STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

ORIGINAL

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:

APPLICATION OF CHEVRON USA INC. FOR AMENDMENT OF DIVISION ORDER NO. R-5530-E TO REVISE THE INJECTION WELL COMPLETION REQUIREMENTS AND TO CHANGE THE BASIS FOR THE CALCULATION OF THE AUTHORIZED INJECTION PRESSURE FOR CARBON DIOXIDE FROM SURFACE PRESSURE TO THE AVERAGE RESERVOIR PRESSURE IN ITS PREVIOUSLY APPROVED TERTIARY RECOVERY PROJECT IN THE CENTRAL VACUUM UNIT EOR PROJECT AREA, LEA COUNTY, NEW MEXICO, — CASE NO. 14401

and the

APPLICATION OF CHEVRON USA, INC. FOR AMENDMENT OF DIVISION ORDER R-4442, AS AMENDED, TO REVISE THE INJECTION PRESSURE FOR CARBON DIOXIDE FROM SURFACE PRESSURE TO THE AVERAGE RESERVOIR PRESSURE IN ITS PREVIOUSLY APPROVED TERTIARY RECOVERY PROJECT IN THE VACUUM GRAYBURG-SAN ANDRES PRESSURE MAINTENANCE PROJECT, LEA COUNTY, NEW MEXICO. — CASE NO. 14402

REPORTER'S TRANSCRIPT OF PROCEEDINGS
EXAMINER HEARING
December 3, 2009
Santa Fe, New Mexico

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BEFORE: DAVID BROOKS: Hearing Examiner
TERRY WARNELL: Technical Advisor

This matter came for hearing before the New Mexico Oil Conservation Division, David Brooks Hearing Examiner, on December 3, 2009, at the New Mexico Energy, Minerals and Natural Resources Department, 1220 South St. Francis Drive, Room 102, Santa Fe, New Mexico.

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A P P E A R A N C E S

FOR THE APPLICANT: WILLIAM F. CARR, ESQ.
Holland & Hart, LLP
P. O. Box 2208
Santa Fe, NM 87504-2208

HEARING EXAMINER: At this time we will call Case No. 14401, application of Chevron USA, Inc. for amendment of Division Order R-5530-E. Do you want us to call both cases?

MR. CARR: Yes, Mr. Examiner, I'd appreciate it if you'd also call 14402.

HEARING EXAMINER: Okay. We will also call Case No. 14402, application of Chevron USA for amendment of Division Order No. R-4442. It's my understanding that appearances will be joined in these two cases, so we'll call for appearances in both cases.

MR. CARR: May it please the Examiner, my name is William F. Carr of the Santa Fe office of Holland and Hart. We represent Chevron USA, Inc. in these cases. We have asked that they be consolidated because they do present the same issues and the same relief is sought.

We have seven wells in the Central Vacuum Unit and two in the vacuum Grayburg-San Andres Unit. And so we will need separate orders because there are separate orders governing the enhanced recovery projects in each of these units.

The cases you will see present really three issues. Two of them relate to the completion requirements in the original orders approving these units. Nine of the wells in these units have the tubing cemented in the case.

The wells failed mechanical integrity tests, they had trouble getting the cement to bond.

And in meetings with the Hobbs District office, this method of completing wells was, in fact, approved. Notice of intent were filed on those wells, C-103s were approved on all.

And the problem is that this procedure conflicts with the Division's order defining how the wells are to be completed. So when this was discovered, we were advised to come back and seek an amendment order.

When it was discovered we didn't know there were nine wells, there was an inventory of the Chevron operated properties in southeast New Mexico, and we discovered several others.

We also discovered that there were packers throughout the units that were set more than 100 feet above the top perforation and the casing ~~sheet~~ Shoe. And that activity would fall err to the same problem as the completion, and so we added that to our application.

The third issue relates to a change in the way injection pressures are calculated. And we'll show you that when the initial orders were entered, the injection pressure was set at a certain surface pressure and we were anticipating injecting a hundred percent C02. We have a contaminated gas stream, it's not only C02, it's 87 percent $CO_2$.

But what this does is, it has about a 400 pound impact on the bottomhole pressure and it is having an adverse effect on our ability to inject principally into the Central Vacuum Unit.

So we're asking and we will show you how we recommend this be handled so that we still have virtually the same bottomhole pressure, but we can get there with a different surface pressure, and we'll explain that to you.

I have four witnesses that I'm going to call. Scott Ingram is the project manager for this area. He's an earth scientist. He's going to give you some general background information and review recent historical events that led to this problem and will summarize our recommendation.

Tejay Simpson, the operations manager, is going to review current operations, he's going to review with you some recent mechanical integrity tests that were run on each of the nine wells at issue. And he's going to address questions that popped up during the meeting with the Division concerning how ultimately these wells could be plugged.

Koby Carlson, our automation analyst, will be here to explain the SCADA system which Chevron uses. This was originally for data acquisition but has recently been affecting the identifying leaks, surface leaks, and he's going to show you how this can be used now. And Chevron proposes to use this downhole as well.

And then we'll call petroleum engineer Paul Brown who is going to address the issue of the packer setting depth and also the change in injection pressures.

And so with that, I would like to at this time call Scott Ingram.

HEARING EXAMINER: Okay. For the record, are there any other appearances in this case? Seeing none, will the witnesses stand and identify themselves for the record?

MR. BROWN: Paul Brown.

MR. SIMPSON: Tejay Simpson.

MR. CARLSON: Koby Carlson.

MR. Ingram: Scott Ingram.

HEARING EXAMINER: Please swear the witnesses.

(Note: The witnesses were placed under.
oath by the Court Reporter.)

MR. CARR: Mr. Examiner, our presentation is in the form of a Power Point presentation, and I have given you a hard copy of the slides. And we're going to refer to them by the slide number you see on the page. And if I slip up, I may call them -- refer to them by page number. But we will go through all of those.

HEARING EXAMINER: Very good. You may call your first witness.

SCOTT INGRAM,

the witness herein, after first being duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. CARR:

Q. Would you state your name for the record, please?

A. My name is Scott Ingram.

Q. Mr. Ingram, by whom are you employed?

A. I work for Chevron USA.

Q. And what is your current position with Chevron?

A. I'm a certified petroleum geologist. I work as an earth scientist and as a project manager for Chevron.

Q. Have you previously testified before the Oil Con Conservation Division?

A. Yes, I have.

Q. At the time of that testimony, were your credentials as an expert witness in geology and earth science accepted and made a matter of record?

A. Yes, they were.

Q. What are your responsibilities day to day at the Vacuum Grayburg-San Andres Unit and the Central Vacuum Unit?

A. I provide earth science support to the team. We work in team environments. And I also provide informal leadership and project management services to the team.

Q. Are you familiar with the applications filed in each of these cases?

A. Yes, I am.

Q. And have you prepared exhibits or slides for presentation here today?

A. Yes.

MR. CARR: We tender Mr. Ingram as an expert in geology and earth science.

HEARING EXAMINER: His credentials are accepted.

Q. Mr. Ingram, would you refer to Slide 2 and review for the Examiners what it is that Chevron seeks in these cases?

A. Yes. As Bill kind of went over in his summary, there are three parts to our hearing application. And they're summarized here and you'll see that the number references again throughout the presentation, the 1, 2 and 3, are identified in three specific parts.

First of which is the injection well completion requirements, and the reason that we're here today is that we have nine wells, nine injectors that were approved by the District with these remediated tubing cemented in place that we subsequently learned don't comply with current injection orders, that the casing tubing annulus can no longer be monitored.

The second item is that the ~~injunction~~ injection packer setting requirements, we want those to be modified. The reason being, we desire the ability to set the injection packer higher than within 100 foot of the top perf but still within the unitized interval.

And then the last number item is that we want to amend the verbiage around the maximum C02 injection pressure. The reason for this is as Bill indicated, we desire to be able to reference the maximum bottomhole ~~injunction~~ injection pressure rather than the maximum surface injection pressure in order to respond to the reduced injection fluid density so that we can essentially have the same bottomhole injection pressure.

Q. Let's go to Slide 3, and would you review the current well completion requirements in the orders that approved each of these EOR projects?

A. Yes, I will. I can't read that from here, but what you see in front of you are the actual text from the injection ~~orders.~~ order. On the top of Slide 3 is the text from the ~~simple~~ Central Vacuum Unit injection order. On the bottom of Slide 3 is the Vacuum Grayburg-San Andres Unit injection orders.

And then the numbers you see beside those, the

1, 2 and 3, are the portions of those orders that deal specifically with the three issues that we're bringing before you today.

The first part is that where it says, "The casing tubing annulus shall be filled with an inner fluid and a gauge ~~where~~ or approved leak detection device shall be attached to the annulus in order to determine leakage."

The second portion is the part that deals with the injection packer placement. And it says, "A packer set within approximately 100 foot of the uppermost injection perforations or casing ~~shoot~~ shoe."

And then the last portion deals with the C02 injection pressure, and the verbiage states that the C02 produced gases at a maximum surface injection pressure of 350 psi above the current maximum surface injection pressure for water, provided, however, such C02 injection shall not occurred at a surface injection pressure in excess of 1850 PSI." That's the verbiage in the current order.

Q. Mr. Ingram, let's address first Issue No. 1, Injection wells with the tubing cemented in the casing. And I'd ask you to go to Slide 3, and by using this slide, basically review for the Examiners how you got to this point and why we're here?

A. Okay. Again, this is the first item in our application. Again, we repeat it at the top of this slide the verbiage from the injection order that states the casing tubing annulus shall be filled with an ~~inner~~ inert fluid.

HEARING EXAMINER: Okay, now your on Slide 4?

THE WITNESS: Yes. It's actually Slide 4.

MR. CARR: I'm sorry, that's right. I just can't read. Slide 4.

A. So this text is from the actual injection order, and this issue around these injectors -- and there's nine of them, this began -- or surfaced in late May of this year with the Vacuum Grayburg-San Andres Unit No. 47.

The actual first well that was remediated this way was Central Vacuum Unit 58 that was done in 2003 after there were seven unsuccessful squeeze attempts made on that wellbore.

The Chevron Operations supervisor at the time and the OCD Hobbs District supervisor at the time met and developed the remedial plan that was subsequently put into place on that well and each of these other nine wells, which was to cement the tubing in place.

We submitted an intent, and that was approved. The work was done, and then all the subsequent C-103s were approved for each of the other nine wells up until the VGSAU 47. In fact, it's first C-103 approved and then we noticed that there had been some detail omitted from that so we filed a second C-103 covering that activity, and that C-103 was subsequently denied.

Then in July of this year, the Santa Fe office for the OCD contacted me personally and conveyed that the OCD District offices didn't have the authority to grant a variation that violates the OCD order.

Then all of our subsequent research, we found that there were a total of nine New Mexico Chevron operated injectors completed this way, all of which are at vacuum following the Central Vacuum Unit 58.

Q. In your meeting with the Santa Fe office, you were required to shut in the Vacuum Grayburg-San Andres Unit No. 47, but allowed to continue to use the other wells pending this hearing?

