INLET SEPARATION & TEG SYSTEM
(RCF) REINJECTION COMPRESSOR FACILITY

SCALE	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	20	4021	–	E

OCCIDENTAL DOCUMENT NUMBER

MEI Project: 16179 - I:\16179\PROCESS\16179-MUS-PRO-PFD-20-4022.DWG 25FEB10 1540 SF 1.00 IMP NLTAN

V-3100/3200
1st STAGE KO DRUM
120" ID x 15'-0" S/S
DESIGN: 500 PSIG @ 200°F
OPERATING: 295 PSIG @ 107°F

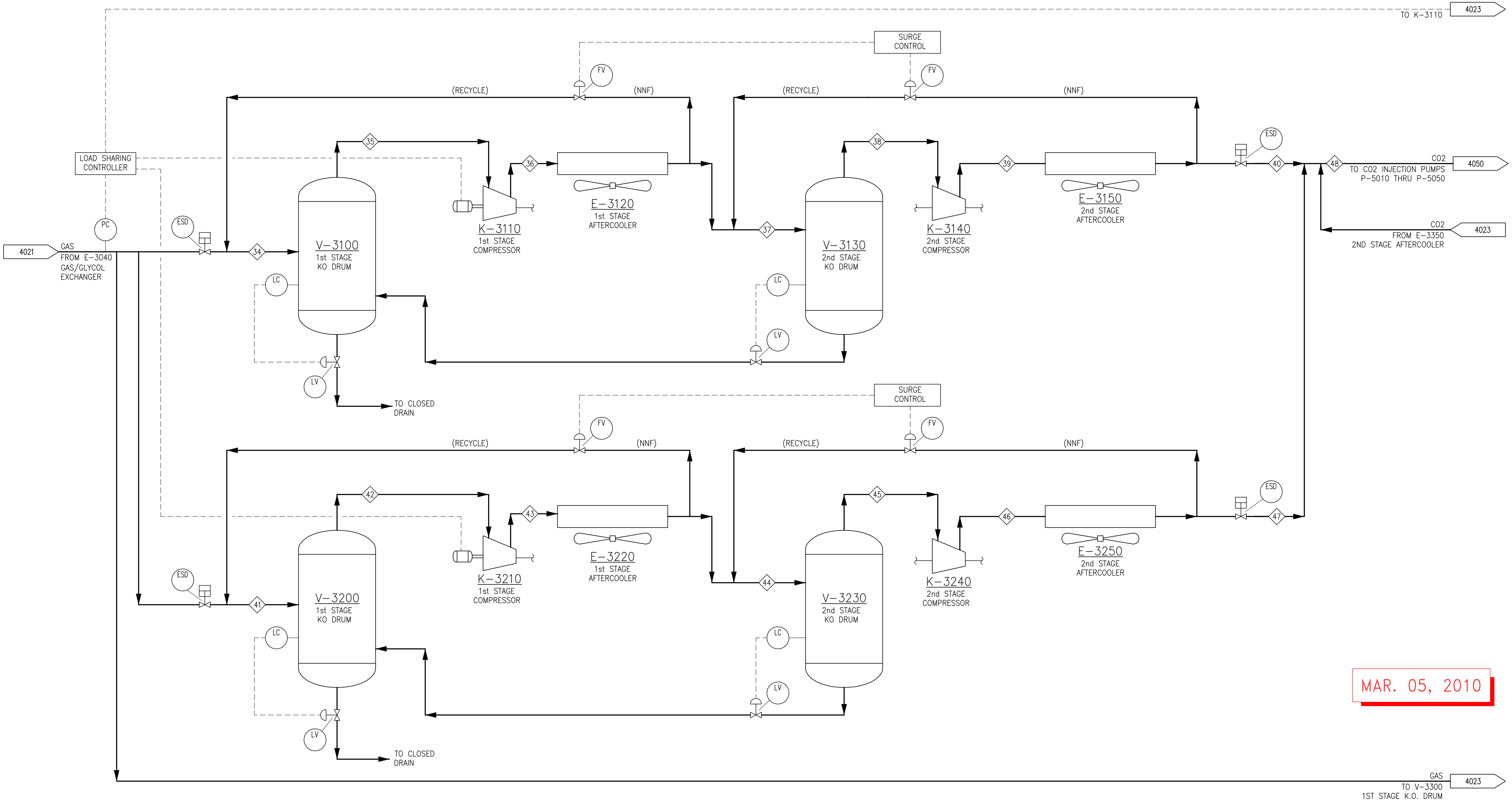
K-3110/3210
1st STAGE REINJECTION COMPRESSOR
110 MMSCFD
MOTOR: 15,350 HP EACH

E-3120/3220
1st STAGE AFTERCOOLER
DUTY: 27.29 MMBTU/hr
DESIGN: 1200 PSIG @ 350°F

V-3130/3230
2nd STAGE KO DRUM
96" DIA x 12'-0" S/S
DESIGN: 1200 PSIG @ 200°F
OPERATING: 875 PSIG @ 120°F

K-3140/3240
2nd STAGE REINJECTION COMPRESSOR
110 MMSCFD
INTEGRAL W/K-3110/3210

E-3150/3250
2nd STAGE AFTERCOOLER
DUTY: 46.37 MMBTU/hr
DESIGN: 2650 PSIG @ 350°F



MAR. 05, 2010

NOTES:

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	18DEC09	ISSUED FOR REVIEW	CCS	BHG	MS	
B	13JAN10	ISSUED FOR HAZID	JOL	BHG	MS	
C	29JAN10	ISSUED FOR REVIEW	NT	BHG	MS	
D	26FEB10	ISSUED FOR FEED	NT	BHG	LS	
E	05MAR10	RE-ISSUED FOR FEED	WR	BHG	MS	

ENGINEERING CONSULTANT:

MUSTANG ENGINEERING, L . P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	04DEC09
DRAWN	C. SOTO	04DEC09
CHECKED	B. GOODWIN	04DEC09
APPROVED	M. SOMERS	04DEC09

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
GAS COMPRESSOR
(RCF) RE-INJECTION COMPRESSOR FACILITY

SCALE	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
	OCCIDENTAL DOCUMENT NUMBER							
NONE	16179	MUS	PRO	PFD	20	4022	–	E

V–3300
1st STAGE KO DRUM
120" ID x 15'–0" S/S
DESIGN: 500 PSIG @ 200°F
OPERATING: 295 PSIG @ 107°F

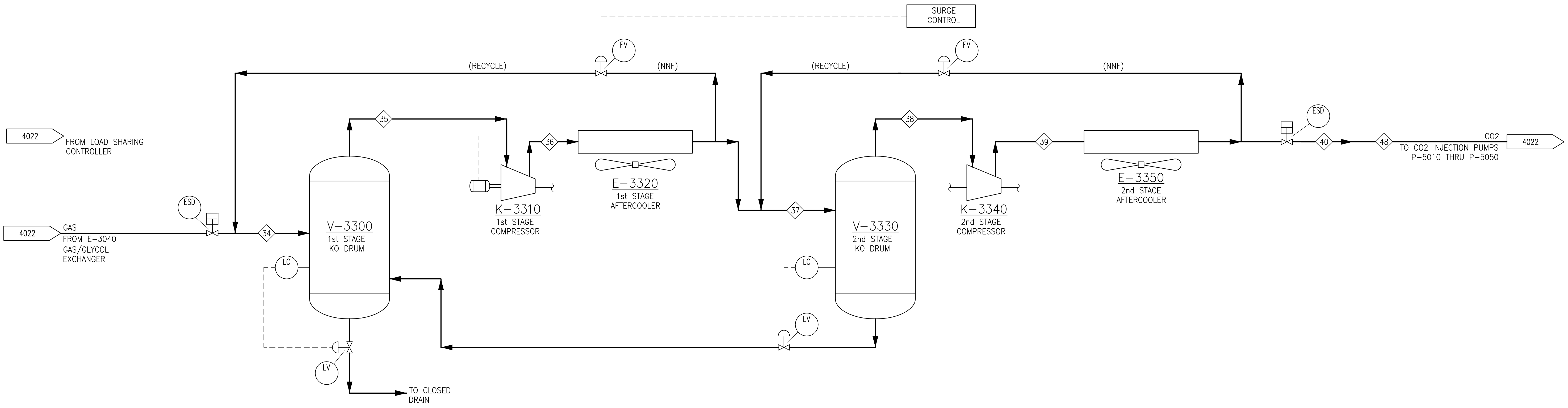
K–3310
1st STAGE REINJECTION COMPRESSOR
110 MMSCFD
MOTOR: 15,350 HP EACH

E–3320
1st STAGE AFTERCOOLER
DUTY: 27.29 MMBTU/hr
DESIGN: 1200 PSIG @ 350°F

V–3330
2nd STAGE KO DRUM
96" DIA x 12'–0" S/S
DESIGN: 1200 PSIG @ 200°F
OPERATING: 875 PSIG @ 120°F

K–3340
2nd STAGE REINJECTION COMPRESSOR
110 MMSCFD
INTEGRAL W/K–3110/3210

E–3350
2nd STAGE AFTERCOOLER
DUTY: 46.37 MMBTU/hr
DESIGN: 2650 PSIG @ 350°F



MAR. 05, 2010

NOTES:

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	05MAR10	ISSUED FOR FEED	WR	BHG	MS	

ENGINEERING CONSULTANT:
MUSTANG ENGINEERING, L . P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	02MAR10
DRAWN	W. ROE	02MAR10
CHECKED	B. GOODWIN	02MAR10
APPROVED	M. SOMERS	02MAR10

OXY Occidental

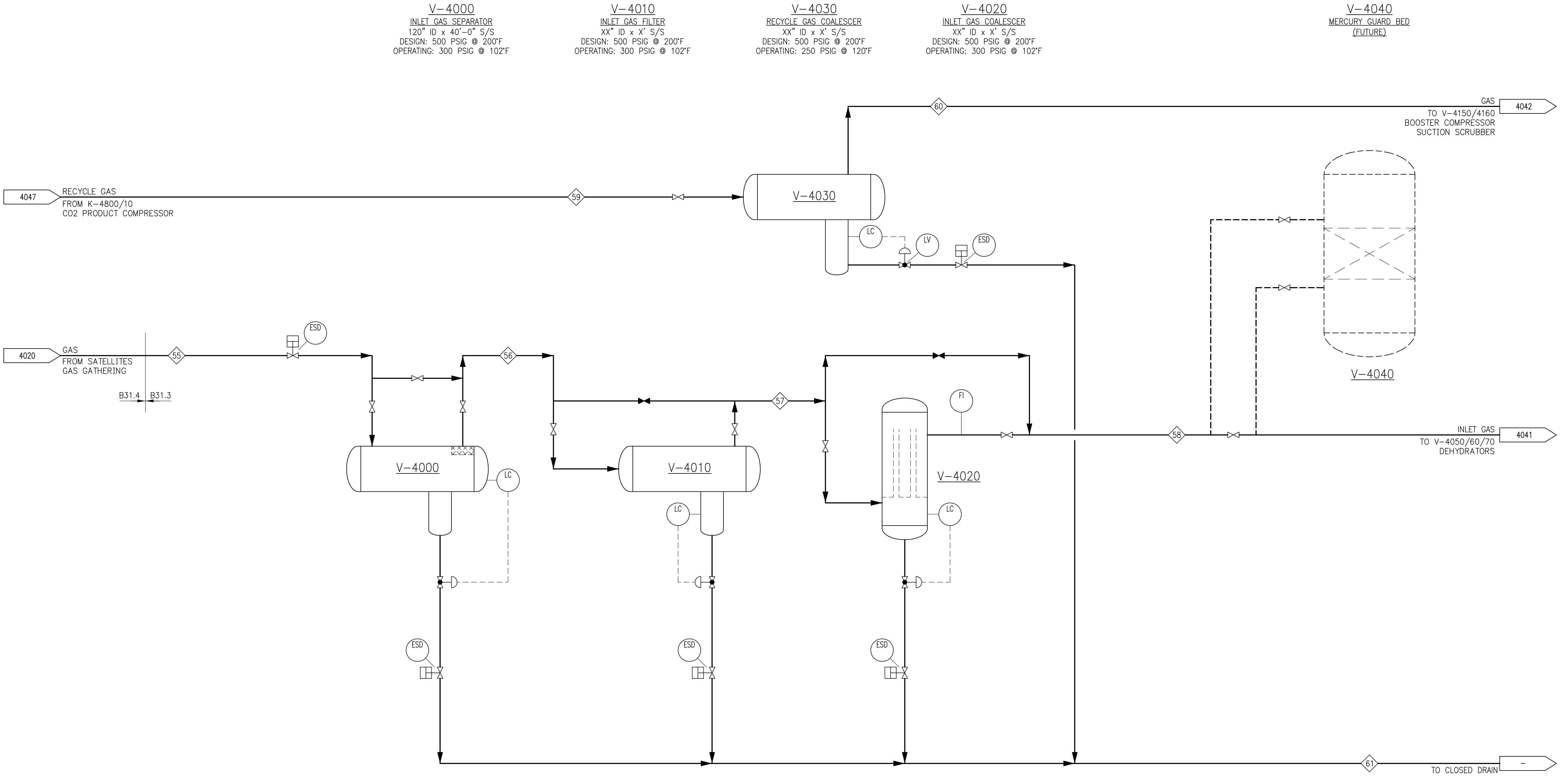
FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
GAS COMPRESSOR
(RCF) RE–INJECTION COMPRESSOR FACILITY

SCALE	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	20	4023	–	A

OCCIDENTAL DOCUMENT NUMBER

MEI Project: 16179 – I:\16179\PROCESS\16179-MUS-PRO-PFD-30-4040.DWG 25FEB10 1540 SF 1.00 IMP NLTAN



FEB. 26, 2010

NOTES:

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	18DEC09	ISSUED FOR REVIEW	CMC	BHG	MS	
B	13JAN10	ISSUED FOR HAZID	JOL	BHG	MS	
C	29JAN10	ISSUED FOR REVIEW	NT	BHG	MS	
D	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:

MUSTANG ENGINEERING
XAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	04DEC09
DRAWN	C. COATS	04DEC09
CHECKED	B. GOODWIN	04DEC09
APPROVED	M. SOMERS	04DEC09

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
INLET GAS SEPARATION
(CRP) CO2 RECOVERY PLANT

OCCIDENTAL DOCUMENT NUMBER

SCALE	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	30	4040		D

MEI Project: 16179 – I:\16179\PROCESS\16179-MUS-PRO-PFD-30-4041.DWG 25FEB10 1540 SF 1.00 IMP NLTAN

V-4100/10
DUST FILTERS
XX" ID x X' S/S
DESIGN: 500 PSIG @ 200°F
OPERATING: 300 PSIG @ 102°F

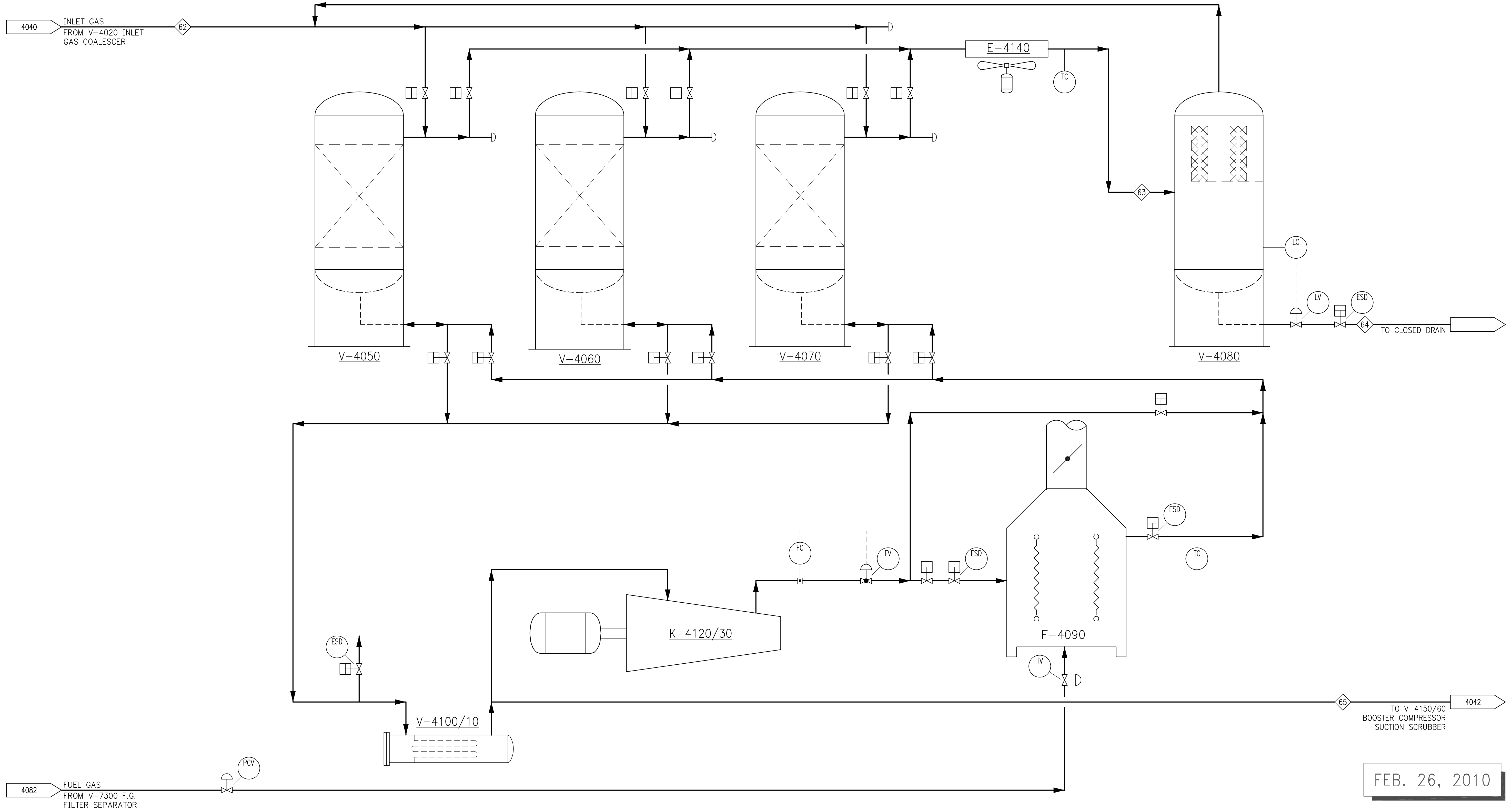
V-4050/60/70
DEHYDRATORS
XX" ID x X' S/S
DESIGN: 500 PSIG @ 600°F
OPERATING: 300 PSIG @ 102°F

