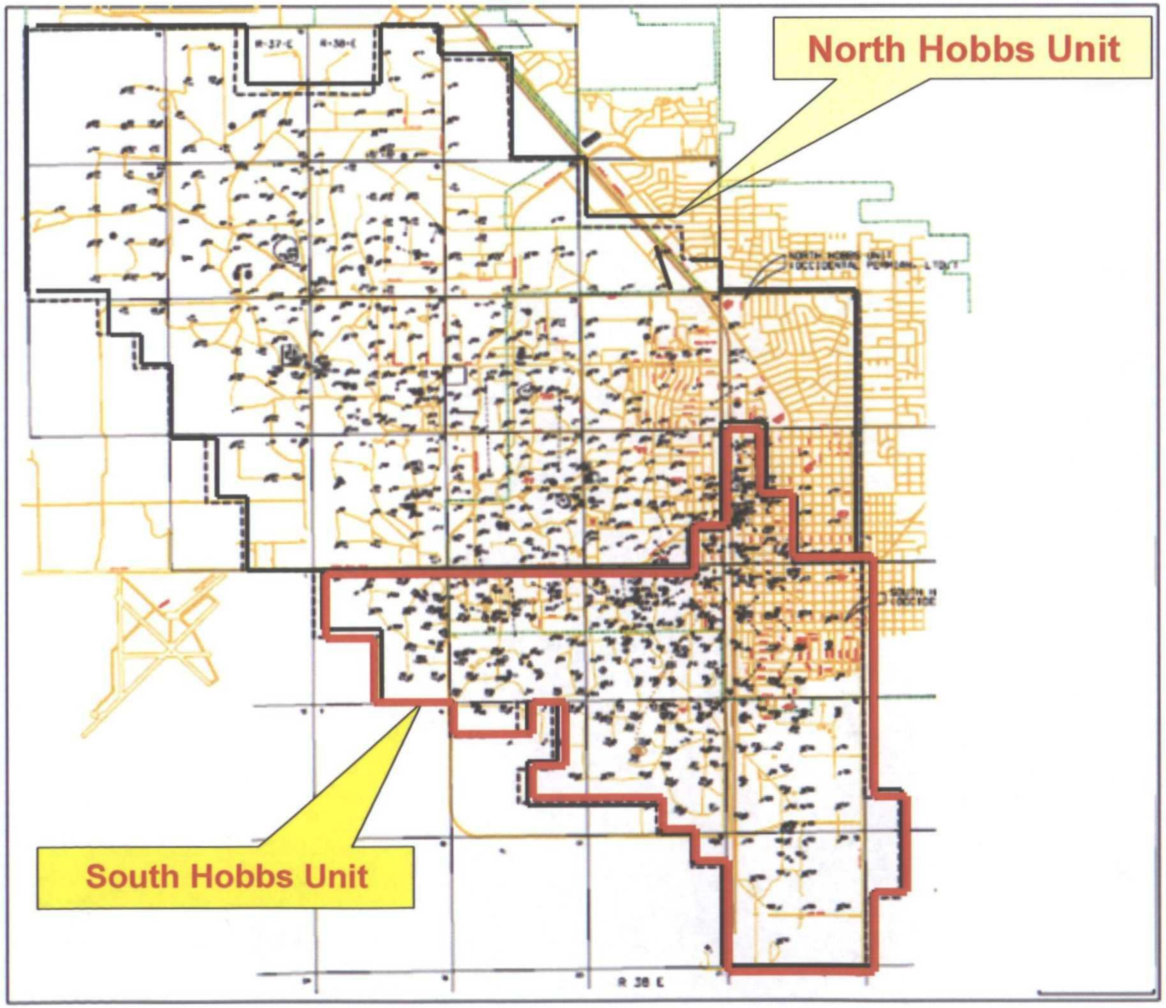
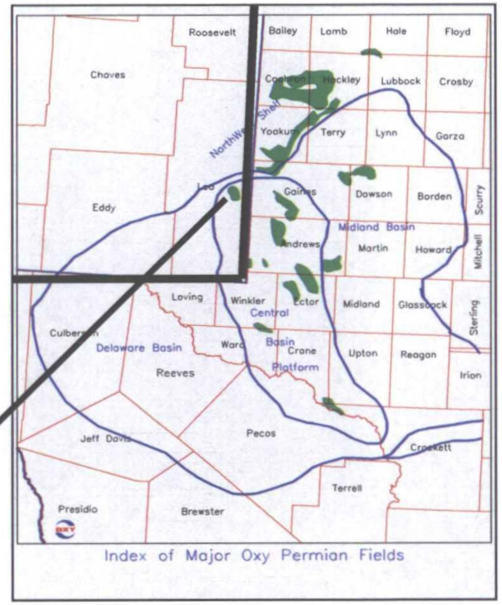
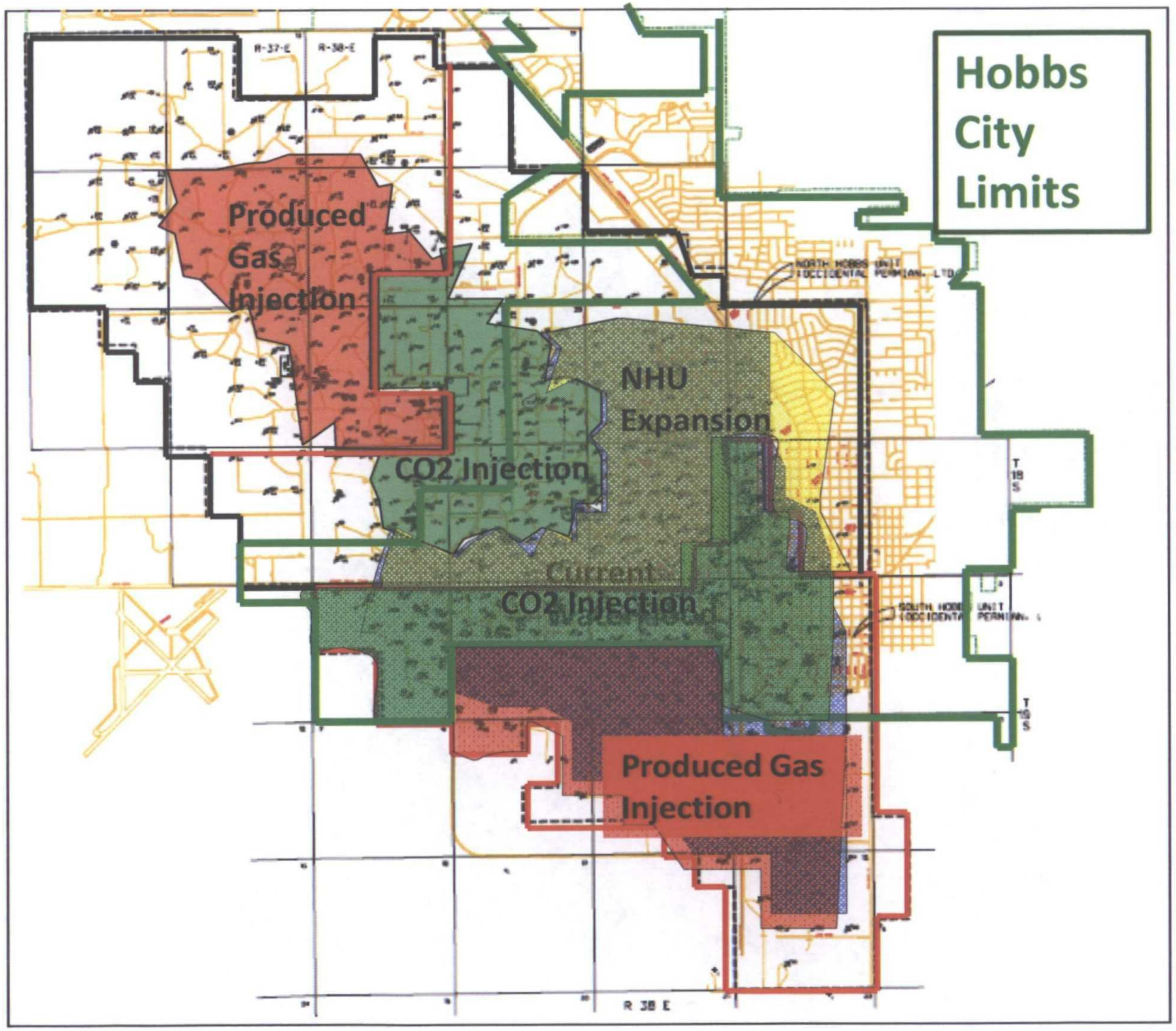




BEFORE THE OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Exhibit No. 8
Submitted by: OXY
Hearing Date: May 9, 2013

1

Hobbs Field



2

SHU CO_2 Flood Highlights	
Capital Cost	$312 Million
Operating Expense	$317 Million
Additional Oil Production	33.2 MMBOE
Workovers	68
New Drills	32
Field Life Extended	40 years

