



***Central Vacuum Unit & Vacuum
Grayburg San Andres Unit – OCPD
Hearing to modify Injection Orders
December 3rd, 2009***

BEFORE THE OIL CONSERVATION DIVISION
Santa Fe, New Mexico
Consolidated Case No. 's 14401 & 14402 Exhibit No. 1
Submitted by:
CHEVRON U.S.A. INC.
Hearing Date: December 3, 2009

Three Parts to the Hearing Application- CVU & VGSAU



Applying to amend current injection orders in 3 areas:

1. Injection well completion requirements: reason - 9 injectors approved by District don't comply with current injection orders (casing/tubing annulus can't be monitored)
2. Injection packer setting requirements: reason - desire ability to set inj packer higher but still within unitized interval
3. Verbiage around maximum CO₂ injection pressure: reason-desire to reference avg maximum BH injection pressure rather than maximum surface inj pressure in order to respond to reduced injection fluid density



CVU & VGSAU Injection Orders – standard verbiage

CVU

(3) WAG injection operations shall be accomplished through internally coated tubing installed ~~in~~ a packer set within approximately 100 feet of the uppermost injection perforations or casing shoe; 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. 1

(4) For those injection wells within the "EOR Project Area" whose current maximum surface injection pressure for water is less than 1500 psi (as shown on applicant's Exhibit No. 12), the applicant is hereby authorized to inject water into each of these wells at the current maximum surface injection pressure, provided however, such pressure may be administratively increased by the Division upon a showing that such increase will not result in the fracturing of the injection formation or confining strata, and shall be further authorized to inject CO₂ and produced gases at a maximum surface injection pressure of 350 psi above the current maximum surface injection pressure for water, provided however, such CO₂ injection shall not occur at a surface injection pressure in excess of 1850 psi. 3

VGSAU

(4) Enhanced tertiary injection operations shall be accomplished through internally coated tubing installed ~~in~~ a packer set within approximately 100 feet of the uppermost injection perforations or casing shoe; 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. 1

(5) For those injection wells within the enhanced oil tertiary recovery project with a current maximum surface injection pressure for water of less than 1500 psi, the applicant is hereby authorized to inject water into each of these wells at the current maximum surface injection pressure, provided however, such pressure may be administratively increased by the Division upon a showing that such increase will not result in the fracturing of the injection formation or confining strata. The applicant is further authorized to inject CO₂ and produced gases at a maximum surface injection pressure of 350 psi above the current maximum surface injection pressure for water, provided however, such CO₂ and produced gas injection may not occur at a surface injection pressure in excess of 1850 psi. Such pressure may be administratively increased by the Division upon a showing that such increase will not result in the fracturing of the injection formation or confining strata. 3



1) Injection well completion requirements

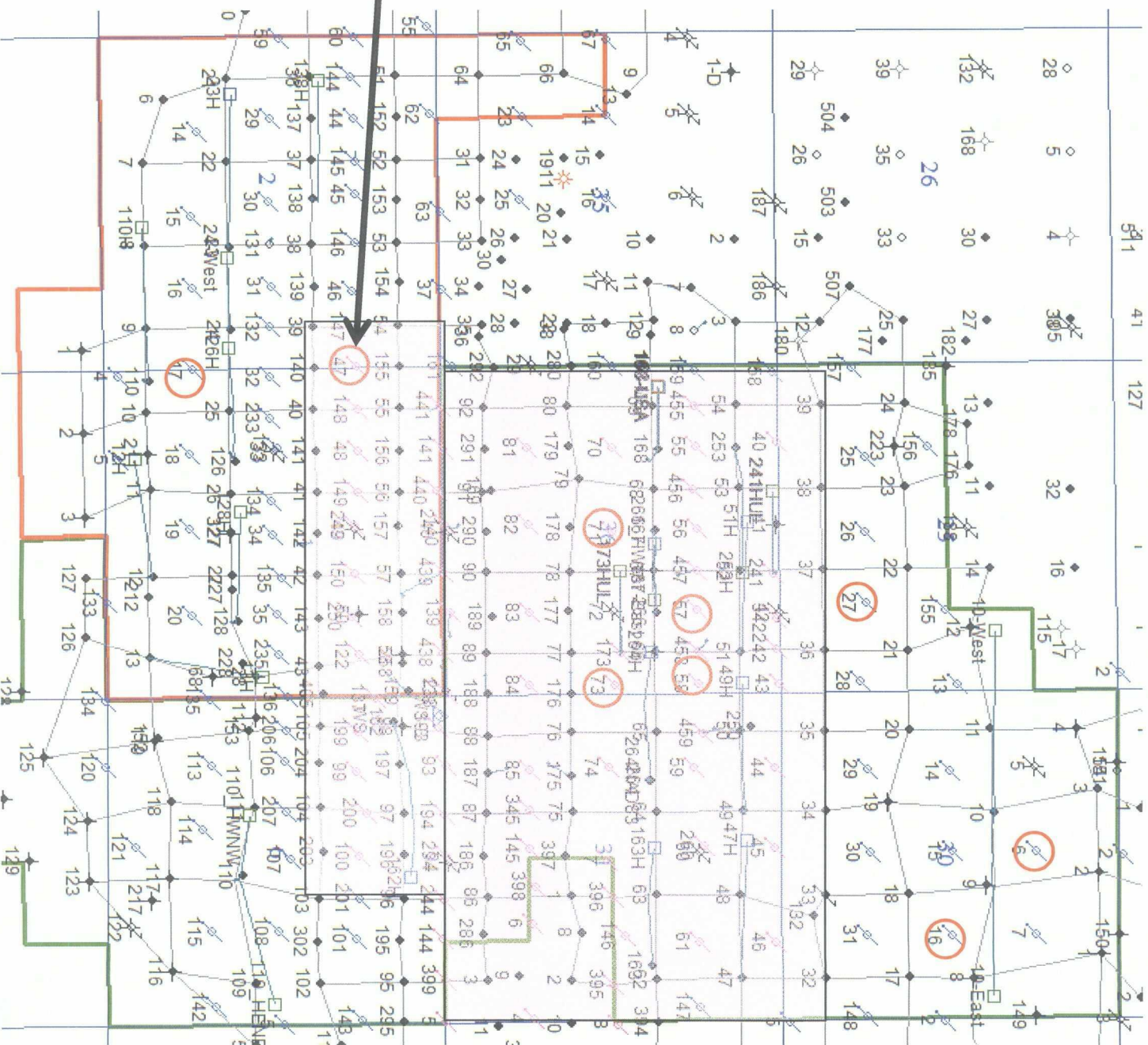
" the casing-tubing annulus shall be filled with an inert fluid and a gauge or approved leak-detection device shall be attached to the annulus in order to determine leakage in the casing, tubing or packer. "

- Issue around injectors with tubing cemented in place first surfaced in late May, 2009 with VGSAU 47
- CVU 58 - First well remediated this way (2003) after 7 unsuccessful squeeze attempts, CVX and OCD District supervisor met and developed remedial plan and District personnel approved this plan and all subsequent C103's until the VGSAU 47
- OCD Santa Fe (7/15/09) - conveyed position that OCD District offices "aren't authorized to grant a variation that violates an OCD order"
- Recent research found a total of 9 New Mexico Chevron injectors completed this way, all at Vacuum following CVU #58

○ Injector with tubing cemented in place; 7 in CO2 phases are important to reserve recovery

Active CO2 Phase

VGSAU 47 -
 Shut in on May 22nd following OCD denial of second C103. Eight others remain active as agreed to by OCD UIC examiner Will Jones.



