DOT	US Department of Transportation
PHMSA	Pipelines and Hazardous Materials Safety Administration
OPS	Office of Pipeline Safety
	Western Region

Principal Investigator	Stephen Bender
Senior Accident Investigator	Peter Katchmar
Regional Director	Chris Hoidal
Date of Report	6/7/2011
Subject	Failure Investigation Report – Chevron Pipe Line Crude Oil Release

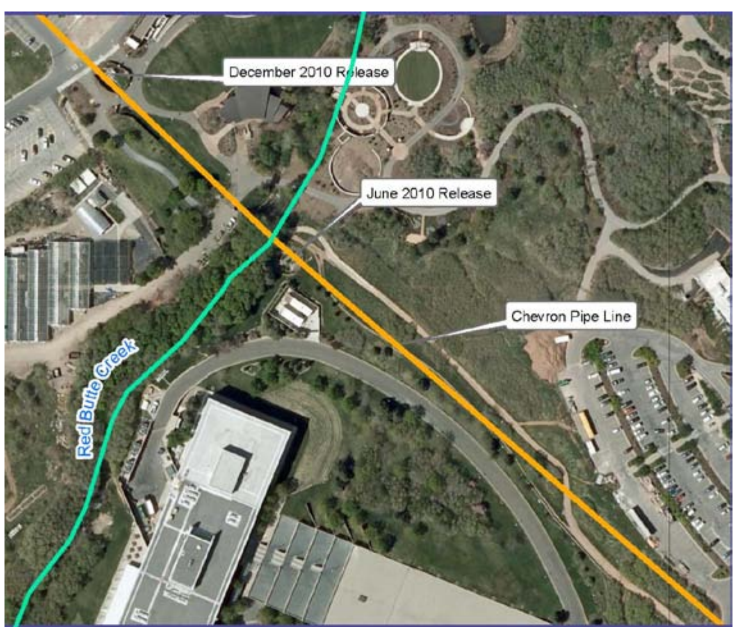
Operator, Location, & Consequences

Date & Time of Failure:	12/1/2010
Commodity Released:	Crude Oil Condensate
City/County & State:	Salt Lake City/Salt Lake County, UT
OpID & Operator Name	2731 Chevron Pipe Line Company
Unit # & Unit Name	225 Crude System
SMART Activity #:	132398
Milepost / Location	Milepost 175.0
Type of Failure:	Leak caused by Inadequate Procedures for Draining Water
Fatalities:	0
Injuries	0
Description of area impacted	Adjacent to University of Utah Campus
Property damage	$7,334,364

Summary
On the evening of December 1, 2010, Chevron Pipe Line Company's (CPL) controller shut down their Number 2 pipeline that delivers crude oil to their Salt Lake City (SLC) refinery. The pipeline transports crude oil from Rangely, Colorado to the SLC refinery via the Hanna pump station. After the Hanna station, the pipeline crosses Wolf Creek Pass and quickly descends into the Salt Lake Basin, traversing the eastern slope of Salt Lake City. The line was shut down because of some erratic supervisory control and data acquisition (SCADA) information following restart of the line after a planned shutdown.

After shutdown, Chevron personnel were dispatched to patrol the right-of-way (ROW). They discovered a release of crude oil from their Number 2 line at their Red Butte Block Valve installation adjacent to the University of Utah's arboretum and 100 yards uphill from Red Butte Creek. The valve is in a below-grade open vault. The released crude oil filled the vault, spilled out of the fenced area and flowed down hill toward Red Butte Creek. The low temperatures experienced that night congealed the crude making it more viscous. The crude oil did not appear to have reached the creek.

Immediately upon discovering the crude oil release, CPL initiated their emergency response procedures and within an hour, numerous city, county, contractor, and CPL personnel were on site. The local fire department established an Incident Command Center (ICC) in a parking lot near the release site. Air monitors were dispatched and a "hot" zone and a "safe" zone were established to facilitate the safe recovery of the oil. **Note: There was a release of crude oil from this pipeline 100 yards up stream of the Red Butte Block Valve on 6/11/2010. That release drained directly into Red Butte Creek and fouled the creek for seven (7) miles until it reached Liberty Park Pond.**



The crude oil release occurred at a damaged 6-inch valve that “stubbed” off of the Number 2 pipeline in the Red Butte block valve vault. The failed valve served as the water injection valve for the stand up water test performed in June 2010, after the first crude oil release in this area. The valve was in the closed position at the time of the release. Forensic lab analysis of the valve confirmed that the formation of ice inside the valve opened a leak path for the oil to flow through the valve, and escape through an opening between the bonnet and valve body. The damaged bonnet/clamp ring assembly was consistent with internal pressure caused by freezing water. The failure resulted in a release of crude oil when the line was restarted but prior to detection and shut down of the line. Due to the line’s topography and the fact the leaky valve was immediately upstream of the mainline block valve, oil continued to flow out the ruptured 6-inch valve even after the shut down. The final spill amount at the time of this writing is 500 barrels, of which 250 were recovered.

The Pipeline System:

This CPL SLC crude oil pipeline system is 182.5 miles long from CPL's Rangely terminal to their SLC refinery and consists of two 10-inch lines: the Number 1 line built in 1948, currently inactive and filled with inert nitrogen, and the active Number 2 line built in 1952. The MOP varies depending on the hydrostatic test pressure it was subjected to. Wall thickness and pipe grade also vary widely. The pipelines are coated and cathodically protected by impressed current with magnesium anodes at low potential points. The pipeline is monitored by SCADA in Houston, Texas.

The Number 2 crude line starts at an elevation of 5,188-feet at the Hanna Station (MP108.5), rises to 8,450-feet at Wolf Creek Pass (MP125), and then descends 4234-feet to Chevron's Salt Lake City refinery (MP182.5). There are many HCAs near the pipeline ROW with most occurring in the last 50 miles prior to the Salt Lake (SL) Station. There are populated and sensitive areas at Emigrant Canyon, Park City, the University of Utah, and the eastern edge of the City. The pipeline crosses numerous streams and rivers that supply SLC’s drinking reservoirs and local lakes, including the Great Salt Lake.

Line History (including pertinent operational facts):

- Since this line was constructed in 1952, there have been four (4) reportable releases on CPL’s Crude Oil Line Number 2. The first three (3) were due to third party damage where a contractor hit the line while digging. The fourth (4th) release was on June 11, 2010, when a surge of electricity from a fault current jumped from a fence post placed within three (3) inches of the pipeline onto the pipeline causing a 1/2 inch hole to be created in the line.

- All releases appear to have occurred downstream of Park City, UT where the pipeline encounters higher population density, more encroachment, and more buried structures including utilities.

- All repairs to this line have been made with pre-tested pipe. It does not appear that any water has ever been intentionally introduced into this line since the post construction hydrotest in 1952 until the hydrostatic leak test after the June 2010 release.

- After the June 2010, fault current event, a stand up leak test with water was required to confirm that there were no additional pinhole leaks made by the electrical current leaving the pipe.

- This line operates "in slack" line conditions from Wolf Creek Pass (MP125) to the end of the line at Chevron's SLC Refinery. This means that the pressure inside the line is very low from Park City into Salt Lake City. The last 14 miles from Little Mountain is on a slope that allows the line to drain into the refinery at no more than 50-80 pounds per square inch gage (psig) normally.

- The line is piggable and has been inspected with an internal device designed to measure wall loss as well as deformations in the wall of the pipe. These devices, called smart pigs are required to be run every five (5) years. At least three (3) In-Line-Inspection surveys have been run on this line, the latest were 2002, 2007 and 2010. All actionable anomalies were repaired in the proper time frames.

- Because of the "slack line" phenomena, CPL's leak detection system triggered numerous false alarms. SCADA controllers could not reliably recognize an actual release below a certain threshold without the leak detection system generating false alarms.

June 11, 2010 Release:

Post release investigation revealed that a large electrical surge was experienced at the electric transfer station located on Chevron's ROW, and just to the southeast of Red Butte Creek. This electrical surge event left an approximate one (1) inch hole in the bottom of the metal fence post and left an approximate one half (1/2) inch hole in the top of the crude oil pipeline. Crude oil was released from the 1/2" hole in the pipe and it flowed to the surface and downhill into Red Butte Creek. There was some arcing damage at the block valve installation approximately 300 feet downstream of the release site where the electrical current tried to discharge from the pipe. This block valve site is known as the Red Butte block valve and was the location of the December 1, 2010 release.