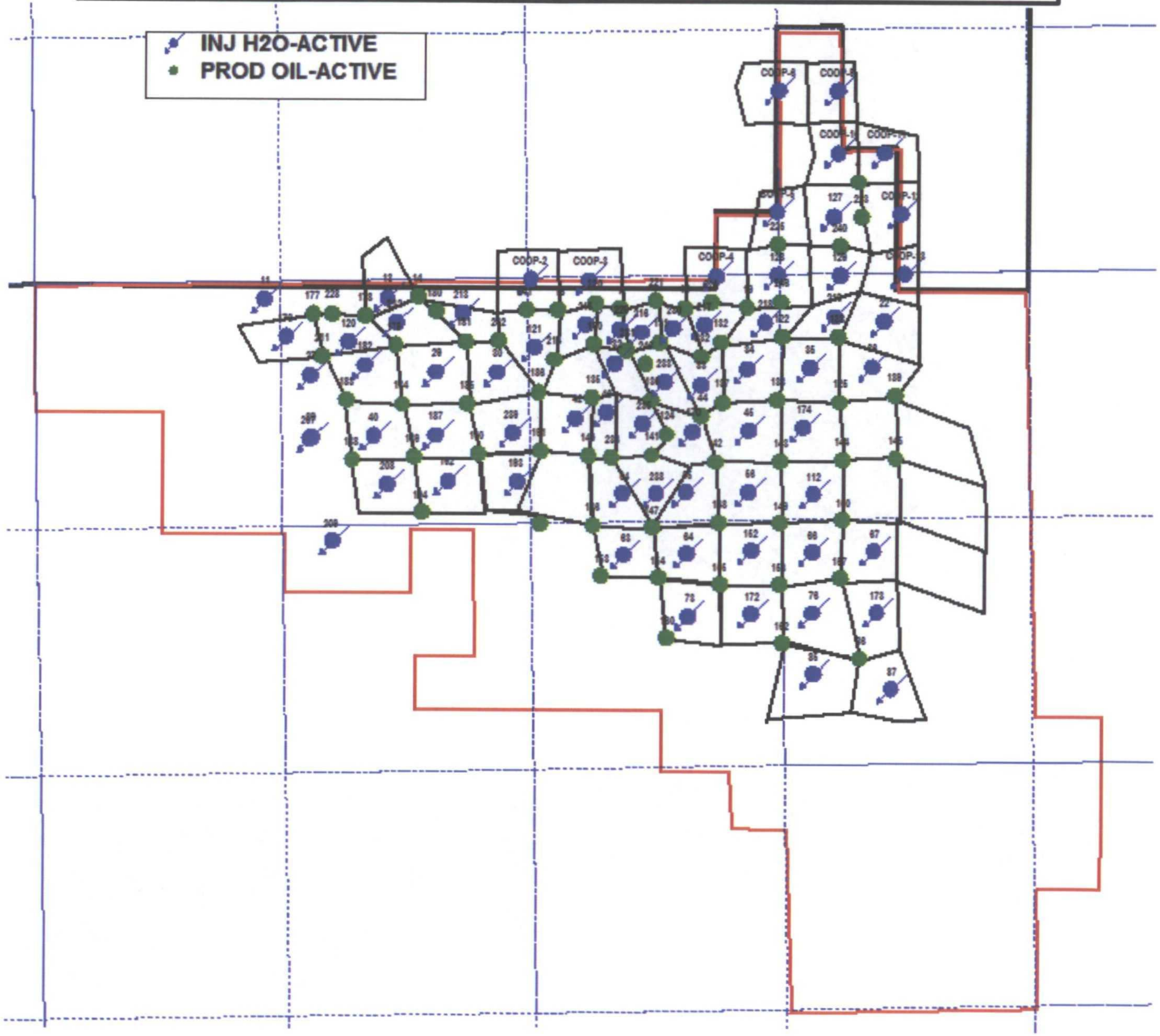
	Current	Projected with CO2
Reservoir Pressure (psig)	1200	2000
Producing Well Count	69	57
Injection Well Count	69	53
Oil Rate (BOPD)	1100	6500
H2S Concentrations	4%	1.1 %

