National Energy Board

Office national de l'énergie

Investigation under the *National Energy Board Act*

In the Matter of:

2012-01-24 Trans Mountain Pipeline ULC
Sumas Tank 121 Leak

November, 2012

Canada

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List of Abbreviations and Definitions

AB	*Alberta*
API	*American Petroleum Institute*
ASME	*American Society of Mechanical Engineers*
BC	*British Columbia*
Board or NEB	*National Energy Board*
CCO	*Control Centre Operator*
CCP&T	*Control Centre Procedures and Training*
CSA Z662-11	*Canadian Standard Association Z662: Oil and gas pipeline systems*
°C	*Degrees Celsius*
EOC	*Emergency Operating Centre*
H_2S	*Hydrogen Sulphide*
ICP	*Incident Command Post*
ICS	*Incident Command System*
Legacy System	SCADA 6.2 control system
LEL	*Lower Explosive Limit*
MST	*Mountain Standard Time*
O_2	*Oxygen*
OPR-99	*Onshore Pipeline Regulations, 1999*
PLC	*Programmable Logic Controller*
PST	*Pacific Standard Time*
SCADA	*Supervisory Control And Data Acquisition*
Test system	*EXCOS SCADA control system*
TMPU	*Trans Mountain Pipeline ULC*
VOC	*Volatile Organic Compounds*

Chapter 1

Summary

On 24 January 2012, a release of 90 m^3 of crude oil into the secondary containment of Tank 121 at Trans Mountain Pipeline ULC's (TMPU) Sumas Terminal in Abbotsford, BC occurred. The investigation revealed that the leak occurred after a gasket in a flange pair of the Tank 121 roof drain system failed under excessive pressure caused by water freezing in the roof drain system.

Although TMPU had a new procedure requiring the tank roof drain valve to normally be closed, the tank roof drain valve was open at the time of the incident. This was a contributing factor to the incident. The investigation found that TMPU's management of the procedural change to the normal drain valve position was inadequate.

The leak was detected later than it should have been. This can be attributed to the fact that the Control Centre Operator (CCO) did not follow TMPU's procedures on two occasions when setting and responding to the alarms and failed to recognize the leak situation. The investigation found that there were improper alarm settings in TMPU's new Supervisory Control and Data Acquisition (SCADA) system and this may have contributed to the CCO's inadequate response to the alarms.

The safety of Canadians and protection of the environment are the National Energy Board's (NEB or Board) top priorities. The Board requires pipeline companies to anticipate, prevent, manage and mitigate potentially dangerous conditions associated with their pipelines. TMPU has identified corrective actions to address all of the findings of cause and contributing factors identified in this investigation report. The Board is satisfied that these actions are appropriate to prevent the occurrence of similar incidents in the future.

Chapter 2

Scope and Objectives of Investigation Under the *National Energy Board Act* (NEB Act)

The scope of the NEB investigation into this accident was determined in accordance with the Board's mandate as set out in the NEB Act, more particularly, subsection 12(1.1):

> ***12****(1.1) The Board may inquire into any accident involving a pipeline or international power line or other facility the construction or operation of which is regulated by the Board and may, at the conclusion of the inquiry, make*
>
> *(a) findings as to the cause of the accident or factors contributing to it;*
>
> *(b) recommendations relating to the prevention of future similar accidents; or*
>
> *(c) any decision or order that the Board can make.*

In light of the authority of the Board set out under subsection 12(1.1) of the NEB Act, the objectives of the NEB investigation were to gather all evidence related to the accident; conduct an analysis of the evidence; make findings as to the cause or factors contributing to it; make recommendations relating to the prevention of future similar accidents; and make any decision or order the Board can make, as appropriate, to prevent similar accidents from occurring.

Chapter 3

Factual Information

3.1 Incident Description

Early in the morning of 24 January 2012, a release of crude oil from Tank 121 at TMPU's Sumas Terminal in Abbotsford, BC occurred (see Maps 1, 2 and 3 in Appendix I). Approximately 90 m^3 of crude oil was released within the secondary containment of Tank 121. At 06:50 PST[1] a TMPU operator arrived on site, discovered the release and closed the Tank 121 roof drain valve to stop the release. The company incident response was initiated and an Incident Command Post (ICP) was established at the nearby Sumas Pump Station. The NEB was notified at 08:16. Soon after receiving the notification, the NEB's Emergency Operations Centre (EOC) was activated. NEB staff arrived at the TMPU ICP at 17:00 on 24 January 2012. The emergency phase of the incident was terminated at 12:50 on 25 January 2012 when the last free oil was removed from the secondary containment. No one was injured during the incident and environmental consequences were limited to the contamination of the secondary containment gravel and air emissions. The secondary containment liner prevented the oil from migrating outside the secondary containment. Figure 1 shows the oil release in the secondary containment of Tank 121 after most of the free oil had been recovered. A foam blanket covers the remaining oil and the darkened gravel shows the original extent of the spill.

Figure 1: Release in Tank 121 Secondary Containment

[1] Unless indicated otherwise, all times in this investigation report will be Pacific Standard Time (PST), the time zone at the location of the incident.