It was revealed during the investigation into the June 11, 2010 crude release that CPL did not have an adequate leak detection system on their Number 2 crude line. It took a CPL controller 10 hours to realize there was a release on the pipeline and only then due to a call from the SLC Fire Department. Much of this was thought to be due to their operating in "slack" line conditions; however, CPL had performed a study to identify potential improvements to their leak detection system in 2007, but had not implemented any of the recommendations before the June 11, 2010 release. After the June release, PHMSA required CPL to implement the improvements identified by the 2007 leak detection study as well as any more recent improvements identified.

December 1, 2010 Release:

PHMSA personnel interviewed eight (8) Chevron employees who were involved in the identification of the December 1, 2010, release. We also reviewed many of CPL's written procedures and reviewed numerous records and SCADA logs during the investigation into this release. The following is a factual summary and analysis of the investigation.

NOTE: Salt Lake City (SLC) is on Mountain Standard Time (MST) and Houston is on Central Standard Time (CST). Because CPL's Control Center is in Houston, TX all of their times are reported as CST. An attempt has been made to show both times when required to assist in the understanding of the report.

Controller Actions Before the Release[1]:

The controller who was on duty during the release started his 12 hour shift at 6:00pm CST on the evening of November 30, 2010, a Tuesday. He recollected that the line Number 2 was operating at a reduced rate of 800 Barrels per Hour (BPH). They were preparing to shut down the line to perform their routine monthly tally. At 5:06am CST, on December 1, 2010, SCADA logs showed that the pumps at Hanna were shut down for the monthly close out. A shift change was performed and a second controller took over the console at 6:00am CST. At 6:14am CST the Salt Lake (SL) Station valve was closed.[2] The monthly tally was completed and all appropriate equipment was reset and the Hanna Station pump was started at 11:34am CST. At 1:07pm CST the valve at CPL's SL delivery was opened.[3] A review of the SCADA alarm logs shows numerous deviation alarms between 11:35am CST and the point at which the Pipeline Leak Monitoring[4] (PLM) system was reset at 4:02pm CST. At 6:00pm CST on December 1, 2010, the first controller came back on duty. During this shift change, he and the previous controller went over the parameters of the line.

At 6:21pm CST (5:21pm MST), a "1 hour cumulative line loss deviation alarm"[5] was received. The controller called SLC field personnel at 7:00pm CST (6:00pm MST) to discuss the deviation alarm. They did additional analysis and trending but by 8:23pm CST (7:23pm MST) a conference call was initiated with additional field personnel including supervisors. It was mentioned that they had launched a scraper pig on Monday at Hanna station and they were

[1] See Control Room Time Line - Exhibit 1
[2] There is a delay of approximately 1 to 1 1/2 hour from pump off @ Hanna to valve closure @ SLC to allow the kinetic energy in the line to dissipate and the fluid to drain into SL Station.
[3] It takes a period of time to pack the line after a shut down due to the drain up into SLC Station.
[4] PLM is the SCADA designation for CPL's Automatic "Pipeline Leak Monitoring" System.
[5] After the June 2010 release, CPL upgraded their leak detection system. The addition of this 100 BBL deviation alarm was one of the enhancements.

unsure if the pig was still in the line or not.[6] It was discussed that the different densities of crudes in the line as well as erratic movement of the pig could cause the type of alarm received. An employee was sent to check the pig trap. At 9:30pm CST (8:30 MST) the pig was confirmed to be in the trap at the SL Station. At this time, the decision was made to shut down the Hanna Pumps to ready the line for a stand up leak test. The SCADA trends show the Hanna Pumps were turned off at 9:40pm CST (8:40 MST). From the first alarm @ 6:22pm CST to shut down @ 9:40pm CST = 3 hours 18 minutes.

<u>Field Personnel Actions prior to the release:</u>
The Salt Lake Area Field Team Leader (TL) had taken leave Wednesday, 12/1/10 through Sunday, 12/5/10. The Salt Lake Field Operations Supervisor (OS) was filling in for the TL during this time period. The OS started his day on Wednesday morning at the SL Station. There was work to be done in Pocatello, ID so the OS drove there to assist in the performance of a safety review as part of the CPL Management of Change (MOC) process. The OS stayed Wednesday night in Pocatello. A field hand from SL Station called the OS at approximately 8:00pm and told him that the controller had called and there was some problem with the leak detection system and they were setting up a conference call. During the call, the OS mentioned that they had launched a scraper pig on Monday and he asked if the pig had arrived at SL Station yet. This was not yet known, so the field hand was sent to check for the pig and the call was ended. The OS took this opportunity to log onto the CPL SCADA system remotely from his hotel room to do some research and trending of pressures, etc.[7] At this point, the pig was confirmed in the trap and the call was resumed. The OS told the group that he had looked at the SCADA information and he didn't see any reason for the alarm so he recommended that the line be shut down and pressures monitored until the morning (leak test). Others on the call agreed so the controller shut down the pump at Hanna Station. This was done at 8:38pm MST.

The group on the call started discussing whether to send out personnel to patrol the line. It was dark and it had been snowing during the evening. It was discussed that the abnormally cold weather might cause the crude in the line to solidify if left stagnant for any extended length of time. Also, tank volumes were discussed. The group decided to call in some of the field personnel and have them ride the ROW to check it for a release. The field folks all were called at approximately 9:00pm MST (10:00pm CST) and arrived at the SL Station to pick up their trucks by around 9:30pm (10:30pm CST). One person left to drive up to Camas where he was going to check the river crossings and come north while two other crews were to start at the Beck Street block valve and drive south. At some point, the two crews decided to split up. One drove to Little Mountain Block Valve site and the other continued along the ROW.

[6] There is a pig signal upstream of the pig trap but it was described as "unreliable".
[7] CPL personnel are able to view-only real time SCADA data via the internet.

At 11:15pm MST (12:15pm CST) a crew arrived at the Red Butte block valve and found the release. They immediately called their supervisor and were told to call 911 and assume the position of Incident Command until help arrived. The University Campus Police came by and were requested to set up a security perimeter until the regular police and fire department arrived. CPL personnel called out their emergency response contractor. Within an hour the response was in full force. The other crew that was moving north was called and told to close the Little Mountain Block valve and the SL Station was called and they were asked to open the main line valve to drain the crude out of the line.

Emergency Response:

As soon as the Fire Department arrived, one of the fire chiefs went across the creek and asked a backhoe operator to come over and build a berm to keep the crude from getting into Red Butte Creek. This contractor was working 24 hour days on a project for the university, adjacent but across the creek to the southwest. The fire department personnel also installed precautionary booms in the creek. An Incident Command Center (ICC) was set up in the parking lot just to the south of the release. CPL's contract personnel arrived with their vacuum trucks and personnel. The immediate area of the release was identified to be the valve vault and the first vacuum truck was set up there and put to work sucking the crude out of the vault. Air monitors were utilized to establish a "hot" zone and a "safe" zone around the release.

The CPL first responders who were in charge of removing the crude from the vault reported seeing crude oil flowing out of the 6" valve stem area just upstream of the 10" main line valve known as the Red Butte Block Valve. They reported that after they vacuumed all of the crude they could, the vault would fill up again because of the ongoing release. The next upstream valve was the Little Mountain Block Valve and it had already been closed and the downstream valve had been open to allow drain up into the station.

The NRC Report and PHMSA's Response:

On the night of December 1, 2010, CPL called the National Response Center (NRC) to report the release of 100 barrels (BBLs) of crude oil @ 11:54:16 pm MST.[8] A second call was made in the early morning hours of December 2, 2010; @ 01:02:39 MST[9] to revise the commodity spilled from crude oil to crude oil condensate.

A PHMSA representative was in Brigham City, UT, an hour north of the release site, performing a construction inspection on the morning of Thursday, December 2, 2010. The representative was dispatched to the release site and arrived at approximately 8:30 MST. The WR Accident Coordinator was dispatched also with an estimated time of arrival of early afternoon December 2, 2010.

[8] See NRC Report # 961183 Exhibit 2
[9] See NRC Report # 961184 Exhibit 3

At 1:30 pm MST, the Western Region Accident Coordinator arrived at the release site and checked in with the ICC. A briefing meeting was held with the on-site PHMSA representative. An investigation plan was made up which included a list of personnel to be interviewed. A list of required procedures and records was also compiled. The next few days were focused on understanding the event, interviewing CPL personnel, gathering appropriate information as well as making the vault area safe for the removal of the valve.