Chevron - Vacuum Field Cemented Tubing Timeline



Well	Activity	2002	2003	2004	2005	2006	2007	2008	2009
CVU 58	attempt casing repair, Unsuccessful, plan to PA develop remedial solution w/ OGD Dist 1 implement OGD approved remedial plan	J J A S C N D X X X X X X	J F N A P V J A S C N D		S C N D J F N A P V J A S C N D	J F N A P V J A S C N D	S C N D J F N	J J J A S	J J J A S C N D
CVU 73	attempt casing repair, Unsuccessful, TA submit & receive approval for remedial plan implement OGD approved remedial plan	X	X X		X X X X X	X X X X X		X X X X	
CVU 71	attempt casing repair, Unsuccessful, TA submit & receive approval for remedial plan implement OGD approved remedial plan		X X	X X	X X X X X			X X X X	
CVU 57	casing repair MIT Failure	X X	X X						
CVU 16	submit & receive approval for remedial plan implement OGD approved remedial plan attempt casing repair, Unsuccessful, TA filed intent to P&A		X X X X		X X X X X				
CVU 6	implement remedial plan, subsequent C-103 approved attempt casing repair, Unsuccessful, TA submit & receive approval for remedial plan implement OGD approved remedial plan				X X X X X				
CVU 27	attempt casing repair, Unsuccessful, TA implement remedial plan, subsequent C-103 approved implement OGD approved remedial plan				X X X X X				
VGS AU 17	attempt casing repair, Unsuccessful, TA submit & receive approval for remedial plan implement OGD approved remedial plan	X X					X X X X		
VGS AU 47	attempt casing repair (2 squeezes), Unsuccessful implement remedial plan, subsequent C-103 approved Subsequent C-103 amended then denied, well shut-in OGD Hearing							X X X X	X



Remedial Options & Consequence of Losing wellbores

□ Remedial Options

- Due to the existing string size (7 wells - 2 7/8" and 2 wells - 2 3/8") remedial options are limited & would reduce injection by ~50% and are prohibitively costly
- Chevron invested >\$1.0MM remediating these wells per OCD District office approved plans

□ Consequences of Losing wellbores

- Losing the use of these wellbores would result in a loss of ~485 BOPD, 2,210 MBO proved reserves
- Loss of ~\$19MM in State revenue at \$70 BBL
- ~\$15MM cost to replace 9 wells. Due to economic and budgetary constraints most wells would not likely be replaced.



Proposal to Assess & Verify Mechanical Integrity of Injection Wells With Cemented Tubing

- Test wells to prove mechanical integrity at 5 times the currently required OCD frequency via annual blanking plug tests.
- Monitor for changes in the inj rate versus inj pressure data daily with SCADA
 - Generate alarms prompting human response & evaluation
 - Valid alarms will require shut in
 - Will not resume injection until MIT is confirmed
- Proposed approach fully complies with EPA UIC regulations
 - Approved method in other jurisdictions

2) EPA 40 CFR 146.8



§ 146.8 Mechanical integrity.

(a) An injection well has mechanical integrity if:

- (1) There is no significant leak in the casing, tubing or packer; and
- (2) There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore.

(b) One of the following methods must be used to evaluate the absence of significant leaks under paragraph (a)(1) of this section:

(1) Following an initial pressure test, monitoring of the tubing-casing annulus pressure with sufficient frequency to be representative, as determined by the Director, while maintaining an annulus pressure different from atmospheric pressure measured at the surface:

(2) Pressure test with liquid or gas; or

(3) Records of monitoring showing the absence of significant changes in the relationship between injection pressure and injection flow rate for the following Class II enhanced recovery wells:

(i) Existing wells completed without a packer provided that a pressure test has been performed and the data is available and provided further that one pressure test shall be performed at a time when the well is shut down and if the running of such a test will not cause further loss of significant amounts of oil or gas; or

(ii) Existing wells constructed without a long string casing, but with surface casing which terminates at the



Current Operational Overview

- ❑ Aging infrastructure
- ❑ Varied construction and maintenance practices
- ❑ Corrosive fluids and gases
- ❑ Historical legacy events
- ❑ Significant exposure in total fluid production, transportation and processing
 - 300,000 BPD Total Fluid
 - 225,000 MCFD
- ❑ Systematic elimination of undesirable events
 - Standards in design
 - Facility consolidations and reconstruction
 - Flowline inspections and testing
 - Supervisory Control And Data Acquisition (SCADA) deployment and leak detection development
 - Trunk line evaluation, testing and inspection

Current Operational Overview

- Secondary and Tertiary floods
- Wells range in age up to 70 years old
- 140 injectors (CVU & VGSAU), 57 in CO₂ service
- SCADA deployed in late 1980s
 - Data acquisition
 - Limited control
- Currently assess mechanical integrity by:
 - Monitor annular pressure monthly
 - Annual OCD witnessed Braidenhead testing
 - 5 year OCD witnessed MIT