A. Yes, that's correct.

Q. All right. Let's go to the next slide which I believe is 5, and I'd ask to you identify that and review it.

A. Okay. This is a plat of the vacuum field area. Vacuum, if you don't know is, located approximately 25 miles northwest of the city of Hobbs. And the colors on the projection here don't come out real well, but this green outline that's in the northeast quarter of the display, that's the Central Vacuum Unit.

The red outline to the southwest is the Vacuum

Grayburg-San Andres Unit boundary. The round circles that you see -- and there should be nine of those total, those are the nine wells that are the subject of this hearing, five of which are inside this what looks up here as gray, but I think on the handouts there's a pink shaded area.

The pink shade represents our current C02 phases, our areas of the two units that are currently under enhanced oil recovery. So there are five in there and we have planned expansions to the north and south that will also bring in those next two closest injectors into C02 or enhanced oil recovery projects in the future.

So there are a total of seven that are involved or will be involved in the C02 process, and those are the ones most important to our reserve recovery. And then it again shows the location of the VGSAU 47, the one that is currently shut in.

Q. When were these units approved and pressure maintenance operations authorized?

A. The Central Vacuum Unit was initially established in 1977. Pressure maintenance was approved in 1978, and then enhanced oil recovery was approved in 1997.

And then for the Vacuum Grayburg-San Andres Unit, it was unitized in '72. Pressure maintenance began later in '72. And then we were initially approved for enhanced oil recovery in 2001, we did not implement that project in time, and that authority expired. We reapplied and received approval for enhanced oil recovery in 2007 and actually initiated C02 flooding in the Vacuum Grayburg-San Andres Unit in 2008.

Q. And when did Chevron assume operation of these units?

A. Chevron assumed operation in the fall of 2001 through a merger with Texaco.

Q. Let's go to Slide No. 6, the timeline. Would you explain what this shows?

A. Yes. This is a time line that shows each of the nine wells that are the subject of this hearing. They are shown here on the left. And they are shown sequentially.

The red blocks are the period in which we established a downhole problem, either an MIT failure or some other evidence that we had a downhole problem.

Then the blocks that are shaded in blue are where we conferred and sought out an intent approval from the OCD to remediate the wells, and then the green blocks show when the wells were remediated, subsequent C-103s approved, and them the wells returned to injection.

So it essentially shows kind of a sequential work. The first four, if you notice, were done in a relatively short time frame. Then there was a span of about a year and a half before we have need to utilize this remedial method again on a subsequent well, and then the last five wells were done between 2005 and 2008.

Q. Since receiving a letter from the OCD concerning this matter and advising Chevron that the District could not approve changes that were inconsistent with the Commission or Division orders, what has Chevron done?

A. Well, we filed application for this hearing. We ran blanking plug tests on each of these nine wells. We also first researched and found that there were a total of nine wells that had been completed this way.

We ran blanking plug MIT tests on each of those nine wells, and each of them passed, which confirmed that today, the tubing is still sound and we have mechanical integrity within the wellbore.

I lost track of my notes, but it seemed like there was another item or two that we did.

Q. Did we attempt to identify wells or packers where --

A. Yes, we did. Thank you. We recognized that since Mr. Jones with the Santa Fe office had told me that the district offices didn't have the authority to approve anything that violated the order, that the longstanding practice of when an injection packer needed to be set higher than 100 foot above the top perf, the practice of contacting the district office and getting either written or verbal approval to do so, was also in violation of the written order. So it's something that needed to be amended by amending the field rules -- or the --

Q. Did Chevron meet with the Oil Conservation Division in Santa Fe?

A. Yes, we did. Actually, each of the four of us came and met with the Santa Fe office here just a few weeks ago and presented a proposal for continued use of these nine wellbores that we feel will very adequately continue to protect the ground water resource and allow us to continue to use these wellbores.

Q. And certain concerns were expressed by the Division at that meeting, were they not?

A. Yes.

Q. And in the testimony today, we addressed those things?

A. Yes, we did.

Q. Let's go to what has been marked Slide 7.

A. Okay, the other witnesses will go into much greater detail as to -- Well, I'm a slide ahead of myself.

This slide summarizes the situation as it is right now, that because of the small size of the tubing string cemented into place in these wells, seven of the wells are 2 7/8 inch tubing, and then in two, it's 2 3/8.

We really don't have any viable remedial options. Anything that you might try would be extremely costly, would put the tubing that's cemented in place at risk of no longer being viable.

By that I mean, one medial option, pretty much the only one would be to go in and mill out this fiber lined tubing and set a cap string inside. And in that milling operation, you're very likely going to violate the wall thickness of the tubing and then have, once again, a lack of mechanical integrity.

And any of those scenarios would require then injecting down a smaller string which would further reduce your injectivity and reduce the value of the wellbore. So none of those are viable options.

The consequences of losing all of these nine wellbores are that we would lose approximately 485 barrels of production currently, and over the life of those portions of the patterns, we would lose 2.2 million barrels, including reserves. And that represents about $19 million in state revenue based on an oil price of $70 a barrel.

To redrill all of those nine wells would cost, based on today's drill costs, approximately $15 million, and that number may actually be a little conservative in that some of our recent wells exceeded that $1.5 million per well to drill.

And that only represents the capital costs to drill the wells, it does not represent the ongoing operational costs, the cost of the C02 to recycle through them.

So when you lump on that kind of a cost to a project where you've got very mature patterns, you really further erode the economics. And with the current economic restraints that we have with our budgetary and capital restraints that we have in -- I really feel like most of these wells would not likely be replaced.

And I need to explain that we are part of Chevron Corporation, and our role within that corporation for the large part is to provide cash to fund other opportunities.

We do receive capital to maintain our production, but we have to compete with all of these other opportunities. And if we can't -- if the opportunities that we have can return a profit, albeit a small one, if it's not as big as a profit that's available elsewhere, we can't get the capital.

And so that's why I'm very comfortable in making that statement, that most of these wells could not be economically replaced.

Q. Have you been able to estimate the costs incurred to date just to go out and cement the tubing in the casing?

A. Yes. Through the operations that we followed on these nine wells of cementing the tubing in place, I personally went back through the well files and reviewed those projects, and the total was over a million dollars on these nine wells in remediating these wells in a fashion that was endorsed by the district office.

Q. Let's go to Slide 8. And can I ask you at this point to just summarize what Chevron's recommendation is going to be, keeping in mind that other witnesses will provide the detail.

A. Right, the detail will follow. Our proposal is that we will test these wells, improve the mechanical integrity at five times the currently required OCD frequency via an annual blanking plug test, and that we will monitor for changes in the injection rate versus injection pressure on a daily basis with our SCADA system.

SCADA stands for supervisory control and data acquisition, and it will be explained more in just a minute.

And by doing that, we'll be able to generate alarms that will prompt human response and evaluation ~~evacuation~~. Valid alarms will require the well to be shut in and the wells would not be able to resume injection until an MIT had been reconfirmed -- or confirmed.

And we did further research and confirmed that this proposal, this proposed approach fully complies with Federal UIC regulations. And in fact, it's an approved method that's being used in the other jurisdictions.

Q. Let's go to the next slide.

A. This a copy of the EPA regulations dealing with mechanical integrity. And under Item 1468B, you see that it states, "One of the following methods must be used to evaluate the absence of significant leaks in Paragraph (a)(1) of this section."

And then the subsection labeled No. 1, there is the section that the State of New Mexico has opted to follow all these years, which is that you confirm mechanical integrity by performing an initial pressure test, and then monitoring the tubing casing annulus pressure with sufficient frequency. That's what is normal in New Mexico.

But what the Federal UIC regulations also alternatively allow is that you either, two, pressure with liquid or gas, which is this proposed blanking plug testing that we're -- you'll hear more about in just a minute, and that also, the UIC regulations give you the option of doing 1, 2, or 3.

Three being that you -- records of monitoring showing the absence of significant changes in the relationship between injection pressure and injection flow rate for the following Class 2 enhanced recovery wells.

And that's the SCADA system that we're proposing. So our proposal actually incorporates not just one of these three, but two of these three.

Q. Mr. Ingram, I will Chevron call additional witnesses to review the operational and technical portions of the case?

A. Yes, it will.

Q. Were Slides 1 through 9 of Exhibit 1 prepared by you?

A. Yes.

MR. CARR: May it please the Examiners, at this time I would move the admission into evidence of Chevron's Slides 1 through 9.

HEARING EXAMINER: Chevron Slides 1 through 9 are admitted.

MR. CARR: That concludes my direct examination of Mr. Ingram.

HEARING EXAMINER: Mr. Warnell?

MR. WARNELL: I think it was Mr. Kellahin this morning that said something about the devil is in the details?

THE WITNESS: Well, I have angels following me.

MR. WARNELL: Angels? Okay. I was glad to see that you addressed the UIC regulations and concerns. I think that was a big concern upstairs. I don't have any other questions.

HEARING EXAMINER: Is there any H2S in this gas stream?

THE WITNESS: Yes.

HEARING EXAMINER: And what are the concentrations?

THE WITNESS: We've got a gas analysis that comes up here shortly. I think it's on the order of 2 percent.

HEARING EXAMINER: Okay, so another witness will be covering that?

THE WITNESS: Yes, sir.

HEARING EXAMINER: Okay. Thank you. I have nothing further.

MR. CARR: May it please the Examiners, at this time I will call Tejay Simpson.

TEJAY SIMPSON,

the witness herein, after first being duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. CARR:

Q. Would you state your name for the record, please?

A. Tejay Simpson.

Q. Would you spell your first name?

A. My first name is spelled T-e-j-a-y.

Q. Mr. Simpson, by whom are you employed?

A. I'm employed by Chevron.

Q. And what is your current position with Chevron?

A. I'm the operations supervisor for our field management team that can include the Central Vacuum Unit and the Vacuum Grayburg Unit.

Q. Have you previously testified before the Oil Conservation Division?

A. I have not.

Q. Would you review your work experience for the Examiners?

A. Certainly. I'm completing my 30th year of experience in oil and gas operation. The last two years of that have been in a first-level supervisory position of oil and gas operations, from primary production to secondary and tertiary, and gas plant operations. The last six years have been primary with C02 operations.

Q. And your area of responsibility does include the area in which we find these two units?

A. Yes. The field management team that I manage includes a number of properties scattered throughout the county, but two primary properties are the Central Vacuum

Unit and the Vacuum Grayburg.

Q. What are your day-to-day responsibilities for the operation of these units?

A. Just general oversight and direction to the workforce, both Chevron and contract workforce in the execution of the daily activities.

My primary responsibility in that is, Chevron has a philosophy of operation excellence that truly governs the way we do our business. And that addresses how we address safety to our people, the protection of the environment, and efficient operation of the resources that we have.

Q. Are you familiar with the applications filed in these consolidated cases?

A. Yes, I am.

Q. And have you prepared exhibits for presentation here today?

A. Yes I have.

MR. CARR: May it please the Examiners, we tender Mr. Simpson as a practical oilman and as the operations supervisor of these units.