3.2 Sequence of Events Leading to the Discovery of the Spill

According to TMPU's Investigation Report, for several consecutive days prior to the incident, the Abbotsford area experienced unusually cold weather conditions, with temperatures reaching a low point on 18 January with a temperature of -14.8 °C. During that period, Tank 121 was inactive and the crude oil level was at a low operating level of 1.2 metres. For five and a half days, the temperature of the crude oil fell below zero degrees Celsius, varying between 0 °C and -1.7 °C. On 23 January 2012, between the hours of 20:37 and 22:26, Tank 121 received a scheduled delivery of 3400 m^3 of crude oil. During this receipt of oil, the level of oil increased from 1.2 m to 7.0 m and the temperature of the crude oil in the tank increased from -0.1 °C to 9.7 °C.

Via a SCADA System, the Sumas tanks are monitored 24 hours, seven days a week by TMPU's Control Centre in Edmonton, AB. The SCADA system is monitored by a CCO. The SCADA log for Tank 121 recorded the following events the night of the incident:

- **22:26, 23 January** – at the completion of the receipt into Tank 121, the CCO set the creep[2] alarm on Tank 121 in the Test System[3].
- **01:11, 24 January** – the CCO set the creep alarm on Tank 121 in the Legacy System[4].
- **02:39, 24 January** – the first creep alarm for Tank 121 was received. This alarm was from the Legacy System. The CCO viewed the trend for the Tank 121 volume, but failed to recognize the drop in volume. The CCO decided it was a false alarm, assuming that it was the result of high winds.
- **03:11, 24 January** – the second creep alarm was received. This alarm was from the Test System. The CCO was unaware of a different basis[4] for this alarm and together with the time proximity to the first alarm the CCO again decided it was a false alarm, assuming that it was the result of high winds.
- **04:11, 24 January** – the third creep alarm was received. This alarm was from the Legacy System. This was deemed notable by the CCO, who accordingly reviewed the trend for Tank 121. Not seeing a material change in the level, the CCO noted it for follow up by the day shift CCO.
- **05:00, 24 January** – a shift transfer occurred. The day shift CCO viewed tank levels for Tank 121 and proceeded with assuming the usual responsibilities of the desk.

[2] A creep alarm is a SCADA generated alarm that is initiated when a pre-defined difference of an analog value has been reached.
[3] At the time of the incident, TMPU was upgrading its legacy SCADA 6.2 System (the "Legacy System") with a new EZXOS SCADA (the "Test System") and both were in use but, as per TMPU's instructions, the Legacy System was to remain the basis for operations. This is discussed in more detail in Section 4.3.
[4] The creep alarm of the Legacy System was triggered by a volume deviation of 10 m^3 (or 17 mm displacement) and the creep alarm of the Test System was triggered by a volume deviation of 59 m^3 (or 100 mm displacement). This is discussed in more detail in Section 4.3.

Approximately 15 minutes into shift, he reviewed Tank 121 levels and determined the changes (about 1 m^3) were within the accuracy of the measurement device (SAAB radar accuracy ± 1 m^3).

- **05:47, 24 January –** the fourth creep alarm was received. This alarm was from the Legacy System. The day shift CCO once again reviewed the trend for Tank 121.

- **05:50, 24 January –** the day shift CCO called out a terminal operator at Sumas to attend the site and investigate the cause of the alarm.

- **06:50, 24 January –** the terminal operator arrived on site, promptly discovered the release and closed the roof drain valve, thereby isolating the source.

- **07:00, 24 January –** the Control Centre received the first odour complaint associated with this incident. The day shift CCO received confirmation of a release from the terminal operator at the same time.

3.3 Emergency Response

Following the isolation of the release, efforts to plan and execute the incident response began. An emergency notification message was sent to TMPU's operations management team at 08:01 and a conference call to plan and execute the response was initiated at 08:15.

Notification calls were made to the following outside agencies:

- Transportation Safety Board of Canada (08:10)
- National Energy Board (08:16)
- Auguston Traditional School Principal (08:48)
- Abbotsford Police Reports Desk (09:15)
- Abbotsford Emergency Program, Fire Dispatch (09:15)
- Abbotsford Communications Manager (09:23)
- FVRD Emergency Program (09:28)
- Abbotsford Police Reports Desk (09:38)
- Beautiworld Development (Auguston Developer) (09:47)
- Fraser Health Authority (09:50)
- MLA Jon Van Dongen (09:54)
- MLA Randy Hawes (09:56)

TMPU's Incident Command System (ICS) was activated and the ICP was established at the nearby Sumas Pump Station.

According to TMPU’s ICS documentation, vacuum trucks were ordered on site before 10:00 on 24 January and, by 10:30, there were three vacuum trucks at the Sumas Terminal to recover the oil from the Tank 121 secondary containment area.

Fire fighting foam was applied by TMPU’s personnel over the free oil to reduce vapour generation and resulting odours; however, it did not completely eliminate odours generated from the spill.

Air monitoring was conducted throughout the response. TMPU’s personnel were assigned to monitor air quality (LEL, O_2, H_2S, benzene and total volatile organic compounds (VOCs)) adjacent to the containment area as well as around the perimeter of the Sumas Terminal.

TMPU’s personnel delivered written notices to approximately 100 residents in the surrounding area.