K-4120/4130
REGEN GAS COMPRESSOR
CAPACITY: 10 MMSCFD
MOTOR: 100 HP EACH

E-4140
REGEN GAS COOLER
DUTY: 6.64 MMBTU/hr
DESIGN: 500 PSIG @ 600°F

F-4090
REGEN GAS HEATER
DUTY: 8.81 MMBTU/hr
DESIGN: 500 PSIG @ 800°F

V-4080
REGEN GAS SEPARATOR
XX" ID x X' S/S
DESIGN: 500 PSIG @ 200°F
OPERATING: 300 PSIG @ 120°F



FEB. 26, 2010

NOTES:

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	18DEC09	ISSUED FOR REVIEW	CMC	BHG	MS	
B	13JAN10	ISSUED FOR HAZID	JOL	BHG	MS	
C	29JAN10	ISSUED FOR REVIEW	NT	BHG	MS	
D	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:
MUSTANG ENGINEERING, L. P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	04DEC09
DRAWN	C. COATS	04DEC09
CHECKED	B. GOODWIN	04DEC09
APPROVED	M. SOMERS	04DEC09

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
CO2 FRACTIONATION UNIT DEHYDRATION
(CRP) CO2 RECOVERY PLANT

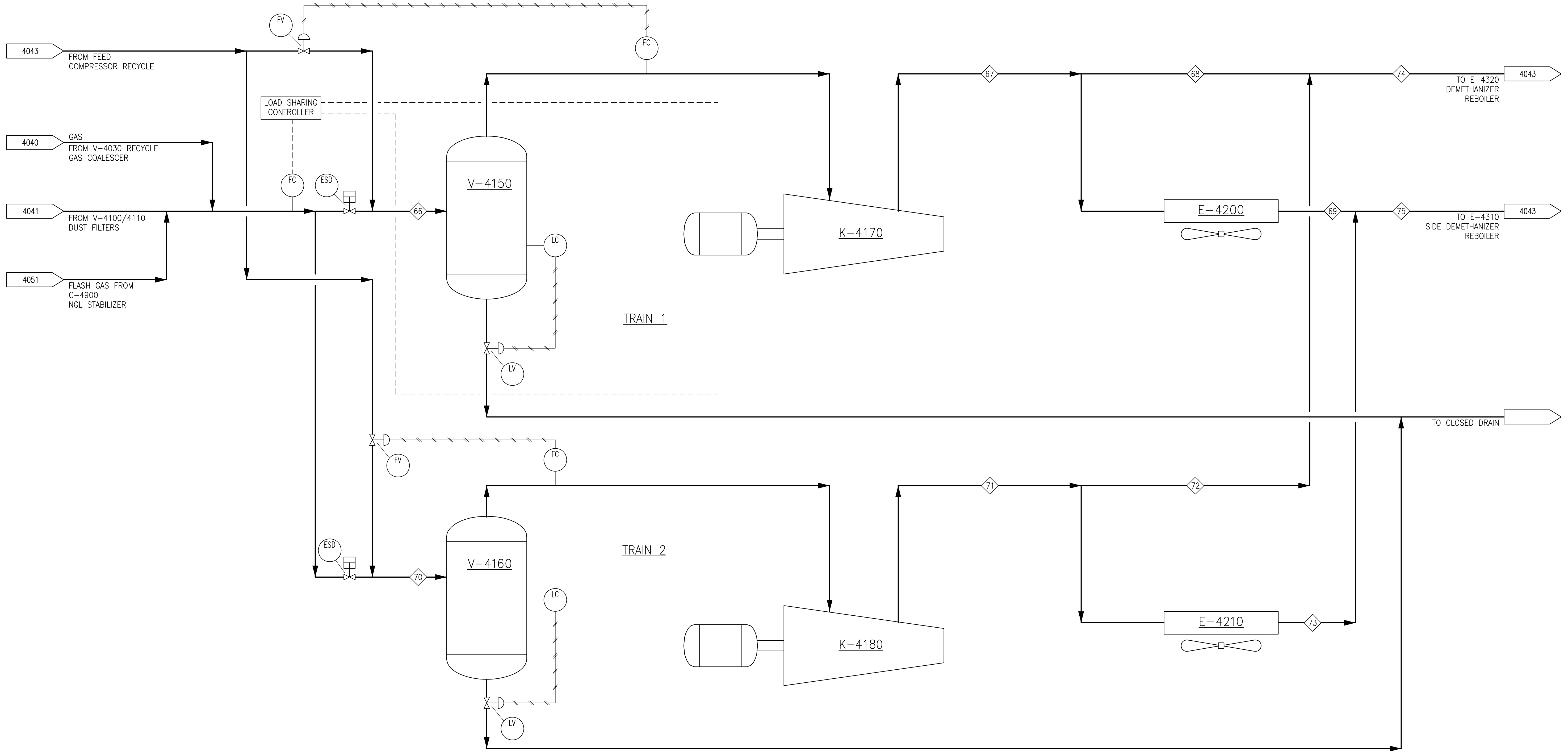
OCCIDENTAL DOCUMENT NUMBER

SCALE	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	30	4041		D

V–4150/4160
BOOSTER COMPRESSOR SUCTION SCRUBBER
120" ID x 15'–0" S/S
DESIGN: 500 PSIG @ 200°F
OPERATING: 250 PSIG @ 129°F

K–4170/4180
BOOSTER COMPRESSOR
CAPACITY: 103 MMSCFD
MOTOR: 7,050 HP EACH

E–4200/4210
BOOSTER COMPRESSOR DISCHARGE COOLER
DUTY: 20.32 MMBTU/hr
DESIGN: 700 PSIG @ 350°F



FEB. 26, 2010

NOTES:

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	18DEC09	ISSUED FOR REVIEW	TWR	BHG	MS	
B	13JAN10	ISSUED FOR HAZID	JOL	BHG	MS	
C	29JAN10	ISSUED FOR REVIEW	NT	BHG	MS	
D	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:
MUSTANG ENGINEERING, L. P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	04DEC09
DRAWN	W. ROE	04DEC09
CHECKED	B. GOODWIN	04DEC09
APPROVED	M. SOMERS	04DEC09

Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
BOOSTER COMPRESSOR
(CRP) CO2 RECOVERY PLANT

SCALE	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	30	4042		D

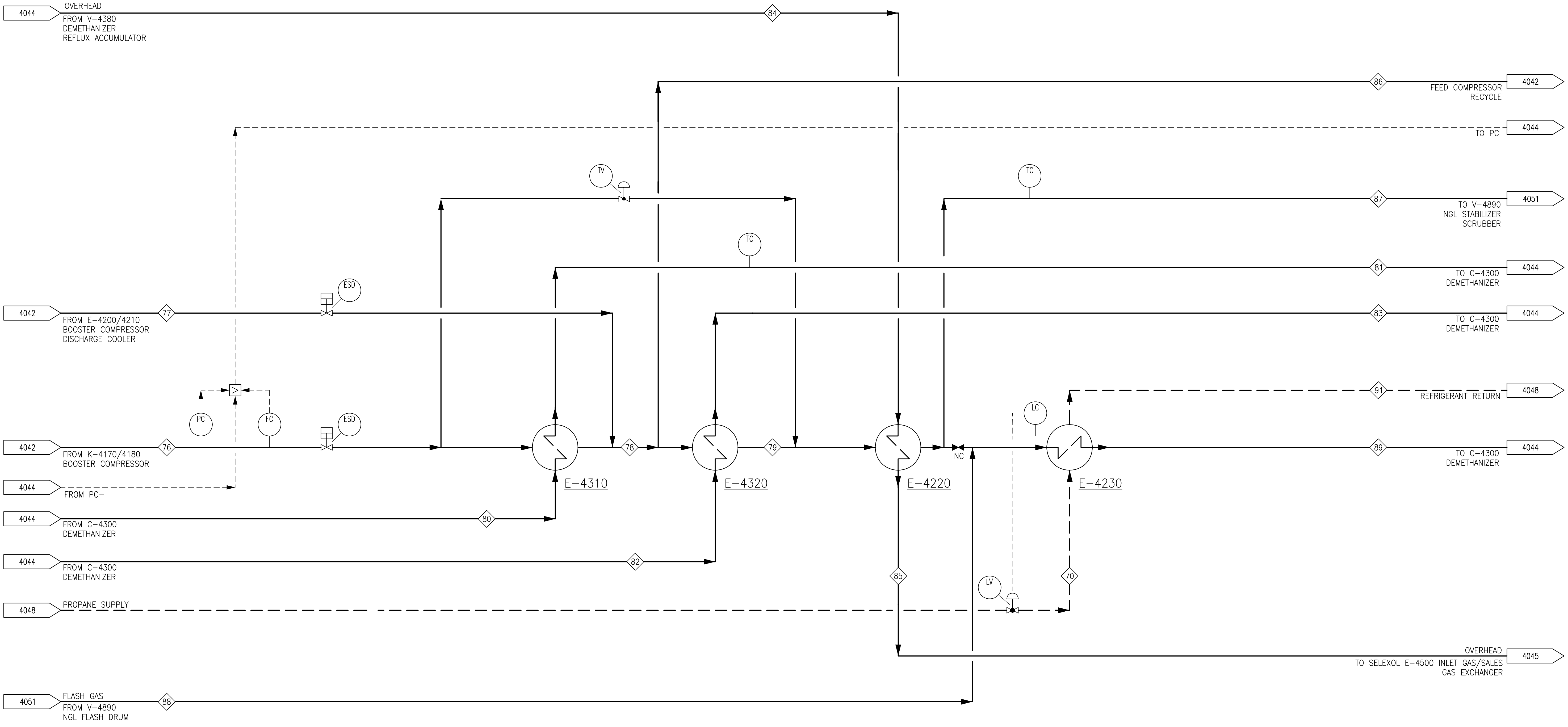
MEI Project: 16179 – I:\16179\PROCESS\16179-MUS-PRO-PFD-30-4043.DWG 25FEB10 1541 SF 1.00 IMP NLTAN

E–4310
DEMETHANIZER REBOILER
DUTY: 3.105 MMBTU/hr
DESIGN: TUBESIDE: 700 PSIG @ 150°F
SHELL: 700 PSIG @ 350°F

E–4320
DEMETHANIZER
SIDE REBOILER
DUTY: 27.3 MMBTU/hr
DESIGN: TUBESIDE: 700 PSIG @ 150°F
SHELL: 700 PSIG @ 150°F

E–4220
FEED/OVERHEAD EXCHANGER GAS CHILLER
DUTY: 1.06 MMBTU/hr
DESIGN: TUBESIDE: 700 PSIG @ 150/–50°F
SHELL: 700 PSIG @ 150°F

E–4230
DEMETHANIZER
FEED GAS CHILLER
DUTY: 90.14 MMBTU/hr
DESIGN: TUBESIDE: 700 PSIG @ 150/–50°F
SHELL: 300 PSIG @ 200/–50°F



FEB. 26, 2010

NOTES:

REFERENCE DRAWINGS	
NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	18DEC09	ISSUED FOR REVIEW	JOL	BHG	MS	
B	13JAN10	ISSUED FOR HAZID	JOL	BHG	MS	
C	29JAN10	ISSUED FOR REVIEW	NT	BHG	MS	
D	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:
MUSTANG ENGINEERING, L . P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	04DEC09
DRAWN	J. LOGAN	04DEC09
CHECKED	B. GOODWIN	04DEC09
APPROVED	M. SOMERS	04DEC09

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
CO2 FRACTIONATION UNIT
(CRP) CO2 RECOVERY PLANT

SCALE	OCCIDENTAL DOCUMENT NUMBER							
	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	30	4043		D

MEI Project: 16179 – I:\16179\PROCESS\16179-MUS-PRO-PFD-30-4044.DWG 25FEB10 1541 SF 1.00 IMP NLTAN

P-4400/10
DEMETHANIZER
REFLUX PUMPS
CAPACITY: 370 GPM AT 75 PSID
MOTOR: 25 HP EACH

V-4380
DEMETHANIZER
REFLUX ACCUMULATOR
72" ID x 20'-0" S/S
DESIGN: 700 PSIG @ 150/-50°F
OPERATING: 600 PSIG @ -35°F

E-4390
DEMETHANIZER
REFLUX CONDENSER
DUTY: 18.5 MMBTU/hr
DESIGN: TUBESIDE: 700 PSIG @ 150/-50°F
SHELL: 300 PSIG @ 150/-50°F

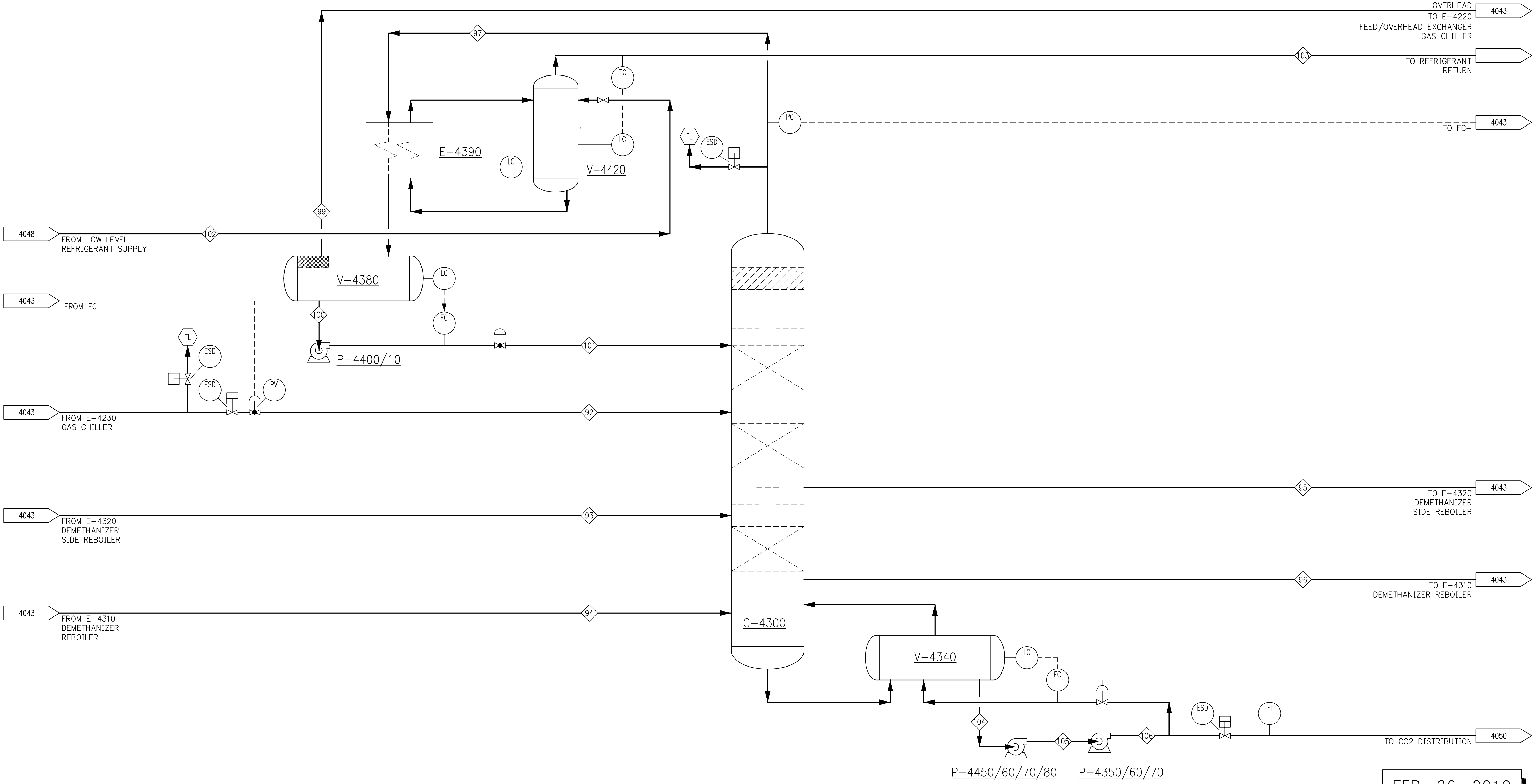
V-4420
DEMETHANIZER CONDENSER
HEAD DRUM
48" ID x 15'-6"' S/S
DESIGN: 700 PSIG @ 100/-50°F
OPERATING: 1 PSIG @ -45°F

C-4300
DEMETHANIZER
120" ID x 60' S/S
DESIGN: 700 PSIG @ 150/-50°F
OPERATING: 600 PSIG @ -35/50°F

V-4340
DEMETHANIZER
BOTTOMS SURGE DRUM
XX" ID x X' S/S
DESIGN: 700 PSIG @ 150/-50°F
OPERATING: 605 PSIG @ 43°F

P-4450/60/70/80
CO2 PRODUCT BOOSTER PUMPS
CAPACITY: 1,145 GPM AT 50 PSID
MOTOR: 60 HP EACH

P-4350/60/70
CO2 PRODUCT PUMPS
CAPACITY: 1,045 GPM AT 1,732 PSID
MOTOR: 1,750 HP EACH



FEB. 26, 2010

NOTES:

REFERENCE DRAWINGS	
NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	18DEC09	ISSUED FOR REVIEW	CMC	BHG	MS	
B	13JAN10	ISSUED FOR HAZID	JOL	BHG	MS	
C	29JAN10	ISSUED FOR REVIEW	NT	BHG	MS	
D	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:
MUSTANG ENGINEERING, L . P.
HOUSTON, TEXAS
PROJECT NO. 16179