HEARING EXAMINER: His credentials are accepted.

Q. Could we go to Slides 10 and 11, and I would ask you to provide the Examiners with a current operational overview of these units.

A. With the Chevron operation, we are the evolution of many mergers and acquisitions. And like many properties in southeast New Mexico, we have aging an infrastructure. We have had various construction and maintenance practices through the different companies and different time periods, clearly different types of construction and the way things are taken care of.

And we clearly, as alluded to with the H2S question, we handle other fluids and gases. The three of these combined have undoubtedly resulted in historical episode issues. He have issues out there that we continue to work.

And part of Chevron's focus on operation excellence is clearly to address that as we do business in the future, that we become world class not only in the protection of people, but in the environment as well.

And so it's a big challenge. And we have specifically in our FNT, is we handle significant amounts of fluid and equipment. We produce about a hundred thousand barrels of day of fluid with about 90 percent of that being produced water, and about 75,000 MCF a day of gases with about 55,000 of that being C02 contaminated gases.

We have three phases of operation: Production, and then separation and processing facilities, and then sales and reinjection.

So in the course of the day, we're handling 300,000 barrels of fluid and 225,000 MCF a day of gas. So our exposure to events is significant.

Chevron -- you know, the thing that's unique -- what I find unique with them is, I was a -- one of the legacy companies is where I have come from, is anything I've seen with Chevron is -- in their drive. And it's actually referred to as an execution of focus in force to become world class in our spill prevention.

So when you look at the combination of the challenges of the equipment that we have and that we operate, it takes a very systematic approach to start addressing each of these challenges that we have so that we can reduce the likelihood of us having continued spills and contamination of the environment.

The first of our rules establishing clear standards is in how we build facilities and installations. So as facilities are built in the future, there is a very clear standard as to how they'll be built for their specific purpose of ensuring reliability and that they are mechanically sound and don't -- and it's very unlikely that we have continued spills in the future.

With the many different properties, we have facility construction, consolidation efforts that are going on, and the leak construction. The big focus in that regard is to minimize our footprint and minimize our exposure.

We operate the facility with 20 tanks, including vessels of operation, all of which create risk. We consolidate those facilities so that we significantly reduce the number of pieces of equipment that we have to operate and maintain, and therefore have at risk.

The next level of approach is in flowline inspection and testing programs. We actually have initiatives now that -- we just completed our third year of performing mechanical integrity tests through hydro testing of all surface-installed flow monitors that we have in our property for the purpose of reducing the likelihood of failures during operation. And it's been a very successful program.

And then the SCADA deployment and the leak detection development that has been in various forms since the late 1980s, we have been limited in how we used that. And what you'll see more of today is how we're taking that to a new level of use, specifically around spill prevention and early detection.

And a very specific focus on it in 2010 is trunk line evaluation where we're evaluating our trunk lines that exist, including testing and inspection of these trunk lines.

So our main components of operation and the main driver force is focused on prevention. And then you'll see as we go forward, to operate SCADA more effectively to supplement that prevention effort with early detection.

Very specific to the Central Vacuum Unit and the Vacuum Grayburg, it is a combination of secondary and tertiary floods. We have wells of up to 70 years in age. Presently, we operate approximately 140 injection wells with 57 of those being in C02 service.

Q. Those are just in the Central Vacuum Unit and Vacuum Grayburg-San Andres Unit?

A. That's correct. And as mentioned earlier, SCADA was deployed in the late 1980s, but the primary purpose of SCADA up until recent years has been on data acquisition, limited control, and a little bit of alarm notification.

As far as the current injection wells, the way we currently assess mechanical integrity, we monitor the annular pressure monthly, and then we conduct annual OCD witnessed Braidenhead inspections, and then five year OCD witnessed pressure mechanical integrity tests.

Those five year tests are ~~disbursed~~ dispersed DB and they are conducted on a rotational basis at the same time as the Braidenhead inspections with our bleach well, and then once every five years.

Q. Let's go to Slide 12, and I'd ask you to just identify it for the Examiners and explain what you have there.

A. This table is for your information. It is the nine wells that are in question with the tubing that's cemented in hole, a list of well numbers, and where these wells are located; a brief summary of the surface casing size and the depth, the pressure casing size and the depth that it's set, and then the tubing strings that are installed.

And each of these tubing strings have a fiberglass liner inside of the tubing. There may be two that have a dual line system, which is a PCV system, through all of that.

And then this shows the dates they were installed, and were there packers at the time they were installed -- and there were, and additionally, profile nipples present, which enabled us to do mechanical integrity tests.

The last column is -- you know, after we discovered we were in noncompliance, we wanted to ensure that we had mechanical integrity, and we did conduct tests in October.

These were nonbinding, nonofficial tests, these were informational only. And then the outcome of the tests. We were able to get successful tests on all nine wells. We'll go into more detail on that testing.

Q. In the last column, we show the pressure to which the wells were tested?

A. Correct.

Q. Some were at 2,500, some were at 2,000 pounds. Why did you reduce the pressure?

A. I'll go into fairly significant detail on the testing procedures that we used. But we hadn't done this approach. And part of our process here was to develop a procedure that we could execute repeatedly and efficiently.

And we started the first few wells -- our well procedure on what we would execute, we did the first few wells at 2,500 psi, because that was the test pressure that they were done when they were originally cemented in place.

As we started doing the testing -- And it's very clear that hydro testing, by its very nature, has the potential to be a destructive test. And since we were significantly above the normal operating injection pressures, we saw that we could lower the pressure in which we tested, still have sufficient differential as compared to what the reservoir pressure injection was, and be able to identify a leak, yet not exaggerate the risk that we had in performing the test on the well.

Q. One of these, in fact, was tested only to 1,715 psi?

A. Yeah, and that's -- You'll see later that, quite frankly, it was a procedure that was not followed. And I don't have an answer for why that happened, it did. You'll see later that we have a very specific procedure --

Q. Mr. Simpson, even that well was tested at pressures above normal operating injection pressure?

A. Yes. The No. 71 is the well in question. And it -- we had to do something mechanically at surface to achieve the test. And we put the well on water injection for a few days and actually had it shut in for, I think, three or four days prior to doing the test. And so we had sufficient differential against the reservoir even to 1,750.

Q. Let's go to Slide 14, and I'd ask you to explain how the mechanical integrity testing was conducted on these wells. First we'll go to 13 which is the schematic?

A. Sure. And this is just intended to be a very simple schematic to show the differences between the conventional setup on our wells that does have the annular areas still intact versus the wells that have the cement as is now in that annular area.

On the left is a conventional well. And the kind of bluish area represents the annular space between the injection tubing and the production casing, and it's filled with inner packer fluid to reduce the corrosion inside there, and also to help us immediately transfer the pressure to surface monitoring equipment in the event that we lose integrity of either our tubing or our packer or develop a casing leak.

The clear advantages of this situation is that we have easy access to monitor the annulus so that we can identify if there has been a condition change that puts the aquifer at risk. The other real clear benefit is it's easy to execute remedial work. The packer can be removed and remedial work can be done. It's fairly simple to do that.

With the -- now shown on the right where we do -- we have replaced the packer fluid with cement that we eventually lost the ability to monitor that annular space that no longer exists.

What we have realized is -- some unintended benefits of the second scenario is, in a conventional method, when you look at the reference between where the fresh water and aquifer is, in our area, the top of the aquifer is approximately 100 feet from surface, in places, maybe as deep as 225 feet from the surface. And our production interval is -- essentially we're -- mid perf is approximately 4,500 feet. So we have a, you know, a significant distance vertically from our production interval to the aquifer.

At any time in a conventional configuration that we developed a tubing leak or a packer leak or a casing leak, the pressure of that failure immediately transfers vertically over the entire interval of the annular area.

So we have the pressure of that event and that potential contamination immediately adjacent to the vertical depth of the aquifer.

A second issue that we've seen is in the tubulars that we're using today, the fiberglass lined tubings. One potential failure point that we see is in the thread and couple connection. There's a seal in there that has a tendency over time that it can break down.

And we think a contributing factor to that is the cyclic loading of the fluids with varying pressures, temperatures, density of fluids, and then just the sheer frictional effect of fluid running in the tubing. And this cycling impacts on the tubing and has vibrational effects on there, and we believe that's a contributor. And that's clearly not intended.

But what we recognized is that with the second scenario with the tubing cemented in the hole, we significantly reduced the likelihood of vertical vibration in the event that we have a leak down lower in the tubing string, there's not an open conduit for that pressure to go up to the aquifer, it has to -- it gets forced back to the cement barriers in the 4,500 feet of the opt that we drilled for.

The second is that we've introduced stability to that injection string to reduce the impact of the cyclic loading and the vibration effect on that, and we expect it to result in increased life in our fluid production.

Q. Now let's go to Slide 14 and I'd ask you to explain how mechanical integrity testing was conducted on these.

A. Again, when we became aware that we were out of compliance, it was critical that we put together a procedure to test these wells at a frequency that would be meaningful to ourselves and to the Commission that we could show mechanical integrity and try to come up with a way that we could execute this efficiently, both for our time and for the Commissions time, and obviously for the expense associated with that.

And so this is a procedure that we started with. We got the pump truck initially, and we flushed our tubing with fresh water, understanding that this is a potentially destructive test, and so if we caused a failure during the test, we want to ensure that we have fresh water present in the tubing at the time of the test.

We have a slip-on unit and we run in hole with a gauge ring, which is a tool that enables us to ensure that there is no restrictions in our tubing all the way down to the point of where our profile nipple is set.

Once we accomplish that and we feel we have no obstructions, we run in hole with a blanking plug. And the blanking plug mechanically engages into the profile nipple and it performs a mechanical seal essentially closing off the bottom of the tubing.

And the way you test to verify that those plugs are set and there's no leaking, is open those up to atmosphere, and the pressure on the tubing would bleed off if the blanking plug is set and the seal is intact. All of the wells bled off as they should have.

After we had set, we did perform hydro testing with the tubing, initially at 2,500 psi. We reduced the target after the first few to 2,000 psi at surface as -- you know, for the reason discussed previously, we ran a chart on these wells for documentation, retrieved our blanking plug, and then returned the well to operation.

On the initial test, we did have Max Brown with the district office come out, and he was able to witness the procedure that we were going to use. Because of other obligations, he wasn't able to stay for the entire test, but he did witness the procedure that we intended to use and approved that procedure.

Again, these were nonbinding, unofficial tests, information only, and because of the sensitive nature, we felt it was important to have them both. The last well that we did test was witnessed for the completion of the job.

Now, we clearly learned some issues in this attempt. We were not successful in acquiring a good test on each well on the first attempt. And the things we learned doing this is, C02 in the tubing was a real factor for us. And our flushing the well with fresh water wasn't sufficient on its own to eliminate the C02.

And the characteristics of C02 is, as the C02 increases in temperature, it has a tendency to expand, and it attracts an environment that manifests itself as increasing pressure. If the temperature decreases, then it contracts and manifests itself and attracts environments that decrease in pressure which would also give the appearance of a leak on a hydro test.