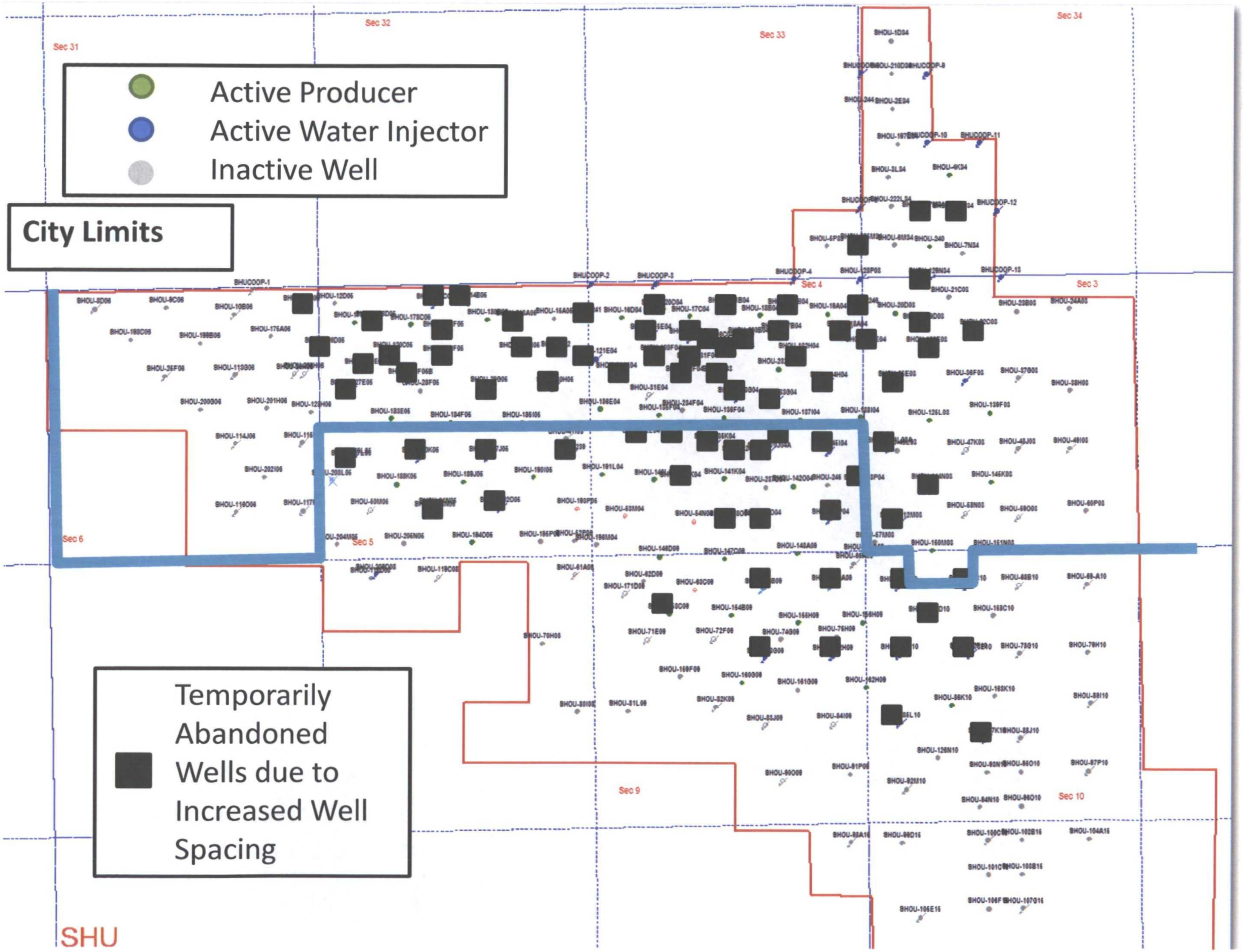
South Hobbs CO2 Project

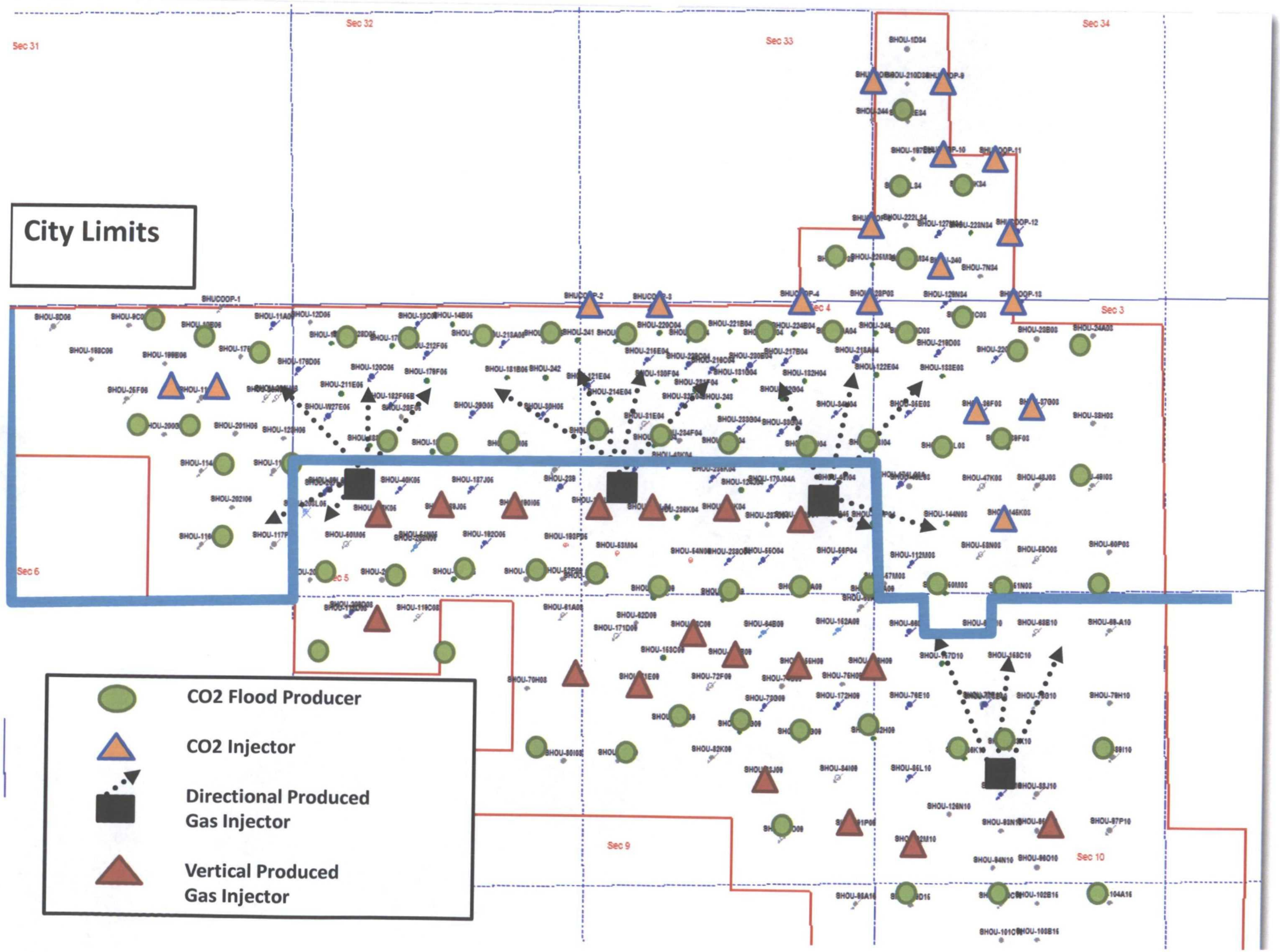
Objectives:

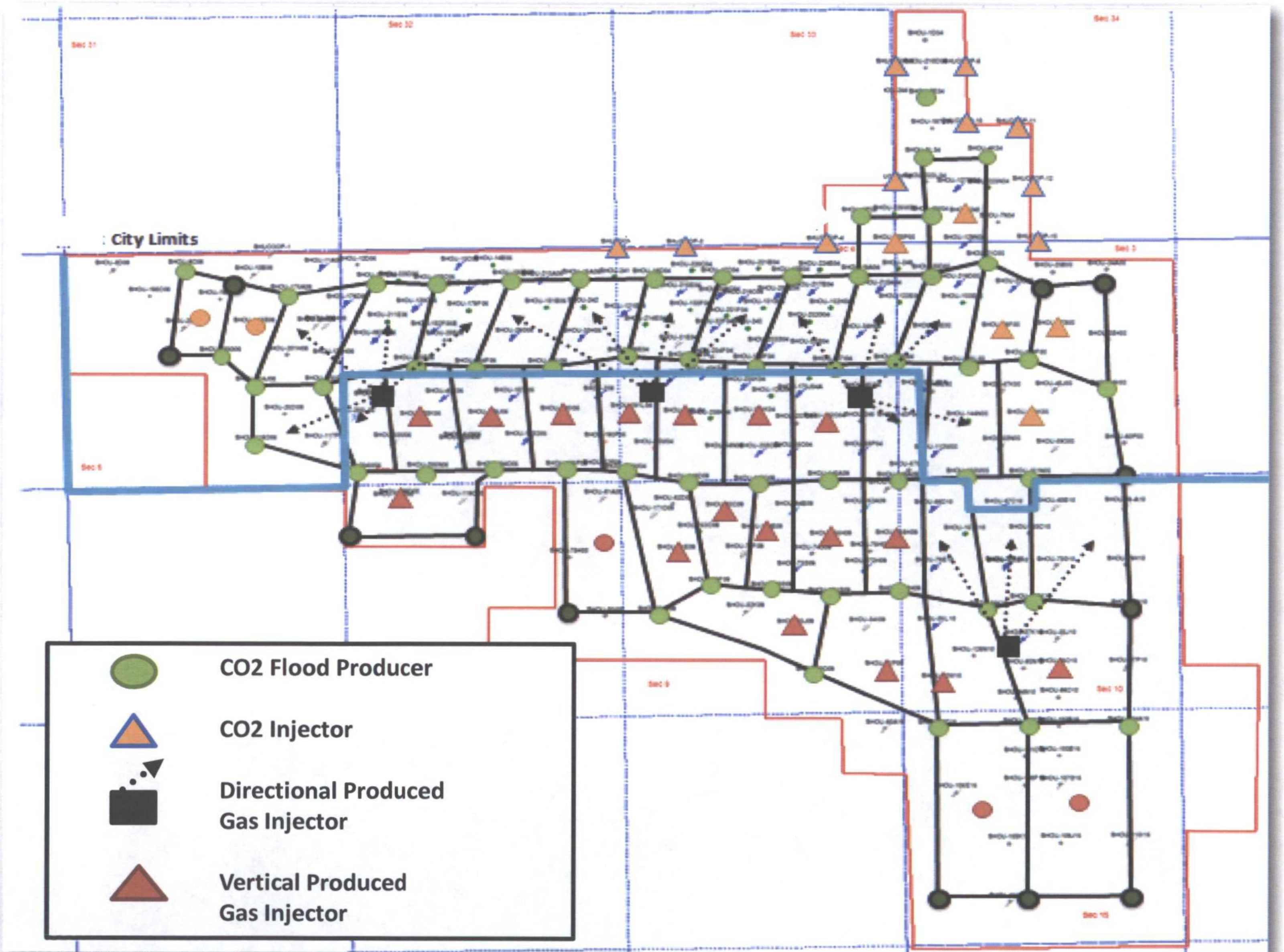
- Re-inject all produced gas and water for EOR
- No produced gas injection inside city limits
- Reduce operational exposure in Hobbs city limits
  - Directional Injectors from remote multi-well pads outside of the city
  - Increased well spacing from 40->80 acre