The Investigation:

PHMSA interviewed 8 personnel from CPL including:

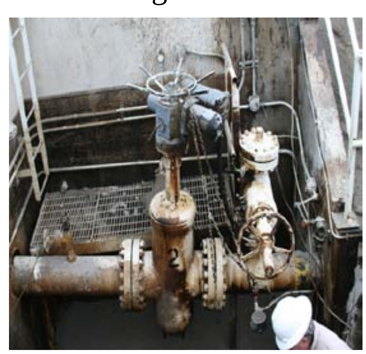
1. Field Team Leader – 10+ years experience
2. Pipeline Controller – 8 years experience
3. Facility Inspector – 2 years experience
4. Senior Mechanic – 25 years experience
5. Mechanic – 4 years experience
6. CP Technician – 7 years experience
7. Facility Inspector – 20 years experience (performed valve maintenance)
8. Operations Supervisor – 25 years experience

PHMSA reviewed appropriate procedures and records, interviewed appropriate CPL personnel, observed the valve removal, preservation and chain-of-custody of the failed valve. The valve was crated up under the observation of PHMSA personnel and the valve was placed in the custody of CPL until a metallurgical laboratory could be identified to examine the valve.

CPL chose Stress Engineering Services (SES) in Houston, TX to perform the forensic analysis of the valve. To the right is a picture of the Red Butte Block valve installation after the June release but before the stand up water test. Notice the flange at the top of the 6" valve to the right in the picture below (Figure 1). CPL had to replace the full flange on this subject valve with a flange with a weld-o-let penetrating it to allow water to be injected into the line for the June 2010, stand up water test. In the next picture (Figure 2), one can see the same flange with a bull plug in it as well as the fact that the downstream valve was removed because the electricity jumped off the line at this point and had damaged the line. A spool piece was installed downstream of the main line valve following the valve removal in June 2010.

Figure 1

Figure 2



After the stand up test was performed in June 2010, the water in the line was drained back into the refinery and disposed of per CPL's procedures. The specific procedures developed for the "stand up" test were reviewed and they did not contain any statements concerning removing water from the injection valve.

The water injection valve was a 6" WKM Gate Valve known as a Model D Lever-lock. The imprints on the valve were, "WKM, Houston, Texas, USA Lever-lock, 6-600, Steel, D 22145" the valve is thought to be originally installed in 1952 during the construction of the Number 2 line as there are no records to show otherwise. The valve was originally installed in the horizontal position shown as a cross over valve between the Number 1 and the Number 2 line. Since the Number 1 line was taken out of service a few years ago, the piping between the valves on the two lines had been removed.

Once the vault was cleaned up and made safe to enter, PHMSA was able to inspect the release site. It appeared that the valve bonnet had been pushed away from the body of the valve by some force from the "bottom-right" in the picture at the right to the "top-left." There was a locked chain looped between the 10" valve handle and the 6" valve handle. It appeared that if the hand wheel on the 10" valve were to have been operated remotely, there may have been enough force applied to cause the damage to the 6" valve bonnet. (Figure 3).


Figure 1

The 10" main line valve had an actuator and motor installed on it. CPL was asked to explain the operation of the valve. It was determined that the valve actuator was designed so during remote operation of the valve, the hand wheel could not move. In fact, the only way to move the hand wheel was to place the valve actuator in manual mode (disengage the motor operator) and then one is able to open or close the valve by moving the hand wheel.

As this failure mechanism was ruled out, there appeared to be only one additional force that could have caused the valve to fail as it did and that was a force from the inside of the valve. Having investigated the release in June, the PHMSA Accident Coordinator was familiar with the repairs made at that time and the fact that a stand up test with water was performed after the repairs. It was also known that this valve was the water injection point for that stand up water test.

PHMSA reviewed the valve inspection records for 2010[10] and they showed that this valve was last inspected on September 20, 2010. In reviewing the records for that inspection, it showed

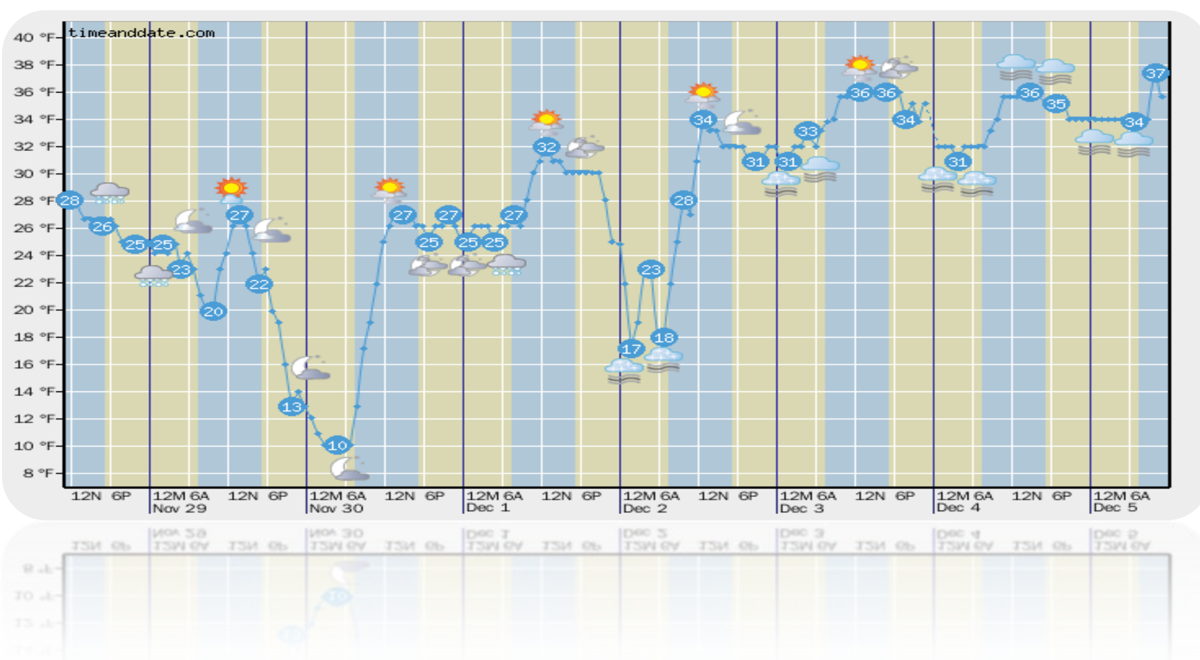
[10] See the 2010 Valve Inspection Records – Exhibit 8

that the CPL technician had operated the 6" water injection valve during that inspection. This was a little confusing because that may have flushed the water out of the valve and then water freezing inside the valve might be ruled out as a failure mechanism.

The CPL employee who performed the valve inspections in October was interviewed on the evening on December 4, 2010, and the valve inspection records were discussed in detail. Each item on the valve report form was discussed and defined by the technician. The 6" water injection valve was identified on the valve inspection form as "FORT DOUGLAS #2 Xover 6" 600 WKM @ MP 174.7" located upstream of the 10" main line valve. When the CPL technician saw that the form under "OPERATION" had "OK" entered, he immediately said, "That is a mistake. I didn't operate that valve. I don't normally operate cross over valves."

Salt Lake City Temperature History:

Because water freezing inside the valve was suspected as the cause of the valve failure, historical temperatures for the area were checked on the internet. Below is a graph of the temperatures encountered in Salt Lake City 12 noon November 28, 2010 through 6 am December 5, 2010. One can see from the graph that the temperatures were well below 32 degrees Fahrenheit (F) from before November 28 2010, until after the release was discovered on the night of December 1, 2010. During this period, the line was shut down for the month end tally for 6 and one half hours in the early morning of Wednesday, December 1, 2010. The line was started up at 10:34am MST (11:34 am CST) on December 1, 2010. The temperature got up to 32 degrees F and the sun was out all day. The temperature of the crude being pumped through the line was at approximately 50 degrees F.



Forensic Analysis of the Failed Valve[11]

The Forensic Analysis of the failed valve was performed by Stress Engineering Services (SES) out of Houston, TX. The report confirms that there was indeed a flow path created by a force internal to the valve which was most likely the pressure created when water freezes and expands in an enclosed space. SES calculated the volume of the crude out of the valve at an upper bound of 6 cubic feet per hour. The final estimate of volume released from CPL was 500 BBLs. At 6 cubic feet per hour it would take 467 hours to release 500 BBLs. This equates to about 19 and one half days. We know the flow rate of the release was greater than this. If we take the flow rate to be 6 cubic feet per minute, it would take 467 minutes or 7.78 hours to release 500 BBLs. This is more realistic and it fits well to the timeline. There is further discussion on this point below.

Discussions with SES:

After performing rough calculations utilizing the maximum flow rate proposed by the report, it was apparent that the calculations were too conservative. I called the engineers who performed the forensic analysis to discuss their findings. The engineer stated that per their analysis, the leak path was about the size of the hole in a coffee stirrer. That is why the release rate was so small. They also explained that they had no information about the ultimate volume out or the density of the fluid or any first hand information of the leak volume, etc.