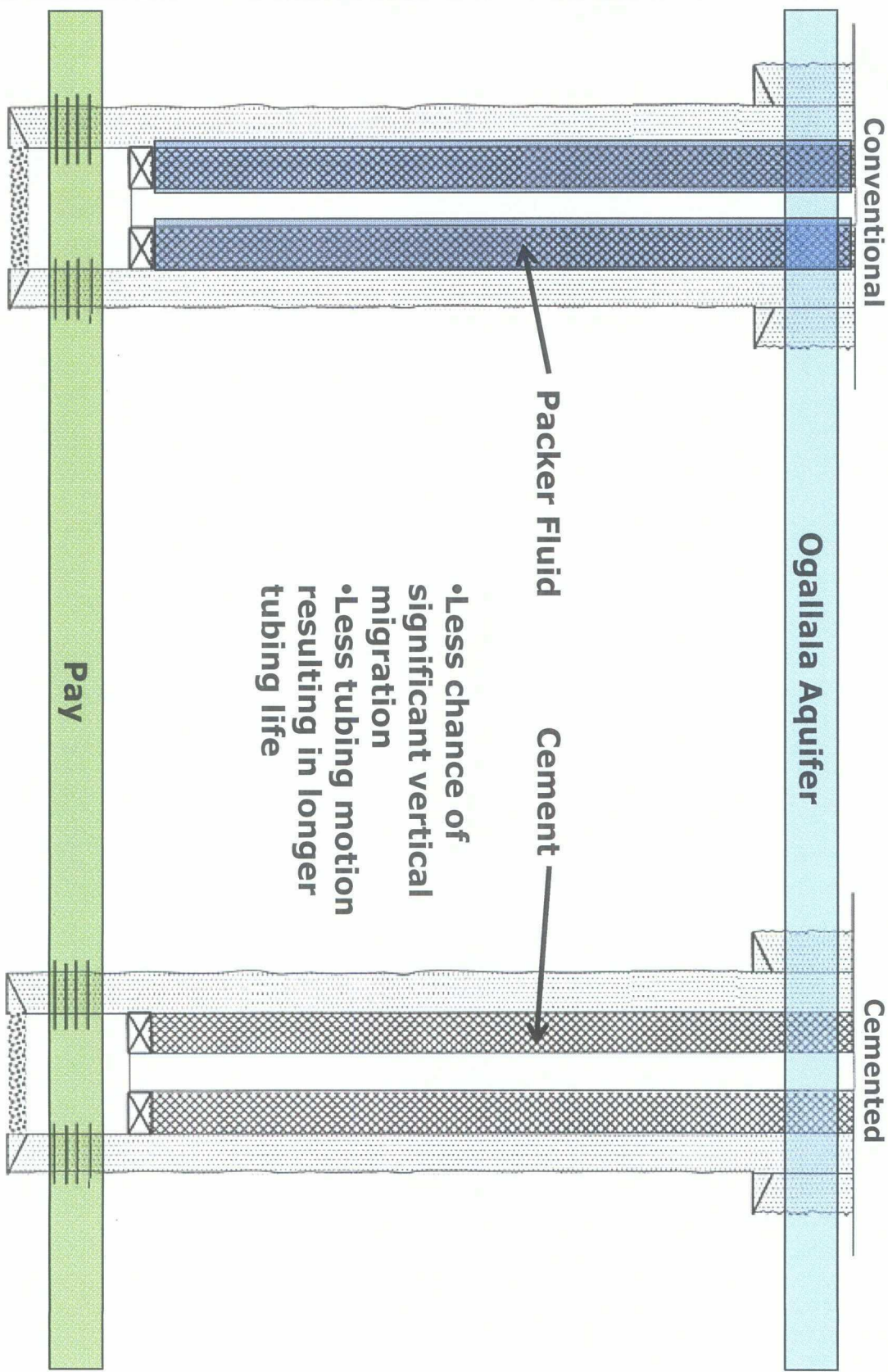


Chevron – Vacuum Wells With Tubing Cemented in Place

well name	Location (S-T-R)	Surface csg size & depth	Prod csg size & depth	Tubing size & depth	Cemented tubing date	Inj Packer?	2009 tubing MIT test results
CVU 58	36-17S-34E	8 5/8" @ 405 circ cement	4 1/2" @ 4800' circ cement	2 7/8" DL @ 4281' circ cement	Jan-03	yes	10/9 - tested to 2500 psi with good chart
CVU 73	36-17S-34E	9 5/8" @ 409 circ cement	4 1/2" @ 4800' circ cement	2 7/8" DL @ 4281' circ cement	Feb-03	yes	10/21 - tested to 2000 psi with good chart
CVU 71	36-17S-34E	8 5/8" @ 399 circ cement	4 1/2" @ 4800' circ cement	2 7/8" DL @ 4289' circ cement	Aug-03	yes	10/14 - tested to 1750 psi with good chart
CVU 57	36-17S-34E	8 5/8" @ 396 circ cement	4 1/2" @ 4800' circ cement	2 7/8" DL @ 4204' circ cement	Sep-03	yes	10/9 - tested to 2500 psi with good chart
CVU 16	30-17S-35E	8 5/8" @ 413 TOC @ 11'	4 1/2" @ 4870' circ cement	2 7/8" FL @ 4345' circ cement	Feb-06	yes	10/9 - tested to 2500 psi with good chart
CVU 6	30-17S-35E	8 5/8" @ 410 circ cement	4 1/2" @ 4830' circ cement	2 7/8" FL @ 4396' circ cement	Mar-06	yes	10/9 - tested to 2500 psi with good chart
CVU 27	25-17S-34E	8 5/8" @ 420 circ cement	4 1/2" @ 4800' circ cement	2 3/8" FL @ 4341' circ cement	Nov-06	yes	10/12 - tested to 2000 psi with good chart
VGSAU 17	2-18S-34E	8 5/8" @ 364 circ cement	4 1/2" @ 4800' TOC @ 2706'	2 3/8" FL @ 4319' circ cement	Feb-07	yes	10/12 - tested to 2000 psi with good chart
VGSAU 47	2-18S-34E	8 5/8" @ 355 circ cement	4 1/2" @ 4800' TOC @ 2460'	2 7/8" FL @ 4204' circ cement	Jul-08	yes	10/14 - tested to 2000 psi with good chart



Wellbore Comparison





Mechanical Integrity Testing

Mechanical integrity Tests Performed on the Nine Project Wells in October 2009. All Wells Showed Mechanical Integrity

- Rigged up pump truck and flushed tubing with fresh water
- Rig up Slick Line Unit and run in hole with gauge ring to profile nipple verifying no restrictions.
- Run in hole with blanking plug on slick line. Set plug in profile nipple.
- Opened well to pump truck to bleed off pressure on tubing to verify plug is set (tubing pressure bleed off to zero)
- Perform pressure test of tubing. Test pressure varied. Initial wells were tested at 2500 PSI. Reduced targeted test pressure to 2000 PSI.
- Ran charts to document test results.
- Retrieve blanking plug
- Return well to normal operations
- Issues: CO₂ in Tubing – Check Valve Failures – No Local Isolation Valve – Risk of damaging liner or Profile Nipple



Lessons Learned From Blanking Plug MIT

- Wells that are on CO₂ will need to be waggged to water for several days prior to testing. CO₂ cannot be effectively swept out of the tubing with a single flush
- Test fluid should be fresh water
- Existing wellhead installation will need to be modified to include an isolation valve, figure eight blinds and local bleed off valves on both sides of isolation valve. Modification will eliminate leaking check valve issues that were identified during initial testing.
- Schedule and execute tests of all project wells during same test period to enable efficient utilization of service company and site supervision
- Attempt to schedule same service company personnel with each test.

Proposed MIT Test Procedure



NMOCD District Office Notification and Witness Opportunity Required

- Ensure well has been on water injection for minimum of five days prior to test date
- Document normal operating injection pressure prior to initiation of test
- Close isolation valve and position the figure eight blind in the closed position
- Rig up Slick Line Unit and run in hole with appropriate sized gauge ring and bailer. Tag PBTB and document depth to top of fill. Stroke bailer to obtain fill sample.
- Rig up pump truck and flush the tubing with fresh water. Pump 150% tubing displacement.
- Run in hole with blanking plug and set in the profile nipple.
- Open tubing and attempt back flow to pump truck (tubing should bleed off)
- Perform pressure test of tubing and profile nipple seal to appropriate pressure based on differential pressure and gradient correction.
- Chart the test as per NMOCD process guidance (default will be 24 hour chart and 96 minute clock). Obtain signatures of tester and witnesses.
- Retrieve blanking plug
- Return figure eight blind to open position
- Return well to normal operations