South Hobbs Unit Waterflood Active Wells

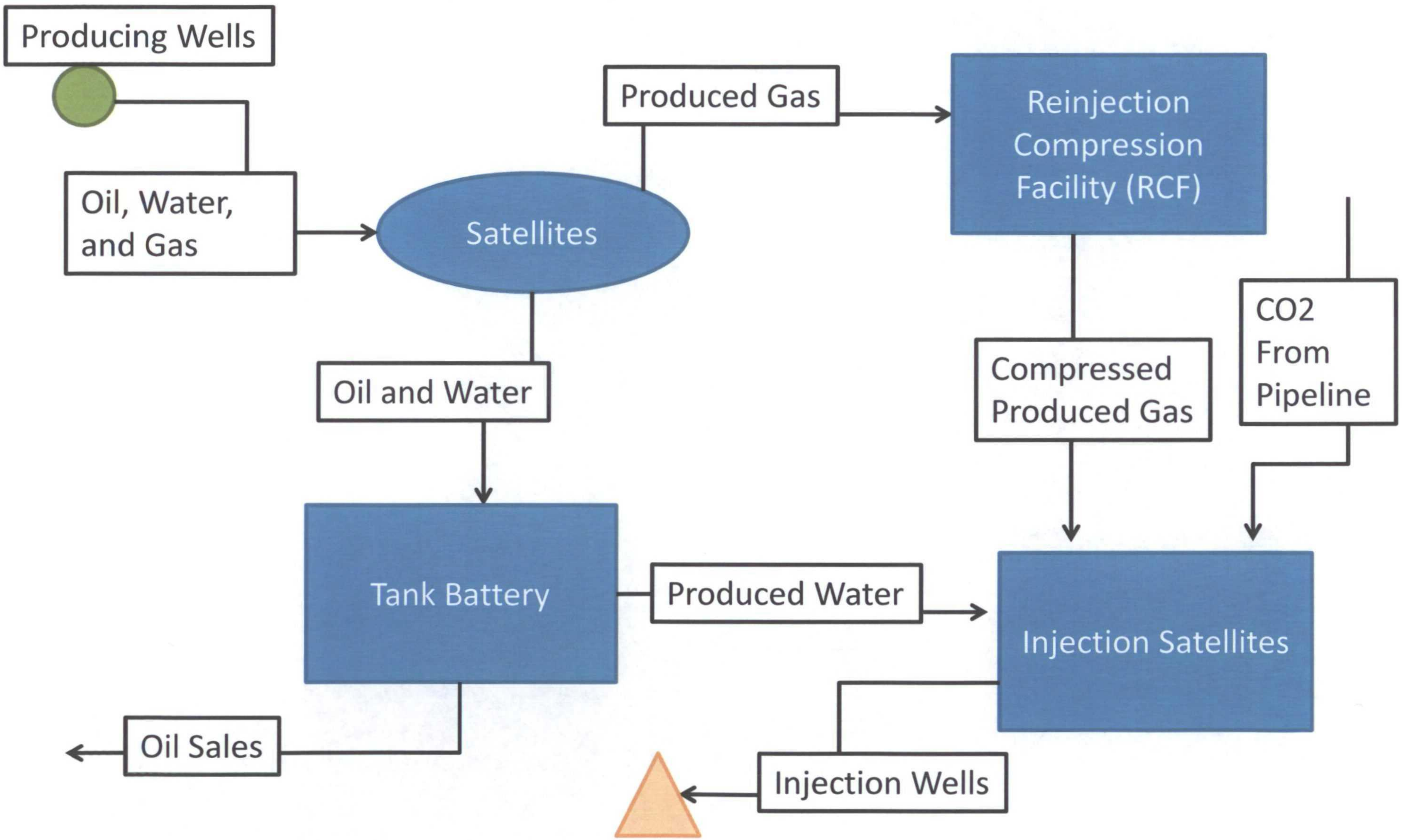



Active Producer
Active Water Injector
Inactive Well
City Limits
Temporarily Abandoned Wells due to Increased Well Spacing
Sec 31
Sec 32
Sec 33
Sec 34
Sec 3
Sec 4
Sec 5
Sec 6
Sec 9
Sec 10
SHU


Sec 31
Sec 32
Sec 33
Sec 34
City Limits
Sec 4
Sec 3
Sec 6
Sec 5
Sec 9
Sec 10
CO2 Flood Producer
CO2 Injector
Directional Produced Gas Injector
Vertical Produced Gas Injector


City Limits
CO2 Flood Producer
CO2 Injector
Directional Produced
Gas Injector
Vertical Produced
Gas Injector