A community ambient air monitoring program with both monitoring and sampling components was conducted by a specialized consultant. The air monitoring activity began at about 16:00 on 24 January and provided regular field screenings of ambient air in locations within the neighborhood surrounding the Sumas Terminal for potential contaminants resulting from the release and clean-up of crude oil. Eight locations close to residential areas and an elementary school were monitored. Data was collected for H_2S, benzene, total VOCs and LEL, as well as O_2, carbon monoxide, and carbon dioxide.

Oil recovery operations continued on 24 January until dusk, when almost all of the free oil was recovered. Site security control and a safety watch were maintained at the Sumas Terminal for the night.

Emergency response operations resumed on the morning of the 25 January and the emergency phase of the incident was terminated at 12:50 when the last free oil was removed from the secondary containment. The project clean-up phase was initiated thereafter.

Tank 121 was shut-in upon discovery of the spill. The tank content was removed until it was almost empty by 20:00 on 24 January. The tank remained out of service until it could be examined and repaired. Tank 121 was returned to service on 1 March 2012.

Chapter 4

Results of the Investigation Under the NEB Act

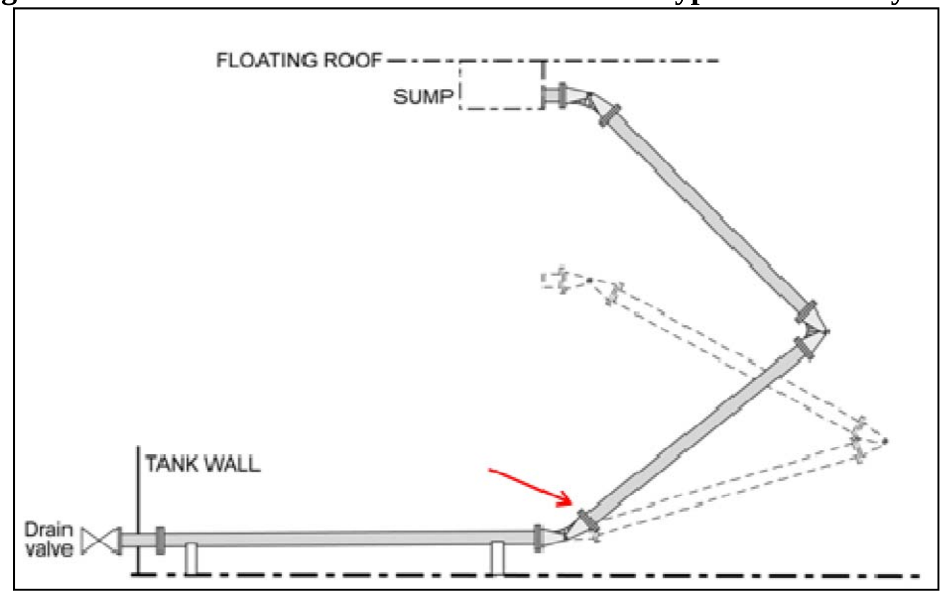
This section presents the results of the investigation pursuant to the NEB Act in terms of the:

- Findings as to the cause of the accident and the factors contributing to it (pursuant to paragraph 12(1.1)(a) of the NEB Act); and
- Corrective actions taken by TMPU.

4.1 Failure Mechanism of the Tank Roof Drain System

In February 2012, TMPU emptied and cleaned Tank 121 in order to enter it and investigate the cause of the failure of the tank roof drain system. Representatives of the roof drain system vendor were on site for the inspection of the roof drain system. As shown in Figure 2 below, the Tank 121 roof drain system is a Pivot Master-type drain system made of a sump attached to the floating roof and steel pipes with flexible joints to carry the roof accumulated water down through and out at the bottom of the tank. A drain valve located just outside the tank wall on the roof drain system allows the water to drain into the secondary containment when open.

Figure 2: Schematic of the Tank 121 Pivot Master-type roof drain system[5]



[5] Figure 2 was taken from TMPU's Investigation Report

TPMU visually inspected the roof drain system and identified that the leak resulted from a failed gasket located in the flange pair indicated by the red arrow in Figure 2. This joint was disassembled and the failed gasket is shown in Figure 3 below. TMPU determined that the gasket appeared to have been damaged by excessive pressure, likely caused by freezing. TMPU explained in its investigation report that the combined effect of the unusually cold weather and low level of oil in Tank 121 in the two weeks preceding the leak may have caused water to freeze in the roof drain system (see section 3.2 for more details on the weather). TMPU indicated that temperature variations throughout the days and within the tank are suspected to have caused cycles of water freezing and melting on the tank roof and in the roof drain system, which led to the accumulation of water and ice in the roof drain system even though the roof drain valve was open and the drain sloped to prevent water accumulation. The freezing of water in the roof drain system would have resulted in excessive internal pressure in the roof drain system causing the gasket to fail while preventing the oil from leaking outside the roof drain system. Tank 121 received the 3400 m^3 of oil on 23 January 2012, thereby increasing the temperature of the tank content from -0.1 °C to 9.7 °C. This would have melted the ice in the roof drain system and therefore allowed the oil in the tank to enter the roof drain system where the gasket was damaged. Because the drain valve of the roof drain system was open, the oil could then flow into the Tank 121 secondary containment.