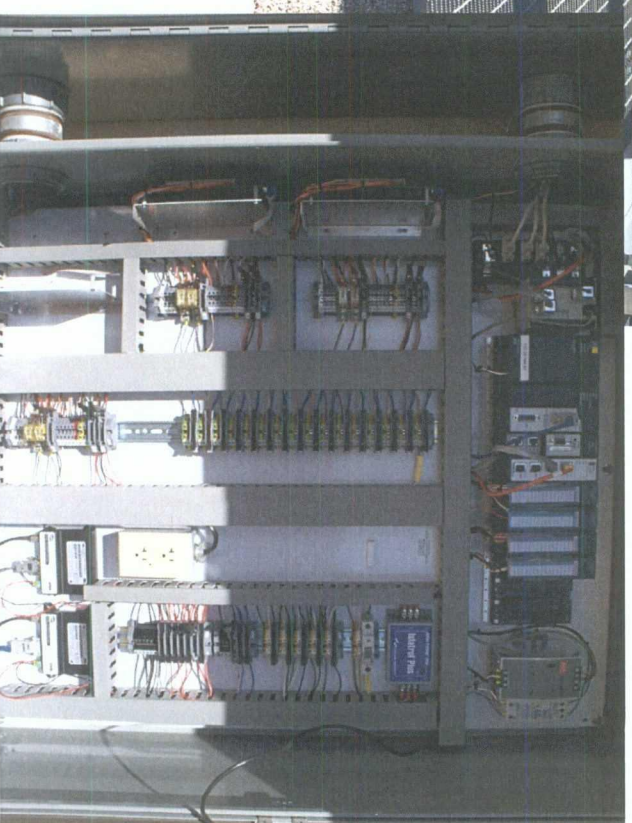


Leak Detection
RTU

Annulus Pressure
Sensor

Tubing Pressure
Sensor

Typical Injection Header and Programmable Logic Controller





Surveillance – Alarm Monitoring – Initial Response

Surveillance and Alarm

- Daily review of SCADA pressure and flow rate trend data for the project wells
- Operating condition inclusion in daily alarm report (“Normal / Alarm”)
- Call out alarm if deviation triggers have been exceeded for determined time period not to exceed 24 hours.

Alarm Response

- Review trend data with Operations Supervisor (OS) or Production Team Lead (PTL) the same day as alarm is received
- Conduct on sight investigation to verify integrity of measurement equipment (*Priority Level 1 Response ... same as reportable spill to surface*)
- Conduct on sight investigation to identify if surface leak may exist (*Priority Level 1 Response ... same as reportable spill to surface*)
- Shut well in and make notifications to OS if subsurface leak is suspected based upon investigation findings.
- OS will provide notification to NMOCD District office of Possible loss of mechanical integrity (*Priority Level 1 Response ... same as reportable spill to surface*)
- OS will having blanking plug installed and conduct mechanical integrity as per procedure including NMOCD witness.



Proposed plugging program -- 2 7/8" Slimhole injection wells

1. Evaluate and prep location.
2. MIRU Sunset Well Service, Inc. plugging equipment. RIH with 2-1/16" workstring and spot cement from original production casing shoe or top perforation to TOC $\pm 2,700'$ on original production casing. WOC & TAG, displace hole w/MLF.
3. RIH w/wireline and perforate 100' below Base of Salt. POH w/wireline. Establish injection rate. Cement squeeze 200' inside 2-7/8" liner and 200' outside original production casing. WOC & TAG.
4. RIH w/wireline and perforate 100' below Top of Salt. POH w/wireline. Establish injection rate. Cement squeeze 200' inside 2-7/8" liner and 200' outside original production casing. WOC & TAG.
5. RIH w/wireline and perforate 100' below surface casing shoe. POH w/wireline. Establish injection rate. Cement squeeze from surface and circulate cement to surface outside original production casing.
6. RDMO Sunset Well Service, Inc. plugging equipment.
7. Install dryhole marker, clean location and turnover for surface remediation operations.



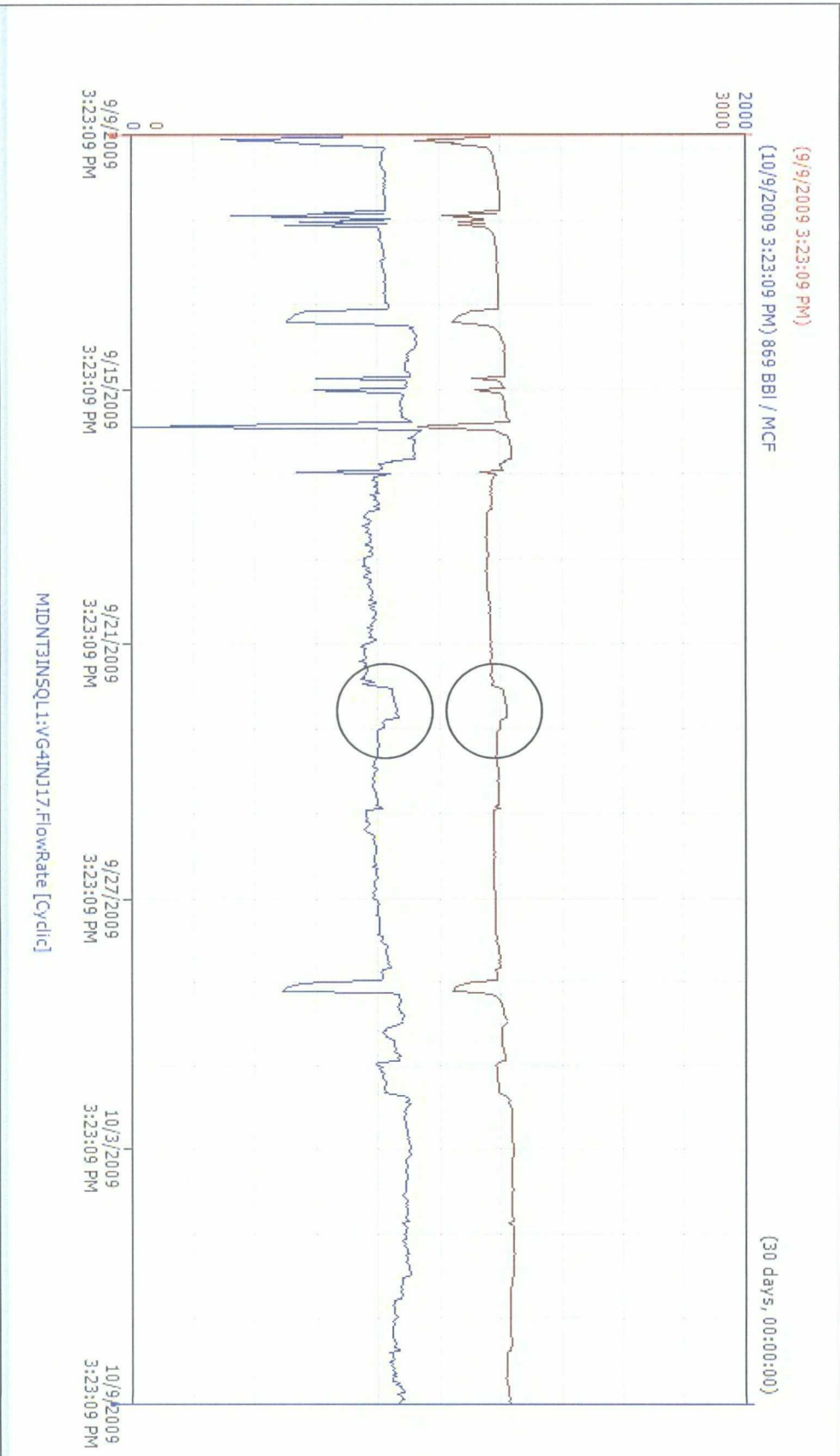
Proposed plugging program – 2 3/8” Slimhole injection wells