We also, as you'll see in some photographs later, we have check valves at the wells. There are local isolation valves at the well, and if our check valve leaked, then it would give the appearance of a reduction pressure agreement test, and can give the appearance of a failed test as well.

And then, just the sheer potential risk associated with running tools in and out of a well, plus the destructive nature -- potential destructive nature of hydro testing, so those are the things that we have learned during an initial test, and we actually had to make some charges in procedures.

Q. Before we go to this slide, Mr. Simpson, you did experience certain problems while you were running the initial blanking plug MIT test?

A. Right.

Q. When you experienced these problems, you then had to go and retest the well?

A. That is correct.

Q. And when you experienced problems, were these problems with the wellbores or were they with the surface equipment?

A. In every case, they were not wellbore issues, they were either failure to effectively sweep the C02 out of the tubing, or they were mechanical failures at surface that allowed the pressure to bleed off back into the surface equipment.

Q. Okay. Let's go now to Slide 15, and would you review the lessons you learned?

A. Sure. These were the very specific lessons that we did learn, and they are instrumental in shaping our new procedure that we're proposing, learning that going forward, wells that are on C02 injection will need to be wagged to water for several days prior to testing. This will enable us to sweep that C02 out of the tubing effectively and not have any interference on test.

The testing with fresh water definitely is needed to be done. It needs to be understood that with -- you know, using fresh water is to minimize exposure to the environment.

And to make sure we understand it when it comes into play, there is a gradient difference of the fresh water versus the produced water, and so that needs to be taken into account on targeted test pressures somewhat.

All nine of these wells, depending on the approval of our request, all nine of these wells will be rebuilt -- wellheads will be rebuilt and configured so that we have isolation wells at the well site, we have figure eight lines, and isolation valves.

What this will allow us to do is to eliminate the possibility of a leaking check valve during the test and -- which we did identify on two of the wells.

And again, our overall purpose in coming up with a very detailed procedure, is so that we can be efficient in our execution of this process and do what we can to have certainty that during our first attempt each time, that we can be successful.

Other key factors is making -- if we can schedule and execute all of these tests at the same time, then we can -- it helps us be efficient in the utilization of the service company personnel at the scene of the pond and our onsite supervision, and would prevent scenarios where a well didn't get tested to the target pressure as a result of different people being involved in the supervision.

And clearly, if we can use the same service company personnel with each test, likelihood of repeatability is greatly improved.

Q. All right. Mr. Simpson, let's go to Slide 16. This is what Chevron is recommending as the test procedure to be conducted annually on each of these wells; is that right?

A. That is correct.

Q. Would you review that?

A. Yes. This procedure is fairly specifically detailed, but it became very obvious that we needed to be very specific in detail to ensure that it would be followed and executed properly each time. As well, we need to ensure that the well has been on water injection for a minimum of five days prior to the test date.

We'll document the well operation injection pressure prior to the initiation of the test, and this will be critical in helping us determine the test pressure. Closing our isolation valves and position figure eight blinds in a closed position which will eliminate any possibility of leaks back to surface equipment.

We'll rig up our slip-on unit, then run the hole with the appropriate sized gauge ring and bailer. And this is a piece we made in a -- you know, in our efforts to be efficient in our work, any time we run tools in the hole on the well, if there is additional information that we can gain, we're going to try to do that.

So this particular item of the bailer and grabbing samples is an operational issue for us to learn about fuel accumulation in our wells that we can plan medial work in the future with full tubing, not specifically around the accomplishment of this test, but using the opportunity for multiple purposes.

We'll rig up our pump truck and flush the tubing with fresh water at 150 percent displacement, and that will help us to get the produced water out of the tubing prior to the test.

Run in hole with a blanking plug and set in the profile nipple and conduct that test as previously explained. Perform a pressure test of tubing and a profile nipple seal to appropriate pressure based on differential pressure and gradient correction.

So the proposal is, instead of an arbitrary pressure of 2,500 of PSI, or 2,000 of psi, or pick your number, actually focusing on differential pressure from normal operating conditions, one that is still sufficient to be very visible if we have any bleedoff, even if it is bleedoff into our reservoir, and that will enable us to recognize the leak, but use the minimum pressure that we could to conduct the test while still proving there's no leak.

And because they would be flushing the tubing with fresh water, which is a different gradient than the produced wear, that would need to be taken into account as well.

And so just roughly, if we had a 300 psi differential target, then we would need to add typically about 90 to 100 psi for the differential of the two gradients, and so we would test at approximately 400 psi above the oil injection pressure that we found when we arrived at the location.

Unless we conducted the test, obviously we want to have very standard on how we gather the data and report it just -- even to the point that we're going to default, we're going to use a 24 hour chart, the 96 minute clock, and it's just a detail that enables every -- every mark that's on that chart represents one minute then, and so it's very easy to read and interpret that chart.

And obviously, if the OCD inspector wants something different than that, then we'll adjust from there, but not given any direction, our default will be that.

We'll retrieve our blanking plug and return the figure eight blind to the open position and return the well to operation, assuming that it did pass the test.

Q. All right. Let's go to the photograph, Slides 17 and 18. What do they show?

A. I'm going to shift from our actual mechanical integrity testing that was performed on the wells to how we are using SCADA in our future.

As I mentioned earlier, Chevron has an operational excellence focus, and one of those goals is world class performance in spill prevention, and that's in the range of single digits, low single digits on barrels spilled per million barrels produced.

And so in that effort -- you know, much of what I described earlier -- what I described is around prevention, preventing events from happening.

We have this year alone in the field management team that I'm responsible for, has spent $1.6 million on inspection and installing new liners in our tanks on the properties that we operate.

We have flowline inspection testing projects, we have reliability projects on our mechanical equipment, all of those are really centered around reliability and prevention of events.

And historically, we have not used our SCADA for that purpose of spill prevention or detection. And one of the ways we can achieve world class performance is, when we're not successful in preventing a failure from occurring, the earlier we can detect it, then the more timely we convene our response, and therefore, the smaller the impact to the environment.

And with all leaks, we presently depend upon human interface. We put a man in a truck and drive around the lease looking at the operation of the equipment and looking for evidence of leaks.

In some places we use aerial -- you know, airplanes to fly over and look for evidence of leaks. And so as we're going forward, we'll continue to use those mechanisms, but with a major dependence on SCADA to accomplish that.

And regardless of the mechanisms that we used, whether it's -- you know, humans in a truck, airplanes, or even in SCADA, the larger the leak, the more likely it is we're going to find it in a short amount of time. The probabilities just simply go up because our senses are more attuned to the things that are there.

And unfortunately, one of the things that we've learned specifically on the injection wells where we have large differential pressures, we're injecting frequently from 1,500 psi to 1,800 psi, and on our surface equipment, obviously they -- you know, we're at atmospheric pressure on the outside, so we have a large differential across those, so when a leak develops, the nature of that high differential across that barrier results in a significant erosion effect and small leaks don't stay small very long. And so the likelihood of us being able to find them increases significantly.

So all of that is going back around to what you see before you here is -- probably 18 months ago, it was clearly understood that we needed to improve our ability to detect leaks. Relying solely on people to drive by and physically look wasn't good enough to take us to world class performance in spill prevention.

And so, the use of SCADA, we started deploying these systems, and so this is one that exists at the Vacuum Grayburg. I think this is Well No. 37. That's not particular important. And this is an indication of what we're presently putting on our equipment.

And through these efforts and understanding this, we understand there may be an opportunity to apply the same technology to subsurface leak identification as well.

So on a typical well installation on the far right-hand side, there is a separate transmitter that's monitoring the pressure on the tubing.

On the bottom left-hand corner is a conventional well that still has the annular area available. There is a pressure transmitter that is mounted on the brushing casing valve.

And the in upper left-hand corner at that well location is simply solar powered equipment with a small -- essentially a small computer that is there purely for the purpose of leak detection to communicate deviations in those pressures back to the hose that then can process the data.

Q. All right. Let's go to the next slide.

A. Now, at the other end, our facility is built in a hub-and-spoke configuration to release our produced water and our C02 to a central point, which we call an injection header.

And we, through our computer equipment at that site, we send the fluid out to the individual wells and we can monitor the rate at which we send the fluid out and the pressure that it leaves and use the computer to operate the mechanical chokes to regulate those target rates and target pressures.

Now, as mentioned earlier, we've had equipment in place since the late 1980s, and this picture we have here is our newest generation equipment that's there and it has the ability to communicate within itself multiple times a second and back to our host SCADA servers every one to two minutes. And our older systems communicate back to our host servers in the range of every seven to ten minutes.

So you can see as we deploy this -- I'm sorry, Koby Carlson is our expert on this, and he'll go into much more detail on the logic and the theory and technical aspects of how this works.

But think about the concept of being able to monitor that equipment in minutes versus the times of day a guy drives by there, more than once a month he's checking the pressure manually, and we have a significant improvement, in my view, to identify deviations that occur.

Q. All right. Let's go to the next slide, Surveillance, Monitoring, and then Initial Response.

A. So obviously, as we deploy the system, we are going to have to change the routine duties of our field inspectors, the guys that are taking care of these wells, to ensure that we provide the data, that that data gets looked at timely, and corrective actions are deployed timely.

This slide is just showing a summary of how we will -- expectations that we'll have in place for our field inspectors that will help us to ensure that we can identify the problems, if they occur, and then the actions that will be taken.

So every day on these nine wells in question, every day the field specialists will be required as part of their routine job duties to visibly go look at the trends, the rate and pressure tends on each of these nine wells looking for deviations that occur from the norm.

Second to that, as part of the reports that get printed out each day will be included the injection wells, we show what state they are in, whether they're in normal condition or if they're in alarm condition based off of exceeding some pretty common triggers that are there.

And then third is a call-out alarm systems. So if we have a deviation trigger that's being exceeded for a term and time period not to exceed 24 hours, then it will do a -- we have a radio and cell phone call-out system that it will notify somebody that they need to go take a look at the equipment.

So it's great to have all of that, but if we don't have a response system in place when this occurs, we have the potential to have a breakdown. So the next part is the response system that we would have in place.

So if the field specialist identifies deviations in those trends, he'll be expected to review that trend with the operations supervisor or our production team lead the same day that that deviation is identified. Also, he'll be expected to conduct an on-site investigation to verify the integrity of our measuring equipment.

We have different levels of responses in Chevron and these will be at our highest level of response. He will also be expected to conduct an on-site investigation to identify if a surface leak may exist.

So in this scenario, whether the leak is a surface leak or it's a subsurface leak, the profile is going to look identical. And so we need to ensure that we don't have a surface leak that's occurred.

If they've done those things and they're still concerned, the well will be shut in, and notifications made to the operations supervisor. If that's suspected, an operations supervisor will at that time provide notification to the OCD district office of a possible loss of mechanical integrity, and then we will put into action the testing of the tubing with a predetermined program that's in place.