Figure 3: Photograph of the damaged gasket (right) as compared to a functional gasket (left)[6]

TMPU has determined that no other factors contributed to the failure of the flanged joint aside from excessive pressure resulting from ice expansion within the piping system. Also, TMPU confirmed that no other damage was identified during the visual inspection of the roof drain system of Tank 121. The failed gasket was replaced and the roof drain system was pressure tested to confirm its integrity prior to returning Tank 121 to service.

[6] Figure 3 was taken from TMPU's Investigation Report

Tank 121, which was built in 1963, is inspected according to the American Petroleum Institute (API) standard 653, *Tank Inspection, Repair, Alteration, and Reconstruction*, which is the mandatory inspection standard for steel storage tanks as per CSA Z662-11 clause 10.9.2.1. Tank 121 was last inspected in 1995, at which time the current roof drain system was installed. TMPU explained that the gasket, which met the American Society for Mechanical Engineers (ASME) standard B16.21, *Non-Metallic Flat Gaskets for Pipe Flanges*, and TMPU's *Bolted Flange Joint Assembly* standard, can be considered as highly reliable for this type of application. TMPU confirmed that it has not experienced any other roof drain gasket failures on its systems.

Therefore, based on the following facts:

- The combination of cold weather (significantly below the freezing point) and of the low level of oil in Tank 121 in the days preceding the leak resulted in the oil in Tank 121 reaching temperatures below 0°C for more than five days, up until the receipt of oil on 23 January 2012;
- The leak appeared just after filling the tank with warmer oil during the night of 23 to 24 January 2012;
- The damage to the gasket shown in Figure 3 appears to have been caused by excessive pressure, as determined by TMPU's investigation;
- The roof drain system does not normally operate under high pressure, the only pressure being the hydrostatic head of liquid in the tank or of the water that could accumulate in the roof drain system if the valve was closed;

and because there is no evidence of other possible failure mechanisms, the Board agrees with TMPU's conclusion that the mechanism of failure of the roof drain gasket appears to be excessive internal pressure caused by freezing of water in the roof drain system.

Finding 1	The mechanism of failure of the roof drain gasket appears to be excessive internal pressure caused by freezing of water in the roof drain system.

4.2 Contributing factor: Roof Drain Valve Kept Open

A factor that contributed to the release of crude oil into the Tank 121 secondary containment is that the drain valve of the roof drain system was open at the time of the incident. The fact that the drain valve was open allowed the oil, which could flow through the failed gasket of the roof drain system, to enter the secondary containment.

Finding 2	The practice of keeping the roof drain valves normally open was a contributing factor to the incident.

Due to the high and often intense level of rainfall at the Sumas and Burnaby terminals, the roof drain valves were normally kept open to allow the water accumulating on the tank roofs to drain continually. This practice is different than TMPU's practice at locations where freezing conditions are frequent and where the roof drain systems are isolated and winterized to prevent freezing damage. At the Burnaby and Sumas terminals, the significant rainfalls of the milder winters require these roof drain systems to be operational year round.

Nevertheless, prior to this incident, TMPU had identified the need to change its procedure regarding the drain valve position. On 24 November 2011, a Facility Modification Request change management procedure was initiated to change TMPU's procedure for water removal from external floating roofs to require the roof drain valves at these locations to be kept normally closed. This change would require more time and attention from terminal staff to manage the rain water accumulation, but it would also provide protection against a roof drain failure. The change was approved by TMPU on 1 December 2011. A work order was issued on 12 December 2011 to update the procedure and was completed on the same day. However, this change to the procedure was not formally communicated to field personnel. TMPU indicated that normally an email notification is made to inform the key stakeholders of the revisions made to a procedure, but this was not completed for this change. Even though the Sumas Terminal field supervisor was aware the procedure was being considered for change, he was not advised that the change had been made and, therefore, field staff continued to keep the roof drain valve normally open as per the previous procedure. Neither the Facility Modification Request change management procedure, nor the work order process in place at that time, required that field personnel be notified of the procedural change. The process that TMPU used to manage the change to the roof drain valve position was inadequate because it did not have a requirement for ensuring that the change would be communicated to field personnel, who were directly affected by such a change. In addition, the fact that TMPU's field personnel were not informed of the new procedure is a non-compliance with the *Onshore Pipeline Regulations 1999* (OPR-99) section 28, which states:

"A company shall inform all persons associated with operation activities on the pipeline of the practices and procedures to be followed and make available to them the relevant portions of the operation and maintenance manuals."

It is reasonable to expect that field staff should have been informed of the change shortly after 12 December 2011 and that the new procedure would have been implemented before the incident occurred.

Finding 3	The process that TMPU used to manage the change to the normal roof drain valve position was inadequate because it did not have a requirement for ensuring that the change would be communicated to field personnel, who were directly affected by such a change. In addition, the fact that TMPU's field personnel were not informed of the new procedure is a non-compliance with the OPR-99 section 28.