1. Evaluate and prep location.
2. MIRU CTU. RIH w/1-1/4” CT and spot cement plug from original production casing shoe or top perforation to TOC \pm 2,700’ on original production casing. WOC & TAG, displace hole w/MLF.
3. Pressure test 2-3/8” liner to 2,000 psig. RDMO CTU. MIRU Sunset Well Service, Inc. plugging equipment.
4. RIH w/wireline and perforate 100’ below Base of Salt. POH w/wireline. Establish injection rate. Cement squeeze 200’ inside 2-3/8” liner and 200’ outside original production casing. WOC & TAG.
5. RIH w/wireline and perforate 100’ below Top of Salt. POH w/wireline. Establish injection rate. Cement squeeze 200’ inside 2-3/8” liner and 200’ outside original production casing. WOC & TAG.
6. RIH w/wireline and perforate 100’ below surface casing shoe. POH w/wireline. Establish injection rate. Cement squeeze from surface and circulate cement to surface outside original production casing.
7. RDMO Sunset Well Service, Inc. plugging equipment.
8. Install dryhole marker, clean location and turnover for surface remediation operations.

NOTE: If 2-3/8” liner does not test and requires cement squeeze or cement spot plug then work will be done w/1-1/4” jointed tubing.



VGSAU 17 30 Day Rate and Pressure



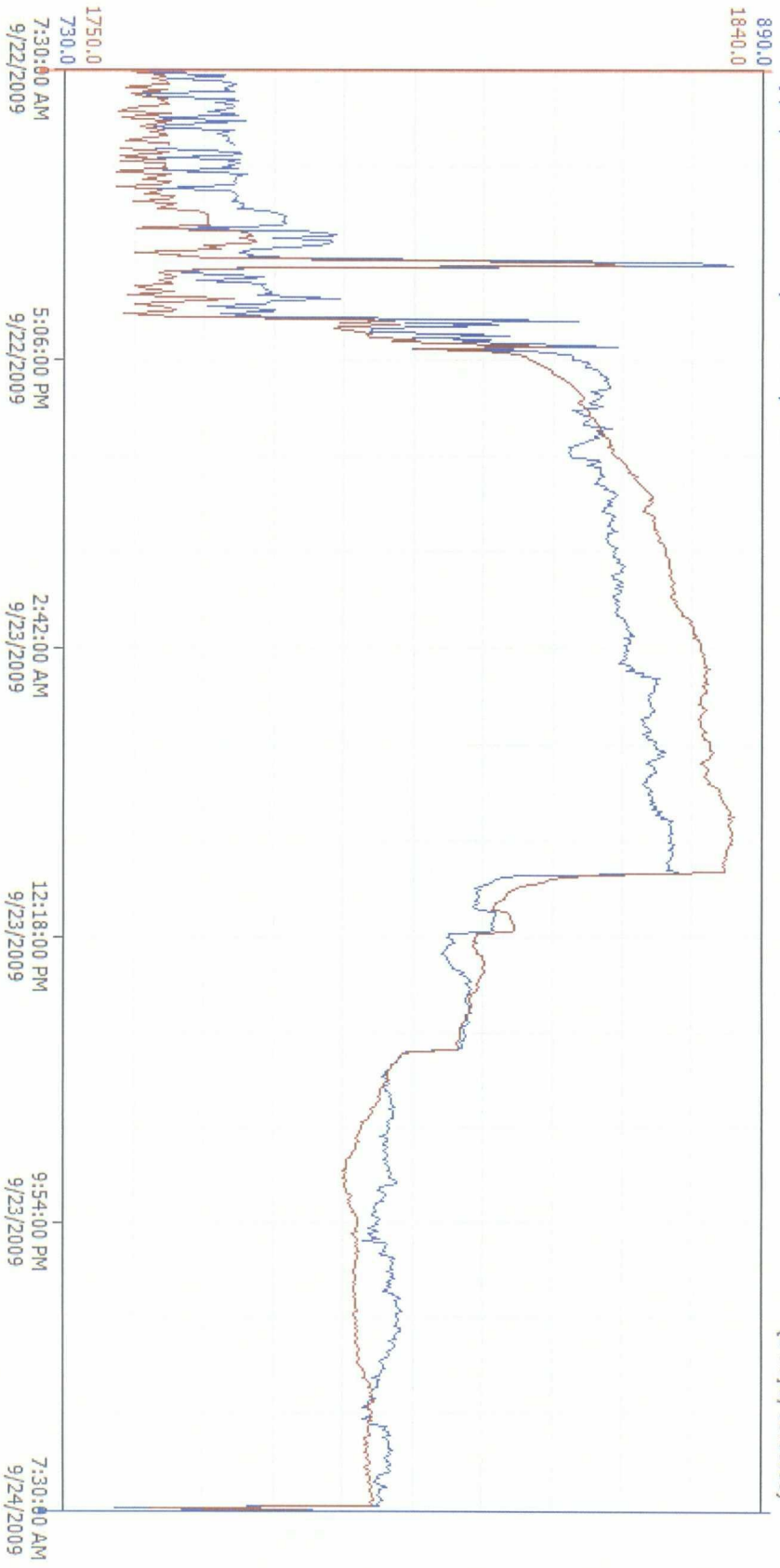


VGSAU 17 2 Day Rate and Pressure

(9/22/2009 7:30:00 AM)

(9/24/2009 7:30:00 AM) 742.1 BBL / MCF

(2 days, 00:00:00)