I explained that the first hand information was that the leak was actually flowing maybe 3 inches up into the air between the 12:00 and 3:00 area of the valve bonnet after the level of the crude oil condensate was first brought down below the level of the top of the valve. Also, they were interested to know that the product released was actually crude oil condensate and not crude oil. Crude oil condensate is much less viscous and, therefore, would have flowed more easily through the leak path in the valve.

After discussing these facts with SES engineers, they did relate that their analysis would not account for any elastic deformation inside the valve which would account for a greater size leak path. After our discussions, the forensic engineers thought that the release could have been as large as an approximate ¾” cross section leak path. The upper limit of flow rate would then be more like 6 cubic feet per minute which was discussed above. The approximate 65 psig pressure in the line at the valve location while the line was flowing would have created an approximate 3200 psi force on the inside of the valve which would have kept the elastic deformation flow path opened until the pressure was relieved.

Final Analysis:

In the final analysis, we know that 500 BBLs of crude oil condensate was released from the valve. If the leak rate was 6 cubic feet per minute, then it would have taken 467 minutes (7.78

[11] See the SES Report - Exhibit 4.

hours) for 500 BBLs to be released. The vault and the "depression" of earth around the vault were calculated to have a volume of approximately 250 BBLs. If one subtracts 7.78 hours from the time the release was stopped at 12:47am MST (1:47am CST) on December 2, 2010, it appears that the release could have started as early as 4:00pm MST (5:00pm CST) on the afternoon of Wednesday, December 1, 2010.

At 5:22pm MST (6:22pm CST), the time line shows the controller in Houston received the first one (1) hour leak detection alarm. At 6 cubic feet per minute, the volume out in 1 hour 22 minutes would be 117 BBLs. This correlates well with the first received leak alarm. It also makes sense that the release would have started as a slow trickle and would have grown larger and larger as the ice inside the valve would have melted. By the time 250 BBLs was released, the crude oil condensate had filled the area around the vault and started flowing toward the creek; it would have been approximately 8:00pm MST (9:00pm CST). The crude then oozed out of the fenced area and started flowing down hill toward the creek. At 11:15pm MST (12:15 CST) the release was discovered and by 12:47pm MST (01:47am CST), the fluid flow in the pipeline had stopped.

Summary of initial start-up plan and return-to-service, including preliminary safety measures:

This was the second release in the area of the Red Butte Creek crossing of the Chevron Pipeline within the last six (6) months. The public and city and county officials were understandably very concerned about the safety of the pipeline and its impact on public safety and the environment. PHMSA observations and review of operation and maintenance documents indicated the valve failed because the 6-inch valve used to inject water in June 2010 was not properly drained and winterized after the stand up water test. CPL had just run another In-Line-Inspection (Smart Pig) survey in September, and the results that showed there were no actionable anomalies requiring repair in the pipe in the last 14 miles of pipe from Little Mountain to Salt Lake Station.

Because CPL determined that the line would not return to service for an extended time and the fact that the temperatures were quite low this time of year, Chevron determined that it would be safer to purge the crude oil from the line with nitrogen. This was beneficial for two main reasons. First, if the crude was allowed to stay in the pipeline for an extended length of time, it was possible that the crude would solidify in the line making it impossible to restart the line until sometime in the spring or summer. Secondly, it would allow CPL the ability to open the pipeline to perform other Smart pig digs and repairs, remove and/or replace valves, and install any required appurtenances on the line.

After the June release, PHMSA ordered CPL to make enhancements to their leak detection system. The Controller's actions during this release appear to substantiate at least some improvements were made. After this second release, PHMSA ordered CPL to add external leak detection at their above ground facilities. CPL decided to install video surveillance at their above ground valves and stations and installed liquid level indicators at their vaults.

PHMSA coordinated closely with the city during the preparation for the purging operation. The city was also kept informed of the purging process. Additionally, the city hired an outside pipeline consultant who performed a review of CPL's pipeline system and provided a report to the city on the pipeline's integrity and ability to operate safely. The consultant identified some safety measure items where CPL could improve their overall safety, and they were considered in PHMSA's approval of Chevron's restart letter. PHMSA was requested by the city to keep the consultant apprised of pertinent events and did so during the period prior to and immediately after restarting the line.

CPL submitted their restart plan on January 25, 2011, 55 days after the line was shut down. PHMSA reviewed the plan, worked with CPL personnel and city personnel as well as the city consultant for their thoughts and concerns on the plan. Based on the collective input, PHMSA provided comments on the plan to CPL. On Thursday January 27, 2011, PHMSA approved the restart plan. Because of some logistical concerns, CPL was not able to get everything in place to restart the line before Tuesday, February 1, 2011. At 8:28 am MST (9:28am CST), CPL restarted the Number 2 crude oil pipeline from Hanna Station to SL Station. A PHMSA representative was on-site for the entire restart operation.

Exhibits

Exhibit #1 – Chevron Control Center Time Line

Exhibit #2 – NRC Report #961183

Exhibit #3 – NRC Report #961184

Exhibit #4 – SES RB II Valve – Final Report 1_24_11

Exhibit #5 – CPL Findings and Recommendations 2nd Valve release

Exhibit #6 – CPL Accident Report to PHMSA

CSC Timeline	
Date/Time	**CSC Event Log**
12/1/2010 5:06	The Hanna Pump station was shutdown in preparation for the month end close-out
12/1/2010 6:14	The block valve was closed at the Salt Lake Station, ending the crude delivery into the Salt Lake Station
12/1/2010 11:34	The Hanna Pump Station was started to resume delivery into Salt Lake
12/1/2010 11:35	The CSC received the 1 Minute (ST1) PLM Alarm.
12/1/2010 11:37	The CSC received the 10 Minute (ST2) PLM Alarm.
12/1/2010 11:39	The CSC received the 20 Minute (ST3) PLM Alarm.
12/1/2010 11:41	The CSC received the 1 Hour (LT1) PLM Alarm.
12/1/2010 12:00	The CSC received the 12 Hour (LT2) PLM Alarm.
12/1/2010 13:00	The CSC received the 24 Hour (LT3) PLM Alarm.
12/1/2010 13:07	The block valve at Salt Lake was opened to resume crude delivery to customer.
12/1/2010 16:02	The CSC resets the Long Term PLM Alarms
12/1/2010 18:00	The CSC does shift change
12/1/2010 18:21	The CSC received the 1 Hour (LT1) PLM Alarm.
12/1/2010 18:28	The 1 Hour (LT1) PLM Alarm returns to Normal
12/1/2010 18:29	The CSC received the 1 Hour (LT1) PLM Alarm.
12/1/2010 18:30	The CSC starts to investigate PLM deviation.
12/1/2010 19:00	The CSC calls Doug Kipfer (Op Rep) to participate in the deviation investigation.
	Historical Condensate delivery data was reviewed.
	The Hanna Outgoing meter factor was verified as comparable to previous Outgoing meter factor.
	The Salt Lake Station meter factor was verified as comparable to previous meter factor.
	Note: Both Hanna and Salt Lake meters were proved at the beginning of month.
	The high amount of Condensate in the line at start-up was reviewed.
	The customer receiving deliver was contacted to verify no operations changes occurred.
	All operational parameters at Salt Lake Station pertaining to the crude delivery was verified as no effect on PLM
	The decision to notify Benny Rager and Bart Smith was made
12/1/2010 19:30	The CSC contacts the Salt Lake Operator to verify status of the incoming scraper
12/1/2010 19:45	The CSC called the Hanna operator to verify time when scraper was launched.
12/1/2010 20:23	Benny Rager, Bart Smith, Billy Bown, Joe Miller, and Doug Kipfer on conference call to review PLM deviation
	The possibility of a scraper transitioning into Salt Lake was discussed and the SL Operator was asked to verify scraper arrival.
12/1/2010 21:15	The Salt Lake Operator verified the scraper had arrived.
12/1/2010 21:30	Benny Rager, Bart Smith, and Doug Kipfer make the decision to shutdown the Hanna to Salt Lake crude
	and do a stand up pressure test until morning.
12/1/2010 21:38	The CSC shutdown the Hanna Station to terminate the outgoing flow.
12/1/2010 22:53	The block valve was closed at the Salt Lake Station, ending the crude delivery into the Salt Lake Station
12/2/2010 0:15	The CSC received notification from Field Team that a leak was found
12/2/2010 0:27	The block valve at Salt Lake was opened to drain Condensate out of line into Salt Lake Station to delivery point.
12/2/2010 1:43	The block valve was closed at the Salt Lake Station, ending the crude delivery into the Salt Lake Station