4.3 Contributing factor: Late Leak Detection

4.3.1 CCO Activation of and Response to the Creep Alarms

A factor that contributed to the amount of crude oil released into the Tank 121 secondary containment area is that the leak was not detected as quickly as it should have been. A first operational error happened when the CCO, who was monitoring the Sumas Terminal during the night shift at TMPU's control centre in Edmonton, did not set the creep alarm on the Legacy System within 15 minutes after completing the receipt of crude oil into Tank 121 as per TMPU's procedure *5.2 SCADA System Creep Alarms*. The operator did set the creep alarm on the Test System right after completing the receipt into Tank 121, but TMPU's verbal instructions were that the Legacy System was to remain the basis for operations until the transition to the new Test System was completed. The CCOs were to familiarize themselves with the new system, and when comfortable, begin issuing duplicate commands on the new system to confirm operational consistency with the Legacy System. The night shift CCO set the creep alarm on the Legacy System at 01:11 on 24 January, 2hr 45 min after completing the receipt of crude oil at Tank 121, which happened at 22:26 on 23 January.

The night shift CCO failed to follow TMPU's procedures by not setting the creep alarm on the Legacy System within 15 minutes of completing the receipt of crude oil in Tank 121. This is a non-compliance with subsection 4(2) of the OPR-99, which states:

"...the company shall ensure that the pipeline is designed, constructed, operated or abandoned in accordance with the design, specifications, programs, manuals, procedures, measures and plans developed and implemented by the company in accordance with these Regulations"

Finding 4	The night shift CCO failed to follow TMPU's procedures by not setting the creep alarm on the Legacy System within 15 minutes of completing the receipt of crude oil in Tank 121. The fact that the CCO did not follow TMPU's procedures is a non-compliance with the OPR-99 subsection 4(2).

As described in section 3.2, the night shift CCO received three alarms, two from the Legacy System and one from the Test System, between 02:39 and 04:11. Each time, the night shift CCO failed to recognize the possible leak situation when viewing the Tank 121 volume trend. Appendix II shows the Tank 121 level and volume trends and, at 02:39, when the night shift CCO received the first alarm, the level and volume trends show a noticeable drop of level and volume from the time the receipt of oil was completed. The night shift CCO had access to both the volume and level trends for the Tank 121, which both show similar trends, but the night shift CCO only viewed the volume trends from the Legacy and Test systems. TMPU indicated that the volume trend was adequately displayed and the night shift CCO did notice the trend but, considering the initial volume change as relatively small, the night shift CCO interpreted the cause as a weather event, not a possible leak. The night shift CCO also had access to the analog (number) value information for the level or volume of Tank 121, but the night shift CCO did not use this information. The SCADA settings allow a change to be made to the volume scale to make it more pronounced, however this scaling feature was not used by the night shift CCO.

Finding 5	The night shift CCO failed to recognize the possible leak situation when viewing the Tank 121 volume trend.

The night shift CCO again failed to follow TMPU's procedures by deciding that the alarms were false alarms, without sending a field technician to verify on site. TMPU's procedure *2.2.3.5 Unexpected Tank Level Deviation* requires that a level deviation that can't be explained as normal operations must be investigated by a field technician. In this case, the CCO assumed the creep alarms, which are a notification of a tank level deviation, were caused by high winds but he did not send a field technician to investigate. TMPU confirmed that high winds are a potential cause for false creep alarms but that this situation is not known to be a normal operating condition. TMPU has no instrumentation to measure and record wind information at the Sumas Terminal and the CCO had therefore no ability to determine the wind conditions at the Sumas Terminal without having someone verify on site. If the night shift CCO had followed TMPU's procedure *2.2.3.5 Unexpected Tank Level Deviation*, the leak could have been stopped earlier as a technician would have been sent on site after the first alarm.

Finding 6	The night shift CCO failed to follow TMPU's procedures by not having a field technician investigate on site the creep alarms which could not be explained by normal operations. The fact that the CCO did not follow TMPU's procedures is a non-compliance with the OPR-99 subsection 4(2).

The three operational errors described in Findings 4, 5 and 6 contributed to a higher volume of crude oil being released into the Tank 121 secondary containment.

The night shift CCO had been qualified in this position since June 2011. TMPU confirmed that the CCO had completed all the required training and training records were provided confirming the CCO had been trained on the *5.2 SCADA System Creep Alarms* and *2.2.3.5 Unexpected Tank Level Deviation* procedures. The training records indicate that, in January 2011, the night shift CCO completed a first *Job Check* on procedures 5.2 and 2.2.3.5, which is an evaluation by a qualified CCO or the Supervisor, Control Centre Procedures and Training (CCP&T) that the CCO being trained understands each step of the procedure. A second *Job Check* was completed in June 2011 prior to completion of the test required for qualifying the CCO to operate the Sumas control desk. The test records show that the night shift CCO successfully answered the test questions related the TMPU's procedures 5.2 and 2.2.3.5. One of the test questions was on the requirement to have a field technician investigate a tank level deviation that can't be explained as normal operations and the night shift CCO had properly answered the questions. The first and second *Job Check* evaluations and the final qualification verification were completed by the Supervisor CCP&T.