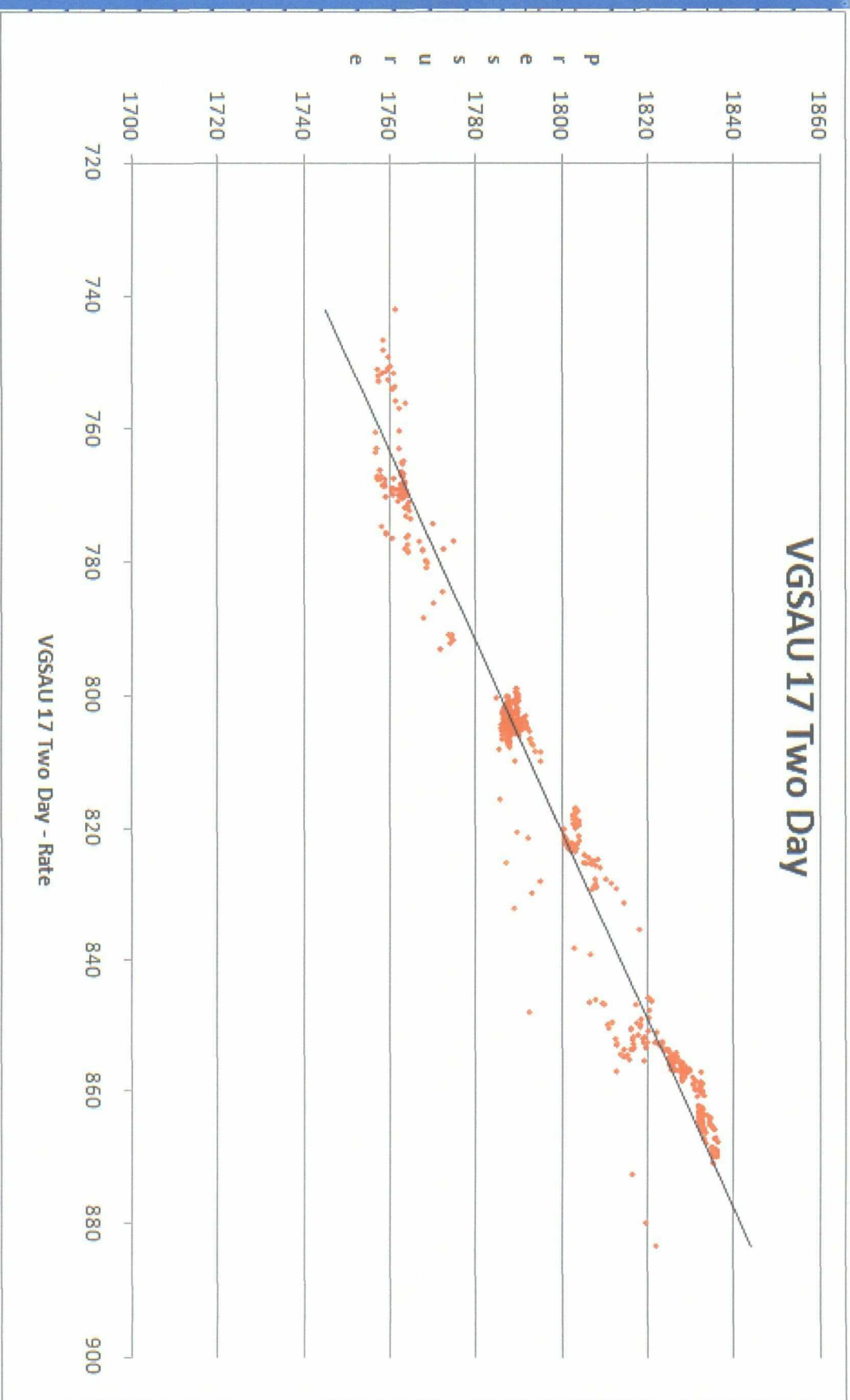


MIDNTRINSQL1:VG4INJ17.FlowRate [Cyclic]

Tag Name	Description	Server	Color	Units	Minimum	Maximum	IO Address	Time Offset
<input checked="" type="checkbox"/> VG4INJ17.FlowRate	CXX Injection Well	MIDNT3I...		BBL / MCF	730.0	890.0	\\MIDNT3INSQL1\IhS...	0:00:00.000
<input checked="" type="checkbox"/> VG4INJ17.TubingPsi	CXX Injection Well	MIDNT3I...		psi	1750.0	1840.0	\\MIDNT3INSQL1\IhS...	0:00:00.000