Q. Mr. Simpson, at the meeting with the Oil Conservation Division several weeks ago, Mr. Fesmire expressed some concern about how these wells could ultimately be plugged and abandoned; have you look into that issue?

A. Yes, we did. And again, with Chevron's approach of operational excellence, commingling wells is not what we do on a day in and day out basis.

HEARING EXAMINER: Let me interrupt at this point. I want to take a luncheon recess and it looks like we're moving from one subject to another.

MR. CARR: Let me tell you that this takes about two minutes, and then we have concluded with Mr. Simpson.

HEARING EXAMINER: Okay, let's conclude with this witness.

A. So we have hired the services of a company that that's the one thing they do. So when this question came up, we contacted one of our contacts in Houston, who is a Chevron employee that manages our plugging operations through Sunset, and sent them wellbore schematics and asked them to prepare general procedures on how we would plug these.

So the next two slides go over the generic procedures for the 2 7/8s and the 2 3/8s tubing. Now, obviously, a very specific procedure will be put in place for an individual well and it will be sent to the OCD office for approval. But these represent that they have gotten an expert in this field to look at this and give us a proposal on how they would conduct a plugging operation in the event that we needed to do that.

Q. And if you need to do that, based on your work with your service company, do you believe that they could be plugged so they would not become a vehicle for the migration of fluids at the zone?

A. Yeah, I asked that question of Mr. Bledso, and I have to yield to his expertise that they are confident they could be successfully plugged.

Q. Could you just briefly summarize your testimony?

A. Sure. Clearly, it's my responsibility to manage the operations of our field on a day in, day out basis. Part of that is making sure that we have good dialogue and interaction with the OCD. And I think we've accomplished that. Not every day is that pleasant, but it's effective.

It is a requirement of Chevron operations that we are compliant with rules and regulation that are in place, and in this case we thought we were. Once we found out that we were not, we knew we needed to look into our options about how we could be in compliance.

I think the proposal that we have, with the combination of mechanical integrity tests with the blanking plugs. And as we go forward into the full use of SCADA, I feel very confident that we are going to be able to probably actually increase our ability to identify when we've lost integrity as compared to our present operations.

Q. Were Slides 10 through 21 in Chevron Exhibit 1 prepared by you, or have you reviewed them and can you testify to their accuracy?

A. Yes, I can.

MR. CARR: May it please the Examiners, at this time we would move the admission of Slides 10 through 21.

HEARING EXAMINER: Slides 10 through 21 will be admitted.

MR. CARR: Mr. Examiner, this would be an appropriate time to break for lunch. They may want to cross Mr. Simpson now or after lunch. The Chevron people are on a 2:45 flight out of Santa Fe, so we do have some time.

HEARING EXAMINER: Okay, yeah, you have a very confining schedule to make that flight. I believe they --

MR. CARR: It will be a company plane, so they just have to be there at 2:45.

HEARING EXAMINER: Very well. We'll stand in recess until 1:20.

(Note: A break was taken for lunch.)

HEARING EXAMINER: We're back on the record.

MR. CARR: Mr. Examiner, we had just completed our direct of Tejay Simpson.

HEARING EXAMINER: Right. Mr. Warnell, do you have any questions for Mr. Simpson?

MR. WARNELL: I did have. I'm not sure where everything went. I wanted to look Slide 13. Can we talk about what's in between that fresh water at the top and the pay zone?

THE WITNESS: There's two casings, there's surface casing, which is on average set around 375 feet or so, and it is circulated to provide the initial barrier, and then the production casing -- If I'm understanding your question correctly.

MR. WARNELL: No, I probably didn't state it very well. What I'm kind of curious about is what kind of formations -- I know that we've got the red beds in there, right?

THE WITNESS: Yes.

MR. WARNELL: And are there any other producing zones between what you say is the pay zone in green and the aquifer up on top near the surface? I think you said it was 225 feet.

THE WITNESS: I think Mr. Ingram would be better suited to answer that question.

MR. WARNELL: All right.

MR. INGRAM: Can I speak from here?

HEARING EXAMINER: Well, we probably need to put you formally on the stand. Do you have any other questions for Mr. Simpson?

MR. WARNELL: No, I don't. Go ahead, let's put that off until --

HEARING EXAMINER: Yeah, we can defer that. I have no questions for Mr. Simpson, so the witness may stand down and you may call your next witness.

MR. CARR: Mr. Examiner, would you prefer to have Mr. Ingram take the stand now just to respond to that question, or should we recall him after we finish the case?

MR. WARNELL: Why don't we just do it now?

HEARING EXAMINER: Okay, let's do it now.

MR. WARNELL: Okay. Mr. Ingram, thank you. I'm trying to get a better handle on -- just help me out here, what's in between those two?

MR. INGRAM: Okay, I think the second question that I heard raised, was there any other producing formation between the Ogallala and this pay zone. And the answer is a qualified no. The San Andres, which is our pay zone here, is the shallowest productive reservoir at this field.

There has been some very spotty Yates production. If I can go back to about Slide 5, there used to be two Yates producers in this vicinity. I do not believe they are active anymore.

So that's in Section 35, which is outside of our two units. And at this scale to the east about two or three miles, there are a group of five or six Yates producers -- again historically, Yates producers, I don't know if any of those are active now.

The Yates reservoir there, when it does produce, produces about a 40 to 45 percent nitrogen content. So it's a low BTU gas reservoir. And if it's productive here -- We have not yet tested it. We considered testing it for a fuel gas source. If it were productive here, that would be the only hydrocarbon bearing reservoir between our pay zone and the Ogallala.

Now, as far as the rest of the strata, the Ogallala, as Tejay testified, is from 100 to 225 feet, roughly. That's part of the Santa Rosa interval. That would continue down to roughly a thousand feet, and then there's an evaporite bed and then the Solato formation, which is from roughly 1,500 foot to about 2,700 foot, which is mainly a massive body of salt.

MR. WARNELL: That's the salt.

MR. INGRAM: And then beneath that, you go into the Tansalon hydrate, and then the Yates, Seven Rivers, Queen, and then the Grayburg. And then beneath that is the San Andres which is the main reservoir in these two units.

MR. WARNELL: Okay.

MR. INGRAM: So there are essentially 4,000 feet of the permeable strata between our reservoir and the Ogallala.

MR. WARNELL: But we do have a big salt zone in there that's -- you say is 1,500 to 2,700 --

MR. INGRAM: It's roughly from 1,500 to 2,700, yes, sir.

MR. WARNELL: Okay. That's all I have.

HEARING EXAMINER: Okay. The witness may stand down. You may call your next witness.

MR. CARR: May it please the, Examiners, at this time I call Mr. Koby Carlson.

KOBY CARLSON,

the witness herein, after first being duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. CARR:

Q. Would you state your name for the record, please?

A. Koby V. Carlson.

Q. And Mr. Carlson, where do you reside?

A. In Midland, Texas.

Q. By whom are you employed?

A. Chevron USA.

Q. And what is your current position with Chevron?

A. I am an I-Field automation analyst.

Q. And what is your area of expertise?

A. It's in instrumentation, control, and SCADA.

Q. Have you previously testified before the New Mexico Oil Conservation Division?

A. No, I have not.

Q. Would you review your education and work background for the Examiners?

A. I attended Albuquerque Technical Vocational institute, the electrician's program. Held a New Mexico journeyman's license for over 25 years.

I'm an International Society of Automation Certified Control System Technician. I've been involved with instrumentation and control over for 30 years, and I have more than 25 years SCADA experience.

In Chevron, I've held the positions of electrician, electronic instrumentation specialist, SCADA technologist, SCADA analyst, and now I-Field SCADA analyst, and that's been over the last 20 and a half years.

I also received a Chairman's Award. At Chevron, that's the highest personal recognition you can get for work in SCADA.

Q. Now, tell us about what you do.

A. I do automation.

Q. And what do you do for Chevron, you build systems; is that fair to say?

A. Yes.

Q. And what are they designed to do?

A. I build lots of different kinds of systems. Related to this case ~~care~~, I've actually designed systems and created technologies for leak detection.

Q. How did you become involved with this project?

A. I believe there's two reasons. My technical competence in this. Like I said, I've created the most advanced leak detections that we use in our business, and possibly the company.

I design hardware, meaning -- Tejay had mentioned earlier, we have these computers throughout the field. I design those from the microchip well. I write the computer codes to go in those microchips to enable those systems.

I do software development. I do advanced algorithm development, and in the case of surface leak detection, I've actually applied artificial intelligence to those processes.

And the second reason, I think, is probably my personal commitment is protecting people, the environment and the way we operate.

And I have a lot of latitude on what I work on at Chevron, and I choose to work on leak detection because it's important to me, and I spend hundreds of hours outside of my Chevron job developing technologies to make us more effective in this area.

Q. Are you familiar with the applications filed in these cases?

A. Yes, I am.

Q. And have you prepared exhibits for presentation today?

A. Yes, I have.

MR. CARR: May it please the, Examiners, I would tender Mr. Carlson as an expert automation analyst.

HEARING EXAMINER: Okay, his credentials are accepted.

Q. I think what would be helpful, Mr. Carlson, initially, to explain to The examiners what is the supervisory control and data acquisition system scan?

A. SCADA is a collection of sensors, computers, radios, networks, programs, algorithms, and the like, that allow us to collect information, control our facilities and our processes, and feed our information systems that are business systems.

Historically, like Tejay mentioned, it's been used a lot for control and data acquisition. So it's mostly used to bring information in from our wells to get it into our information system. So when Scott needs to go look at performance of a well, he has that information available to him.

But now we've started to move this technology to really achieve our goals for protecting the environment. We've been developing what I consider pretty advanced leak detection for a number of years, and I believe those leak detection technologies that we've developed at the surface can be applied downhole to do leak detection.

Q. Let's go to the slides you've prepared, and I'd ask you to go through these and explain to the Examiners what we're looking for and what SCADA shows you. And I think we should start with Slide 22 on the Vacuum Grayburg-San Andres 17 30 day grade pressure graph.

A. This is VGSAU 17. It's a 30 day rate and pressure graph before you. This information was gathered by our SCADA system. This information is a trend of values over time. So the oldest data on this graph is on the left side, and the newest data is on the right.

So one of our proposals is to monitor the relationship between rate and pressure in our wells to try to determine if we have leaks downhole. I purposely chose a period on this graph when our operations were not stable.

And as you can see, there's a lot of spikes in rate and pressure, with flow rate being the blue that's on the bottom, and pressure, the red line that's on the top. And as you can see, whenever our pressure changes, our rate changes -- maybe not to the exact extent, but the two trends definitely follow each other very closely.

So the purpose of this slide is to demonstrate that there is a very tight relationships between rate and pressure in a well. And this tight relationship exists for a couple of reasons. It exists because of the friction in our tubulars, which is just the basic physics of the flood flowing, and it exists because of the dcharacteristics of the reservoir.

So note the circled area approximately in the middle of the graph. What I've done here, I've zoomed in on that circle --

Q. And you're on Slide 23, right?

A. On Slide 23. And this information is now present in a zoomed in form on Slide 23. And this is the same well, same data. And again, I purposely chose a point in the graph where things are not stable.