4.3.2 Creep Alarm Threshold Value on the Test System

Another factor that may have contributed to the late leak detection is that the threshold value for the creep alarm on the Test System was not set at the proper volume deviation value. The creep alarm on the Test System was set to alarm for a change in level of 100 millimeters, which corresponds to a volume deviation of 59 m^3. The creep alarm should have been triggered by a volume deviation of 10 m^3, which is a level change of 17 mm. The 100 mm threshold for triggering the creep alarm was a default value in the Test System. CCOs were able to modify this threshold, but it was not modified by the night shift CCO to the right value. TMPU's investigation report revealed that the night shift CCO was unaware of the different creep alarm threshold on the Test System. If the creep alarm threshold on the Test System had been set to the right value, it would have triggered alarms prior to the initial alarm that came from the Legacy System. The fact that the Test System, which the night shift CCO was relying on for 2hr 45 min prior to setting the Legacy System, had not triggered any alarms prior to the Legacy System initial alarm was potentially confusing information for the night shift CCO to assess. This may have contributed to the decision by the CCO to consider the alarms as false. TMPU concluded in its investigation report that the "*CCO application of and response to the creep alarms... was compounded by the basis error for the creep alarm in the test system*".

Finding 7	The threshold value for the creep alarm on the Test System was not set at the proper value. This information was not known by the night shift CCO and it may have contributed to the inappropriate response from the night shift CCO to the creep alarms.

4.4 Corrective Actions

This section presents the corrective actions taken, or to be taken, by TMPU to prevent the occurrence of a similar incident. The corrective actions are presented for each of the findings.

4.4.1 Corrective Actions for Finding 1

Finding 1 The mechanism of failure of the roof drain gasket appears to be excessive internal pressure caused by freezing of water in the roof drain system.

Corrective Action 1

TMPU revised its *General Operating Procedure 2.2.4 Winterization of External Floating Roof Drain Systems* to require that the external nozzle and roof drain valve be heat traced and insulated in locations where high winter rainfall makes other winterization methods impractical. The Board has reviewed the revised procedure and the Board is satisfied that this corrective action addresses Finding 1.

This corrective action may not completely eliminate the risk of freezing of water in the roof drain system components inside the tank, but it will significantly reduce the risk of freezing of water in the drain valve and external nozzle which, with the drain valve now normally kept closed (see Corrective Action 2), would contain the crude oil in the internal components of the roof drain system if such components were to fail again.

TMPU indicated that this incident will not result in changes to its tank internal inspection program because, when considering the mechanism of failure involved in this incident, there is no evidence to suggest that changes to the inspection scope or frequency would prevent such an incident.

4.4.2 Corrective Actions for Finding 2

Finding 2 The practice of keeping the roof drain valves normally open was a contributing factor to the incident.

Corrective Action 2

Since the incident, TMPU has implemented its new procedure and all roof drain valves are now operated in the normally closed position. Also, the new procedure requires TMPU operations staff to monitor the draining of water from the roof and if any oil were to be detected, the drain valve would be immediately closed. The Board is satisfied that this corrective action addresses Finding 2.

4.4.3 Corrective Actions for Finding 3

Finding 3 The process that TMPU used to manage the change to the normal roof drain valve position was inadequate because it did not have a requirement for ensuring that the change would be communicated to field personnel, who were directly affected by such a change. In addition, the fact that TMPU's field personnel were not informed of the new procedure is a non-compliance with the OPR-99 section 28.

Corrective Action 3

TMPU revised its Facility Modification Request change management procedure to correct the communication gap identified in Finding 3. The new procedure requires a work order to be issued to ensure direct communication to affected personnel when a critical procedural change has been approved. TMPU submitted the new procedure to the Board on 31 May 2012 and the Board is satisfied that the new procedure addresses Finding 3.

4.4.4 Corrective Actions for Finding 4

Finding 4 The night shift CCO failed to follow TMPU's procedures by not setting the creep alarm on the Legacy System within 15 minutes of completing the receipt of crude oil in Tank 121. The fact that the CCO did not follow TMPU's procedures is a non-compliance with the OPR-99 subsection 4(2).

Corrective Action 4

TMPU reviewed the use of the Legacy System as the basis for operation of the system and the process for commissioning and testing the Test System (the new SCADA system) with all the CCOs, with specific attention to the requirements and actions for tank alarms. The Board is satisfied that this corrective action addresses Finding 4.

4.4.5 Corrective Actions for Finding 5

Finding 5 The night shift CCO failed to recognize the possible leak situation when viewing the Tank 121 volume trend.

Corrective Action 5

TMPU has undertaken the following corrective actions to ensure timely and accurate diagnosis in future:

a) Formal Communications with CCOs: This event was discussed with the CCOs at the Control Centre Safety meeting and CCO focus group meeting.
b) Revision to *Procedure 2.2.3.5: Unexpected Tank Level Deviation* to include the following corrective actions, all of which are now complete:
    i. additional evaluation requirements when investigating and determining the cause of a deviation;
    ii. steps to ensure that the CCO uses the proper SCADA trend scaling to determine the severity of deviation; and
    iii. revision of the procedure to ensure more prompt call-out of a Field Technician to investigate these type of conditions.

The CCO review and signoff on Procedure 2.2.3.5 was completed on 30 September, 2012. The Board is satisfied that these corrective actions address Finding 5.

4.4.6 Corrective Actions for Finding 6

Finding 6 The night shift CCO failed to follow TMPU's procedures by not having a field technician conduct an on-site investigation of the tank levels to determine the cause of the creep alarms which could not be explained by normal operations. The fact that the CCO did not follow TMPU's procedures is a non-compliance with the OPR-99 subsection 4(2).