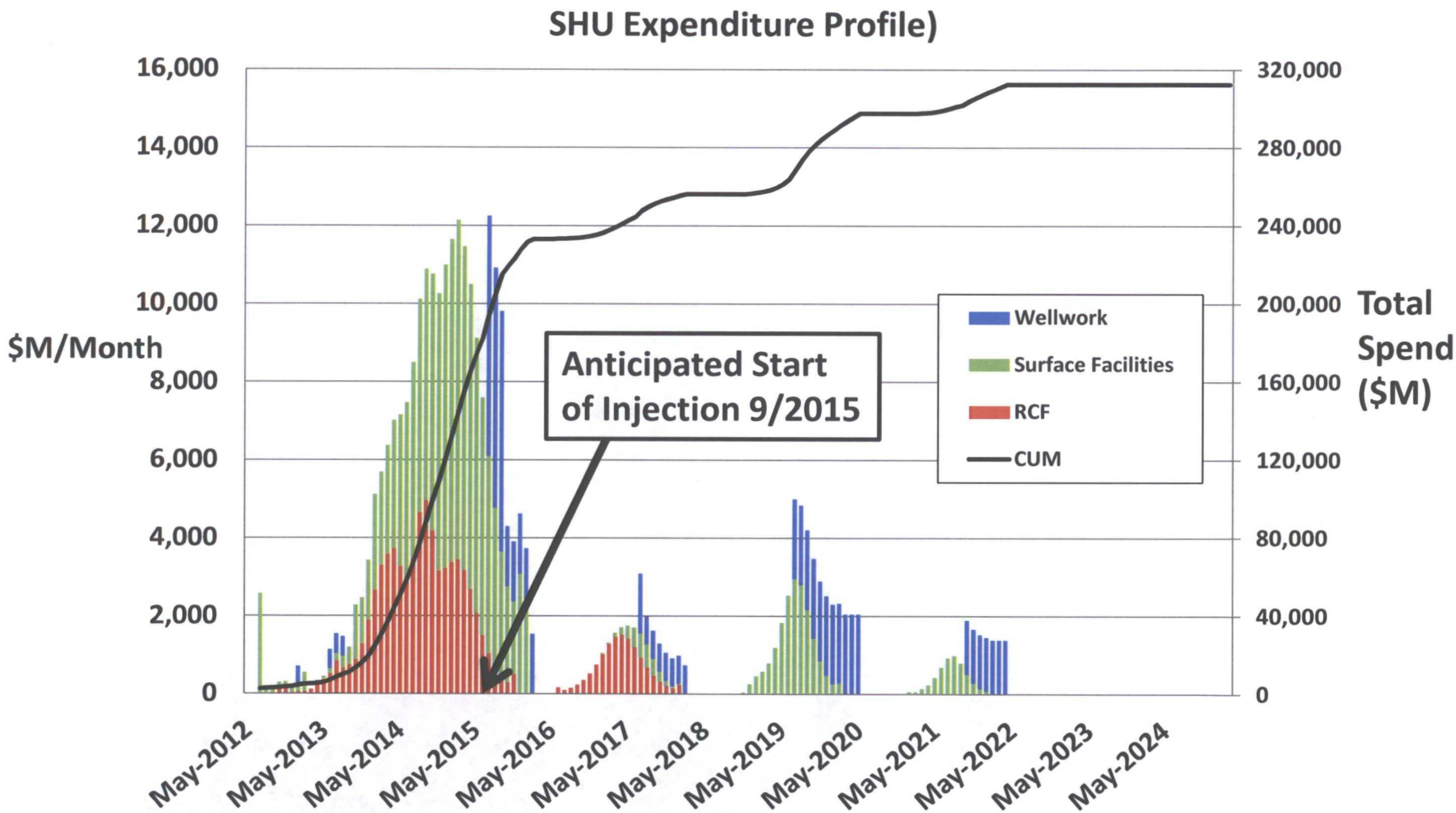
Field Flow Diagram

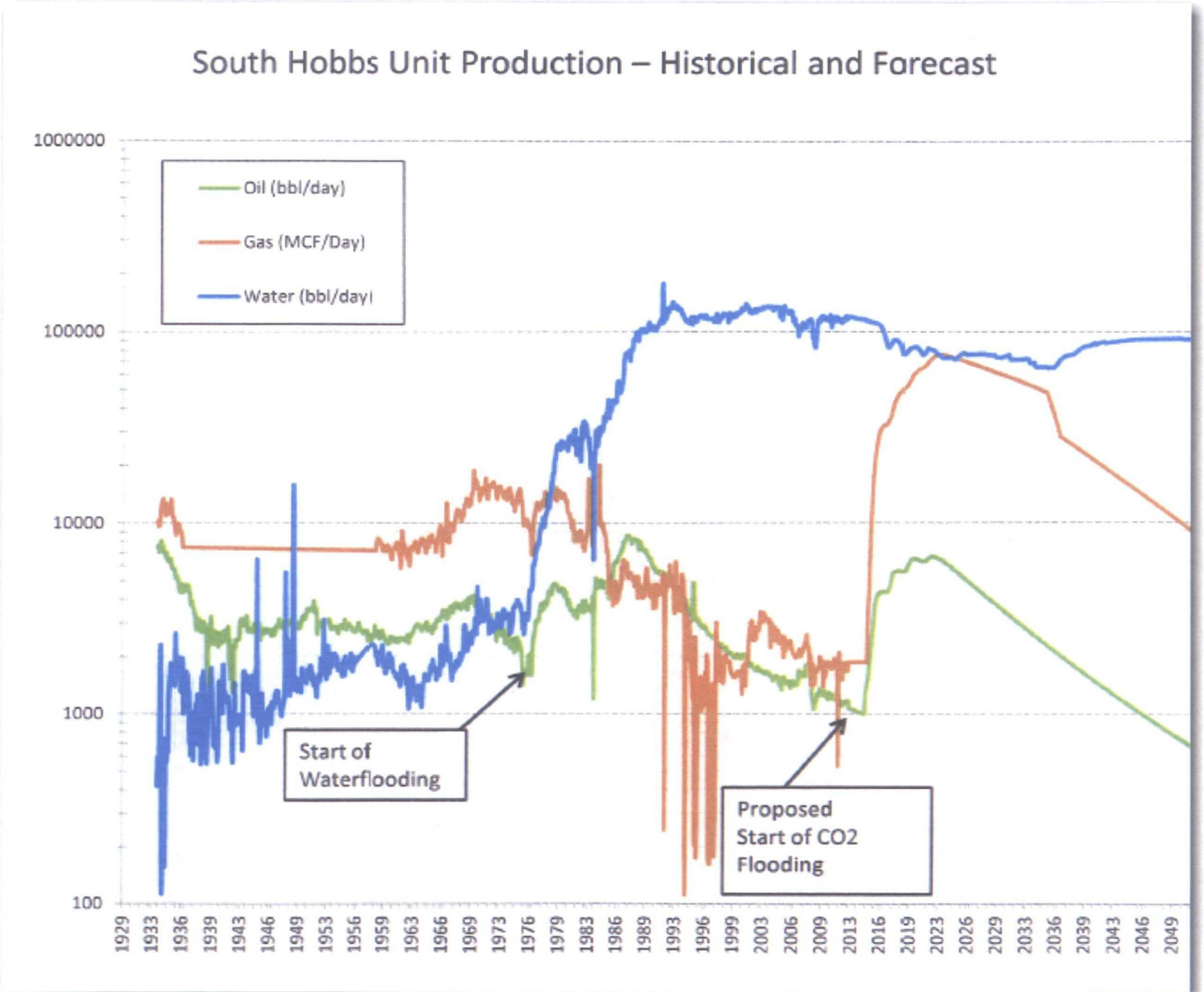


SHU CO_2 Project – Projected Schedule

Project Key Milestone Start Dates	
Detailed Design Engineering	Mar– 2013
Procurement Begins	July – 2013
Field Construction Begins	Jan. – 2014
RCF Construction Begins	June – 2014
Field Commissioning	May – 2015
Field Well Work Over & Drilling	July - 2015
Field 1st CO_2 Injection	Sept – 2015
RCF Commissioning	Jan – 2016
RCF Start Up	Feb– 2016

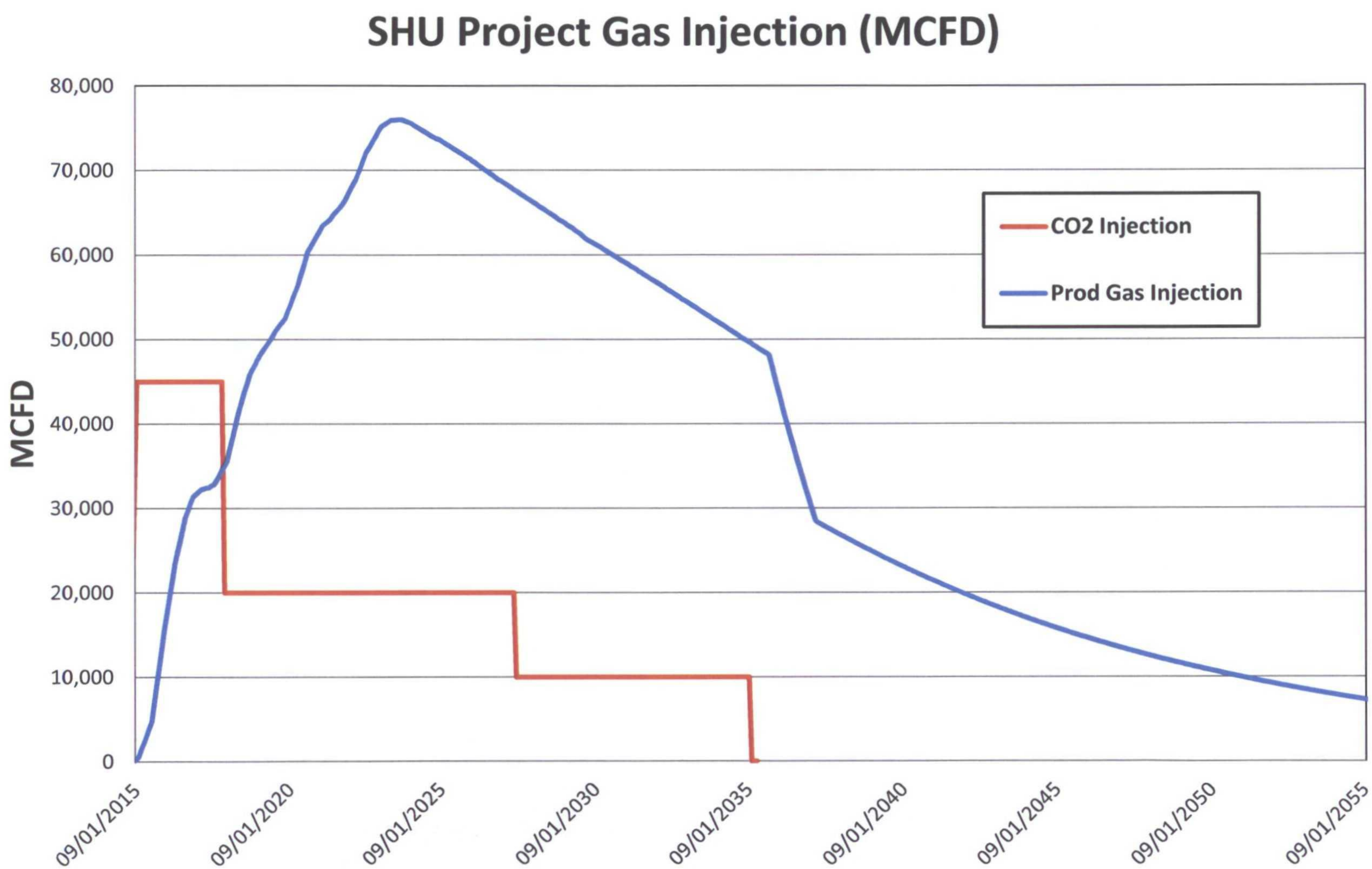
SHU CO_2 Project – Capital Expenditures – Overall Project



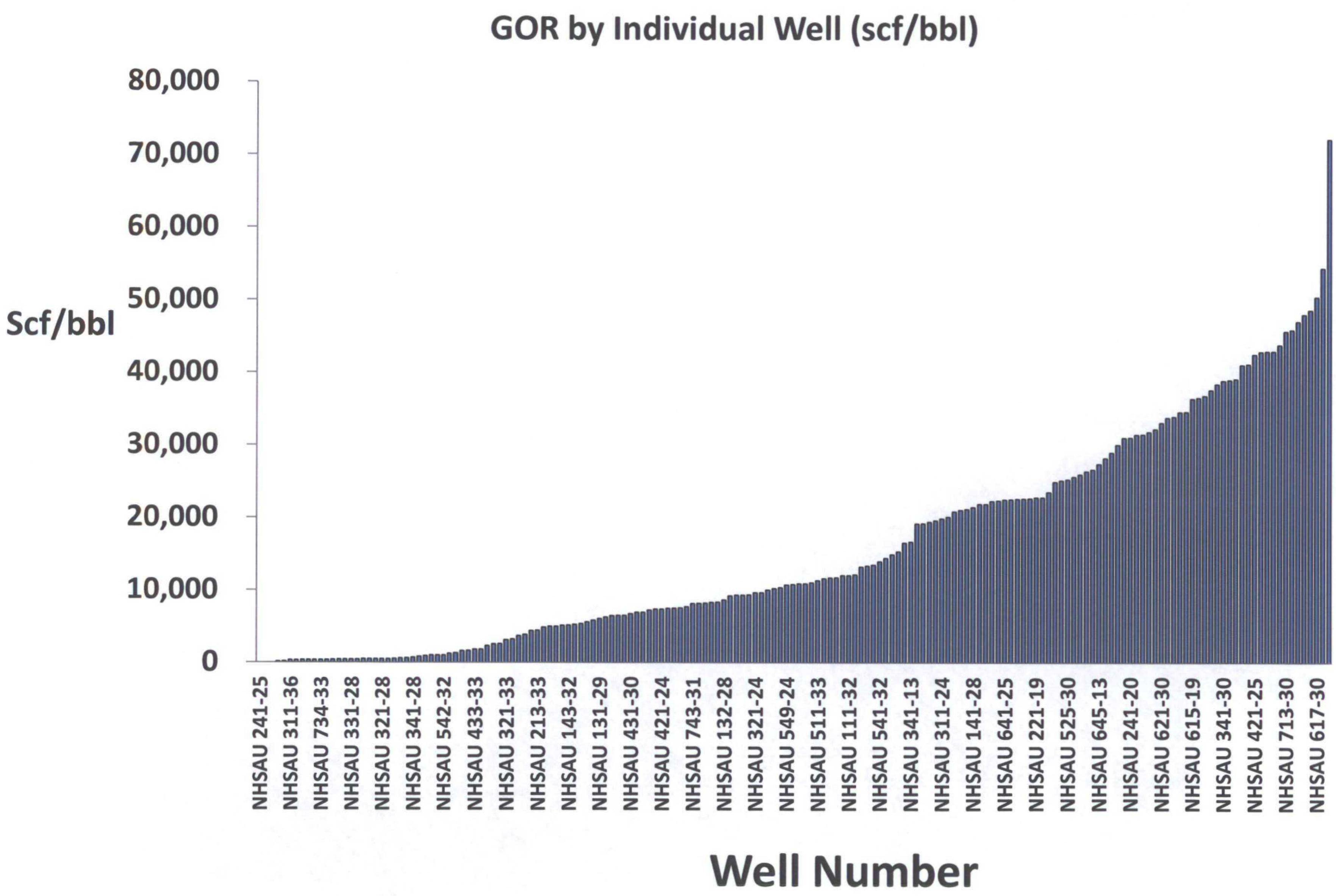


South Hobbs Unit Production – Historical and Forecast
1000000
100000
10000
1000
100
Oil (bbl/day)
Gas (MCF/Day)
Water (bbl/day)
Start of Waterflooding
Proposed Start of CO2 Flooding
1929
1933
1936
1939
1943
1946
1949
1953
1956
1959
1963
1966
1969
1973
1976
1979
1983
1986
1989
1993
1996
1999
2003
2006
2009
2013
2016
2019
2023
2026
2029
2033
2036
2039
2043
2046
2049