And this graph is actually scaled so that the left side of the graph, you'll notice that the tubing pressure in red is below the rate. In the middle where it's higher, it's above the rate, and towards the middle of the graph, the lines actually overlap.

And the scaling is done like that to really show you how closely the two process variables are related to each other. Although they're not perfectly lined up, you can see that as it goes through its range of operation, the variables do correlate very well.

Q. If we look at this graph, it's obviously based on a number of data points. Is this typical of the number of measurements you would get in a two day period on one of these wells using the SCADA system?

A. Yes, sir. I think Tejay testified earlier that our newer systems get information about everything two minutes, and the older ones were on the order of eight minutes. This graph is probably made up of a thousand data points, maybe. So this is typical of the frequency we get, the data into our SCADA systems.

And the time line again is on the bottom, oldest data on the left, the newest data on the right. And the scaling for the blue and red rates and pressures is on the left-hand side of the graph.

Q. Are you ready to go to Slide 24?

A. Yes, sir.

Q. Let's go.

A. Slide 24 is the exact same data that was in Slide 23, only instead of the values being rate and pressure being plotted over time, now we have rate and pressure plotted against each other.

And so there is a couple of things to note about this. If you look towards the right-hand side of this graph, you'll notice that the little red dots are above the line. In the middle, they're on the line and towards the left. It appears to me that the majority of the them are below the line.

Now, each one of these dots represents a reading coming back from the SCADA system. So again, this data was purposely collected with our operations in an unstable state.

And the line that is drawn through this data set isn't something I just arbitrarily drew through there, it's something called a linear regression line, which is a scientific way to draw a line through a data set and actually have it fit to the data set with the least amount of overall error. It's called linear regression.

So what we would expect to see, is if we developed a leak in this well, we would see these grouping of dots, say, this middle group, it would devolve to the right and possibly down, because we would have an increase in flow rate and a reduction in pressure on our wells.

So the bottom line is, this is -- this is worse case, almost. We would never purposely go choose unstable states to build well models, but I think it does demonstrate that even choosing unfavorable data points on the well, that most of those data points fall along that line.

And the whole theory of monitoring rate versus pressure to look for leaks is based around the fact that when something physical changes in your system, you will see something physical change in the way your data fits your regression lines.

Q. Now, this is a water injection well?

A. Yes, sir.

Q. Have you prepared similar data on the C02 injection well?

A. Yes, sir, I did.

Q. And that's Slide 25?

A. This is Slide 25. This slide was prepared the same way as the previous slides, I just didn't include the slides that led up to the linear regression line, just because they were somewhat redundant.

I think the important things to note of the -- with C02, you heard Tejay say that with C02, it's very sensitive to changes in temperature causing wide swings in pressure.

As you see, the data points are not as closely grouped to the linear regression line as we saw with water. And it's apparent to me by looking at this graph that the grouping of the dots near the middle means that this process may be more tightly controlled in the field than the water injection. And it's just an observation.

But again, the way the data points fit the linear regression line, we would expect to see the rate go up and the pressure go down. And what we expect to see actually depends on the types of pumping systems we have, but with the pumping systems we have in these fields, that would be the pattern we would see in the data set if we developed a leak.

MR. WARNELL: So the time period here on this graph is --

THE WITNESS: There is no time period on this graph, it is rate versus pressure.

A. So what this is saying, if you look at 2,500 -- MCF, you're going to be running approximately 55 PSI pressure.

Q. This was a two day test, was it not?

A. Oh, the data that this was based on? I think this was approximately two days of data that this graph is based on.

MR. WARNELL: So if my eyes were good enough, I could count those little dots there and I could get some kind of a sample rate?

THE WITNESS: Yes, sir.

MR. WARNELL: And that sample rate is going to be --

THE WITNESS: It's the -- When we wag wells between water and C02, the sample rate doesn't change, whatever it is is what it is, and this is probably in the order of something less than ten minutes, ten minutes per point.

Q. Of both C02 and water you do have a high degree of correlation?

A. Yes, sir. And we have the ability to -- if we wanted to, we could go to the instrument and pull this data much more frequently, it's just there's really no -- we don't have any operational reason to do it.

Q. And these are wells that were not leaking?

A. To the best of my knowledge, they're not leaking.

Q. Do you have a slide that shows a profile for a typical leak?

A. Yes, sir, I do.
Q. And that is the next slide?
A. That is the next slide.
Q. So let's go to that.
A. I want to spend a little bit of time on this slide because it really takes a lot of explanation to understand what we're seeing on the data here.
The top line that I have labeled pressure was an absolute pressure. And you'll notice that I did this test in 2006. So it's been quite some time, so I can't remember the exact conditions that this test was performed under.
But I would assume this pressure, absolute pressure, is going to be something over a thousand pounds, probably 1,200 or 1,300 pounds. And I have no idea what the flow rate was in this cases.
But what you can see looking towards the left side of the graph, looking at the top and the bottom lines, the red one and the blue, is that they are very stable up to the point where you see something happen. And at that point in time and before that, where that little blue dot is on the top line and I'll -- For your information, this graph is a 30 minute time period here that we're looking at.
So what we did, we went out and we simulated a

leak at the point where you see the little blue dot on the pressure line, and you see that graph starting to head down. And this pattern that you see of pressure going down and rate going up is exactly what we expect to see when we lose downstream resistance to our pumping systems.

This is different than what we see -- if we ramp up our rates, up we see rate and pressure go up, if we slow our pumps down, we see rate and pressure go down.

So the only time we really see this, that these lines go in opposite direction, is the result of losing integrity, or for some reason, flow increasing downstream of our system is down.

We've cast these algorithms into something called design patterns, and this one we call a rate and pressure provider. It's looking at what happens with a piece of equipment that is a source for flow and pressure. And the rate and pressure provider design pattern is exactly what we do with our injection wells, we're providing rate and pressure to an injection well.

So I want to move to the two lines there in the middle. Because one of the challenges with leak detection, when we use absolute set points, it is -- you remember I told you I couldn't recall exactly what the pressure was, or exactly what the rate is, is that as operations change day to day, if we were to set an alarm on this pressure, we would have to set it here, and then if we were going to go for an extended time and operate at a different pressure, we would have to be moving those alarms all the time, and that is -- It's pretty tedious for humans to do.

So what's happened here, we've run the pressure and rate data through some algorithms that actually change that information into the two center lines which is looking for change.

So now the left-hand graph is relevant in that 50 on the upside is an increase in either 50 pounds or 50 barrels a day in rate, same with on the negative side. So now what we see is, under normal operating conditions, the zero line is the line that's in the middle of the graph between the positive 10 and the negative 10.

So what we're seeing is, we're not seeing any change. And as soon as we simulated the leak here, you can tell probably a minute or so, now we see rate going up and pressure going down.

The significance of this is now we can alarm on a certain number of barrels increase in rate, or a certain number of pressure decrease. We can do that with absolute pressure.

The one flaw that exists in doing that is that a human still has to do it, and what I mentioned earlier, when we change our operations, if we reduce the speed of our pumps, we still see rate and pressure going down and we may trip our alarms.

So the final step that we've done for surface leak detection, is to run this information, the processed information on the middle two lines, through artificial intelligence that is smart enough to actually look at these graphs and tell which direction they're going.

And if it sees rate and pressure going up, or rate and pressure going down, it knows that's a result of our supply changing, but yet if it sees the values go in an opposite direction, it can make a decision to alarm us.

And Tejay covered the expected response from an alarm condition that happens on one of these wells.

Q. And you in fact are using this data to identify leaks on the surface; is that right?

A. Yes, sir, this technology is running today and it's used in various places to detect the patterns and data of leaks.

Q. And under normal conditions, rate and pressure --

A. I mean normally, if this was a one day trend, you would just see this on zero. It can move around a little bit. If we have an event, we see this type of response.

And although this was a test to test the accuracy of these algorithms and their ability to see this information, when we've seen actual leaks, we've seen data that's virtually identical.

Q. And when you have a leak, you immediately see the trends take off in different directions, pressure one way, rate the other way?

A. Depending on the types of pumps. With the types of pumps that are at vacuum, we would see this kind of trend. If we have something we call positive displacement pumps, the rate will stay the same, but the pressure will fall more dramatically than we've seen in this graph here, and our artificial intelligence is coded to know about that as well.

Q. All right. Let's go to the next slide, Slide 27. What does this show?

A. Slide 27 is a -- this came out of one of our information systems called DSS. We have data that's collected on different frequencies. Operations in the field gets data in minutes, or sometimes seconds, depending on the process.

Engineering gets information on a daily rate, meaning they just see the results for the day, they don't need to see the small changes in our processes.

What we see here is, in the blue triangle that's labeled "Injection Rate," you can see that things were running along pretty constant. And in this graph, each one of the little blue colored triangles is one data point each day.

So each one of those triangles represents one day in time, again, the oldest information being on the left-hand side of the graph, then newer information moving to the right.

What you see just to the right of the marker on the bottom of the graph that's labeled "'05," I believe, about four data points to the right of there, you see the blue and purple trends were running along in pretty stable horizontal positions, and that some event happened to cause the injection rate to go up and the pressure to go down. And it looks like approximately two to three weeks later, there is a diamond on the top of this graph that's labeled "MIT Failed Test." So I guess the mechanical integrity test failed.

And at that time what you notices is that if you look down at the bottom of the graph in approximately the middle, the little blue diamonds are there but they're right against the bottom line, so they're difficult to see, and you notice that the injection pressure didn't fail.

I believe this is when they shut in the well to actually repair the well. And then you see the injection pressure fall over the next several weeks and months as they were working on this well.

The significance of this is, if you look back to the previous slide and you look at this slide, the patterns that we normally see on our surface equipment and this graph that we see when we actually have been able to document a downhole failure, the patterns in the data are virtually identical now.

There was no violation of the OCD's rules or regulations in that this was -- we normally are required to test this every 30 days, and apparently when they did go do their test, they picked up that this was failed and they shut the well in, and I presume either left it down or maybe it's been worked over since then, and as of today, I have no knowledge of that.

But I think these two slides are compelling in that they really demonstrate that what we expect to see, we see.

Q. If we look at the slide that is on the screen now, there was a leak and it wasn't detected for several weeks; is that correct?

A. I believe judging from when the well was shut in, that would be correct.

Q. If we go to back to the prior graph, we were able to detect a leak within a matter of minutes?

A. Yes, sir, that's correct.

Q. So by using SCADA, isn't it reasonable to assume you'd be able to identify leaks much more rapidly than operating under current procedures by the OCD?

A. If our leak detection algorithms would have been on this, we would have detected that something was wrong at the first data point that -- I don't know which number it would be, but it's the obvious one that's above the normal -- what I would call the regression line for the injection rate.

So we would have of detected this much sooner if we had had our current leak detection algorithms on this one.