Corrective Action 6

a) TMPU is undertaking a review of creep alarms to determine the frequency of false alarms caused by roof oscillation. The overall goal of this review will be to implement an improved function for the detection of releases from tanks. This work will involve the monitoring of tank instrumentation measurements during various conditions, the development and testing of a Programmable Logic Controller (PLC) based algorithm for detecting abnormal tank level deviations (while filtering out false indications), and the clarification of CCO instructions for initiating a field investigation if an unexplained tank volume loss alarm should occur. This review and appropriate modifications will be completed by the end of December 2012.

b) TMPU will install a petroleum gas detection sensor on a trial basis at one of the secondary containment sumps at the Sumas terminal to confirm the ability of this equipment to augment the existing oil detection equipment. Planning for this installation is underway and it is expected to be in-service by the end of 2012.

The Board is satisfied that these corrective actions address Finding 6.

4.4.7 Corrective Actions for Finding 7

Finding 7 The threshold value for the creep alarm on the Test System was not set at the proper value. This information was not known by the night shift CCO and it may have contributed to the inappropriate response from the night shift CCO to the creep alarms.

Corrective Action 7

TMPU modified the creep alarm threshold values in the Test System for all of TMPU's tanks so that they correspond to 10 m^3 volume deviations and the threshold values are no longer manually set by the CCOs. The Board is satisfied that this corrective action addresses Finding 7.

Chapter 5

Conclusions

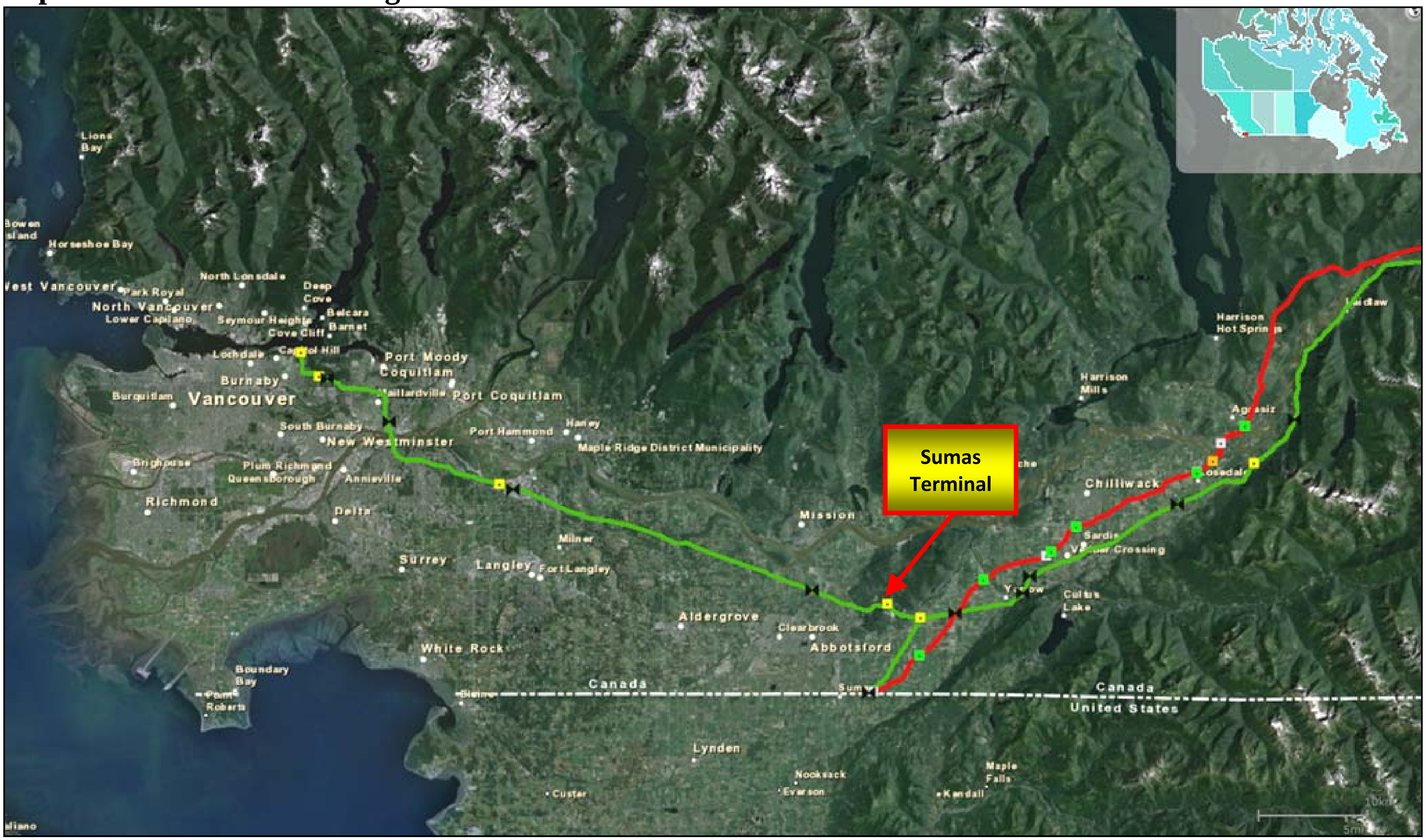
The NEB requires regulated companies to develop and implement management systems that set out policies, processes and procedures for the planning and execution of an organization's core business to manage the safety of people and protection of the environment. The NEB investigation revealed that several factors contributed to this incident. The mechanism of failure appears to be excessive pressure caused by freezing of water in the tank roof drain system. The release of 90 m^3 of crude oil in the secondary containment of Tank 121 may have been avoided or minimized if TMPU had ensured that its change to the drain valve normal position procedure had been implemented and if the leak had been detected earlier. If appropriate actions had been taken while setting and responding to the SCADA system alarms, the leak could have been detected earlier.