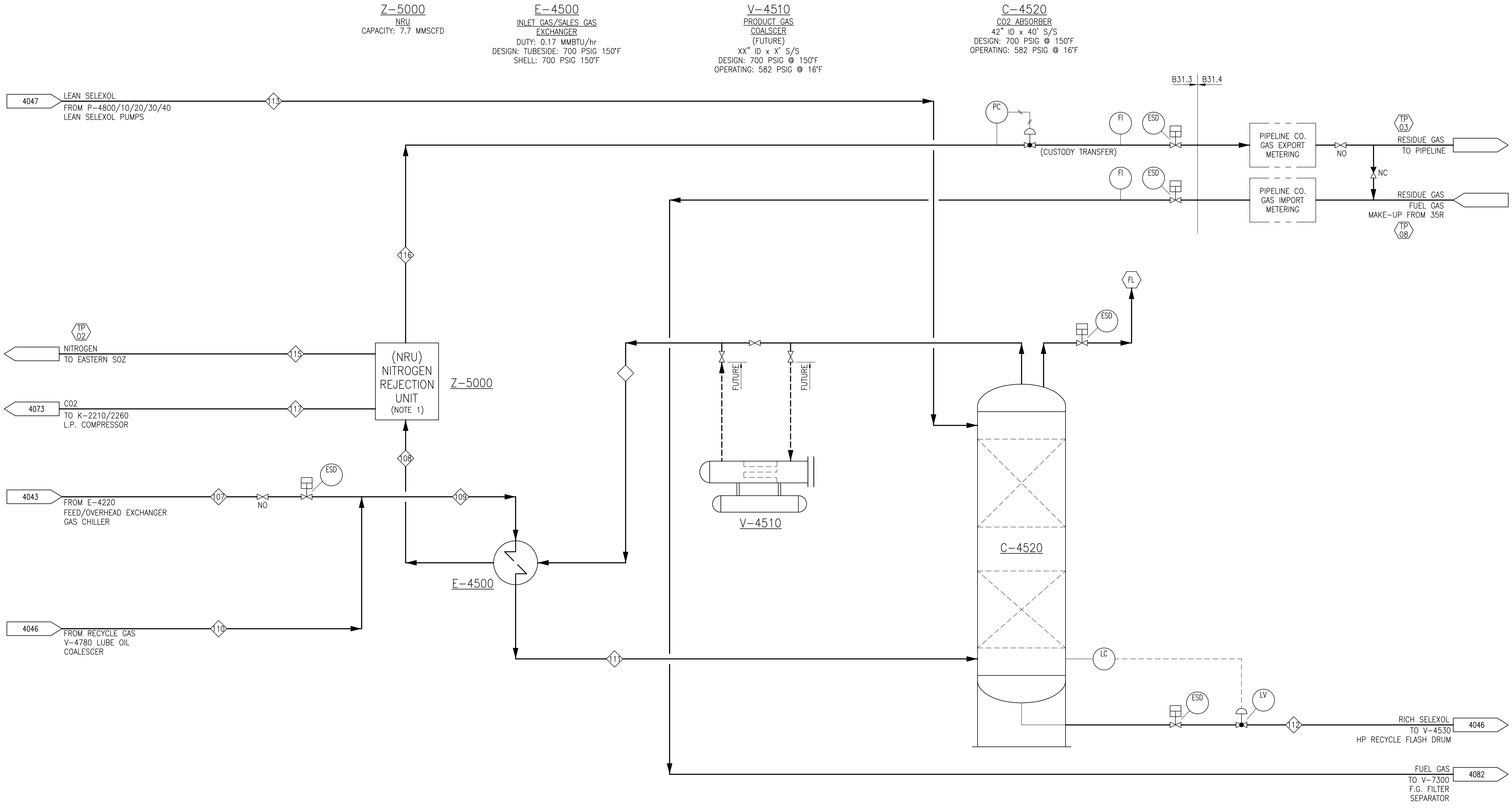
	BY	DATE
DESIGNED	A. JOHNS	04DEC09
DRAWN	C. COATS	04DEC09
CHECKED	B. GOODWIN	04DEC09
APPROVED	M. SOMERS	04DEC09

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
CO2 FRACTIONATION UNIT DEMETHANIZER
(CRP) CO2 RECOVERY PLANT

SCALE	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	30	4044		D



MAR. 05, 2010

NOTES:

1. INCLUDED WITHIN NRU SKID IS CO2 REMOVAL UNIT, NRU SALES GAS COMPRESSOR AND NRU NITROGEN COMPRESSOR.

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	18DEC09	ISSUED FOR REVIEW	JOL	BHG	MS	
B	13JAN10	ISSUED FOR HAZID	JOL	BHG	MS	
C	29JAN10	ISSUED FOR REVIEW	NT	BHG	MS	
D	26FEB10	ISSUED FOR FEED	NT	BHG	LS	
E	05MAR10	RE-ISSUED FOR FEED	WR	BHG	MS	

ENGINEERING CONSULTANT:

MUSTANG ENGINEERING, L . P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	04DEC09
DRAWN	J. LOGAN	04DEC09
CHECKED	B. GOODWIN	04DEC09
APPROVED	M. SOMERS	04DEC09

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
SELEXOL UNIT
(CRP) CO2 RECOVERY PLANT

SCALE	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	30	4045		E

OCCIDENTAL DOCUMENT NUMBER

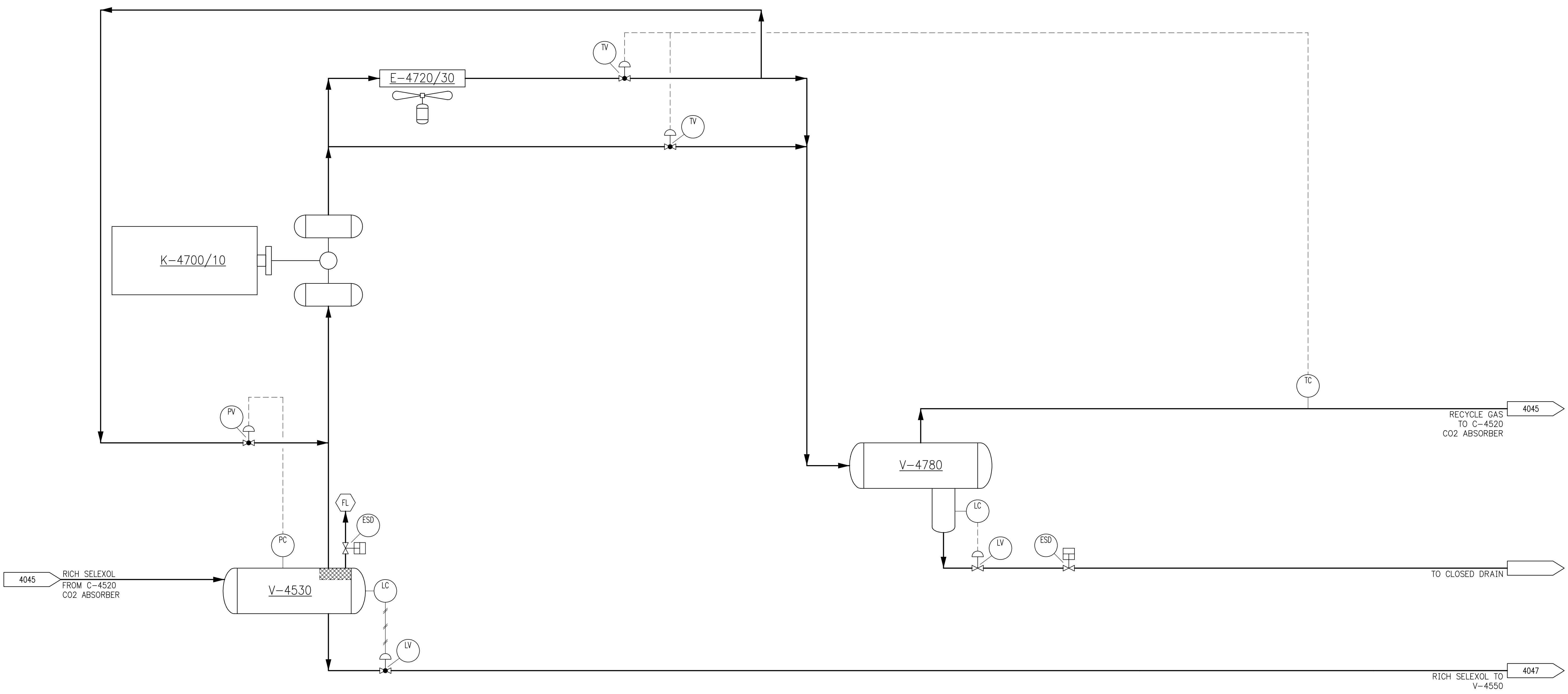
MEI Project: 16179 – I:\16179\PROCESS\16179-MUS-PRO-PFD-30-4046.DWG 25FEB10 1542 SF 1.00 IMP NLTAN

V–4530
HP RECYCLE FLASH DRUM
48" ID x 15'–6" S/S
DESIGN: 700 PSIG @ 100°F
OPERATING: 250 PSIG @ 42°F

K–4700/10
RECYCLE FLASH GAS COMPRESSOR
CAPACITY: 0.4 MMSCFD
MOTOR: 100 HP EACH

E–4720/30
RECYCLE COMPRESSOR AFTERCOOLER
DUTY: 0.05 MMBTU/hr
DESIGN: 700 PSIG @ 200°F

V–4780
LUBE OIL COALESCER
XX" ID x X' S/S
DESIGN: 700 PSIG @ 200°F
OPERATING: 620 PSIG @ 120°F



FEB. 26, 2010

NOTES:

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	18DEC09	ISSUED FOR REVIEW	CMC	BHG	MS	
B	13JAN10	ISSUED FOR HAZID	JOL	BHG	MS	
C	29JAN10	ISSUED FOR REVIEW	NT	BHG	MS	
D	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:
MUSTANG ENGINEERING, L . P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	04DEC09
DRAWN	C. COATS	04DEC09
CHECKED	B. GOODWIN	04DEC09
APPROVED	M. SOMERS	04DEC09

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
SELEXOL UNIT RECYCLE FLASH GAS COMPRESSOR
(CRP) CO2 RECOVERY PLAN

SCALE	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
	OCCIDENTAL DOCUMENT NUMBER							
NONE	16179	MUS	PRO	PFD	30	4046		D

MEI Project: 16179 – I:\16179\PROCESS\16179-MUS-PRO-PFD-30-4047.DWG 25FEB10 1542 SF 1.00 IMP NLTAN

V-4550
HP CO2
FLASH DRUM
48" ID x 15'-6" S/S
DESIGN: 275 PSIG @ 100°F
OPERATING: 60 PSIG @ 38°F

V-4560
MP CO2
FLASH DRUM
48" ID x 15'-0" S/S
DESIGN: 100 PSIG @ 100°F
OPERATING: 10 PSIG @ 17°F

V-4570
LP CO2
FLASH DRUM
48" ID x 15'-0" S/S
DESIGN: 100 PSIG @ 100°F
OPERATING: -7 PSIG @ 13°F

E-4620/30
CO2 PRODUCT COMPRESSOR
1ST STAGE COOLER
DUTY: 0.04 MMBTU/hr
DESIGN: 50 PSIG @ 250°F

E-4640/50
CO2 PRODUCT COMPRESSOR
2ND STAGE COOLER
DUTY: 0.124 MMBTU/hr
DESIGN: 50 PSIG @ 250°F

P-4950/60/70/80
LEAN SELEXOL
BOOSTER PUMPS
CAPACITY: 110 GPM @ 75 PSID
MOTOR: 10 HP EACH

V-4580
LEAN SELEXOL
FILTER
CAPACITY: 30 GPM

E-4660/70
LEAN SELEXOL CHILLER
DUTY: 0.251 MMBTU/hr
DESIGN: TUBESIDE: 100 PSIG @ 100°F
SHELL: 100 PSIG @ 100°F

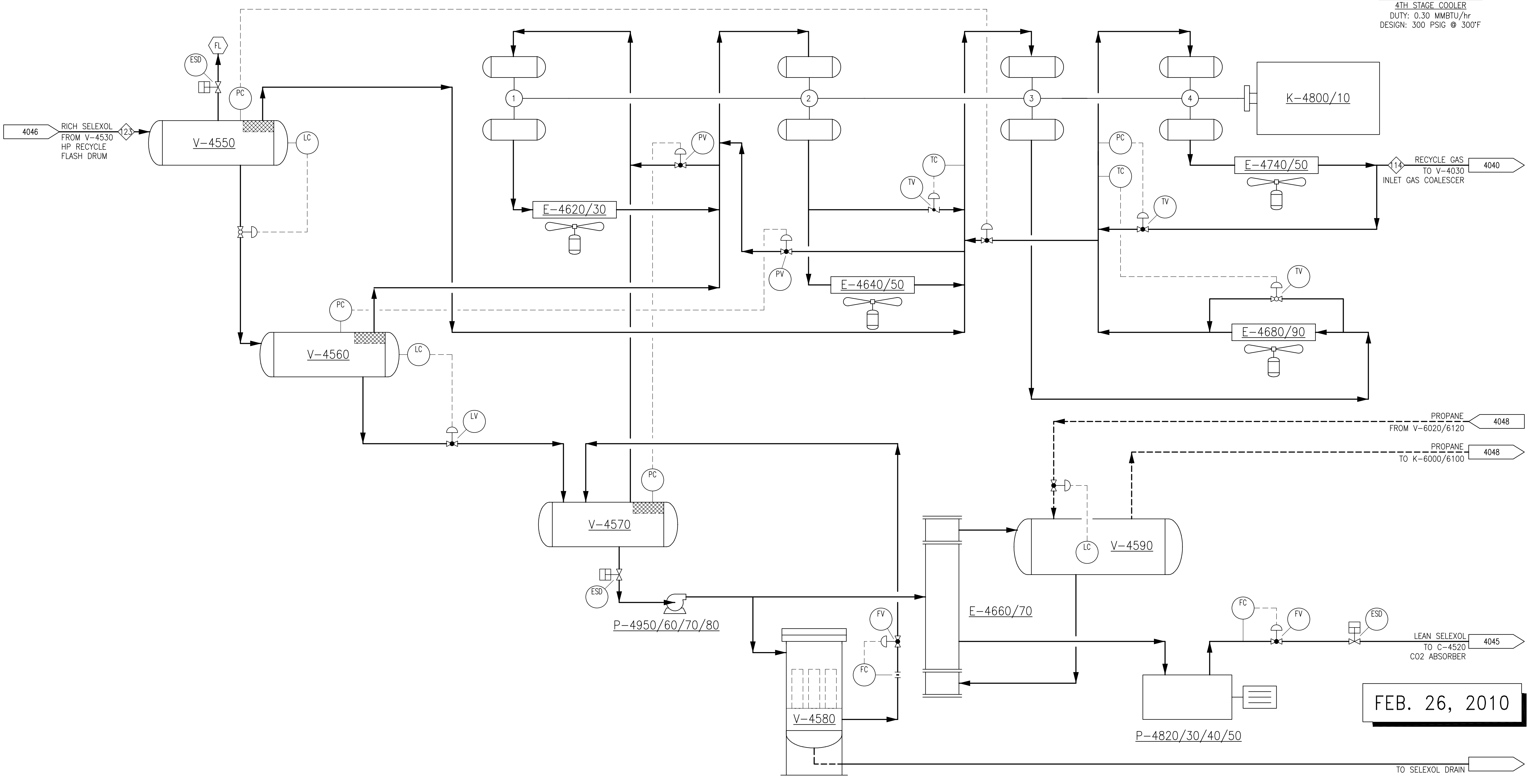
V-4590
LEAN SELEXOL CHILLER
HEAD DRUM
30" ID x 8' S/S
DESIGN: 50 PSIG @ 100°F
OPERATING: 38 PSIG @ 10°F

E-4680/90
CO2 PRODUCT COMPRESSOR
3RD STAGE COOLER
DUTY: 0.072 MMBTU/hr
DESIGN: 100 PSIG @ 300°F

K-4800/10
CO2 PRODUCT COMPRESSOR
CAPACITY: 2.13 MMSCFD
450 HP

P-4820/30/40/50
LEAN SELEXOL PUMPS
CAPACITY: 110 GPM @ 550 PSID
MOTOR: 75 HP EACH

E-4740/50
CO2 PRODUCT COMPRESSOR
4TH STAGE COOLER
DUTY: 0.30 MMBTU/hr
DESIGN: 300 PSIG @ 300°F



FEB. 26, 2010

NOTES:

REFERENCE DRAWINGS	
NO.	TITLE

REVISIONS						
NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	18DEC09	ISSUED FOR REVIEW	CCS	BHG	MS	
B	13JAN10	ISSUED FOR HAZID	JOL	BHG	MS	
C	29JAN10	ISSUED FOR REVIEW	NT	BHG	MS	
D	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:
MUSTANG ENGINEERING, L. P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	04DEC09
DRAWN	C. SOTO	04DEC09
CHECKED	B. GOODWIN	04DEC09
APPROVED	M. SOMERS	04DEC09

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
SELEXOL UNIT
(CRP) CO2 RECOVERY PLANT

SCALE	OCCIDENTAL DOCUMENT NUMBER							
	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	30	4047	–	D