Pipeline & Hazardous Materials Safety Administration PHMSA

(Version 3.4.05 PROD)

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Rescinded **Comments** (max 250 characters)

NRC Number:	**961183**		
Call Date:	**12/02/2010**	**Call Time:**	**01:54:16**

Caller Information

First Name:	JOSEPH	Last Name:	WHITE
Company Name:	CHEVRON PIPELINE CO.		
Address:	4800 FOURNACE PL		
City:	BELLAIRE	State:	TX
Country:	USA	Zip:	77401
Phone 1:	2816301927	Phone 2:	7134326167
Organization Type:	PRIVA	Is caller the spiller?	(•) Yes ( ) No ( ) No Response
Confidential:	( ) Yes (•) No ( ) No Response		

Discharger Information

First Name:	JOSEPH	Last Name:	WHITE
Company Name:	CHEVRON PIPELINE CO.		
Address:	4800 FOURNACE PL		
City:	BELLAIRE	State:	TX
Country:	USA	Zip:	77401
Phone 1:	2816301927	Phone 2:	7134326167
Organization Type:	PRIVA		

Spill Information

State:	UT	County:	SALT LAKE
Nearest City:	SALT LAKE CITY	Zip Code:	

Location

Spill Date:	12/01/2010 (mm/dd/yyyy)	Spill Time:	23:00:00 (24hh:mm:ss)
DTG Type:	OCCURRED		
Incident Type	PIPELINE	Reported Incident Type	PIPELINE

Description

RELEASE OF MATERIAL FROM A PIPELINE DUE TO UNKNOWN CAUSES.

Materials Involved

Material / Chris Name	Chris Code	Total Qty.	Water Qty.
OIL: CRUDE	OIL	100 BARREL(S)	0 UNKNOWN AMOUNT

Medium Type: SOIL

Additional Medium Information:

Injuries: Fatalites:

Evacuations: Yes No Unknown No. of Evacuations:

Damages: Yes No Unknown Damage Amount:

Federal Agency Notified: Yes No Unknown State Agency Notified: Yes No Unknown

Other Agency Notified: Yes No Unknown

Remedial Actions

EMERGENCY RESPONSE EN ROUTE

Additional Info

NO ADDITIONAL INFORMATION.

Latitude

Degrees: 40 Minutes: 45 Seconds: 59 Quadrant: N

Longitude

Degrees: 111 Minutes: 49 Seconds: 38 Quadrant: W

Distance from City: Direction:

Section: Township:

Range: Milepost:

Pipeline & Hazardous Materials Safety Administration

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Rescinded **Comments** (max 250 characters)

NRC Number:	**961184**		
Call Date:	**12/02/2010**	**Call Time:**	**03:02:39**

Caller Information

First Name:	JOSEPH	Last Name:	WHITE
Company Name:	CHEVRON PIPELINE CO.		
Address:	4800 FOURNACE PL		
City:	BELLAIRE	State:	TX
Country:	USA	Zip:	77401
Phone 1:	2816301927	Phone 2:	7134326167
Organization Type:	PRIVA	Is caller the spiller?	(•) Yes ( ) No ( ) No Response
Confidential:	( ) Yes (•) No ( ) No Response		

Discharger Information

First Name:	JOSEPH	Last Name:	WHITE
Company Name:	CHEVRON PIPELINE CO.		
Address:	4800 FOURNACE PL		
City:	BELLAIRE	State:	TX
Country:	USA	Zip:	77401
Phone 1:	2816301927	Phone 2:	7134326167
Organization Type:	PRIVA		

Spill Information

State:	UT	County:	SALT LAKE
Nearest City:	SALT LAKE CITY	Zip Code:	

Location

Spill Date:	12/01/2010 (mm/dd/yyyy)	Spill Time:	00:28:00 (24hh:mm:ss)
DTG Type:	OCCURRED		
Incident Type	PIPELINE	Reported Incident Type	PIPELINE

Description

RELEASE OF MATERIAL FROM A PIPELINE DUE TO UNKNOWN CAUSES.

Materials Involved

Material / Chris Name	Chris Code	Total Qty.	Water Qty.
CRUDE OIL CONDENSATE	OTH	100 BARREL(S)	

Medium Type: SOIL

Additional Medium Information:

Injuries: Fatalites:

Evacuations: Yes No Unknown No. of Evacuations:

Damages: Yes No Unknown Damage Amount:

Federal Agency Notified: Yes No Unknown State Agency Notified: Yes No Unknown

Other Agency Notified: Yes No Unknown

Remedial Actions

EMERGENCY PERSONNEL ON SCENE

Additional Info

NO ADDITIONAL INFORMATION.

Latitude

Degrees: 40 Minutes: 45 Seconds: 59 Quadrant: N

Longitude

Degrees: 111 Minutes: 49 Seconds: 38 Quadrant: W

Distance from City: Direction:

Section: Township:

Range: Milepost:

Exhibit 4 SES RB II Valve – Final Report 1_24_11

Stress Engineering Services Investigation

January 24, 2011

This document is on file at PHMSA

03-18-11P01:49 RCVD

Chevron

Gary M. Saenz
Team Leader

Chevron Pipe Line
Global Gas
4800 Fournace Place
Bellaire, TX 77401-2324
Tel (713) 432-3332
garysaenz@chevron.com

March 17, 2011

Electronic Transmittal

Mr. Chris Hoidal
Director, Western Region
Pipeline and Hazardous Materials Safety Administration
12300 W, Dakota Ave., Suite 110
Lakewood, CO 80228

RE: Chevron Pipe Line Company – Salt Lake, UT
Accident Investigation Findings & Recommendations

Dear Mr. Hoidal:

Pursuant to your request, attached is Chevron Pipe Line Company's (CPL) accident report findings and recommendations regarding the failure that occurred on December 1, 2010, on the 10-inch diameter crude pipeline system in Salt Lake City, UT.

Should you have any questions, please contact me.

Sincerely,

Attachment

Electronic Transmittal
cc: PHP-500 P. Katchmar
T.P. Duhon, Asset VP
T.W. Harlan, CPL Sr. Counsel

Incident Report

Report Type: Incident	**Incident Type:** Release	**Date Occurred:** 12/01/2010
Team: Salt Lake	**Location:** Red Butte Area	**State:** Utah
Incident Description:		
On 01 DEC 10, Chevron Pipe Line (CPL) controller noticed an over-short on the Salt Lake Crude System. The line was shut down @ 20:30 MST and Field Personnel were dispatched to investigate. Personnel discovered a release of 500 bbls of Condensate Mixture to land near the Red Butte Block Valve compound. Local 911 were contacted for assistance and Salt Lake Fire Department was dispatched. Emergency response personnel were dispatched to the area. No impact to Red Butte Creek.		

Findings

1	The original equipment manufacturer recommendations that address winterization were not consulted and utilized for routine valve maintenance and water standup procedures; No formal winterization plan to find and correct this circumstance; when valve was in jump-over service, there were specific maintenance procedures to flush water from the equipment.
2	Water standup test / commissioning procedures were only high-level procedures lacking site-specific details of execution (removal of water from all of the pipeline equipment).
3	Test procedure was developed without adequate input and communication; Operations personnel were not aware that water was isolated in the valve after commissioning.

Recommendations

1	Develop and communicate "If Report" to address Red Butte Valve Box Release incident, Root Cause Analysis findings, and corrective actions.
2	Review equipment specific original equipment manufacturer manuals and recommendations to develop and implement written winterization plan for Mid-Con Asset Northwest operations field teams and address equipment susceptible to freezing.
3	Identify procedures that involve introduction of water to process flow or control systems to include steps for dewatering and drying prior to placing back in service; incorporate Sections 5.4.6 and 5.8 from Maintenance and Inspection Procedure (MIP) 301 Pipe Hydrostatic Testing.
4	Train appropriate Mid-Con Asset Northwest operations field team personnel on Pre-Startup Safety Review process to assure information transfer when operational control shifts from one group to another.
5	Evaluate non-DOT valve maintenance program for separation from DOT valve maintenance and implement appropriate changes.