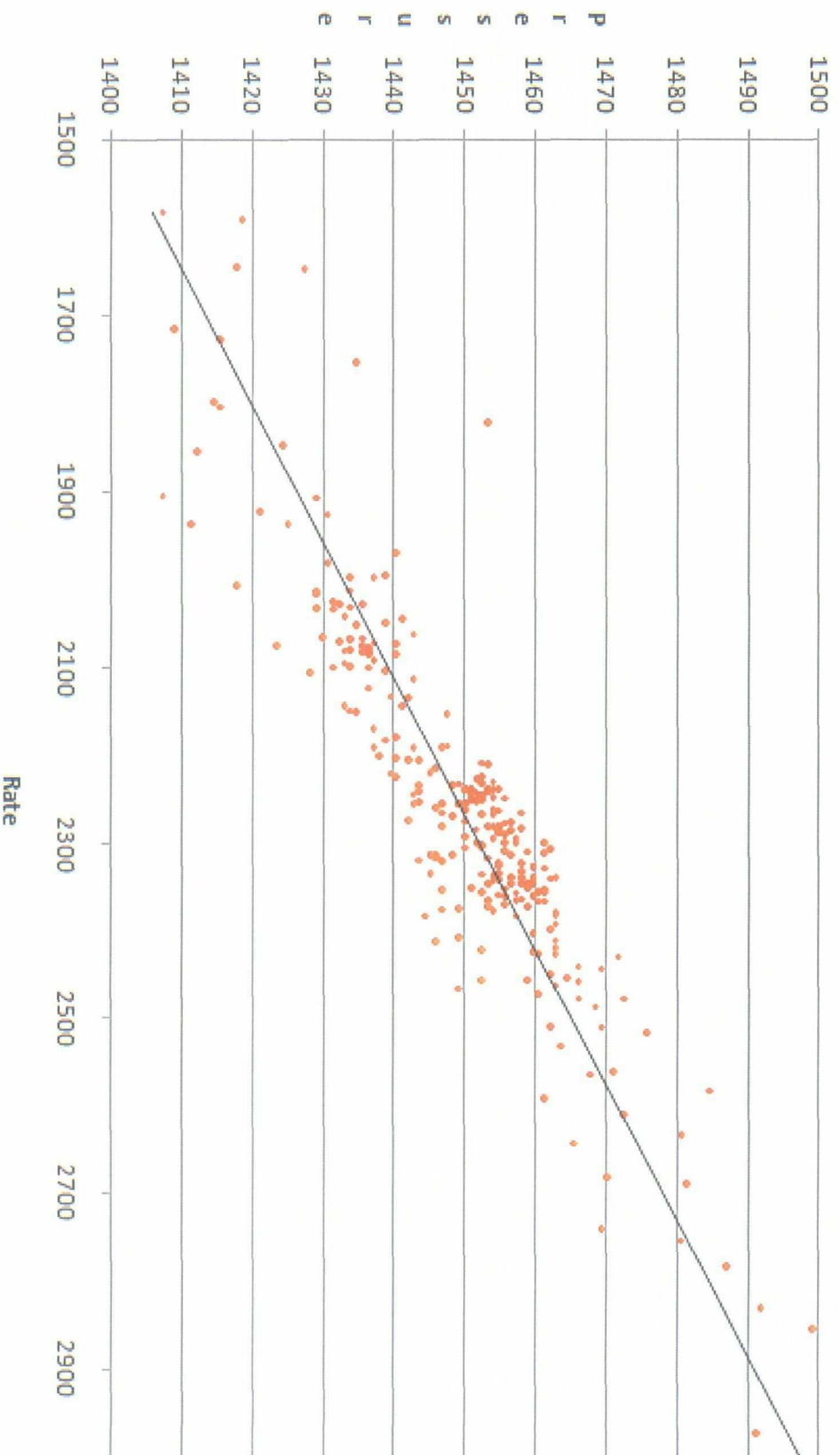
VGSAU 17 2 Day Rate Versus Pressure



CVU 459 2 Day Rate Versus Pressure



CVU 459 CVX CO2



Typical Leak Profile Rate Rising – Pressure Falling





CVU 27 MIT Failed

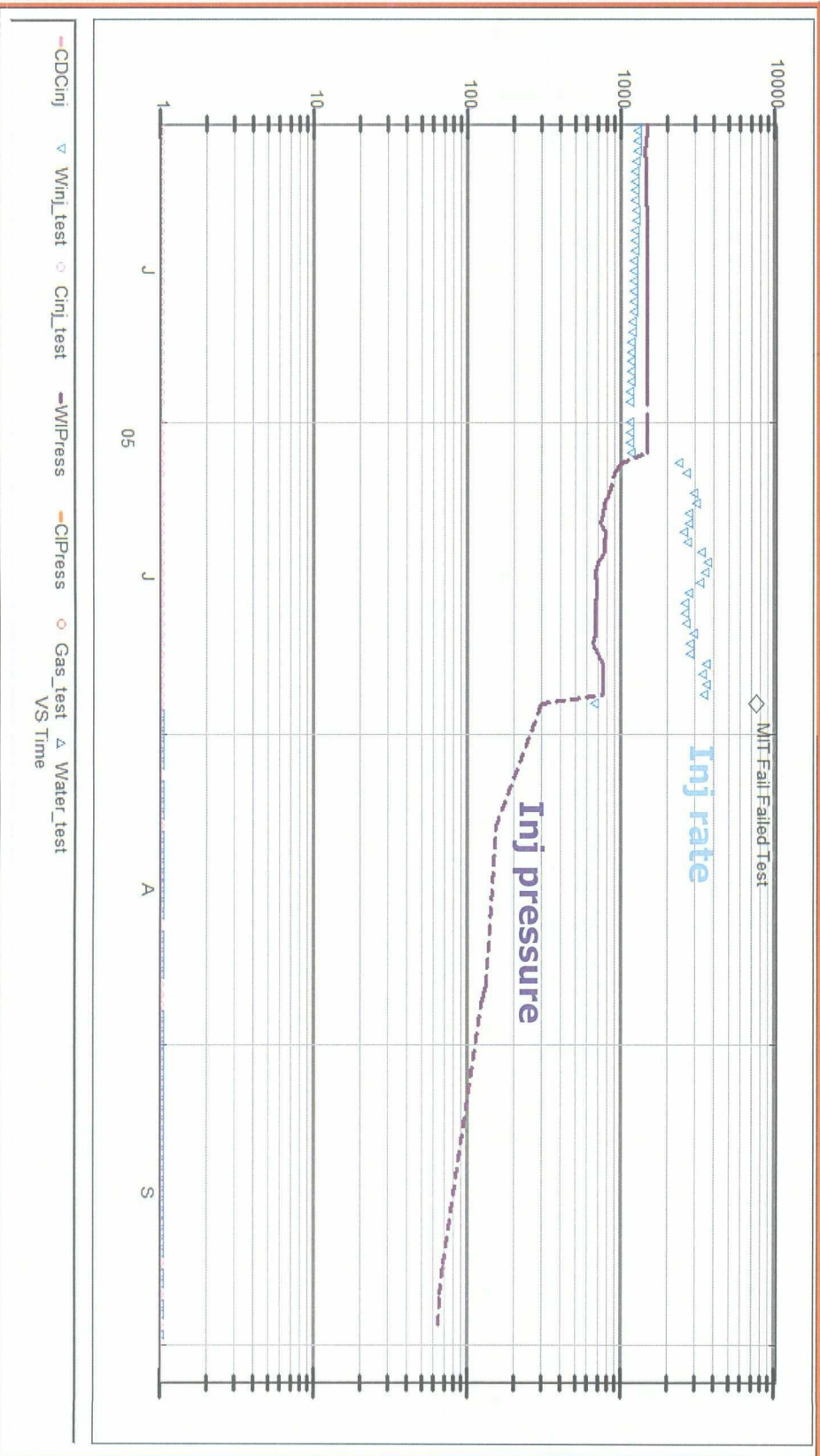
Name: CVU 027 ID: 30025258150001 Type: Completion Format: [p] Comp - Prod Inj vs Time

WELL LABEL: CVU 027
CHEVNO: EQ0048
SIDETRACK: 0
COMP_NUM: 01

FIELD CODE: T49
FIELD: FLD-VACUUM
LEASE: CENTRAL VACUUM U
SEC-T-R: 25 - S017 - E034

PROD METH: U
CLASS_CODE: WI
SAP_CODE: BCT494500
RES_CODE: 0000006849

LASTOCUM: 0
LASTGCUM: 0
CC_NM: CENTRAL VACUUM UNIT
RES: GRAYBURG/SAN ANDRES



2) Injection packer setting requirements



" WAG injection operations shall be accomplished through internally coated tubing installed in a packer set within approximately 100 feet of the uppermost injection perforations or casing shoe; "

- Once an injection packer is released for remedial actions, we often can't regain a packer seat at the same depth due to corrosion, must reset packer higher: This often requires the packer to be greater than the approved "100' of top perf"
- As a result, practical practice has evolved to the Operator shutting down operations, contacting the District office and asking for a waiver, which are commonly granted (verbal or written).
- This delay costs time & money and based on July 15th Santa Fe communication the District offices can't approve anyway



2) Chevron CVU & VGSAU wells with high packers

well	Packer height above		Unit top height above packer
	top perf		
CVU 14	136		442
CVU 28	139		406
CVU 31	108		341
CVU 46	121		373
CVU 56	151		332
CVU 70	103		397
CVU 82	143		317
CVU 83	121		310
CVU 93	118		270
CVU 115	193		283
CVU 133	165		376
CVU 134	190		296
CVU 146	120		352
CVU 155	285		184
CVU 156	102		369
CVU 158	291		198
CVU 160	104		358
VGSAU 4	123		256
VGSAU 14	103		202
VGSAU 15	294		106
VGSAU 19	211		270
VGSAU 29	164		218
VGSAU 30	252		96
VGSAU 31	212		126
VGSAU 34	165		208
VGSAU 45	193		207
VGSAU 59	121		228
VGSAU 60	106		299
VGSAU 65	121		288
VGSAU 148	101		213
VGSAU 233	105		297