MEI Project: 16179 – I:\16179\PROCESS\16179-MUS-PRO-PFD-30-4048.DWG 25FEB10 1542 SF 1.00 IMP NLTAN

E-6050/6150
PROPANE
CONDENSER
DUTY: 78.4 MMBTU/hr each
DESIGN: 300 PSIG @ 200°F

V-6090/6190
PROPANE
ACCUMULATOR
108" ID x 26'-0" S/S
DESIGN: 300 PSIG @ 250°F
OPERATING: 238 PSIG @ 120°F

V-6040/6140
PROPANE
DRYER
CAPACITY: __ GPM
@ __ PSID

V-6010/6110
PROPANE
HIGH-LEVEL ECONOMIZER
84" ID x 21'-0" S/S
DESIGN: 110 PSIG @ 110/-50°F
OPERATING: 96 PSIG @ 60°F

V-6020/6120
PROPANE
MP ECONOMIZER
72" ID x 21'-0" S/S
DESIGN: 50 PSIG @ 100/-50°F
OPERATING: 33 PSIG @ 10°F

V-4590
SELEXOL CHILLER
HEAD DRUM
30" ID x 8' S/S
DESIGN: 50 PSIG @ 100°F
OPERATING: 38 PSIG @ 10°F

E-4230
DEMETHANIZER
FEED GAS CHILLER
DUTY: 90.14 MMBTU/hr
DESIGN: 700 PSIG @ 200/-50°F

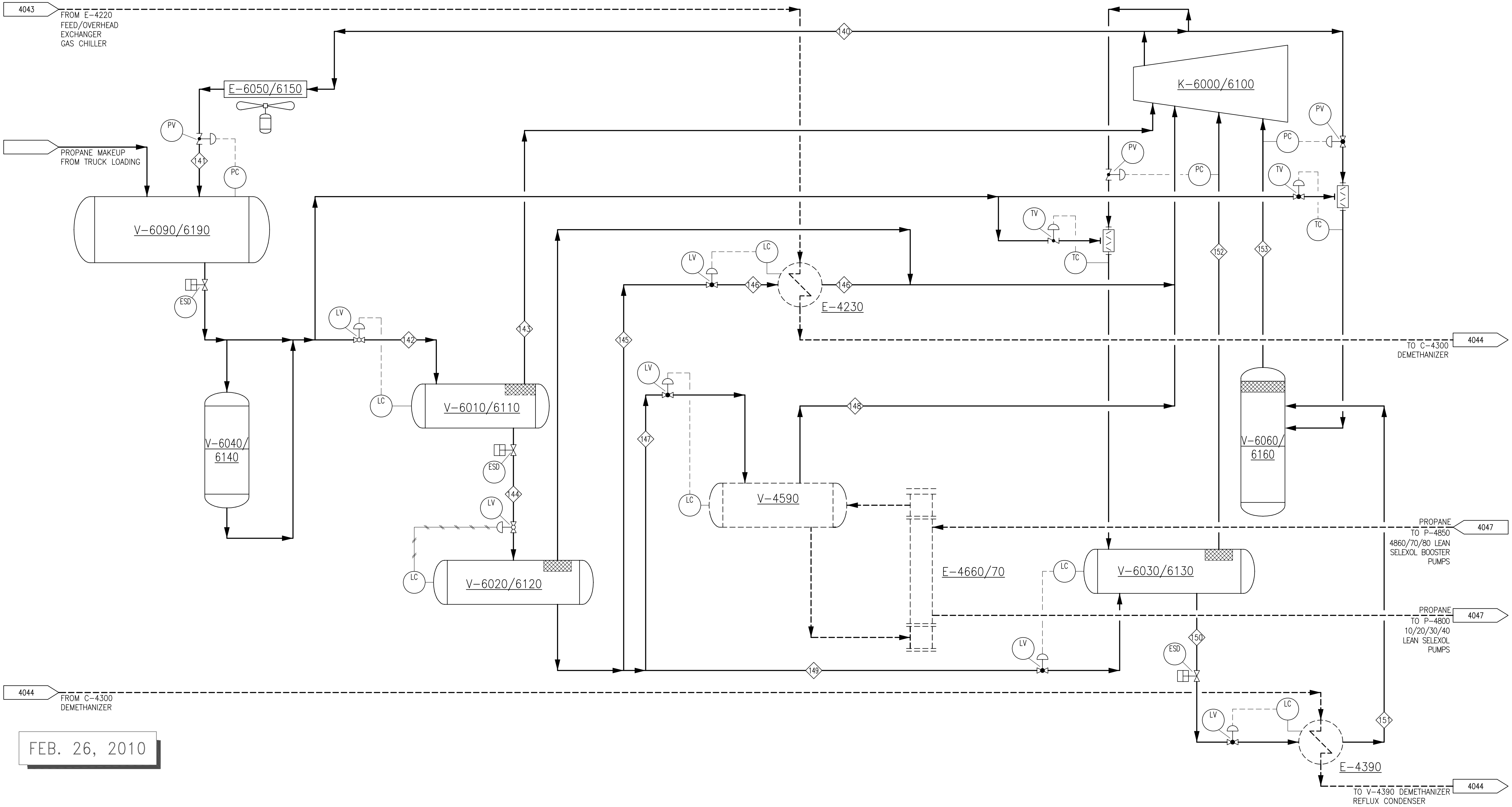
E-4660/70
LEAN SELEXOL CHILLER
DUTY: 0.251 MMBTU/hr each
DESIGN: 100 PSIG @ 100°F

V-6030/6130
PROPANE
LOW-LEVEL ECONOMIZER
42" ID x 12'-0" S/S
DESIGN: 50 PSIG @ 100/-50°F
OPERATING: 11 PSIG @ -20°F

K-6000/6100
PROPANE
COMPRESSOR
MOTOR: 10,400 HP EACH

V-6060/6160
PROPANE
SUCTION SCRUBBER
78" ID x 10'-6" S/S
DESIGN: 50 PSIG @ 100/-50°F
OPERATING: 0 PSIG @ -43°F

E-4390
DEMETHANIZER
REFLUX CONDENSER
DUTY: 18.5 MMBTU/hr
DESIGN: 700 PSIG @ 150/-50°F



FEB. 26, 2010

NOTES:

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	18DEC09	ISSUED FOR REVIEW	CCS	BHG	MS	
B	13JAN10	ISSUED FOR HAZID	JOL	BHG	MS	
C	29JAN10	ISSUED FOR REVIEW	NT	BHG	MS	
D	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:
MUSTANG ENGINEERING, L . P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	04DEC09
DRAWN	CCSOTO	02DEC09
CHECKED	B. GOODWIN	04DEC09
APPROVED	M. SOMERS	04DEC09

OXY Occidental

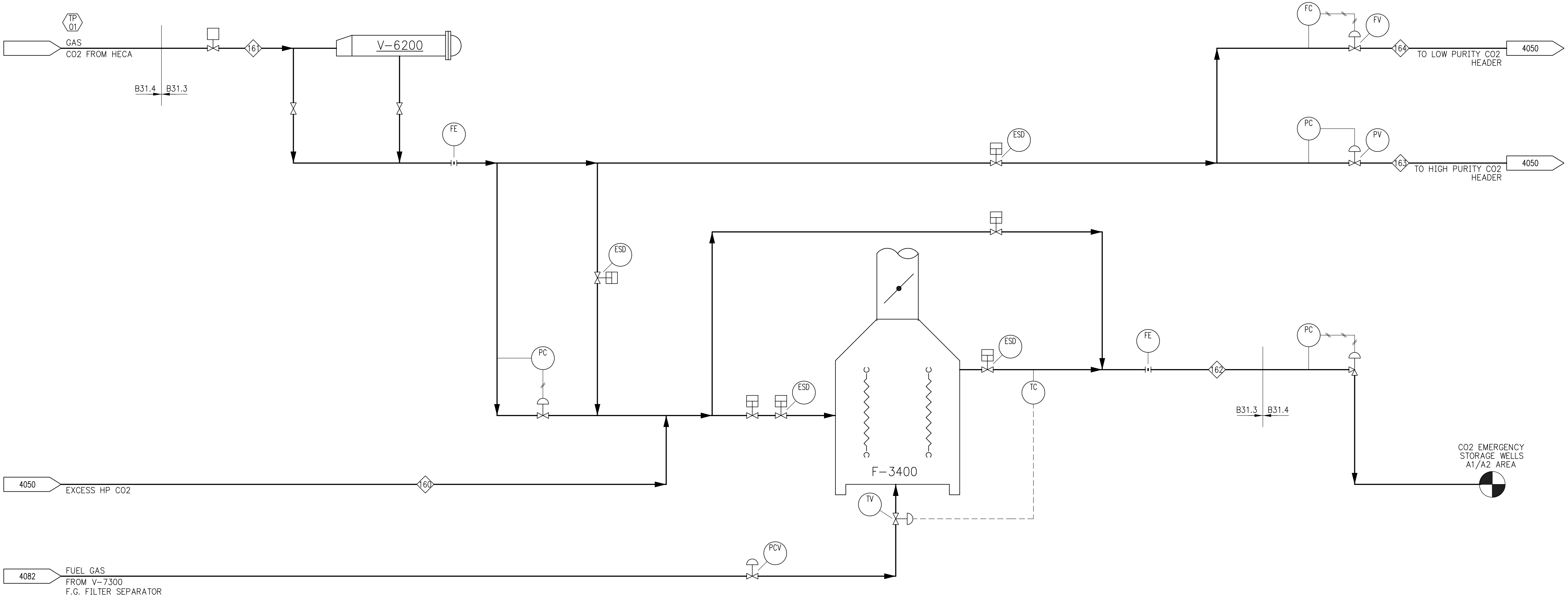
FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
CO2 FRACTION UNIT-REFRIGERATION
(CRP) CO2 RECOVERY PLANT

SCALE	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	30	4048		D

V–6200
RECEIVER
12" x 16" DIA x 8' L
DESIGN: 2,650 PSIG @ 200'F

F–3400
CO2 INJECTION HEATER



MAR. 05, 2010

NOTES:

REFERENCE DRAWINGS	
NO.	TITLE

REVISIONS						
NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	13JAN10	ISSUED FOR HAZID	JOL	BHG	MS	
B	29JAN10	ISSUED FOR REVIEW	NT	BHG	MS	
C	26FEB10	ISSUED FOR FEED	NT	BHG	LS	
D	05MAR10	RE–ISSUED FOR FEED	WR	BHG	MS	

ENGINEERING CONSULTANT:

MUSTANG ENGINEERING, L . P.
HOUSTON, TEXAS
PROJECT NO. 16179

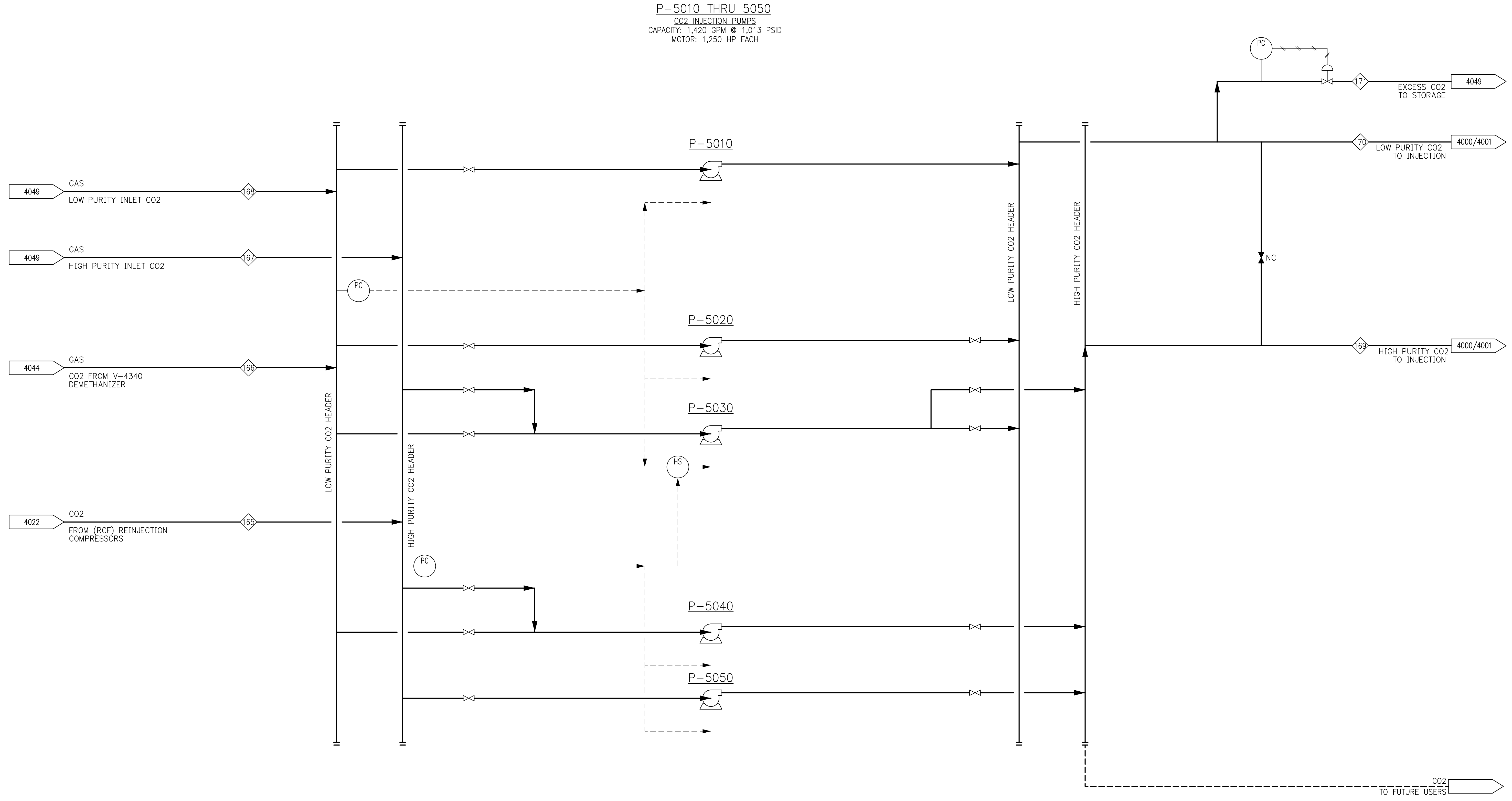
	BY	DATE
DESIGNED	A. JOHNS	04DEC09
DRAWN	J. LOGAN	04DEC09
CHECKED	B. GOODWIN	04DEC09
APPROVED	M. SOMERS	04DEC09

Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
CO2 INLET AND STORAGE
(CRP) CO2 RECOVERY PLANT

SCALE	OCCIDENTAL DOCUMENT NUMBER						
	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	30	4049		D



FEB. 26, 2010

NOTES:

REFERENCE DRAWINGS	
NO.	TITLE

REVISIONS						
NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	13JAN10	ISSUED FOR HAZID	JOL	BHG	MS	
B	29JAN10	ISSUED FOR REVIEW	NT	BHG	MS	
C	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:

MUSTANG ENGINEERING, L. P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	04DEC09
DRAWN	J. LOGAN	04DEC09
CHECKED	B. GOODWIN	04DEC09
APPROVED	M. SOMERS	04DEC09

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
CO2 INJECTION PUMPS
(CRP) CO2 RECOVERY PLANT

SCALE	OCCIDENTAL DOCUMENT NUMBER							
	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	30	4050		C

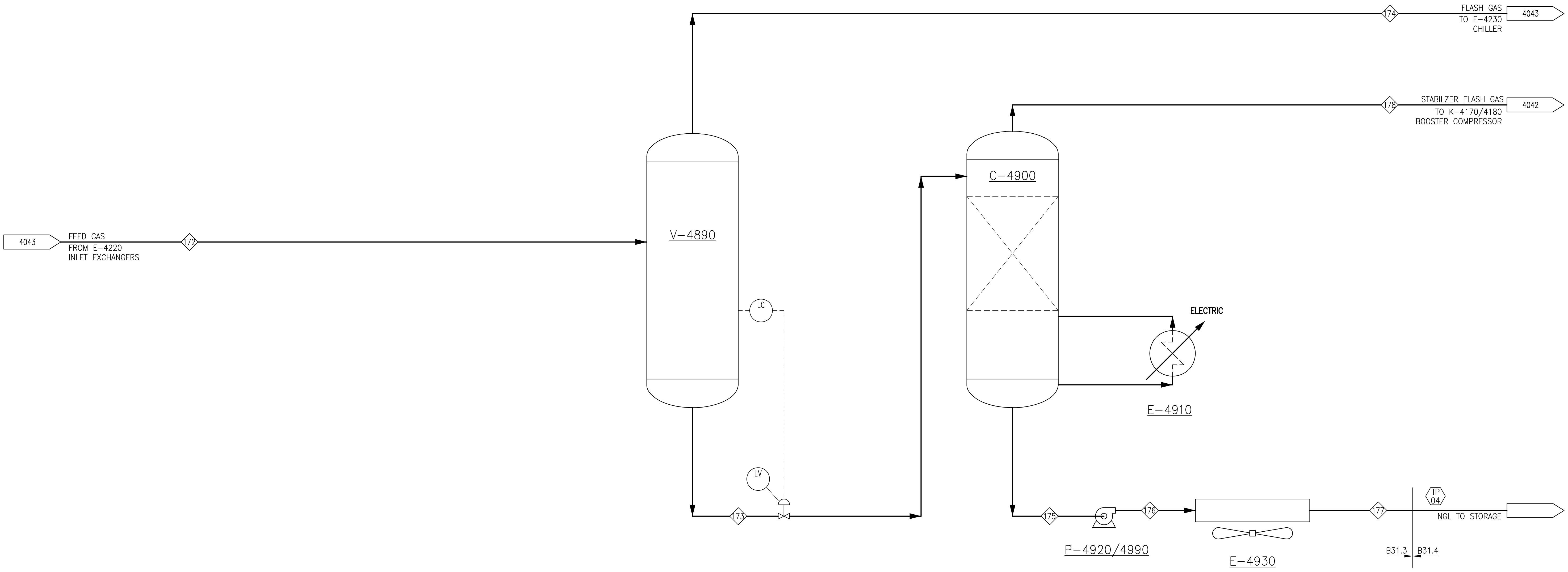
V–4890
STABILIZER–SCRUBBER
132" ID x 14' S/S
DESIGN: 700 PSIG @ 100°F
OPERATING: 630 PSIG @ 45°F

C–4900
NGL STABILIZER
36" ID x 40' S/S
DESIGN: 300 PSIG @ 300°F
OPERATING: 265 PSIG @ –6/268°F

E–4910
STABILIZER REBOILER
DUTY: 0.62 MMBTU/hr
DESIGN: TUBESIDE: 300 PSIG @ 300°F

P–4920/4990
NGL PUMP
20 GPM
MOTOR: 1 HP EACH

E–4930
NGL COOLER
DUTY: 0.022 MMBTU/hr



FEB. 26, 2010

NOTES:

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	13JAN10	ISSUED FOR HAZID	JOL	BHG	MS	
B	29JAN10	ISSUED FOR REVIEW	NT	BHG	MS	
C	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:

MUSTANG ENGINEERING, L . P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	04DEC09
DRAWN	C. SOTO	04DEC09
CHECKED	B. GOODWIN	04DEC09
APPROVED	M. SOMERS	04DEC09

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
NGL RECOVERY
(CRP) CO2 RECOVERY PLANT

SCALE	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	30	4051	–	C

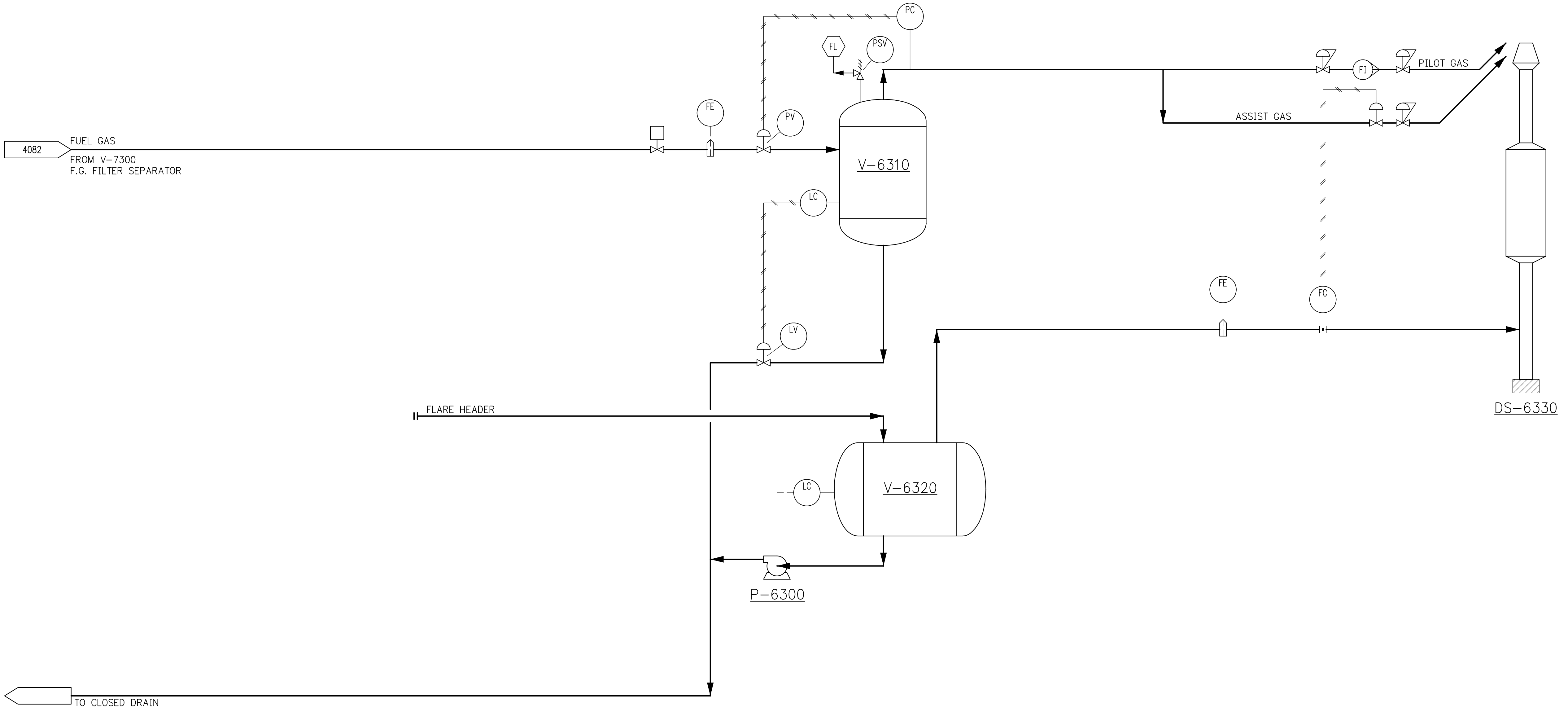
OCCIDENTAL DOCUMENT NUMBER

P-6300
FLARE SCRUBBER PUMP
10 GPM AT 30 PSID
MOTOR: 1 HP

V-6310
BLANKET GAS SCRUBBER
132" OD x 14'-6" S/S
DESIGN: 150 PSIG AT 150°F
OPERATING: 100 PSIG AT 100°F

V-6320
FLARE SCRUBBER
120" ID x 40'-0" S/S
DESIGN: 100 PSIG AT 150°F
OPERATING: 75 PSIG AT 100°F

DS-6330
FLARE
CAPACITY: 619 MMSCFD



FEB. 26, 2010

NOTES:

REFERENCE DRAWINGS	
NO.	TITLE

REVISIONS						
NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:
MUSTANG ENGINEERING, L. P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	17FEB10
DRAWN	N. TAN	17FEB10
CHECKED	B. GOODWIN	17FEB10
APPROVED	M. SOMERS	17FEB10

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
FLARE SYSTEM
(CRP) CO2 RECOVERY PLANT

SCALE	OCCIDENTAL DOCUMENT NUMBER							
	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	30	4052		A

K-7000/10
INSTRUMENT AIR
COMPRESSOR
500 SCFM
MOTOR: 200 HP EACH

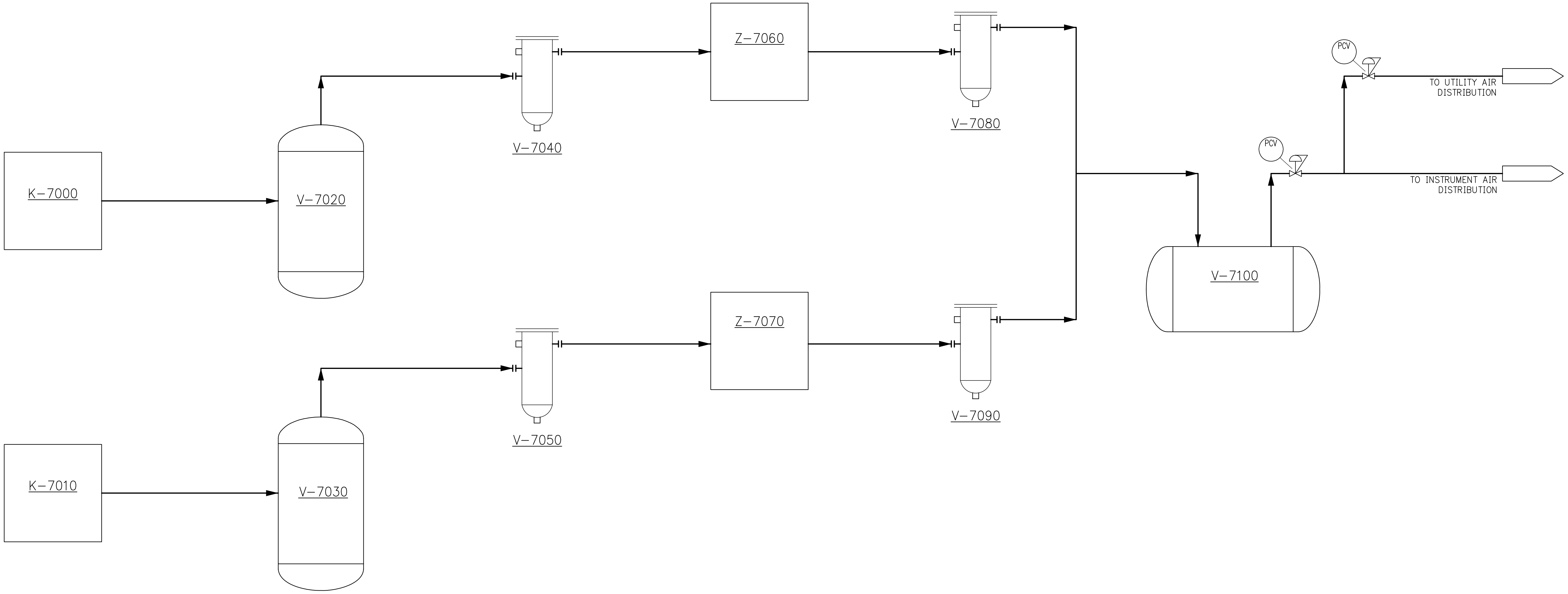
V-7020/30
INSTRUMENT AIR
KO DRUM

V-7040/50
INSTRUMENT AIR
PRE-FILTER

Z-7060/70
INSTRUMENT AIR
DRYER PACKAGE

V-7080/90
INSTRUMENT AIR
AFTER FILTER

V-7100
INSTRUMENT AIR
RECEIVER
120" ID x 30'-0" S/S
DESIGN: 200 PSIG AT 150°F



FEB. 26, 2010

NOTES:

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	29JAN10	ISSUED FOR REVIEW	WR	BHG	MS	
B	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:

MUSTANG ENGINEERING, L . P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	PMB	27JAN10
DRAWN	W. ROE	27JAN10
CHECKED	B. GOODWIN	27JAN10
APPROVED	M. SOMERS	27JAN10

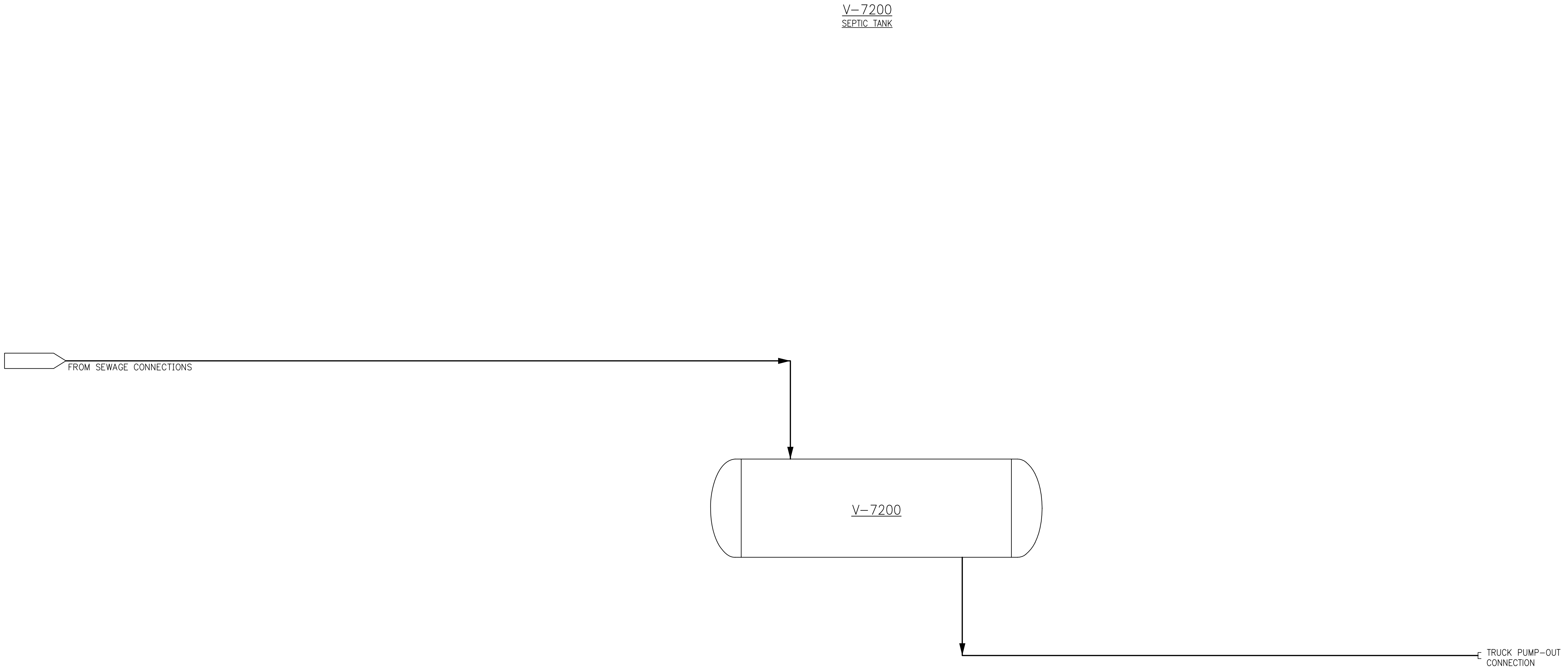
OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
UTILITY PROCESS FLOW DIAGRAM
INSTRUMENT AIR SYSTEM
(CRP) CO2 RECOVERY PLANT

SCALE	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	30	4080		B

MEI Project: 16179 – I:\16179\PROCESS\16179-MUS-PRO-PFD-30-4081.DWG 25FEB10 1544 SF 1.00 IMP NLTAN



FEB. 26, 2010

NOTES:

REFERENCE DRAWINGS	
NO.	TITLE

REVISIONS						
NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	29JAN10	ISSUED FOR REVIEW	WR	BHG	MS	
B	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:

MUSTANG ENGINEERING, L . P.
HOUSTON, TEXAS
PROJECT NO. 16179

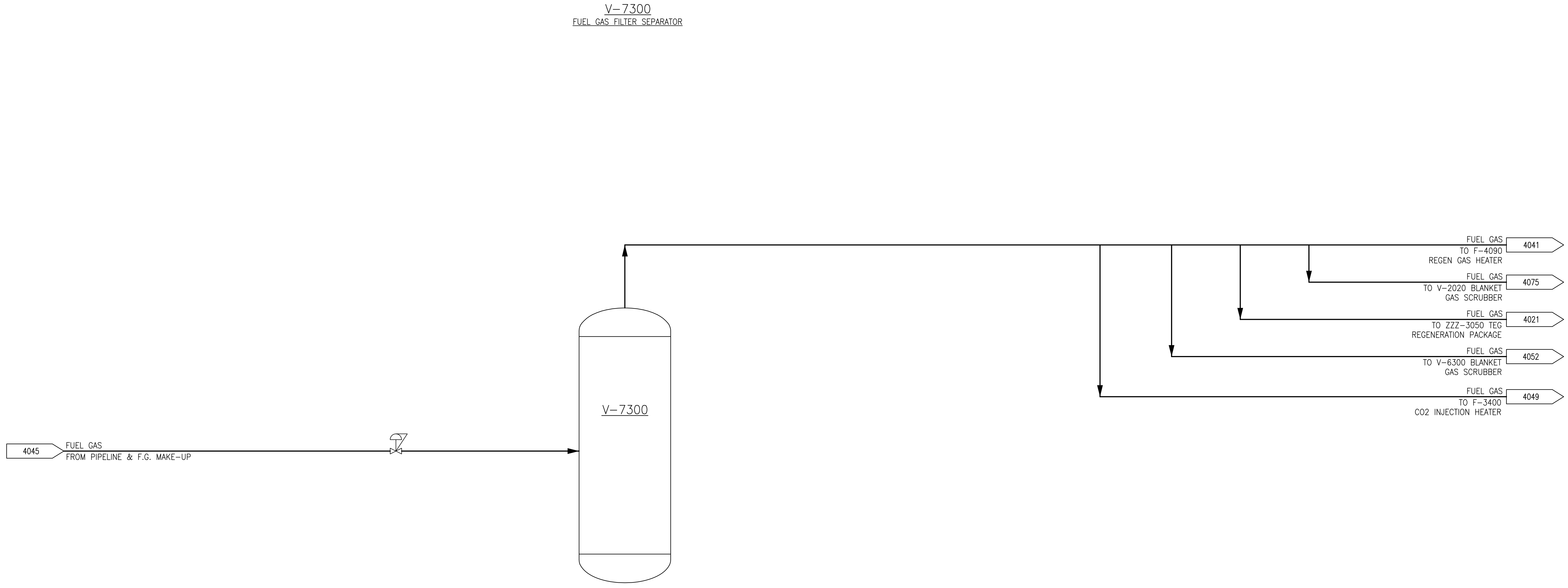
	BY	DATE
DESIGNED	PMB	27JAN10
DRAWN	N. TAN	27JAN10
CHECKED	B. GOODWIN	27JAN10
APPROVED	M. SOMERS	27JAN10

Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
UTILITY PROCESS FLOW DIAGRAM
SEPTIC TANK
(CRP) CO2 RECOVERY PLANT

SCALE	OCCIDENTAL DOCUMENT NUMBER							
	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	30	4081		B



MAR. 05, 2010

NOTES:

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	29JAN10	ISSUED FOR REVIEW	WR	BHG	MS	
B	26FEB10	ISSUED FOR FEED	NT	BHG	LS	
C	05MAR10	RE-ISSUED FOR FEED	WR	BHG	MS	

ENGINEERING CONSULTANT:

MUSTANG ENGINEERING, L . P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	PMB	27JAN10
DRAWN	N. TAN	27JAN10
CHECKED	B. GOODWIN	27JAN10
APPROVED	M. SOMERS	27JAN10

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
UTILITY PROCESS FLOW DIAGRAM
FUEL GAS FILTER SEPARATOR
(CRP) CO2 RECOVERY PLANT

OCCIDENTAL DOCUMENT NUMBER

SCALE	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	30	4082		C

MEI Project: 16179 – I:\16179\PROCESS\16179-MUS-PRO-PFD-30-4083.DWG 25FEB10 1545 SF 1.00 IMP NLTAN

T–7400
FIREWATER STORAGE TANK
CAPACITY: 35,700 BBLS

P–7410/20
FIREWATER PUMPS
CAPACITY: 1,500 GPM AT 130 PSID
MOTOR: 200 HP EACH

FEB. 26, 2010

NOTES:

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	29JAN10	ISSUED FOR REVIEW	WR	BHG	MS	
B	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:
MUSTANG ENGINEERING, L . P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	PMB	27JAN10
DRAWN	N. TAN	27JAN10
CHECKED	B. GOODWIN	27JAN10
APPROVED	M. SOMERS	27JAN10

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
UTILITY PROCESS FLOW DIAGRAM
FIREWATER SYSTEM
(CRP) CO2 RECOVERY PLANT