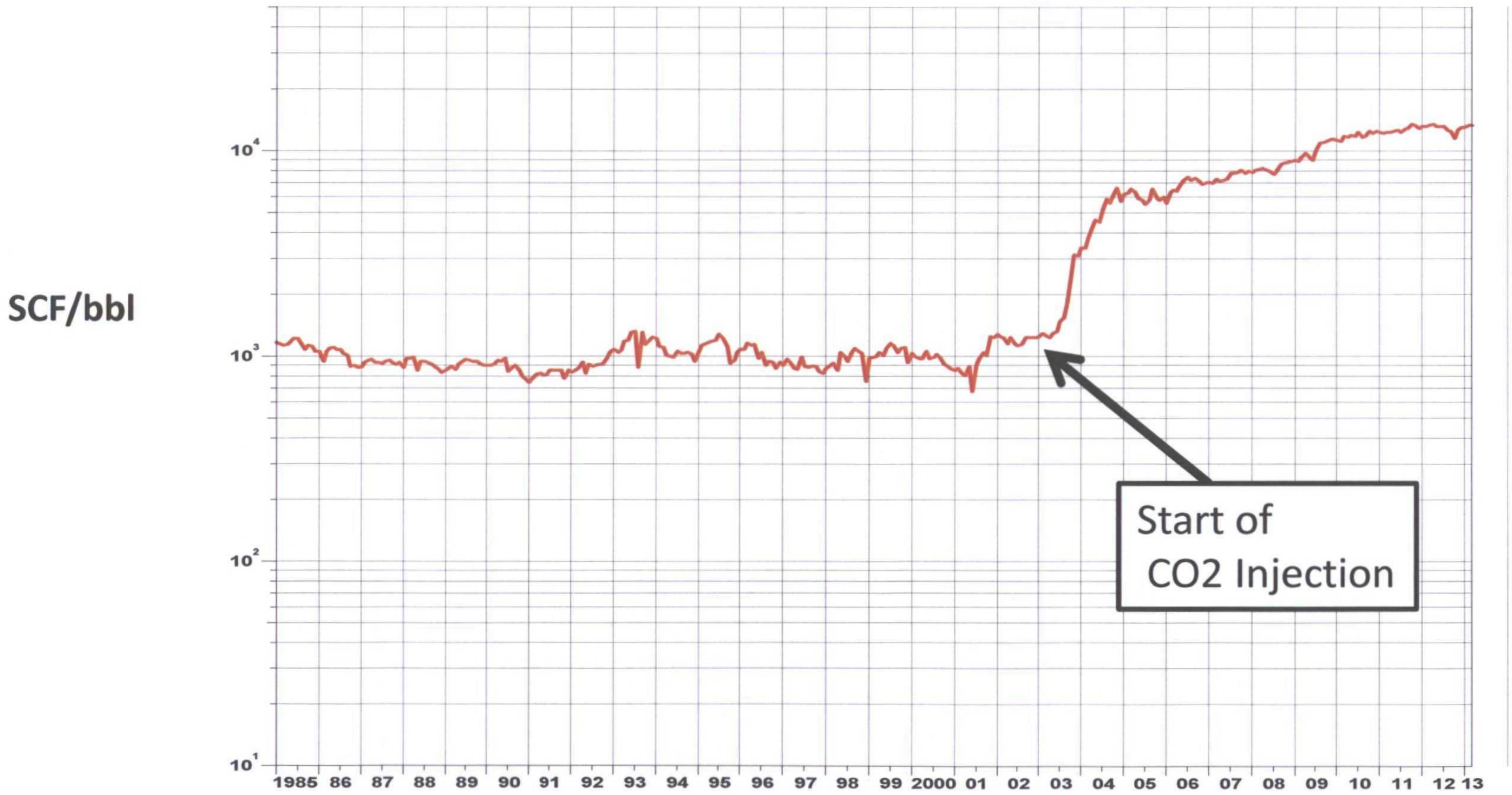
13



SHU Project Gas Injection (MCFD)
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
MCFD
CO2 Injection
Prod Gas Injection
09/01/2015
09/01/2020
09/01/2025
09/01/2030
09/01/2035
09/01/2040
09/01/2045
09/01/2050
09/01/2055

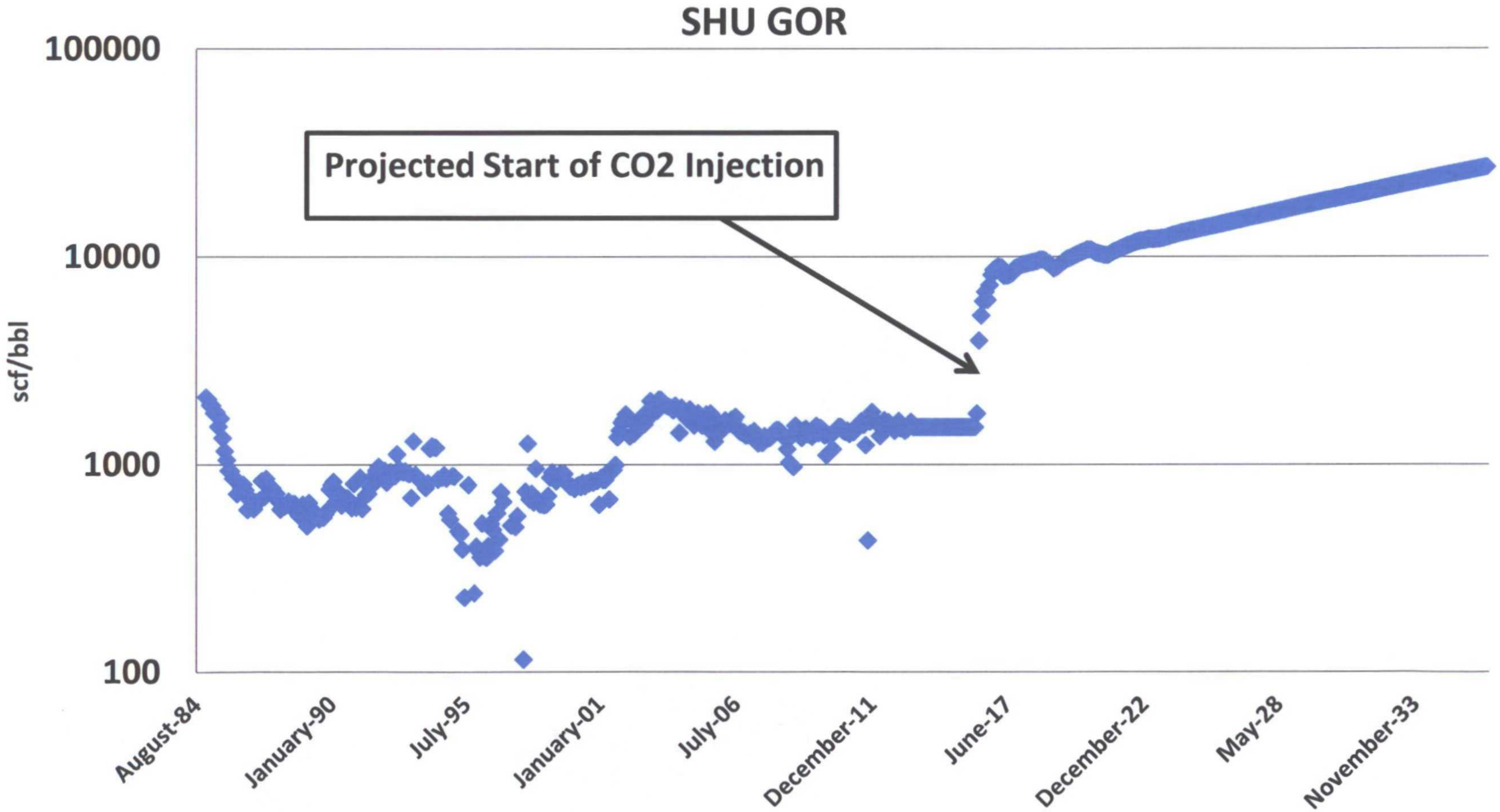

GOR by Individual Well (scf/bbl)
Scf/bbl
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
NHSAU 241-25
NHSAU 311-36
NHSAU 734-33
NHSAU 331-28
NHSAU 321-28
NHSAU 341-28
NHSAU 542-32
NHSAU 433-33
NHSAU 321-33
NHSAU 213-33
NHSAU 143-32
NHSAU 131-29
NHSAU 431-30
NHSAU 421-24
NHSAU 743-31
NHSAU 132-28
NHSAU 321-24
NHSAU 549-24
NHSAU 511-33
NHSAU 111-32
NHSAU 541-32
NHSAU 341-13
NHSAU 311-24
NHSAU 141-28
NHSAU 641-25
NHSAU 221-19
NHSAU 525-30
NHSAU 645-13
NHSAU 241-20
NHSAU 621-30
NHSAU 615-19
NHSAU 341-30
NHSAU 421-25
NHSAU 713-30
NHSAU 617-30
Well Number