Q. Can the SCADA system be deployed on each of the nine wells that are the subject of this hearing?

A. Yes, it can.

Q. And how long would it take you to deploy these systems on those wells?

A. Approximately a day.

Q. And what you've shown us is a system you use to detect surface leaks, and from this data, it's your belief that they will also work to show downhole leaks?

A. Yes.

Q. Okay. Do you have anything to add to your testimony?

A. No, I do not.

Q. Were Slides 22 through 27 prepared by you?

A. Slides 22 through 26 were prepared by me, Slide 27 was prepared by Scott.

Q. And have you reviewed Slide 27?

A. Yes, I have.

Q. And in your opinion, is it an accurate representation?

A. I believe it is.

MR. CARR: May it please the Examiners, at this time I'd move the admission of Slides 22 through 27.

HEARING EXAMINER: Slides 22 through 27 are admitted.

MR. CARR: And that concludes my examination of Mr. Carlson.

HEARING EXAMINER: Okay. Mr. Warnell?

MR. WARNELL: Mr. Carlson, I have a question here. On Slide 26, up at the top of the chart where you've got your rate and pressure, you've got the date there, 5/1/2006?

THE WITNESS: Okay.

MR. WARNELL: Right there where the date is captured and the time?

THE WITNESS: On the top left?

MR. WARNELL: Yes.

THE WITNESS: Yes, sir.

MR. WARNELL: Can you tell me why is the time different?

THE WITNESS: If you'll notice, there are two vertical lines on this graph, one about -- on your printout approximately an inch from the left, and another one an inch from the right.

MR. WARNELL: Right.

THE WITNESS: The significance of that is the red line, the date and time at the top left is where the red line was captured, and the date and time where the blue line that's on the right is time stamped there. And on the right-hand side of the graph where you're looking at -- where it says "Negative 9 none," it is showing the difference in time between those two data points. They were not significant on this graph.

MR. WARNELL: Okay.

THE WITNESS: The snapshot I've taken here is not of the full software package we used to do this, so if you click on any one of these four lines, it will show you the date and time and the difference in the readings.

And I really don't know which value those are representative of. They're kind of irrelevant, but they're just always there in the picture.

MR. WARNELL: All right. That was confusing. I thought maybe the red line represented rate, and the blue line represented pressure or something, but I see what you're doing now.

THE WITNESS: Now, if you were to put the -- they're called scooters -- on two different points on one of the lines and then chick on it, it would tell you the difference in time and the difference in value, but they're just not important to this graph, the important time values are on the bottom.

MR. WARNELL: Okay, thank you. Now, you're the expert, so maybe you can help me out on Slide 17. I'm curious, what is that three-quarter inch rod sticking up in the air coming off of that flange?

THE WITNESS: This one?

MR. WARNELL: Yes, that. What is that?

THE WITNESS: I'm going to have to say that I have no idea, but I'm sure Tejay knows.

MR. SIMPSON: These wells used to have a pressure safety relief valve coming off the top, and it was a brace to hold that in place.

MR. WARNELL: Okay. Everything else looked like it had a purpose, but that I just couldn't figure out. Okay, thank you. I have no other questions.

HEARING EXAMINER: Very good. I have no

questions.

MR. CARR: That concludes our portion of the case related to the cemented tubing in the case. I would now like to call Paul Brown, our engineering witness, to discuss the issue concerning the depths packers have been set, and also, the calculation of the detection pressure. So I call Mr. Brown.

PAUL BROWN,

the witness herein, after first being duly sworn upon his oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. CARR:

Q. Would you state your name for the record, please?

A. Paul Brown.

Q. And Mr. Brown, where do you reside?

A. Midland, Texas.

Q. By whom are you employed?

A. Chevron.

Q. And what is your current position with Chevron?

A. Petroleum engineer.

Q. Have you previously testified before the New Mexico Oil Conservation Division?

A. I have not, no.

Q. Could you briefly summarize your educational background and your work experience?

A. I have a bachelors degree in chemical engineering from Texas A&M. I'm a registered petroleum engineer in the State of Texas. I have 26 years of experience starting with Texaco and now currently with Chevron. I have been assigned to the vacuum field operation for the past two years.

Q. And are you familiar with the applications filed in these cases?

A. Yes.

Q. And are you familiar with the engineering issues involved in these cases?

A. Yes.

MR. CARR: We tender Mr. Brown as an expert witness in petroleum engineering.

HEARING EXAMINER: He is so qualified.

Q. I'd like now to address the injection well completion requirements as they relate to packer setting depth, and I would ask you to refer to what is our Slide 28 and review that for the Examiners.

A. Okay. At the very top of the slide in the small print is the actual wording from the orders dictating where the packer needs to be set in that -- you know, needs to be set approximately within a hundred feet of the uppermost injection perforation or casing ~~tube~~ shoe.

As these wells -- every time that we have to pull an injection well, just due to the corrosion that is induced down below in the casing, we're always having to raise the packer seat each time just so we can have a good seat in the casing so we can restore mechanical integrity.

And just over time, you know, every time we have to enter a well, we're constantly going up the hole with our packer seats. And we -- there have been situations where we have gotten above -- we've had to set the packer greater than one hundred feet above the top perforation.

And to do that, we have either gotten written permission from the District, or we've gotten verbal permission from the District to do that, but according to the notice we got from Santa Fe in July, the District did not have that authority to grant those waivers.

Q. When you go to the District and get one of these waivers, do they require that the packers still be set within the unitized interval?

A. They do. Of the ones I have personally been involved with, when we're seeking to get that permission, we tell them where the top of the -- where we want to set the packer where the top of the unitized interval is, so they know that the packer is still going to be set below the -- or set within the unitized interval.

Q. All right. Let's go to Slide 29. What is this?

A. ~~Slight~~ Slide 29 is a listing of the -- we researched our data base, and we have 31 wells that have the packer set at greater than 100 feet above the top perforation or the casing shoe.

And then we've also determined that there's 38 other injection wells where the packer is set currently within 75 to 100 feet of the top perf. So in all likelihood, the next time we have to pull those wells, we'll be having to set our packer greater than 100 feet. And as the field ages, this is just going to be a continual situation of more and more wells over time having to raise the packer above the 100 foot data.

Q. The 31 wells where the packers are 100 feet above the perfs or casing shoe, those have each been approved by the District office?

A. Right.

Q. But that procedure is inconsistent with the directive we've received from the Division?

A. It's inconsistent with their orders, yes.

Q. Let's go to Slide 30.

A. Slide 30 is a north/south cross-section across the vacuum field with the CVU to the north and the VGSAU to the south. And what we have highlighted correlated the top of the unit boundary, and if you just follow along there.

And then down here we have a correlated the uppermost perf in all these wells going from north to south. And it shows that there is roughly 350 feet from the top of the unit boundary to the uppermost perf. So there is a pretty good spread between the top of the boundary to the perfs.

Q. Okay. Then let's go down to Slide 31.

A. And Slide 31 -- you know, our recommendation would be to amend the orders from how they currently are to really stay where we have -- to set the injection packer as close as possible to the uppermost injection perforations to a casing shoe, so long as it remains within the unitized interval.

And this change will protect our other formations and protect correlative rights, and it will be in compliance with the Federal UIC regulations which we have on the next slide.

Q. Okay, let's go to the next slide.

A. We researched -- A question that was posed to us at our meeting with OCD a couple weeks ago, was if we raised -- if we set our packers greater than 100 feet above the top perf, would that be in compliance with federal regulations.

And we researched this, and we actually saw that the regulations allow for having injection -- not actually requiring a packer in an injection well, that -- And then it was also determined that there's really no regulation on where the packer has to be set in an injection well if an operator even chooses to run a packer.

Q. If we look at your testimony, you have identified 38 wells that look like within the foreseeable future may have to have an exception to the 100 foot provision?

A. That's right.

Q. If the District can't grant those, we're going to have to come to Santa Fe 38 times, I guess, to get that approved?

A. That's correct.

Q. Mechanically, when you're going back in to some of these old wells over and over again, you naturally have to come up the hole with the packer to get a good seal; isn't that correct?

A. That's correct.

Q. And so unless we're able to go some sort of a change in the orders and the provisions, you're going to have no choice but to return to the OCD again?

A. That's correct.

Q. Now, let's talk about the last issue, the change in the rules to base injection pressures on average reservoir pressure, and I'd ask you to refer to Slide 33.

A. Slide 33 up at the top is the actual wording from the injection orders. I believe it's the same wording for the Vacuum Grayburg-San Andres Unit and Central Vacuum Unit, but "...shall be further authorized to inject C02 and produced gases at a maximum surface pressure of 350 psi above the current maximum surface injection pressure for water, provided, however, that the C02 injection pressure does not exceed 1,850 psi."

And we have noticed that as our C02 projects have matured, we are processing more of recycled gas. And so, on -- I guess on the average for the entire field, the density of our injection is going down.

And in order to maintain -- to keep all -- or both leases, the two leases whole on the gas that comes from -- that comes into the plant that is sent back out to the field, the proportions of purchased C02, which is 100 percent C02 and the recycled CO2, can be different.

And currently, with the Central Vacuum Unit sending the more -- it's the more mature unit, it's sending more gas to our recycle facility, so it's getting a larger share of recycled gas than it is receiving of purchased C02.

So it's -- we're injecting a lower density C02 into the Central Vacuum Unit which is causing us some operational pressures of a reduction in our bottomhole pressure.

Q. About how much approximately?

A. Approximately 400 psi.

Q. Let's go to Slide 34, what is this?

A. Slide 34 is a recent gas analysis of this sample at the tailgate of our recycled plant, and this shows the composition of gas as it is right before it enters our C02 injection system.

And there you can see that we are at 87 percent C02, about 2 percent nitrogen, and then about 11 percent remaining as hydrocarbon gas going from methane to up to hexane.

Q. And this is the gas that you're recycling?

A. That is a typical composition of our recycled gas.

Q. Is 87 about the worst case scenario?

A. That's about the lowest we've seen.

Q. Let's go to Slide 35.

A. Okay, Slide 35 is just some computer simulations we did using type phase that calculates, based on the gas composition in the surface pressure, what the bottomhole pressure will be.

And on the far left is where we have a pure C02 stream 100 percent, and surface pressure of 1,850, which is our maximum allowed injection pressures. Down at bottom hole, which the datum is 4,550 feet, that would be about mid perf, the bottom hole pressure is 3,596.

Q. This is what you were anticipating at the time the original order was entered; is that correct?

A. That is correct.

Q. All right. Let's go now to the other columns -- And that's why you have 100 percent CO2?

A. Right. On the far right column, we're showing 87 percent C02, and the surface pressure of 1,850 psi, and the bottomhole pressure is 3,200 psi. So we've had about a 400 psi reduction in our bottomhole pressure just because of our -- the reduction and the density of our injected where we're still -- we're still at 1,850 at the surface, but our bottomhole pressure is reduced by 400 psi.

And in the middle, we did this simulation to -- where we started out with still using the 87 percent C02 mixture starting out with a bottomhole pressure of 3,600 psi to calculate what surface pressure would be required to have 3,600 psi at bottomhole, and it calculated to be 2,200 psi.