SCALE	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	30	4083		B

OCCIDENTAL DOCUMENT NUMBER

MEI Project: 16179 – I:\16179\PROCESS\16179-MUS-PRO-PFD-30-4084.DWG 25FEB10 1545 SF 1.00 IMP NLTAN

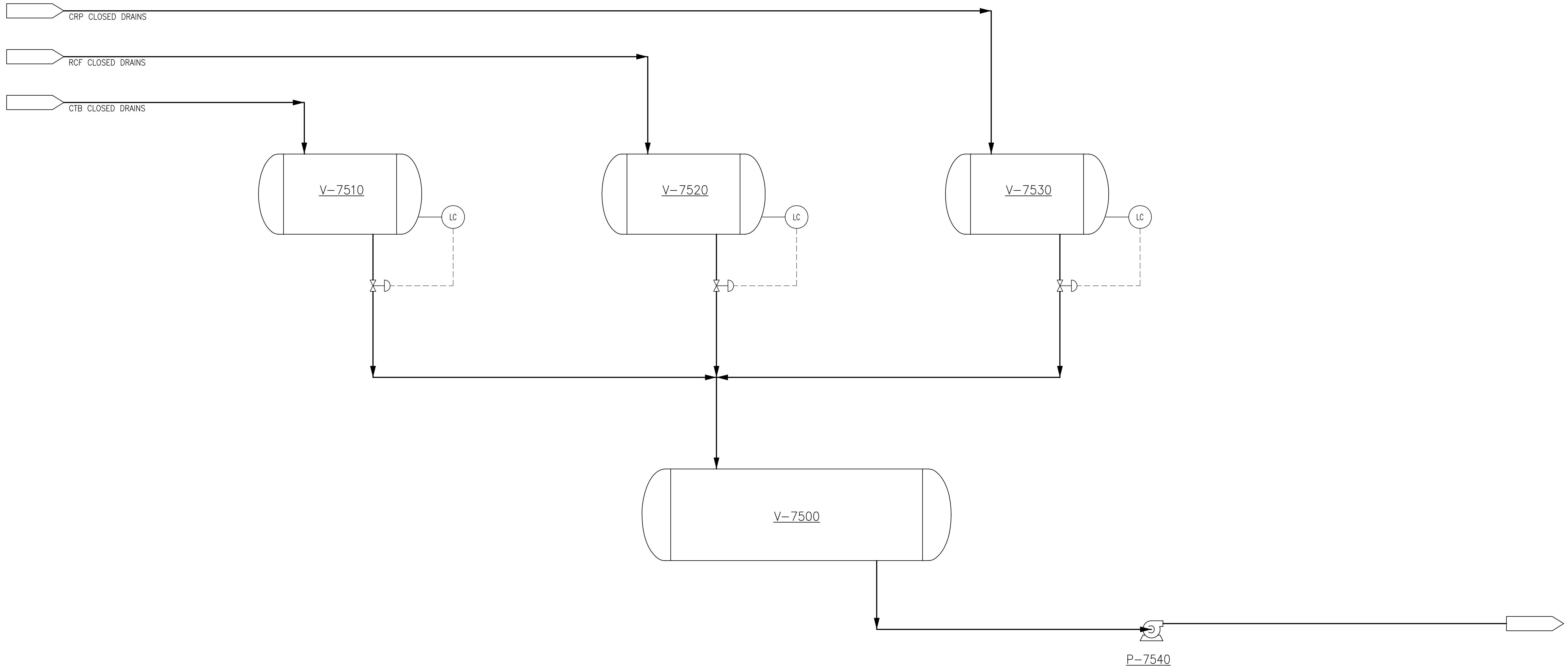
V-7510
(CTB) CLOSED DRAIN TANK
42" ID x 12'-0" S/S
DESIGN: 100 PSIG AT 150/-20°F

V-7520
(RCF) CLOSED DRAIN TANK
42" ID x 12'-0" S/S
DESIGN: 100 PSIG AT 150/-20°F

V-7530
(CRP) CLOSED DRAIN TANK
42" ID x 12'-0" S/S
DESIGN: 100 PSIG AT 150/-20°F

V-7500
COMMON CLOSED DRAIN TANK
60" ID x 20'-0" S/S
DESIGN: 100 PSIG @ 150/-20°F

P-7540
CLOSED DRAIN PUMP
CAPACITY: 70 GPM @ 150 PSID
MOTOR: 10 HP



FEB. 26, 2010

NOTES:

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	29JAN10	ISSUED FOR REVIEW	WR	BHG	MS	
B	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:
MUSTANG ENGINEERING, L. P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	PMB	27JAN10
DRAWN	W. ROE	27JAN10
CHECKED	B. GOODWIN	27JAN10
APPROVED	M. SOMERS	27JAN10

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
UTILITY PROCESS FLOW DIAGRAM
CLOSED DRAIN SYSTEM
(CRP) CO2 RECOVERY PLANT

SCALE	OCCIDENTAL DOCUMENT NUMBER							
	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	30	4084		B

MEI Project: 16179 – I:\16179\PROCESS\16179-MUS-PRO-PFD-30-4085.DWG 25FEB10 1545 SF 1.00 IMP NLTAN

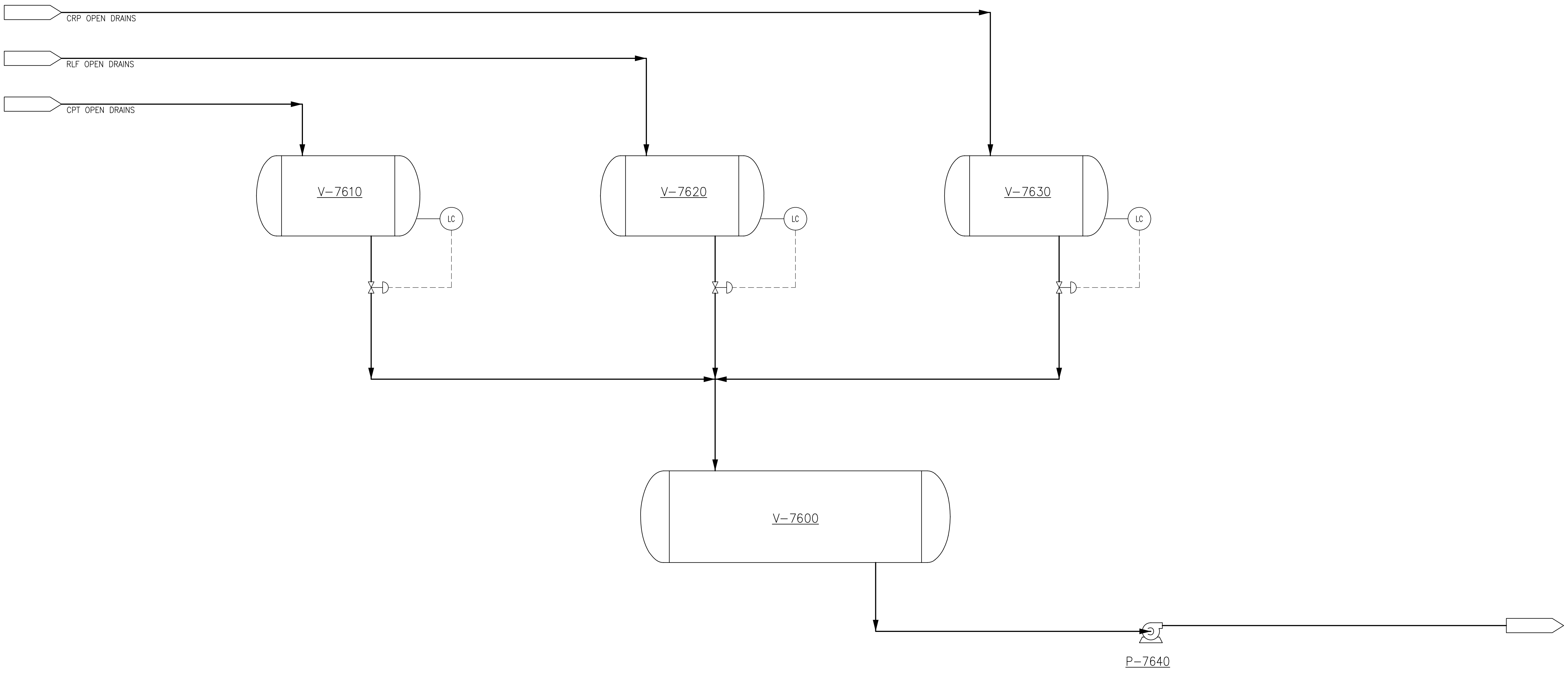
V–7610
(CTB) OPEN DRAIN TANK
48" ID x 15'–0" S/S
DESIGN: 1 PSIG AT 150/–20°F

V–7620
(RCF) OPEN DRAIN TANK
48" ID x 15'–0" S/S
DESIGN: 1 PSIG AT 150/–20°F

V–7630
(CRP) OPEN DRAIN TANK
48" ID x 15'–0" S/S
DESIGN: 1 PSIG AT 150/–20°F

V–7600
COMMON OPEN DRAIN TANK
72" ID x 21'–0" S/S
DESIGN: 1 PSIG AT 150/–20°F

P–7640
OPEN DRAIN PUMP
CAPACITY: 70 GPM @ 150 PSID
MOTOR: 10 HP



FEB. 26, 2010

NOTES:

REFERENCE DRAWINGS	
NO.	TITLE

REVISIONS						
NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	29JAN10	ISSUED FOR REVIEW	WR	BHG	MS	
B	26FEB10	ISSUED FOR FEED	NT	BHG	MS	

ENGINEERING CONSULTANT:

MUSTANG ENGINEERING, L . P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	PMB	27JAN10
DRAWN	W. ROE	27JAN10
CHECKED	B. GOODWIN	27JAN10
APPROVED	M. SOMERS	27JAN10

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
UTILITY PROCESS FLOW DIAGRAM
OPEN DRAIN SYSTEM
(CRP) CO2 RECOVERY PLANT

SCALE	OCCIDENTAL DOCUMENT NUMBER							
	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	30	4085		B

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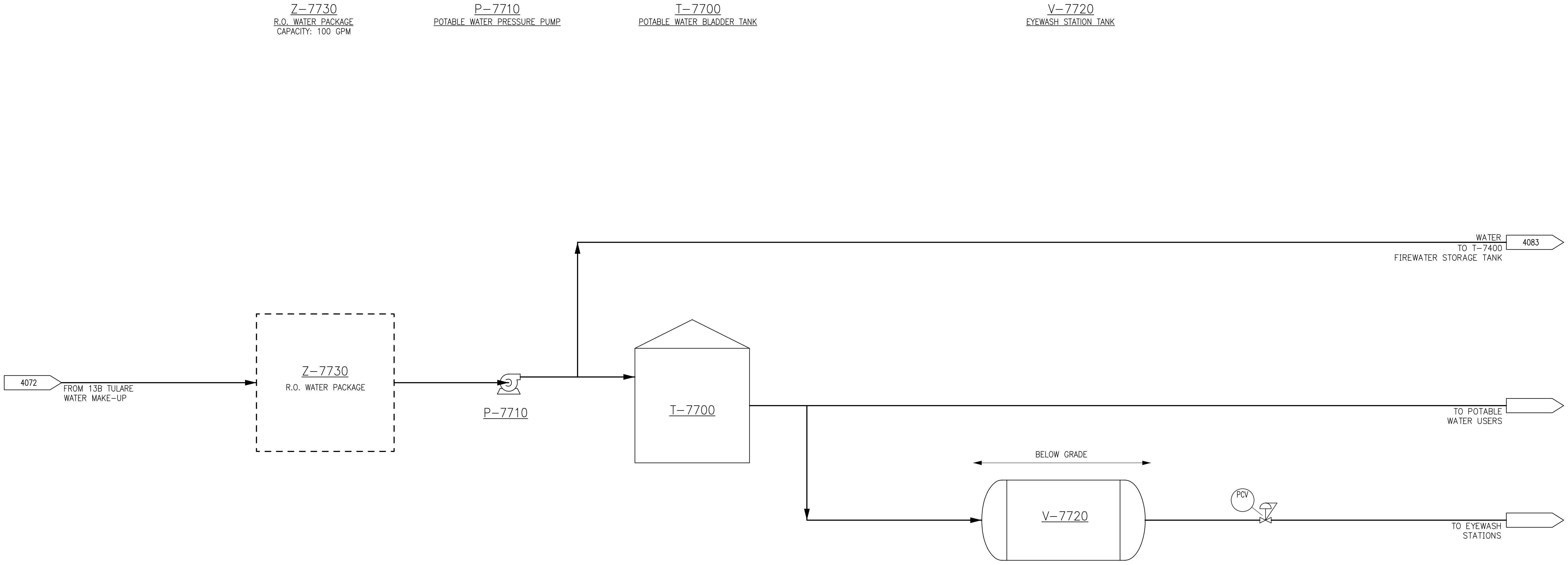

FEB. 26, 2010

NOTES:

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	29JAN10	ISSUED FOR REVIEW	WR	BHG	MS	
B	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:

MUSTANG ENGINEERING, L. P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	PMB	27JAN10
DRAWN	W. ROE	27JAN10
CHECKED	B. GOODWIN	27JAN10
APPROVED	M. SOMERS	27JAN10

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
UTILITY PROCESS FLOW DIAGRAM
POTABLE WATER SYSTEM
(CRP) CO2 RECOVERY PLANT

OCCIDENTAL DOCUMENT NUMBER

SCALE	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	30	4086		B

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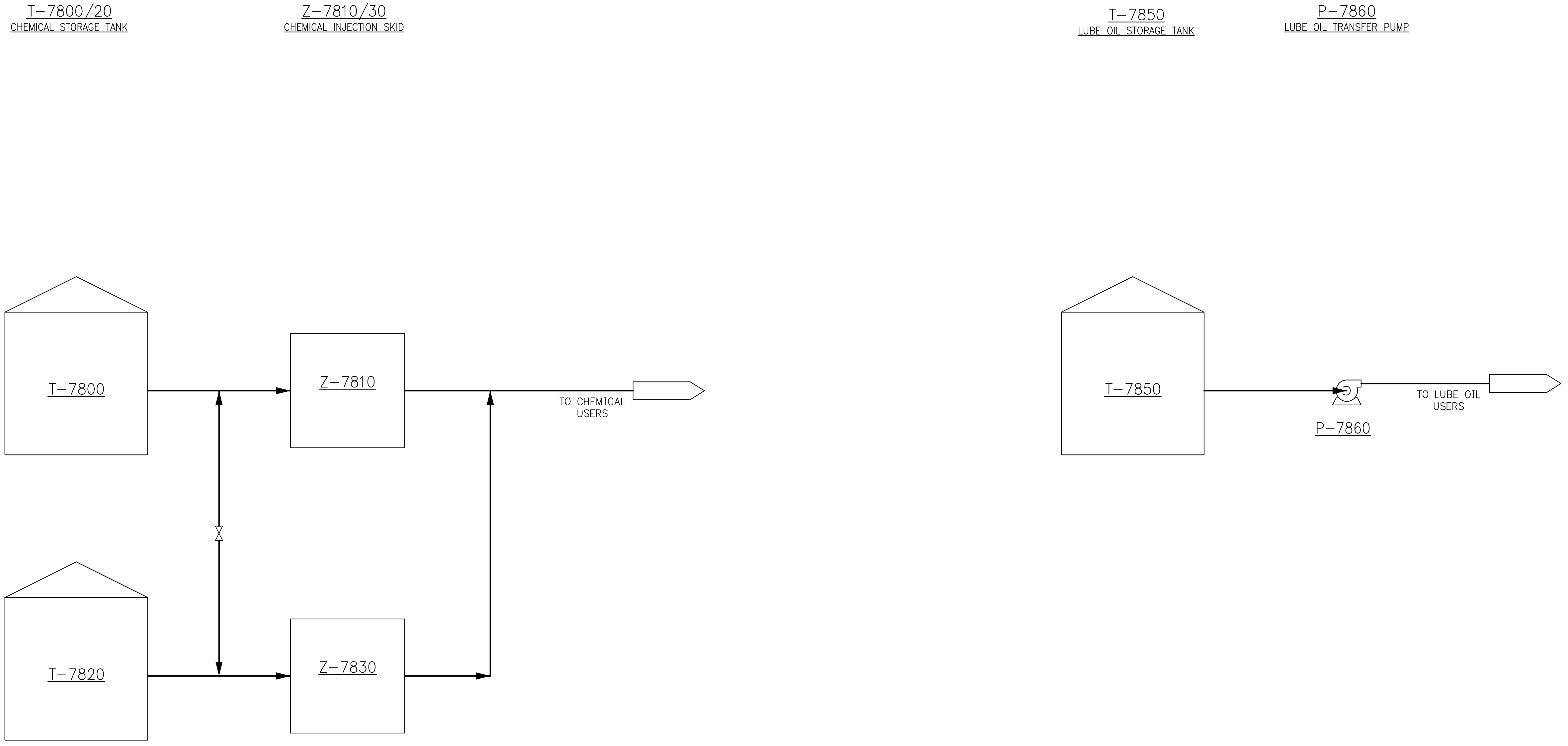


FEB. 26, 2010

NOTES:

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	29JAN10	ISSUED FOR REVIEW	WR	BHG	MS	
B	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:

MUSTANG ENGINEERING, L . P.
HOUSTON, TEXAS
PROJECT NO. 16179

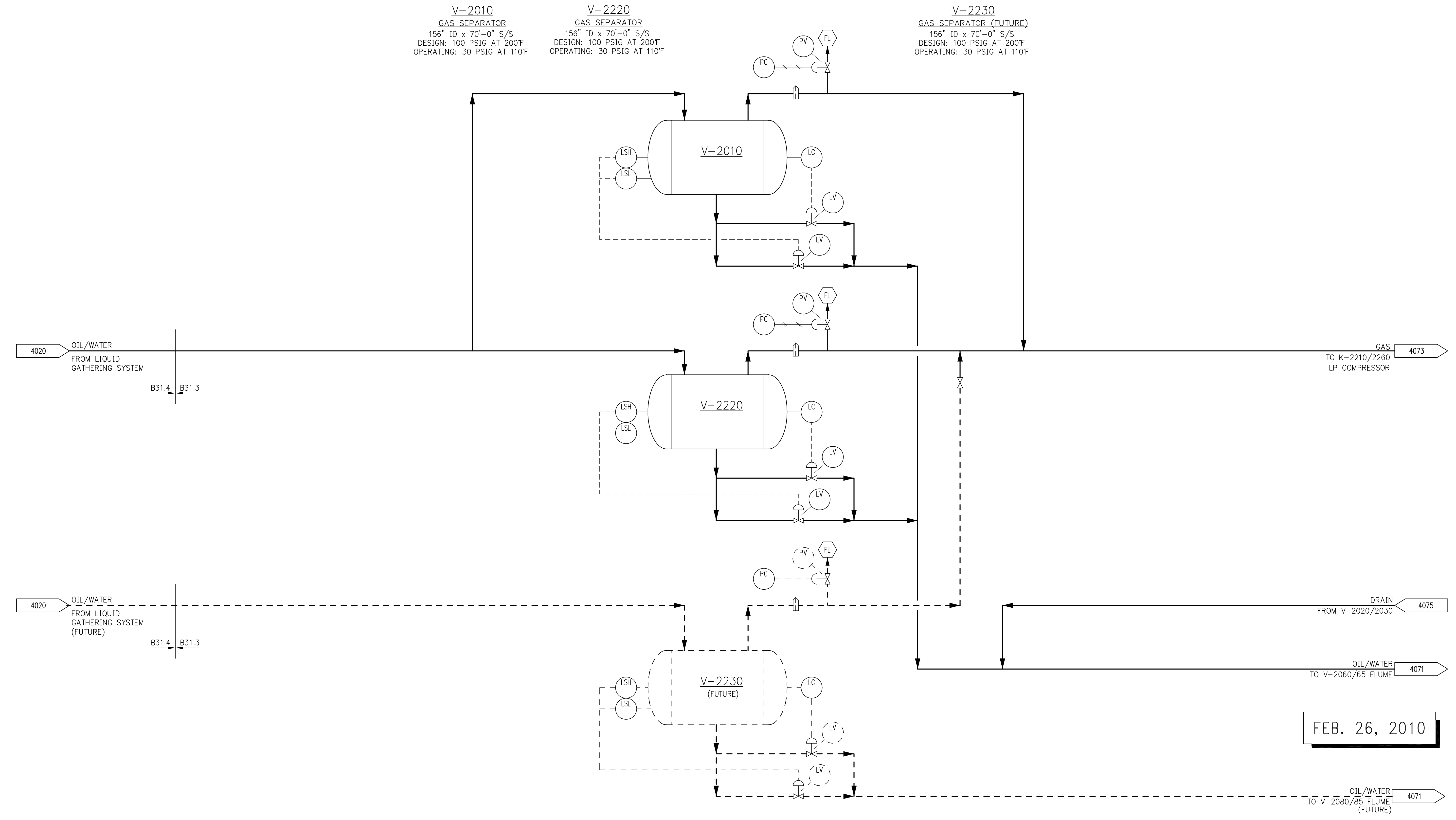
	BY	DATE
DESIGNED	PMB	27JAN10
DRAWN	W. ROE	27JAN10
CHECKED	B. GOODWIN	27JAN10
APPROVED	M. SOMERS	27JAN10

Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
UTILITY PROCESS FLOW DIAGRAM
CHEMICAL AND LUBE OIL STORAGE
(CRP) CO2 RECOVERY PLANT

SCALE	OCCIDENTAL DOCUMENT NUMBER						
	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	30	4087		B



FEB. 26, 2010

NOTES:

REFERENCE DRAWINGS	
NO.	TITLE

REVISIONS						
NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	18DEC09	ISSUED FOR REVIEW	NT	BHG	MS	
B	13JAN10	ISSUED FOR HAZID	JOL	BHG	MS	
C	29JAN10	ISSUED FOR REVIEW	NT	BHG	MS	
D	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:

MUSTANG ENGINEERING, L. P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	04DEC09
DRAWN	N. TAN	04DEC09
CHECKED	B. GOODWIN	04DEC09
APPROVED	M. SOMERS	04DEC09

Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
GAS SEPARATOR
(CTB) CENTRAL TANK BATTERY

SCALE	OCCIDENTAL DOCUMENT NUMBER							
	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	40	4070		D

MEI Project: 16179 – I:\16179\PROCESS\16179-MUS-PRO-PFD-40-4071.DWG 04MAR10 1136 SF 1.00 IMP SMWEINS

V–2060/65
FLUME
26" OD x 36" OD x 50'–0" OAL

V–2080/85
FLUME (FUTURE)
26" OD x 36" OD x 50'–0" OAL

T–2070/75
VORTEX TANK
CAPACITY: 10,000 BBL
55'–0" D x 24'–0" H

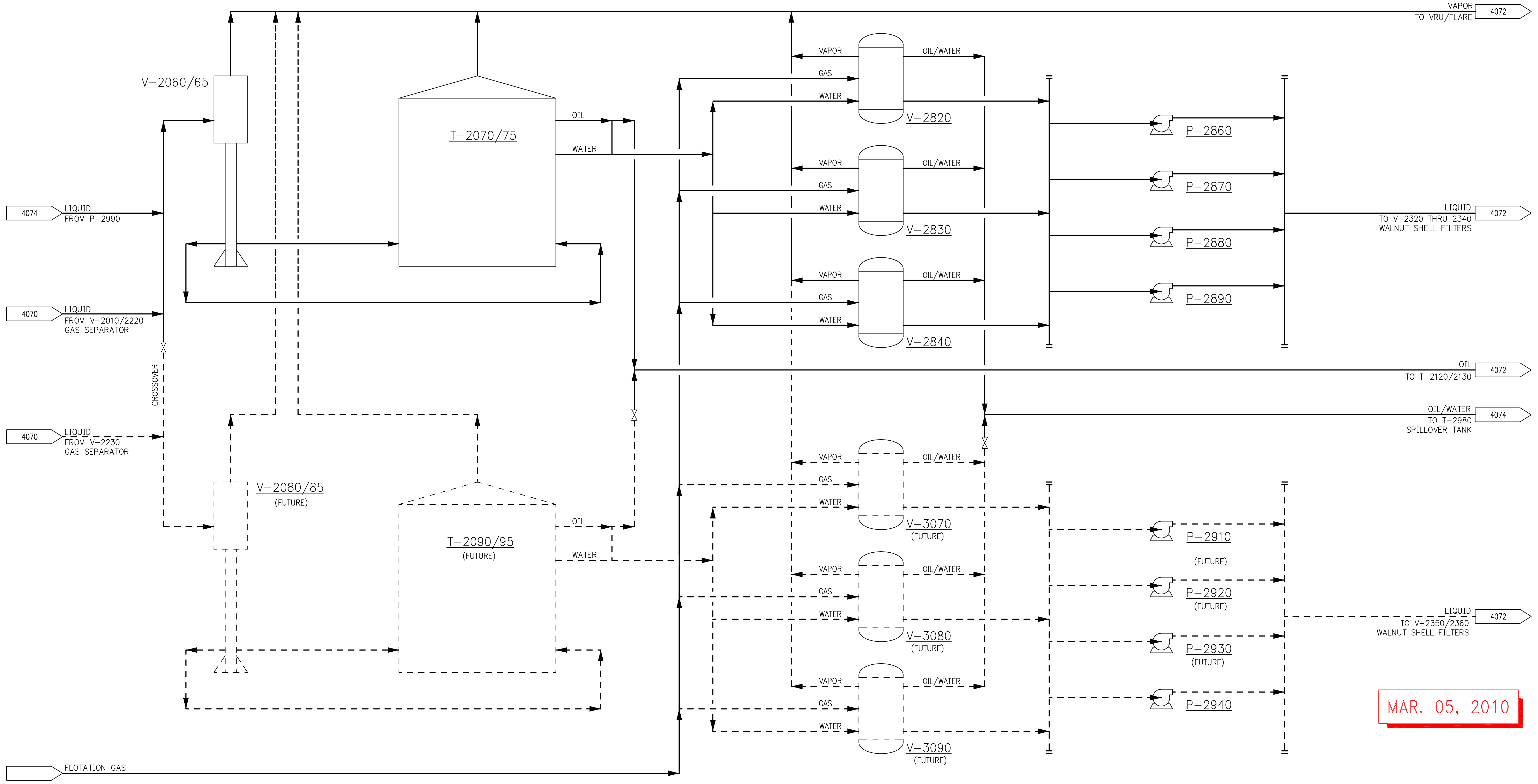
T–2090/95
VORTEX TANK (FUTURE)
CAPACITY: 10,000 BBL
55'–0" D x 24'–0" H

V–2820/30/40
FLOTATION CELLS
CAPACITY: 100,000 BPD

V–3070/80/90
FLOTATION CELLS
(FUTURE)
CAPACITY: 100,000 BPD

P–2860 THRU 2890
FILTER CHARGE PUMPS
3650 GPM AT 70 PSID
MOTOR: 200 HP EACH

P–2910 THRU 2940
FILTER CHARGE PUMPS
(FUTURE)



MAR. 05, 2010

NOTES:

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	18DEC09	ISSUED FOR REVIEW	NT	BHG	MS	
B	13JAN10	ISSUED FOR HAZID	JOL	BHG	MS	
C	29JAN10	ISSUED FOR REVIEW	NT	BHG	MS	
D	26FEB10	ISSUED FOR FEED	NT	BHG	LS	
E	05MAR10	RE-ISSUED FOR FEED	NT	BHG	MS	

ENGINEERING CONSULTANT:
MUSTANG ENGINEERING, L. P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	04DEC09
DRAWN	N. TAN	04DEC09
CHECKED	B. GOODWIN	04DEC09
APPROVED	M. SOMERS	04DEC09

OXY Occidental

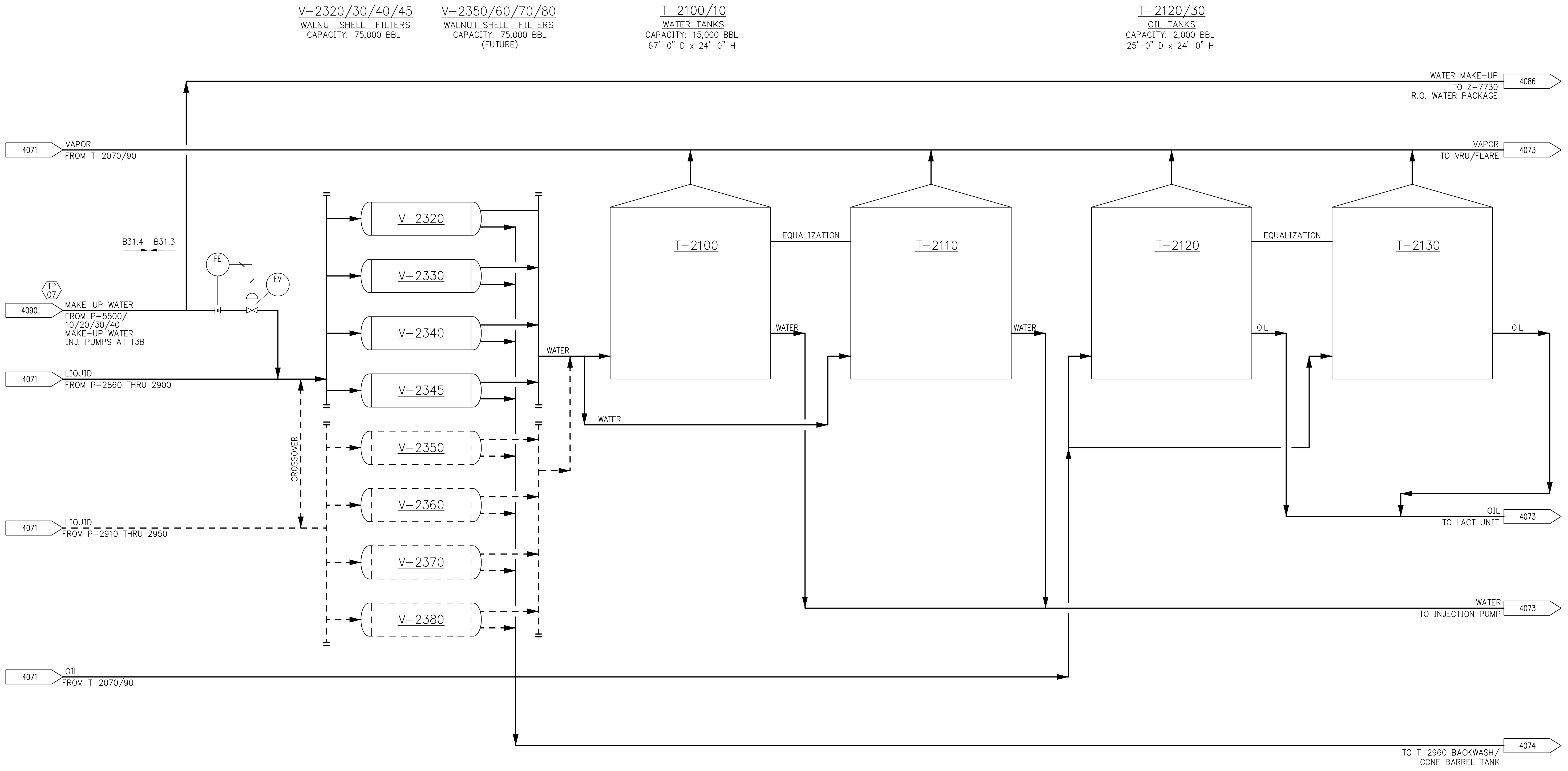
FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
VORTEX TANK/FILTERS AND PUMPS
(CTB) CENTRAL TANK BATTERY

SCALE	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	40	4071		E

OCCIDENTAL DOCUMENT NUMBER

MEI Project: 16179 – I:\16179\PROCESS\16179-MUS-PRO-PFD-40-4072.DWG 04MAR10 1153 SF 1.00 IMP SMWEINS



MAR. 05, 2010

NOTES:

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	18DEC09	ISSUED FOR REVIEW	NT	BHG	MS	
B	13JAN10	ISSUED FOR HAZID	JOL	BHG	MS	
C	29JAN10	ISSUED FOR REVIEW	NT	BHG	MS	
D	26FEB10	ISSUED FOR FEED	NT	BHG	LS	
E	05MAR10	RE-ISSUED FOR FEED	NT	BHG	MS	

ENGINEERING CONSULTANT:

MUSTANG ENGINEERING, L . P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	04DEC09
DRAWN	J. LOGAN	04DEC09
CHECKED	B. GOODWIN	04DEC09
APPROVED	M. SOMERS	04DEC09

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
WALNUT FILTERS AND TANKAGE
(CTB) CENTRAL TANK BATTERY

OCCIDENTAL DOCUMENT NUMBER

SCALE	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	40	4072		E

P–2150/2160/2170
BOOSTER PUMPS
8350 GPM AT 50 PSID
MOTOR: 350 HP EACH

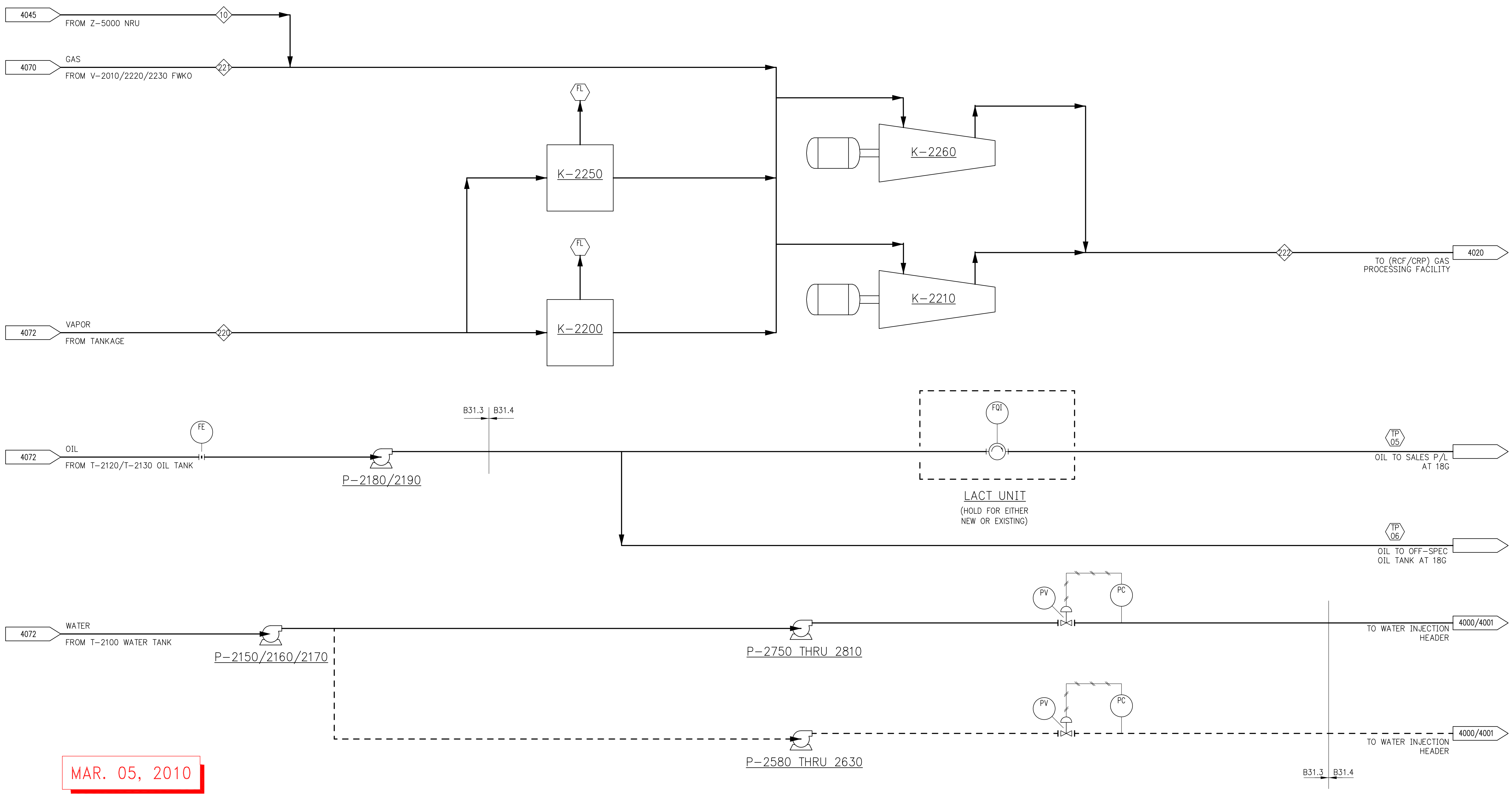
P–2180/2190
LACT UNIT PUMP
510 GPM AT 300 PSID
MOTOR: 150 HP EACH

K–2200/2250
VRU
CAPACITY : 0.36 MMSCFD
MOTOR: 50 HP EACH

K–2210/2260
LP COMPRESSOR
CAPACITY: 4.5 MMSCFD
MOTOR: 1,000 HP EACH

P–2750 THRU 2810
WATER INJECTION PUMPS
1,490 GPM AT 3,455 PSID
MOTOR: 5,000 HP EACH

P–2580 THRU 2630
WATER INJECTION PUMPS
1,490 GPM AT 3,455 PSID
MOTOR: 5,000 HP EACH
(FUTURE)