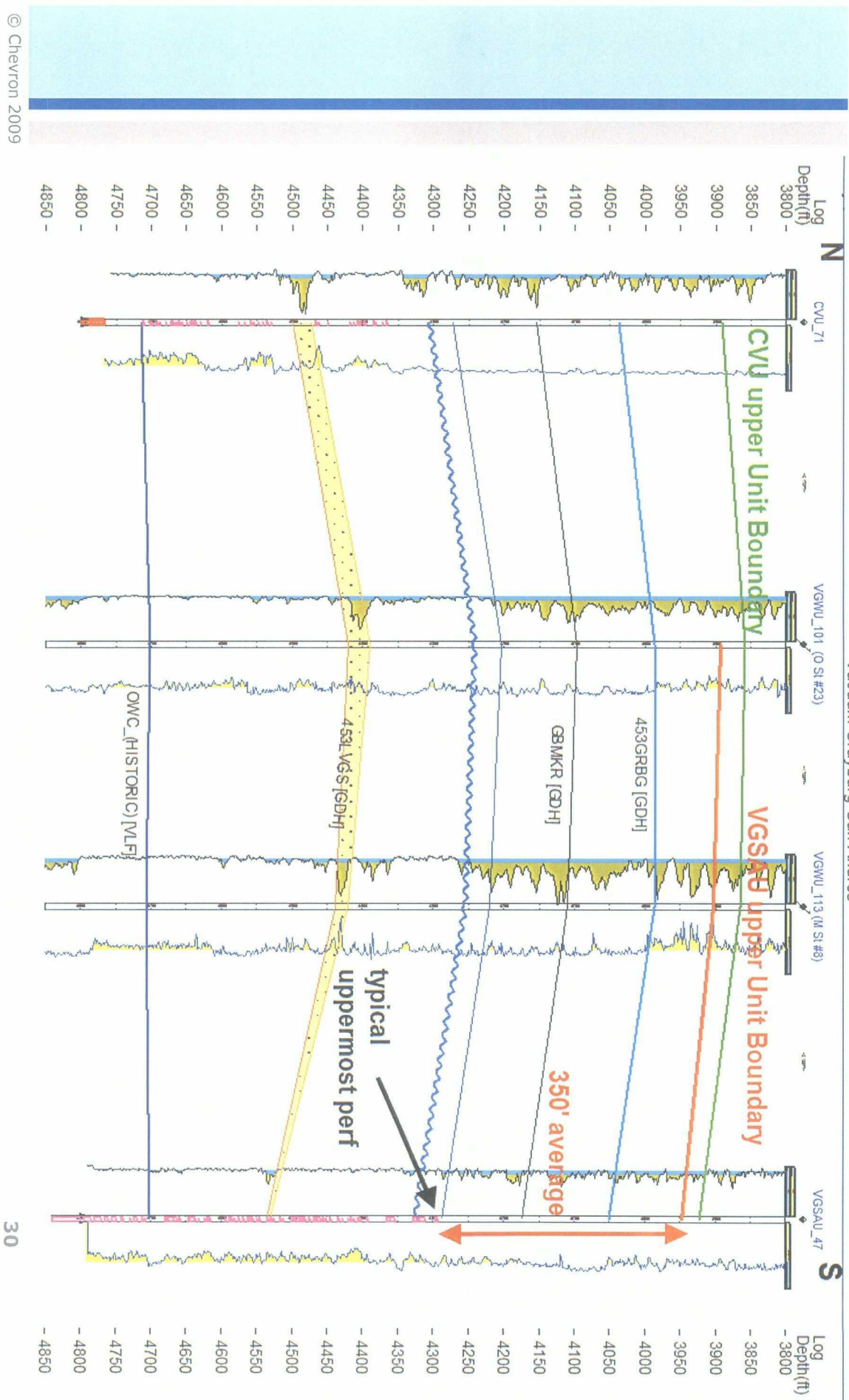
© Chevron 2009

- 31 wells with packers > 100' above top perf or casing shoe
- 38 more injectors with packer from 75' to 100' above top perf; next well work will likely result in packer being > 100' above top perf.



2) Vacuum Field N-S Cross Section with Unit Boundaries

Vacuum Grayburg-San Andres



2) Injection packer setting requirements



WAG injection operations shall be accomplished through internally coated tubing installed in a packer set within approximately 100 feet of the uppermost injection perforations or casing shoe; "

- Since CVU & VGSAU upper Unit boundaries are ~350' above top perf, propose to amend verbiage to allow setting the injection packer "as close as possible to the uppermost injection perforations or casing shoe, so long as it remains within the unitized interval"
- This change will still fully protect other formations and correlative rights
- Fed UIC regulations do not limit injection packer setting depths, they even allow injection without a packer

2) EPA 40 CFR 146.8



§ 146.8 Mechanical integrity.

(a) An injection well has mechanical integrity if:

- (1) There is no significant leak in the casing, tubing or packer; and
- (2) There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore.

(b) One of the following methods must be used to evaluate the absence of significant leaks under paragraph (a)(1) of this section:

(i) Following an initial pressure test, monitoring of the tubing-casing annulus pressure with sufficient frequency to be representative, as determined by the Director, while maintaining an annulus pressure different from atmospheric pressure measured at the surface:

(2) Pressure test with liquid or gas, or

(3) Records of monitoring showing the absence of significant changes in the relationship between injection pressure and injection flow rate for the following Class II enhanced recovery wells:

(i) Existing wells completed without a packer provided that a pressure test has been performed and the data is available and provided further that one pressure test shall be performed at a time when the well is shut down and if the running of such a test will not cause further loss of significant amounts of oil or gas; or

(ii) Existing wells constructed without a long string casing, but with surface casing which terminates at the

3) Maximum CO2 injection pressure



“ and shall be further authorized to inject CO₂ and produced gases at a maximum surface injection pressure of 350 psi above the current maximum surface injection pressure for water, provided however, such CO₂ injection shall not occur at a surface injection pressure in excess of 1850 psi.

- Both CVU & VGSAU Injection orders tie maximum CO2 injection pressure back to a surface pressure, yet the OCD allows this value to tie to an average maximum BH pressure (i.e. Conocophillip’s EVGSAU)
- Similar verbiage for our Units would allow Operations to mitigate BHIP drops created by injection stream density reductions due to Hc gas contamination, which greatly reduces our effective BHIP (impact is ~400 psi @ 87% CO2).



3) Buckeye Plant Recycle Gas Analysis

MOBILE ANALYTICAL LABORATORIES, INC.

P. O. BOX 69210
 DRESSA, TEXAS 79769
 PHONE (432)337-4744

8764

ANALYSIS REPORT

COMPANY: CHEVRON U.S.A.
 LEASE/PLANT: CO2 BACK TO FIELD
 OPERATOR: BUCKEYE
 CYLINDER: 0139
 H2S PPM: 414600

STATION:
 PRESS. PSIG: 800
 TEMP. DEG. F: 104
 SAMPLED / RECEIVED: 10/22/09
 SAMPLED BY: SR

FRACTIONAL ANALYSIS

COMPONENT	MOL %	GPW	CS+	GPW	CS+
NITROGEN	1.782	0.000		0.000	
CARBON DIOXIDE	87.032	0.000		0.000	
METHANE	4.208	0.000		0.000	
ETHANE	2.506	0.000		0.000	
PROPANE	1.126	0.473		0.000	
ISO-BUTANE	0.281	0.091		0.000	
N-BUTANE	0.816	0.256		0.000	
ISO-PENTANE	0.294	0.107		0.107	
N-PENTANE	0.299	0.108		0.108	
HEXANES PLUS	0.641	0.278		0.278	
H2S	0.415	0.000		0.000	
TOTALS	100.000	1.313		0.493	

CALC. SP. GRAVITY 1.486 BTU/CU. FT. (14.650 PSIA, 60 DEG. F)
 CALC. GROSS NET 222
 CALC. GROSS DRY 225

DISTRIBUTION:
 MR. MARK GARNER

NOTES:
 SPOT

3) Recycled CO2 Bottom Hole Pressure Effects



Surface Pressure, Psi	1,850	1,850	2,195
% CO2	100	87	87
Bottom Hole Pressure, PSI	3,596	3,202	3,600

To maintain the desired & permitted bottom hole pressure with recycled CO2, allowing Chevron to efficiently manage the tertiary recovery of hydrocarbons from these Units:

- Chevron requests a CO2 average (mid-perf) maximum bottom hole injection pressure of 3600psi,
- or an increase in the maximum surface injection pressure to 2200psi (an increase of 350 psi over the current limit)