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.	OMB NO: 2137-0047 EXPIRATION DATE: 01/31/2013

U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Report Date:**	12/30/2010
	No.	20100317 - 15832 -------------------------- (DOT Use Only)

ACCIDENT REPORT - HAZARDOUS LIQUID PIPELINE SYSTEMS

INSTRUCTIONS

Important: *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the PHMSA Pipeline Safety Community Web Page at http://www.phmsa.dot.gov/pipeline.*

PART A - KEY REPORT INFORMATION

Report Type: *(select all that apply)*	**Original:**	**Supplemental:**	**Final:**
		Yes	

Last Revision Date:	05/27/2011
1. Operator's OPS-issued Operator Identification Number (OPID):	2731
2. Name of Operator	CHEVRON PIPE LINE CO
3. Address of Operator:	
3a. Street Address	4800 FOURNACE PLACE, Rm C382A
3b. City	BELLAIRE
3c. State	Texas
3d. Zip Code	774012324
4. Local time *(24-hr clock)* and date of the Accident:	12/01/2010 17:00
5. Location of Accident:	
Latitude:	40.766643
Longitude:	-111.827358
6. National Response Center Report Number (if applicable):	961183
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	12/01/2010 23:51
8. Commodity released: *(select only one, based on predominant volume released)*	Crude Oil
- Specify Commodity Subtype:	
- If "Other" Subtype, Describe:	
- If Biofuel/Alternative Fuel and Commodity Subtype is Ethanol Blend, then % Ethanol Blend: %:	
- If Biofuel/Alternative Fuel and Commodity Subtype is Biodiesel, then Biodiesel Blend (e.g. B2, B20, B100): B	
9. Estimated volume of commodity released unintentionally (Barrels):	500.00
10. Estimated volume of intentional and/or controlled release/blowdown (Barrels):	
11. Estimated volume of commodity recovered (Barrels):	500.00
12. Were there fatalities?	No
- If Yes, specify the number in each category:	
12a. Operator employees	
12b. Contractor employees working for the Operator	
12c. Non-Operator emergency responders	
12d. Workers working on the right-of-way, but NOT associated with this Operator	
12e. General public	
12f. Total fatalities (sum of above)	
13. Were there injuries requiring inpatient hospitalization?	No
- If Yes, specify the number in each category:	
13a. Operator employees	
13b. Contractor employees working for the Operator	
13c. Non-Operator emergency responders	
13d. Workers working on the right-of-way, but NOT	

associated with this Operator	
13e. General public	
13f. Total injuries (sum of above)	
14. Was the pipeline/facility shut down due to the Accident?	Yes
- If No, Explain:	
- If Yes, complete Questions 14a and 14b: *(use local time, 24-hr clock)*	
14a. Local time and date of shutdown:	12/01/2010 20:30
14b. Local time pipeline/facility restarted:	02/02/2011 08:00
- Still shut down? (* Supplemental Report Required)	
15. Did the commodity ignite?	No
16. Did the commodity explode?	No
17. Number of general public evacuated:	0
18. Time sequence *(use local time, 24-hour clock)*:	
18a. Local time Operator identified Accident:	12/01/2010 23:30
18b. Local time Operator resources arrived on site:	12/01/2010 23:30

PART B - ADDITIONAL LOCATION INFORMATION

1. Was the origin of Accident onshore?	Yes
If Yes, Complete Questions (2-12)	
If No, Complete Questions (13-15)	
- If Onshore:	
2. State:	Utah
3. Zip Code:	84113
4. City	Salt Lake City
5. County or Parish	Salt Lake
6. Operator-designated location:	Milepost/Valve Station
Specify:	175.0
7. Pipeline/Facility name:	Red Butte Block Valve Site
8. Segment name/ID:	Rangely to Salt Lake Crude System
9. Was Accident on Federal land, other than the Outer Continental Shelf (OCS)?	No
10. Location of Accident:	Originated on Operator-controlled property, but then flowed or migrated off the property
11. Area of Accident (as found):	Aboveground
Specify:	Other
- If Other, Describe:	Valve vault (box)
Depth-of-Cover (in):	
12. Did Accident occur in a crossing?	No
- If Yes, specify below:	
- If Bridge crossing –	
Cased/ Uncased:	
- If Railroad crossing –	
Cased/ Uncased/ Bored/drilled	
- If Road crossing –	
Cased/ Uncased/ Bored/drilled	
- If Water crossing –	
Cased/ Uncased	
- Name of body of water, if commonly known:	
- Approx. water depth (ft) at the point of the Accident:	
- Select:	
- If Offshore:	
13. Approximate water depth (ft) at the point of the Accident:	
14. Origin of Accident:	
- In State waters - Specify:	
- State:	
- Area:	
- Block/Tract #:	
- Nearest County/Parish:	
- On the Outer Continental Shelf (OCS) - Specify:	
- Area:	
- Block #:	
15. Area of Accident:	

PART C - ADDITIONAL FACILITY INFORMATION

1. Is the pipeline or facility:	Interstate
2. Part of system involved in Accident:	Onshore Pipeline, Including Valve Sites
- If Onshore Breakout Tank or Storage Vessel, Including Attached Appurtenances, specify:	
3. Item involved in Accident:	Valve

- If Pipe, specify:	
3a. Nominal diameter of pipe (in):	
3b. Wall thickness (in):	
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	
3d. Pipe specification:	
3e. Pipe Seam , specify:	
- If Other, Describe:	
3f. Pipe manufacturer:	
3g. Year of manufacture:	
3h. Pipeline coating type at point of Accident, specify:	
- If Other, Describe:	
- If Weld, including heat-affected zone, specify:	
- If Other, Describe:	
- If Valve, specify:	Auxiliary or Other Valve
- If Mainline, specify:	
- If Other, Describe:	
3i. Manufactured by:	
3j. Year of manufacture:	
- If Tank/Vessel, specify:	
- If Other - Describe:	
- If Other, describe:	
4. Year item involved in Accident was installed:	
5. Material involved in Accident:	Carbon Steel
- If Material other than Carbon Steel, specify:	
6. Type of Accident Involved:	Other
- If Mechanical Puncture – Specify Approx. size:	
in. (axial) by	
in. (circumferential)	
- If Leak - Select Type:	
- If Other, Describe:	
- If Rupture - Select Orientation:	
- If Other, Describe:	
Approx. size: in. (widest opening) by	
in. (length circumferentially or axially)	
- If Other – Describe:	The valve is currently being analyzed for the cause.

PART D - ADDITIONAL CONSEQUENCE INFORMATION

1. Wildlife impact:	No
1a. If Yes, specify all that apply:	
- Fish/aquatic	
- Birds	
- Terrestrial	
2. Soil contamination:	Yes
3. Long term impact assessment performed or planned:	
4. Anticipated remediation:	Yes
4a. If Yes, specify all that apply:	
- Surface water	
- Groundwater	
- Soil	Yes
- Vegetation	Yes
- Wildlife	
5. Water contamination:	No
5a. If Yes, specify all that apply:	
- Ocean/Seawater	
- Surface	
- Groundwater	
- Drinking water: *(Select one or both)*	
- Private Well	
- Public Water Intake	
5b. Estimated amount released in or reaching water (Barrels):	
5c. Name of body of water, if commonly known:	
6. At the location of this Accident, had the pipeline segment or facility been identified as one that "could affect" a High Consequence Area (HCA) as determined in the Operator's Integrity Management Program?	Yes
7. Did the released commodity reach or occur in one or more High Consequence Area (HCA)?	Yes
7a. If Yes, specify HCA type(s): *(Select all that apply)*	
- Commercially Navigable Waterway:	
Was this HCA identified in the "could affect"	

determination for this Accident site in the Operator's Integrity Management Program?	
- High Population Area:	Yes
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	Yes
- Other Populated Area	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Unusually Sensitive Area (USA) - Drinking Water	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Unusually Sensitive Area (USA) - Ecological	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
8. Estimated cost to Operator :	
8a. Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator	$ 0
8b. Estimated cost of commodity lost	$ 720,000
8c. Estimated cost of Operator's property damage & repairs	$ 190,247
8d. Estimated cost of Operator's emergency response	$ 3,982,042
8e. Estimated cost of Operator's environmental remediation	$ 2,173,059
8f. Estimated other costs	$ 269,016
Describe:	Costs associated with reassembly of truck rack at Hanna Stn, new truck rack at R
8g. Estimated total costs (sum of above)	$ 7,334,364