Q. Okay. So if you went to that approximately 2,200 psi at the surface, you would still have the bottomhole pressure that you were originally approved for when you were injecting 100 percent CO2?

A. That's correct. We would be maintaining the same bottomhole pressure as we were initially permitted for.

Q. Okay. Now, let's go to the last slide, Slide 36.

A. Okay, the last slide in tabular form at the top, these are just -- takes a lot of the clutter out of that last slide, but -- you know. But at 1,850 at the surface at 100 percent CO2, our bottomhole pressure is 3,596. And at 1,850 psi and 87 percent C02, our bottomhole pressure is 3,200 psi. But if we raise our pressure to 2,200 psi at an 87 percent C02 string, we would achieve 3,600 psi at bottom hole.

Q. So we've got what we originally had -- or the operator thought he had, the middle column is where we are and what we're recommending to go back to what the original recommendation or approval was?

A. Right.

Q. Okay. What do you recommend?

A. Well, I recommend that what we really need since the density of the fluid is going to be changing over time, ideally, that we would need to get -- we would want to have our maximum injection pressure based on the bottom hole and not at the surface.

What we really want to do is maintain 3,600 psi at bottom hole. And we understand that, you know, enforcing a bottomhole pressure is difficult, so our proposal would be to request -- you know, that our orders be written so that our maximum bottomhole injection pressure is 3,600 psi, but also say that that is a -- that equates to 2,200 psi at the surface. And that would be, you know -- the net effect would be increasing our maximum limit at the surface by 350 psi.

Q. All right. Your recommendations are as to packer setting depths?

A. Recommendation on the packer setting depths is to allow us to set our packers as close to the uppermost perf as possible, as long as -- but staying within the unitized interval.

Q. And the recommendation as to the injection pressure?

A. The recommendation for the injection pressure will be to change the orders from a maximum surface injection pressure of 1,850 psi on C02 to a maximum bottomhole injection pressure of 3,600 psi on C02.

Q. In your opinion, will the approval of this application and the implementation of the proposed amendments to the original injection orders be in the best interest of conservation and the prevention of waste and the protection of correlative rights?

A. Yes.

Q. Without these amendments, will substantial waste of hydrocarbons occur in these two units?

A. Yes.

Q. Will your recommendation result in not only efficiently for Chevron, but an easier system for the OCD to regulate and monitor?

A. Yes.

Q. Were Slides 28 through 36 prepared by you?

A. Or that I've reviewed them.

Q. Can you testify as to their accuracy?

A. Correct.

MR. CARR: I move the admission of Slides 28 through 36.

HEARING EXAMINER: Slides 28 through 36 will be admitted. Mr. Warnell, did you have questions?

MR. WARNELL: Yeah, I do. I think if I heard Mr. Carlson right, he said something about your recommendations to make OCD's life easier? And that kind of caught my attention.

MR. CARR: Out of character for me.

MR. WARNELL: I'm not sure how much easier our life would be if we were to assign bottomhole pressures rather than surface pressures. Because -- I'm -- Why do we have surface pressures to start with? They're easy for the field inspector to go out there and eye all and -- How would he go out there and eyeball your bottomhole pressure?

THE WITNESS: He would have to extrapolate from the surface to calculate a bottomhole pressure.

MR. WARNELL: Now, most people, if they've got an order that says 1,850 psi surface pressure, and for whatever reason they decide they need to increase it by 350 psi or whatever and go to 2,200, then they historically would go out and do a step rate test and apply administratively for a pressure increase. We couldn't do that in this case?

THE WITNESS: We can't -- I don't believe we're able to do step rate tests with C02. I don't know if we have that capacity.

MR. WARNELL: I'm not sure we'd have to do the step rate test with C02, but what we'd be looking -- what I would be interested in is -- because I do most of the pressure increase orders, is some assurance that that increased pressure at the surface, or increase pressure at bottom hole, is not going to fracture the formation or anything like that.

THE WITNESS: Right.

MR. WARNELL: Or break it down.

THE WITNESS: I don't know -- I don't really have the -- any exact numbers, but I do know -- I know that every -- We have a form that step rate tests on every well out in the field, and I don't know if we have the data collected.

But at the -- the decision was made to commit C02 injection, we did reduce our water injection pressure, and I want to say that it reduced it from roughly 1,900 psi to 1,500 psi.

And the primary reason for doing that was to reduce our CO2 requirements. We are operating our C02 project well below frac pressure, but to what degree, I don't know. But we have operated the field under water flooding at a higher pressure before.

MR. WARNELL: Okay. Thank you.

HEARING EXAMINER: What you're saying is that because you're injecting less dense gas than what you originally contemplated, that the pressure, injection pressure, equates to a lesser bottom hole?

THE WITNESS: Lower bottomhole pressure, yeah.

HEARING EXAMINER: That's what I thought you were saying.

THE WITNESS: Right.

HEARING EXAMINER: Is there any possibility or probability that that would change so that your bottomhole pressure would go back up if we authorized a certain increase in the surface pressure?

THE WITNESS: If we were able to -- I'm not really sure how to answer that. Our desire is to maintain 3,600 psi of bottomhole pressure, and if we're at a point -- if we're in the situation where we were not purchasing any C02 fieldwide, then, you know, the entire field would be getting at 87 percent --

HEARING EXAMINER: Of course, what you would intend to do in that situation would be to ~~reissue~~ reduce RB surface pressure back so you'd still get your 3,600 bottom hole.

THE WITNESS: Right.

HEARING EXAMINER: However, from a regulatory standpoint, if we're going to use a certain level as the criterion, then the question rises to -- because our objective is to be sure that fracture pressure is not exceeded. So -- I just raised that issue, I don't really expect you to have an answer to it at this point.

THE WITNESS: Well, the reason we -- there is a precedent set for the injection orders being based on a bottomhole pressure. That's what ConocoPhillips does in their East Vacuum Grayburg-San Andres Unit. How that's being enforced, I'm not aware of, but there have been orders written in that regard.

HEARING EXAMINER: Okay. That's all my questions.

MR. CARR: That concludes my examination of Mr. Brown. With your permission, I'd like to call Mr. Ingram back for some very brief testimony on that last point.

HEARING EXAMINER: Okay.

MR. CARR: And I have marked two plots that are the same, and Mr. Ingram will refer to that.

REDIRECT EXAMINATION

BY MR. CARR:

Q. Mr. Ingram, you've been present and heard the testimony concerning the request for a change in the way injection pressures are calculated in the field?

A. Yes, I have.

Q. And is the method that Chevron is proposing similar to what has been authorized for other operators in the area?

A. Yes. I'm a linear thinker, and the chronology here is, when we recognized that we were in effect reducing our bottomhole injection pressure as we injected this contaminated gas stream, and that was causing us operational problems, loss of injectivity, particularly the Central Vacuum Unit, we wanted to address that.

And our first proposal, our first application to the OCD, was to increase our surface injection pressure. But then as we prepared for that hearing and did further investigation, we noticed that ConocoPhillips, our direct offset operator in the East Vacuum Grayburg-San Andres Unit, in fact made reference to a maximum bottomhole injection pressure. And we thought, well then that was the way to proceed to address this gas density.

When we did come here three weeks ago and met with the OCD, and in particular, Mr. Fesmire, he raised the question of how would we administer that.

So that's actually the reason that this last slide is prepared the way it is. We're proposing, so that we can adjust for this reduced gas density, we've stayed with the proposal for a maximum bottomhole injection pressure of 3,600 psi, but to allow an alternative way to more easily administer it that equates to a surface pressure at 87 percent C02, equates to a surface pressure of 2,200 psi.

Now, I believe you raised the question about well, what if our gas density changes, and in the future, you know, if you permitted based on 2,200, you know, we could in theory then inject 100 percent C02 and surpass that 3,600 psi bottomhole pressure.

And I can tell you that, for a couple of reasons, you know, that that will never happen. One, the cost to create a 100 percent C02 gas string is -- well, our plan is not configured to do that. We would have to install a multiple million dollar hydrocarbon gas stripping operation to accomplish that, and that's not in the plan.

And it's also not in our plan to inject at any higher pressure than we need to, because that, in effect, you take horsepower to create that pressure and you use more C02. And it's not our desire to inject at any higher pressure than absolutely necessary, it's only to adjust for this loss of injectivity due to the reduced density in our C02 string.

In fact, our current surface injection pressure capabilities are limited to somewhere around 1,900 or 1,950 psi. So even if this were permitted at 2,200 today, we couldn't do it. But we thought while we're here, and since we are permitted at 1,850 on 100 percent C02, which equates to 3,600 at bottomhole pressure, let's try to amend the verbiage to allow us to maintain that bottom hole pressure with a contaminated gas stream.

Q. What's the impact of the current situation on your ability to inject in the Central Vacuum?

A. It's really impeding the injectivity. Mr. Simpson, as our operations supervisor, has raised that issue with us over and over.

Because we're sending a more pure gas stream back to the Vacuum Grayburg-San Andres Unit than we are the Central Vacuum Unit, and that's to maintain an equity in the NGLs associated with that stream, but it's really reducing the injectivity in the Central Vacuum Unit.

Q. What about exceeding the fracture of gradient for pressures in the reservoir itself?

A. The display that was handed out that is now labeled Exhibit 3, what that is, is we have on a number of wells in the history of this field gone through step rate tests and received permits for higher pressures on water.

And what are shown there are all of those that are at 1,900 psi or greater. So you can see that there is pretty good aerial distribution across the two units of step rate tests on water approved in the range of 1,900 -- I believe all the way up to 2,500 psi.

So based on that sampling of the data, I don't feel that approving a C02 injection pressure at 2,200 psi is going to exceed our frac pressures anywhere within the unit.

MR. CARR: May it please the Examiners, I have one remaining thing, and that is my notice affidavit as Exhibit 2.

What I did was, I notified some 30 operators. I went around both units and I notified the surface owners and the offset operators in every one of those sections, and I have identified them. And so this is the notice.

And I'd like at this time to move the admission of Exhibits 2 and 3.

HEARING EXAMINER: Okay, both Exhibits 2 and 3 are admitted.

MR. CARR: And that concludes our presentation of this case.

HEARING EXAMINER: Very good. If there is nothing further, then Cases Nos. 14401 and 14402 will be taken under advisement, and this docket will stand adjourned.

(Whereupon, the proceedings concluded.)

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 14401-14402 heard by me on 12-3-09.

David K. Brooks, Examiner
Oil Conservation Division



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STATE OF NEW MEXICO )
) ss.
COUNTY OF BERNALILLO )

REPORTER'S CERTIFICATE

I, PEGGY A. SEDILLO, Certified Court Reporter of the firm Paul Baca Professional Court Reporters do hereby certify that the foregoing transcript is a complete and accurate record of said proceedings as the same were recorded by me or under my supervision.

Dated at Albuquerque, New Mexico this 10th day of December, 2009.

Peggy Sedillo

PEGGY A. SEDILLO, CCR NO. 88
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