MAR. 05, 2010

NOTES:

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	18DEC09	ISSUED FOR REVIEW	NT	BHG	MS	
B	13JAN10	ISSUED FOR HAZID	JOL	BHG	MS	
C	29JAN10	ISSUED FOR REVIEW	NT	BHG	MS	
D	26FEB10	ISSUED FOR FEED	NT	BHG	LS	
E	05MAR10	RE–ISSUED FOR FEED	WR	BHG	MS	

ENGINEERING CONSULTANT:
MUSTANG ENGINEERING, L. P.
HOUSTON, TEXAS
PROJECT NO. 16179

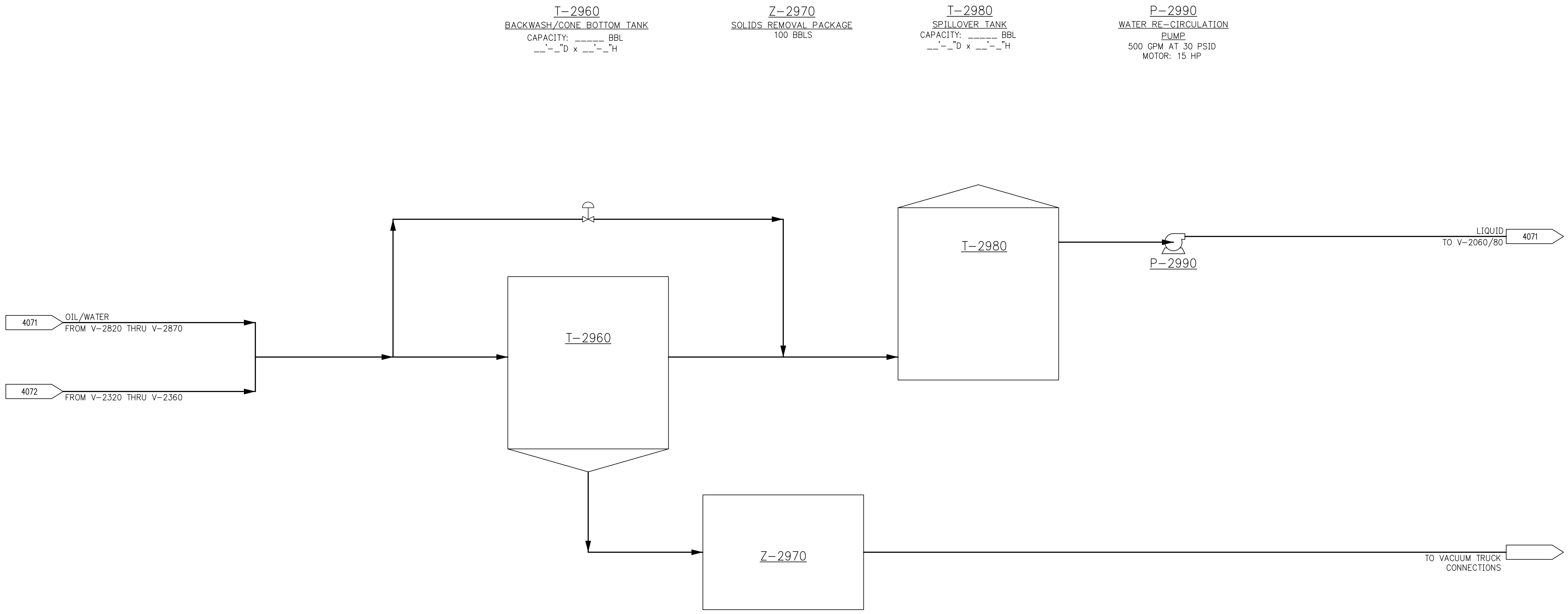
	BY	DATE
DESIGNED	A. JOHNS	04DEC09
DRAWN	N. TAN	04DEC09
CHECKED	B. GOODWIN	04DEC09
APPROVED	M. SOMERS	04DEC09

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
VRU, LACT UNIT AND WATER INJECTION PUMP
(CTB) CENTRAL TANK BATTERY

SCALE	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
	OCCIDENTAL DOCUMENT NUMBER							
NONE	16179	MUS	PRO	PFD	40	4073		E



FEB. 26, 2010

NOTES:

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	18DEC09	ISSUED FOR REVIEW	NT	BHG	MS	
B	13JAN10	ISSUED FOR HAZID	JOL	BHG	MS	
C	29JAN10	ISSUED FOR REVIEW	NT	BHG	MS	
D	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:

MUSTANG ENGINEERING, L . P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	04DEC09
DRAWN	J. LOGAN	04DEC09
CHECKED	B. GOODWIN	04DEC09
APPROVED	M. SOMERS	04DEC09

OXY Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
BACKWASH AND SPILLOVER TANK
(CTB) CENTRAL TANK BATTERY

SCALE	OCCIDENTAL DOCUMENT NUMBER							
	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	40	4074		D

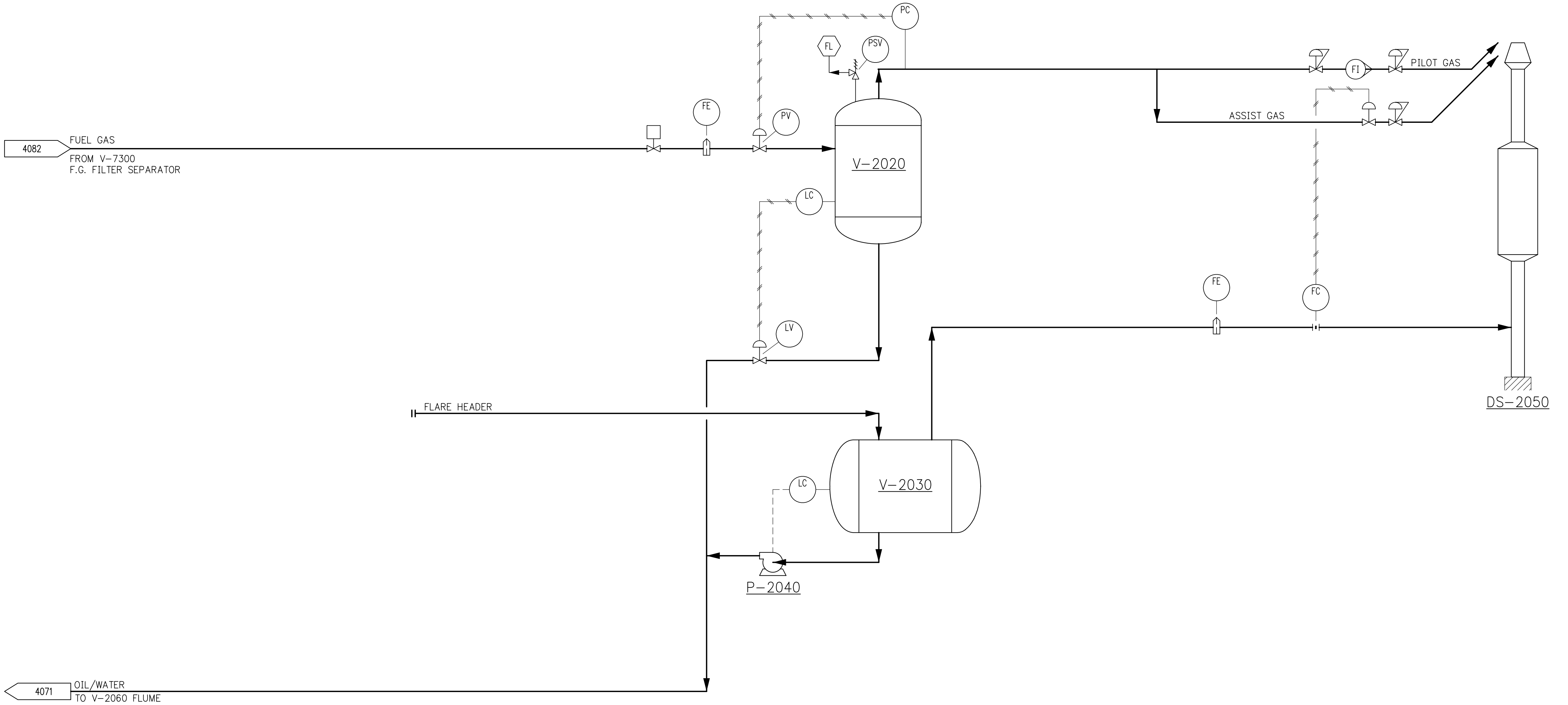
MEI Project: 16179 – I:\16179\PROCESS\16179-MUS-PRO-PFD-40-4075.DWG 25FEB10 1547 SF 1.00 IMP NLTAN

P–2040
FLARE SCRUBBER PUMP
10 GPM AT 30 PSID
MOTOR: 1 HP

V–2020
BLANKET GAS SCRUBBER
132" OD x 14'-6" S/S
DESIGN: 150 PSIG AT 150°F
OPERATING: 100 PSIG AT 100°F

V–2030
FLARE SCRUBBER
120" ID x 40'-0" S/S
DESIGN: 100 PSIG AT 150°F
OPERATING: 75 PSIG AT 100°F

DS–2050
FLARE
CAPACITY: 619 MMSCFD



FEB. 26, 2010

NOTES:

REFERENCE DRAWINGS	
NO.	TITLE

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:
MUSTANG ENGINEERING, L . P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	17FEB10
DRAWN	N. TAN	17FEB10
CHECKED	B. GOODWIN	17FEB10
APPROVED	M. SOMERS	17FEB10

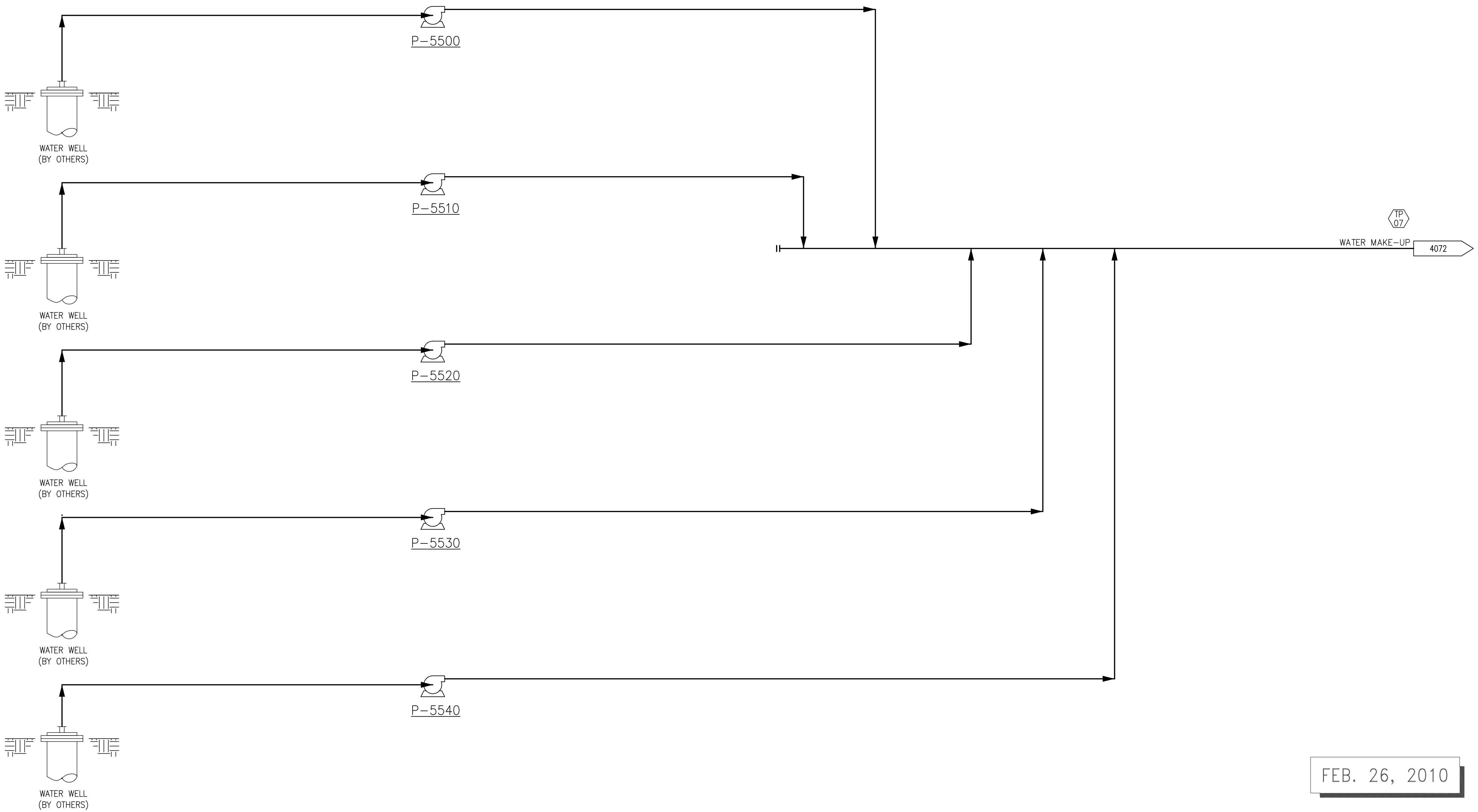
Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
FLARE SYSTEM
(CTB) CENTRAL TANK BATTERY

SCALE	OCCIDENTAL DOCUMENT NUMBER							
	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	40	4075		A

P-5500/10/20/30/40
MAKE-UP WATER INJECTION PUMPS
CAPACITY: 292 GPM AT 400 PSID
MOTOR: 100 HP EACH



FEB. 26, 2010

NOTES:

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	BY	CHK.	APP.	APP.
A	26FEB10	ISSUED FOR FEED	NT	BHG	LS	

ENGINEERING CONSULTANT:
MUSTANG ENGINEERING, L. P.
HOUSTON, TEXAS
PROJECT NO. 16179

	BY	DATE
DESIGNED	A. JOHNS	04DEC09
DRAWN	N. TAN	04DEC09
CHECKED	B. GOODWIN	04DEC09
APPROVED	M. SOMERS	04DEC09

Occidental

FACILITY NAME:
OCCIDENTAL OF ELK HILLS, INC.
UNIT OPERATOR

DRAWING TITLE:
PROCESS FLOW DIAGRAM
MAKE-UP WATER INJECTION PUMPS AT 13B
(TWW) TULARE WATER WELLS

SCALE	PROJ. NO.	ORIG.	DISCP.	TYPE	AREA	DWG. NO.	SHT.	REV.
NONE	16179	MUS	PRO	PFD	50	4090		A

OCCIDENTAL DOCUMENT NUMBER

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT
COMMISSION OF THE STATE OF CALIFORNIA
1516 NINTH STREET, SACRAMENTO, CA 95814
1-800-822-6228 – WWW.ENERGY.CA.GOV

AMENDED APPLICATION FOR CERTIFICATION FOR THE HYDROGEN ENERGY CALIFORNIA PROJECT

Docket No. 08-AFC-08A
(Revised 10/9/12)

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ENERGY COMMISSION – PUBLIC ADVISER

Jennifer Jennings
Public Adviser's Office
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DECLARATION OF SERVICE

I, Dale Shileikis, declare that on November 5, 2012, I served and filed a copy of the attached OEHI Responses to CEC Data Requests Set Two Nos. A136-A138 and A171-A177, dated November, 2012. This document is accompanied by the most recent Proof of Service list, located on the web page for this project at: http://www.energy.ca.gov/sitingcases/hydrogen_energy/index.html

The document has been sent to the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit or Chief Counsel, as appropriate, in the following manner:
(*Check all that Apply*)

For service to all other parties:

X Served electronically to all e-mail addresses on the Proof of Service list; CD mailed to those with email inbox restrictions.

____ Served by delivering on this date, either personally, or for mailing with the U.S. Postal Service with first-class postage thereon fully prepaid, to the name and address of the person served, for mailing that same day in the ordinary course of business; that the envelope was sealed and placed for collection and mailing on that date to those addresses marked ***"hard copy required"** or where no e-mail address is provided.

AND

For filing with the Docket Unit at the Energy Commission:

X by sending one electronic copy to the e-mail address below (preferred method); OR

____ by depositing an original and 12 paper copies in the mail with the U.S. Postal Service with first class postage thereon fully prepaid, as follows:

CALIFORNIA ENERGY COMMISSION – DOCKET UNIT
Attn: Docket No. 08-AFC-08A
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512
docket@energy.ca.gov

OR, if filing a Petition for Reconsideration of Decision or Order pursuant to Title 20, § 1720:

____ Served by delivering on this date one electronic copy by e-mail, and an original paper copy to the Chief Counsel at the following address, either personally, or for mailing with the U.S. Postal Service with first class postage thereon fully prepaid:

California Energy Commission
Michael J. Levy, Chief Counsel
1516 Ninth Street MS-14
Sacramento, CA 95814
michael.levy@energy.ca.gov

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, that I am employed in the county where this mailing occurred, and that I am over the age of 18 years and not a party to the proceeding.