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Accident (psig):	75.00
2. Maximum Operating Pressure (MOP) at the point and time of the Accident (psig):	880.00
3. Describe the pressure on the system or facility relating to the Accident (psig):	Pressure did not exceed MOP
4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Accident operating under an established pressure restriction with pressure limits below those normally allowed by the MOP?	No
- If Yes, Complete 4.a and 4.b below:	
4a. Did the pressure exceed this established pressure restriction?	
4b. Was this pressure restriction mandated by PHMSA or the State?	
5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore Pipeline, Including Riser and Riser Bend" selected in PART C, Question 2?	Yes
- If Yes - (*Complete 5a. – 5f. below)*	
5a. Type of upstream valve used to initially isolate release source:	Manual
5b. Type of downstream valve used to initially isolate release source:	Automatic
5c. Length of segment isolated between valves (ft):	
5d. Is the pipeline configured to accommodate internal inspection tools?	Yes
- If No, Which physical features limit tool accommodation? (*select all that apply)*	
- Changes in line pipe diameter	
- Presence of unsuitable mainline valves	
- Tight or mitered pipe bends	
- Other passage restrictions (i.e. unbarred tee's, projecting instrumentation, etc.)	
- Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)	
- Other -	
- If Other, Describe:	
5e. For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run?	No
- If Yes, Which operational factors complicate execution? (*select all that apply*)	

- Excessive debris or scale, wax, or other wall buildup	
- Low operating pressure(s)	
- Low flow or absence of flow	
- Incompatible commodity	
- Other -	
- If Other, Describe:	
5f. Function of pipeline system:	=< 20% SMYS Regulated Trunkline/Transmission
6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Accident?	Yes
If Yes -	
6a. Was it operating at the time of the Accident?	Yes
6b. Was it fully functional at the time of the Accident?	Yes
6c. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Yes
6d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Yes
7. Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	No
- If Yes:	
7a. Was it operating at the time of the Accident?	
7b. Was it fully functional at the time of the Accident?	
7c. Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	
7d. Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	
8. How was the Accident initially identified for the Operator?	CPM leak detection system or SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations)
- If Other, Specify:	
8a. If "Controller", "Local Operating Personnel", including contractors", "Air Patrol", or "Guard Patrol by Operator or its contractor" is selected in Question 8, specify the following:	
9. Was an investigation initiated into whether or not the controller(s) or control room issues were the cause of or a contributing factor to the Accident?	No, the Operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: (provide an explanation for why the Operator did not investigate)
- If No, the Operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: *(provide an explanation for why the operator did not investigate)*	The cause of the failure was equipment and not operator (controller) error.
- If Yes, specify investigation result(s): *(select all that apply)*	
- Investigation reviewed work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	
- Investigation did NOT review work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	
Provide an explanation for why not:	
- Investigation identified no control room issues	
- Investigation identified no controller issues	
- Investigation identified incorrect controller action or controller error	
- Investigation identified that fatigue may have affected the controller(s) involved or impacted the involved controller(s) response	
- Investigation identified incorrect procedures	
- Investigation identified incorrect control room equipment operation	
- Investigation identified maintenance activities that affected control room operations, procedures, and/or controller response	
- Investigation identified areas other than those above:	
Describe:	

PART F - DRUG & ALCOHOL TESTING INFORMATION

1. As a result of this Accident, were any Operator employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	No
- If Yes:	
1a. Specify how many were tested:	
1b. Specify how many failed:	
2. As a result of this Accident, were any Operator contractor employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	No
- If Yes:	
2a. Specify how many were tested:	
2b. Specify how many failed:	

PART G – APPARENT CAUSE

Select only one box from PART G in shaded column on left representing the APPARENT Cause of the Accident, and answer the questions on the right. Describe secondary, contributing or root causes of the Accident in the narrative (PART H).

Apparent Cause:	G7 - Incorrect Operation

G1 - Corrosion Failure - only one **sub-cause** can be picked from shaded left-hand column

Corrosion Failure – Sub Cause:	
- If External Corrosion:	
1. Results of visual examination:	
- If Other, Describe:	
2. Type of corrosion: *(select all that apply)*	
- Galvanic	
- Atmospheric	
- Stray Current	
- Microbiological	
- Selective Seam	
- Other:	
- If Other, Describe:	
3. The type(s) of corrosion selected in Question 2 is based on the following: *(select all that apply)*	
- Field examination	
- Determined by metallurgical analysis	
- Other:	
- If Other, Describe:	
4. Was the failed item buried under the ground?	
- If Yes :	
4a. Was failed item considered to be under cathodic protection at the time of the Accident?	
If Yes - Year protection started:	
4b. Was shielding, tenting, or disbonding of coating evident at the point of the Accident?	
4c. Has one or more Cathodic Protection Survey been conducted at the point of the Accident?	
If "Yes, CP Annual Survey" – Most recent year conducted:	
If "Yes, Close Interval Survey" – Most recent year conducted:	
If "Yes, Other CP Survey" – Most recent year conducted:	
- If No:	
4d. Was the failed item externally coated or painted?	
5. Was there observable damage to the coating or paint in the vicinity of the corrosion?	
- If Internal Corrosion:	
6. Results of visual examination:	
- Other:	
7. Type of corrosion *(select all that apply)*: -	
- Corrosive Commodity	
- Water drop-out/Acid	
- Microbiological	
- Erosion	
- Other:	
- If Other, Describe:	
8. The cause(s) of corrosion selected in Question 7 is based on the following *(select all that apply)*: -	
- Field examination	
- Determined by metallurgical analysis	
- Other:	

- If Other, Describe:	
9. Location of corrosion *(select all that apply)*: -	
- Low point in pipe	
- Elbow	
- Other:	
- If Other, Describe:	
10. Was the commodity treated with corrosion inhibitors or biocides?	
11. Was the interior coated or lined with protective coating?	
12. Were cleaning/dewatering pigs (or other operations) routinely utilized?	
13. Were corrosion coupons routinely utilized?	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Tank/Vessel.	
14. List the year of the most recent inspections:	
14a. API Std 653 Out-of-Service Inspection	
- No Out-of-Service Inspection completed	
14b. API Std 653 In-Service Inspection	
- No In-Service Inspection completed	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
15. Has one or more internal inspection tool collected data at the point of the Accident?	
15a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage Tool	
Most recent year:	
- Ultrasonic	
Most recent year:	
- Geometry	
Most recent year:	
- Caliper	
Most recent year:	
- Crack	
Most recent year:	
- Hard Spot	
Most recent year:	
- Combination Tool	
Most recent year:	
- Transverse Field/Triaxial	
Most recent year:	
- Other	
Most recent year:	
Describe:	
16. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
If Yes -	
Most recent year tested:	
Test pressure:	
17. Has one or more Direct Assessment been conducted on this segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident::	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
18. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
18a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
G2 - Natural Force Damage - only one **sub-cause** can be picked from shaded left-handed column	

Natural Force Damage – Sub-Cause:	
- If Earth Movement, NOT due to Heavy Rains/Floods:	
1. Specify:	
- If Other, Describe:	
- If Heavy Rains/Floods:	
2. Specify:	
- If Other, Describe:	
- If Lightning:	
3. Specify:	
- If Temperature:	
4. Specify:	
- If Other, Describe:	
- If High Winds:	
- If Other Natural Force Damage:	
5. Describe:	
Complete the following if any Natural Force Damage sub-cause is selected.	
6. Were the natural forces causing the Accident generated in conjunction with an extreme weather event?	
6a. If Yes, specify: *(select all that apply)*	
- Hurricane	
- Tropical Storm	
- Tornado	
- Other	
- If Other, Describe:	
G3 - Excavation Damage - only one **sub-cause** can be picked from shaded left-hand column	
Excavation Damage – Sub-Cause:	
- If Excavation Damage by Operator (First Party):	
- If Excavation Damage by Operator's Contractor (Second Party):	
- If Excavation Damage by Third Party:	
- If Previous Damage due to Excavation Activity:	
Complete Questions 1-5 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
1. Has one or more internal inspection tool collected data at the point of the Accident?	
1a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage	
Most recent year conducted:	
- Ultrasonic	
Most recent year conducted:	
- Geometry	
Most recent year conducted:	
- Caliper	
Most recent year conducted:	
- Crack	
Most recent year conducted:	
- Hard Spot	
Most recent year conducted:	
- Combination Tool	
Most recent year conducted:	
- Transverse Field/Triaxial	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
2. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
3. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
4. Has one or more Direct Assessment been conducted on the pipeline segment?	