NHU Historical GOR

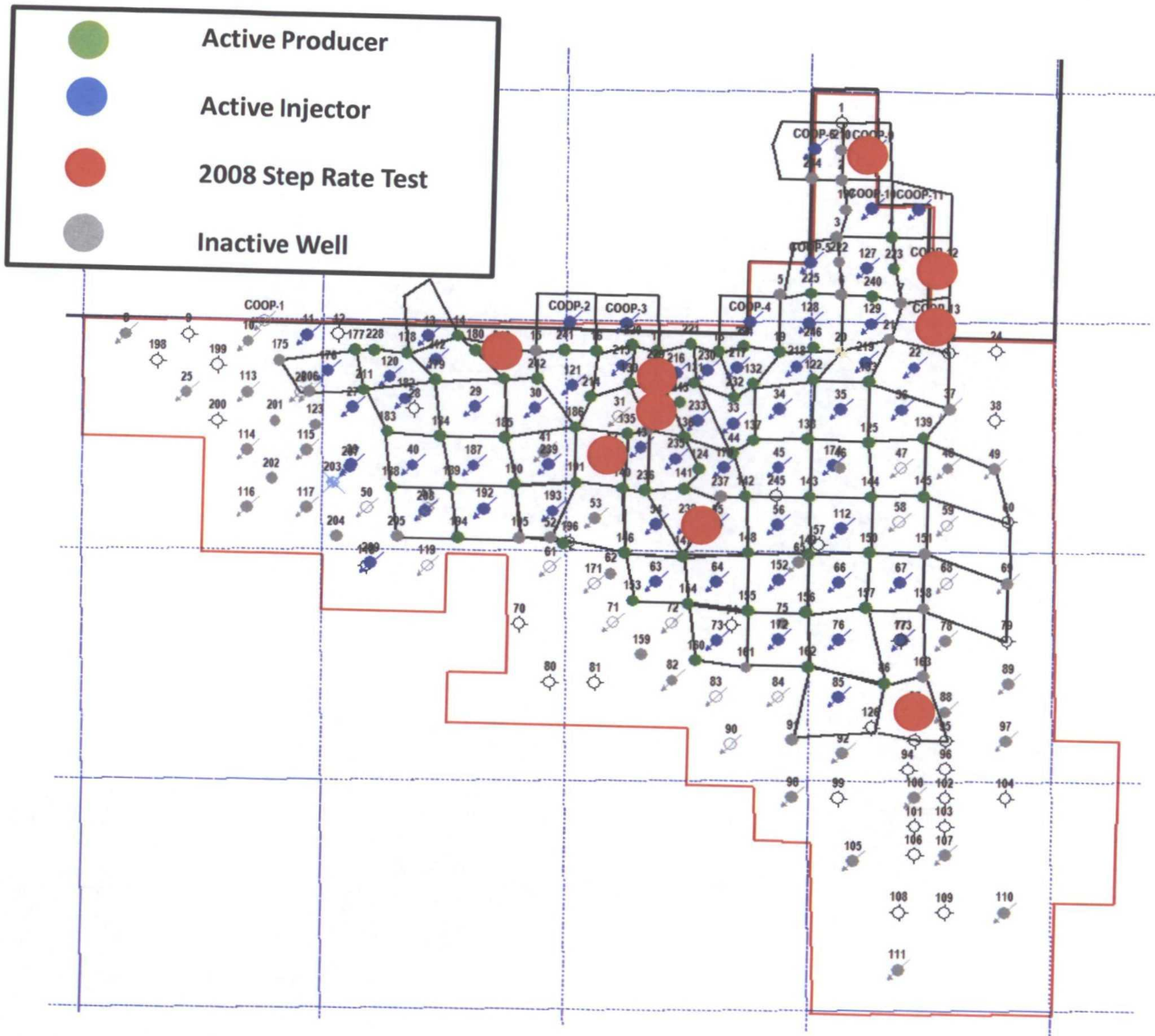


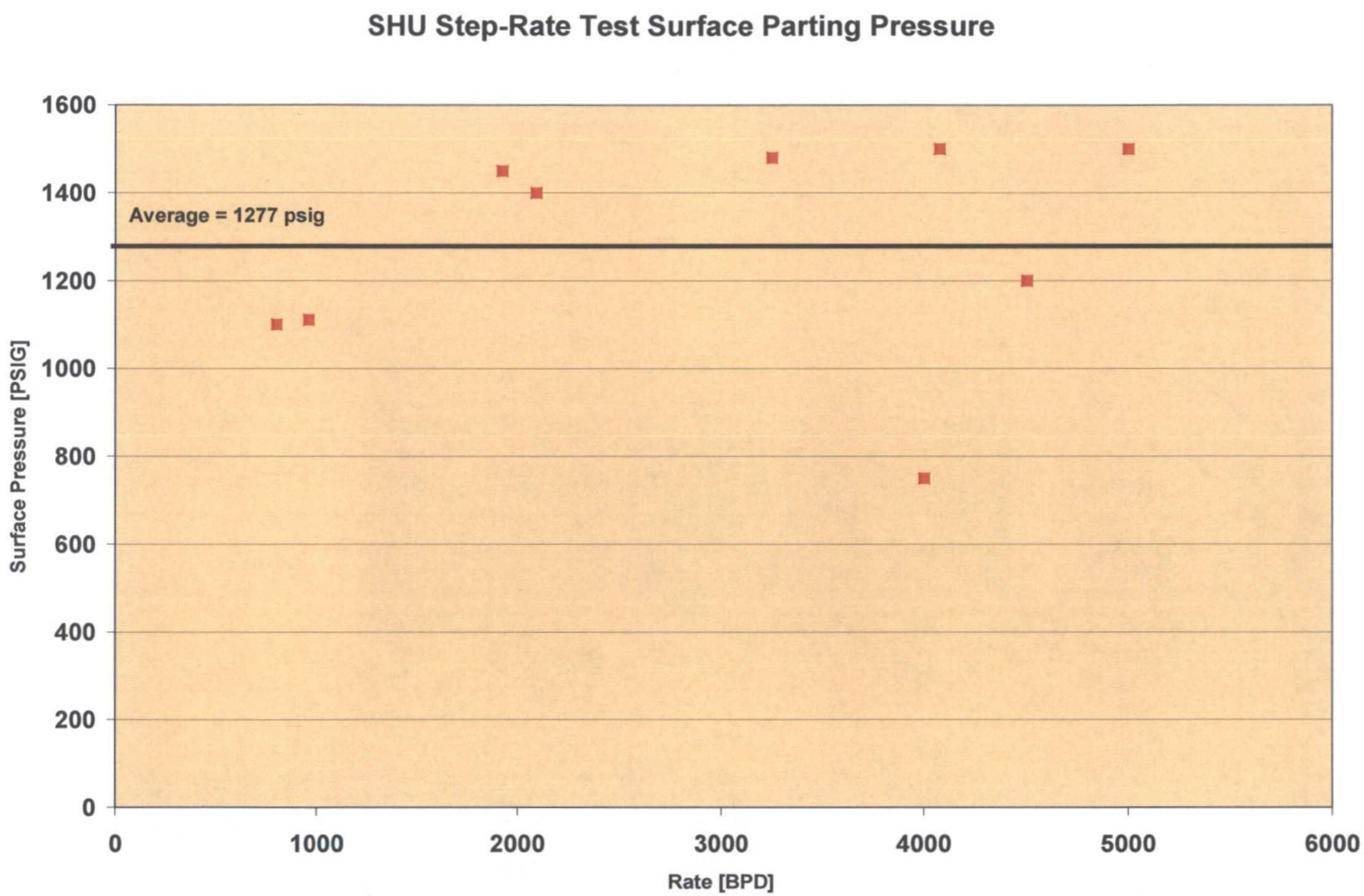
SHU GOR

Historical and Forecast



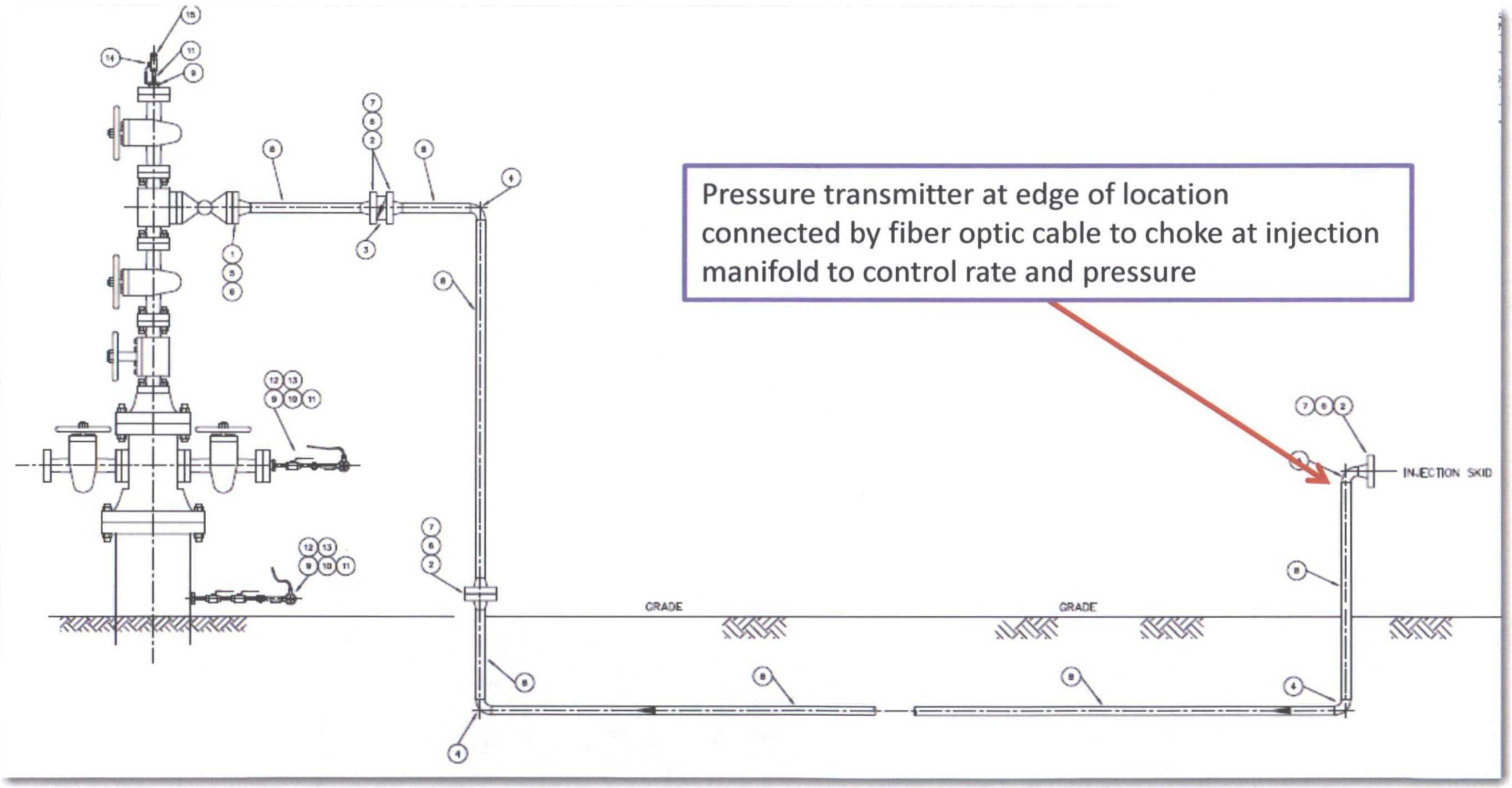
South Hobbs Unit Step Rate Tests




SHU Step-Rate Test Surface Parting Pressure
Average = 1277 psig
Surface Pressure [PSIG]
Rate [BPD]
0
200
400
600
800
1000
1200
1400
1600
0
1000
2000
3000
4000
5000
6000

Injectant	Surface Parting Pressure w/ Water (psig)	Hydrostatic Pressure Adjustment (psig)	Adjusted Surface Parting Pressure (psig)	Requested Surface Pressure Limits (psig)
Water	1277	0	1277	**1100**
CO2	1277	390	1667	**1250**
Produced Gas	1277	900	2177	**1770**

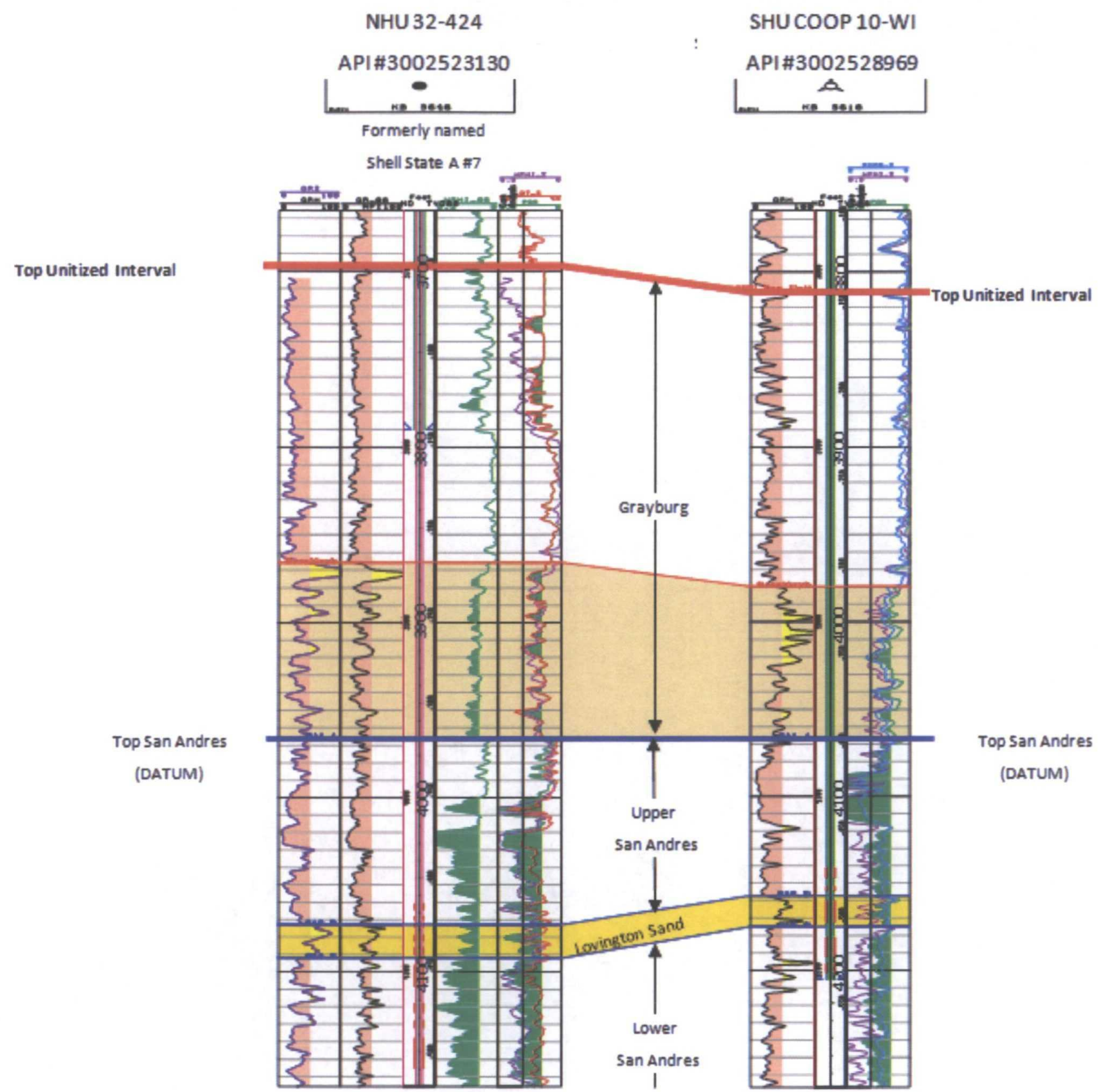
Injection Pressure Control



Order R-5897-A (Entered May 30, 2012)

<ins>RULE 11.</ins> Injection into any injection well shall be accomplished through internally coated tubing installed in a packer set as close as practically possible to the uppermost injection perforations or casing shoe (of an open hole completion); so long as the packer set point remains within the Unitized Formation, as defined in the Unit Agreement, or as the same may be subsequently modified. The casing-tubing annulus shall be filled with an inert fluid and a gauge or approved leak detection device shall be attached to the annulus in order to determine leakage in the casing, tubing or packer.

South Hobbs Unit COOP #10-WI Type Log



Downhole Corrosion Mitigation

- Compliant with NACE MRO175
- Injection tubing is fiberglass lined
- Injection packer is nickel plated carbon steel
- Annulus is filled with inert packer fluid