- If Yes, and an investigative dig was conducted at the point of the Accident:	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
5. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
5a. If Yes, for each examination, conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
Complete the following if Excavation Damage by Third Party is selected as the sub-cause.	
6. Did the operator get prior notification of the excavation activity?	
6a. If Yes, Notification received from: *(select all that apply)* -	
- One-Call System	
- Excavator	
- Contractor	
- Landowner	
Complete the following mandatory CGA-DIRT Program questions if any Excavation Damage sub-cause is selected.	
7. Do you want PHMSA to upload the following information to CGA-DIRT (www.cga-dirt.com)?	
8. Right-of-Way where event occurred: *(select all that apply)* -	
- Public	
- If "Public", Specify:	
- Private	
- If "Private", Specify:	
- Pipeline Property/Easement	
- Power/Transmission Line	
- Railroad	
- Dedicated Public Utility Easement	
- Federal Land	
- Data not collected	
- Unknown/Other	
9. Type of excavator:	
10. Type of excavation equipment:	
11. Type of work performed:	
12. Was the One-Call Center notified?	
12a. If Yes, specify ticket number:	
12b. If this is a State where more than a single One-Call Center exists, list the name of the One-Call Center notified:	
13. Type of Locator:	
14. Were facility locate marks visible in the area of excavation?	
15. Were facilities marked correctly?	
16. Did the damage cause an interruption in service?	
16a. If Yes, specify duration of the interruption (hours)	
17. Description of the CGA-DIRT Root Cause *(select only the one predominant first level CGA-DIRT Root Cause and then, where available as a choice, the one predominant second level CGA-DIRT Root Cause as well):*	
Root Cause:	
- If One-Call Notification Practices Not Sufficient, specify:	
- If Locating Practices Not Sufficient, specify:	
- If Excavation Practices Not Sufficient, specify:	
- If Other/None of the Above, explain:	
G4 - Other Outside Force Damage - *only one **sub-cause** can be selected from the shaded left-hand column*	
Other Outside Force Damage – Sub-Cause:	
- If Nearby Industrial, Man-made, or Other Fire/Explosion as Primary Cause of Incident:	

- If Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation:	
1. Vehicle/Equipment operated by:	
- If Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring:	
2. Select one or more of the following IF an extreme weather event was a factor:	
- Hurricane	
- Tropical Storm	
- Tornado	
- Heavy Rains/Flood	
- Other	
- If Other, Describe:	
- If Routine or Normal Fishing or Other Maritime Activity NOT Engaged in Excavation:	
- If Electrical Arcing from Other Equipment or Facility:	
- If Previous Mechanical Damage NOT Related to Excavation:	
Complete Questions 3-7 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
3. Has one or more internal inspection tool collected data at the point of the Accident?	
3a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year conducted:	
- Ultrasonic	
Most recent year conducted:	
- Geometry	
Most recent year conducted:	
- Caliper	
Most recent year conducted:	
- Crack	
Most recent year conducted:	
- Hard Spot	
Most recent year conducted:	
- Combination Tool	
Most recent year conducted:	
- Transverse Field/Triaxial	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
4. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
5. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
6. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident:	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
7. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
7a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
- If Intentional Damage:	

8. Specify:	
- If Other, Describe:	
- If Other Outside Force Damage:	
9. Describe:	
G5 - Material Failure of Pipe or Weld - only one **sub-cause** can be selected from the shaded left-hand column	
Use this section to report material failures ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is "Pipe" or "Weld."	
Material Failure of Pipe or Weld – Sub-Cause:	
1. The sub-cause selected below is based on the following: *(select all that apply)*	
- Field Examination	
- Determined by Metallurgical Analysis	
- Other Analysis	
- If "Other Analysis", Describe:	
- Sub-cause is Tentative or Suspected; Still Under Investigation (Supplemental Report required)	
- If Construction, Installation, or Fabrication-related:	
2. List contributing factors: *(select all that apply)*	
- Fatigue or Vibration-related	
Specify:	
- If Other, Describe:	
- Mechanical Stress:	
- Other	
- If Other, Describe:	
- If Original Manufacturing-related (NOT girth weld or other welds formed in the field):	
2. List contributing factors: *(select all that apply)*	
- Fatigue or Vibration-related:	
Specify:	
- If Other, Describe:	
- Mechanical Stress:	
- Other	
- If Other, Describe:	
- If Environmental Cracking-related:	
3. Specify:	
- Other - Describe:	
Complete the following if any Material Failure of Pipe or Weld sub-cause is selected.	
4. Additional factors: (*select all that apply*):	
- Dent	
- Gouge	
- Pipe Bend	
- Arc Burn	
- Crack	
- Lack of Fusion	
- Lamination	
- Buckle	
- Wrinkle	
- Misalignment	
- Burnt Steel	
- Other:	
- If Other, Describe:	
5. Has one or more internal inspection tool collected data at the point of the Accident?	
5a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year run:	
- Ultrasonic	
Most recent year run:	
- Geometry	
Most recent year run:	
- Caliper	
Most recent year run:	
- Crack	
Most recent year run:	
- Hard Spot	
Most recent year run:	
- Combination Tool	
Most recent year run:	

- Transverse Field/Triaxial	
Most recent year run:	
- Other	
Most recent year run:	
Describe:	
6. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
7. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident -	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site -	
Most recent year conducted:	
8. Has one or more non-destructive examination(s) been conducted at the point of the Accident since January 1, 2002?	
8a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted: -	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
G6 – **Equipment Failure** - only one **sub-cause** can be selected from the shaded left-hand column	
Equipment Failure – **Sub-Cause:**	
- If Malfunction of Control/Relief Equipment:	
1. Specify: *(select all that apply)* -	
- Control Valve	
- Instrumentation	
- SCADA	
- Communications	
- Block Valve	
- Check Valve	
- Relief Valve	
- Power Failure	
- Stopple/Control Fitting	
- ESD System Failure	
- Other	
- If Other – Describe:	
- If Pump or Pump-related Equipment:	
2. Specify:	
- If Other – Describe:	
- If Threaded Connection/Coupling Failure:	
3. Specify:	
- If Other – Describe:	
- If Non-threaded Connection Failure:	
4. Specify:	
- If Other – Describe:	
- If Defective or Loose Tubing or Fitting:	
- If Failure of Equipment Body (except Pump), Tank Plate, or other Material:	
- If Other Equipment Failure:	
5. Describe:	
Complete the following if any Equipment Failure sub-cause is selected.	
6. Additional factors that contributed to the equipment failure: *(select all that apply)*	

- Excessive vibration	
- Overpressurization	
- No support or loss of support	
- Manufacturing defect	
- Loss of electricity	
- Improper installation	
- Mismatched items (different manufacturer for tubing and tubing fittings)	
- Dissimilar metals	
- Breakdown of soft goods due to compatibility issues with transported commodity	
- Valve vault or valve can contributed to the release	
- Alarm/status failure	
- Misalignment	
- Thermal stress	
- Other	
- If Other, Describe:	

G7 - Incorrect Operation - only one **sub-cause** can be selected from the shaded left-hand column

Incorrect Operation – Sub-Cause:	Other Incorrect Operation
- If Damage by Operator or Operator's Contractor NOT Related to Excavation and NOT due to Motorized Vehicle/Equipment Damage:	
- If Tank, Vessel, or Sump/Separator Allowed or Caused to Overfill or Overflow:	
1. Specify:	
- If Other, Describe:	
- If Valve Left or Placed in Wrong Position, but NOT Resulting in a Tank, Vessel, or Sump/Separator Overflow or Facility Overpressure:	
- If Pipeline or Equipment Overpressured:	
- If Equipment Not Installed Properly:	
- If Wrong Equipment Specified or Installed:	
- If Other Incorrect Operation:	
2. Describe:	Pipeline was pressure tested back in June of 2010. Prior to this pressure test the pipeline has not contained water...only crude oil. Thus, winterizing was not required. We have implemented a valve winterization program.
Complete the following if any Incorrect Operation sub-cause is selected.	
3. Was this Accident related to *(select all that apply)*: -	
- Inadequate procedure	
- No procedure established	Yes
- Failure to follow procedure	
- Other:	
- If Other, Describe:	
4. What category type was the activity that caused the Accident?	Routine Maintenance
5. Was the task(s) that led to the Accident identified as a covered task in your Operator Qualification Program?	No
5a. If Yes, were the individuals performing the task(s) qualified for the task(s)?	

G8 - Other Accident Cause - only one **sub-cause** can be selected from the shaded left-hand column

Other Accident Cause – Sub-Cause:	
- If Miscellaneous:	
1. Describe:	
- If Unknown:	
2. Specify:	

PART H - NARRATIVE DESCRIPTION OF THE ACCIDENT

On 01 DEC 10, Chevron Pipe Line (CPL) controller noticed an over-short on the Salt Lake Crude System. The line was shut down @ 20:30 MST and Field Personnel were dispatched to investigate. Personnel discovered a release of approximately 100 bbls of Condensate Mixture to land near the Red Butte Block Valve compound. Local 911 were contacted for assistance and Salt Lake Fire Department were dispatched. Emergency response personnel were dispatched to the area. There has been no water impacted at this time.

File Full Name

PART I - PREPARER AND AUTHORIZED SIGNATURE

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