The NEB expects companies to demonstrate a commitment to continual improvement in safety, security, and environmental protection, and in promoting a positive safety culture and strong management systems. The Board is satisfied that TMPU's corrective actions are appropriate to prevent the occurrence of similar incidents in the future. The Board will conduct compliance verification activities to verify that all the corrective actions identified in this investigation report are properly implemented by TMPU.

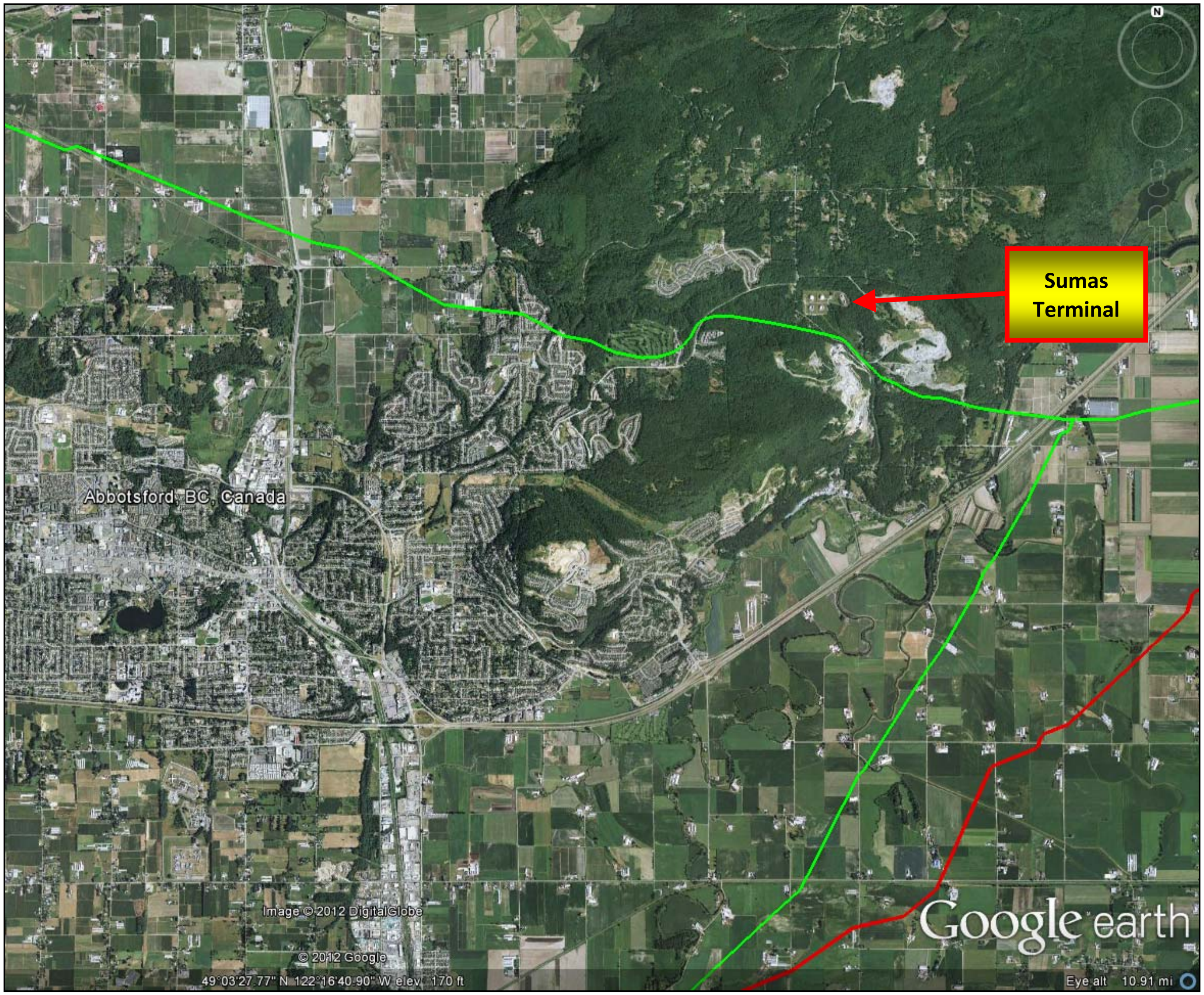
Appendix I

Maps

Map 1: Sumas Terminal – Regional View



Map 2: Sumas Terminal – Local View



Map 3: Sumas Terminal – Tank 121

Appendix II

Tank 121 Level and Volume Trends

Level Trend

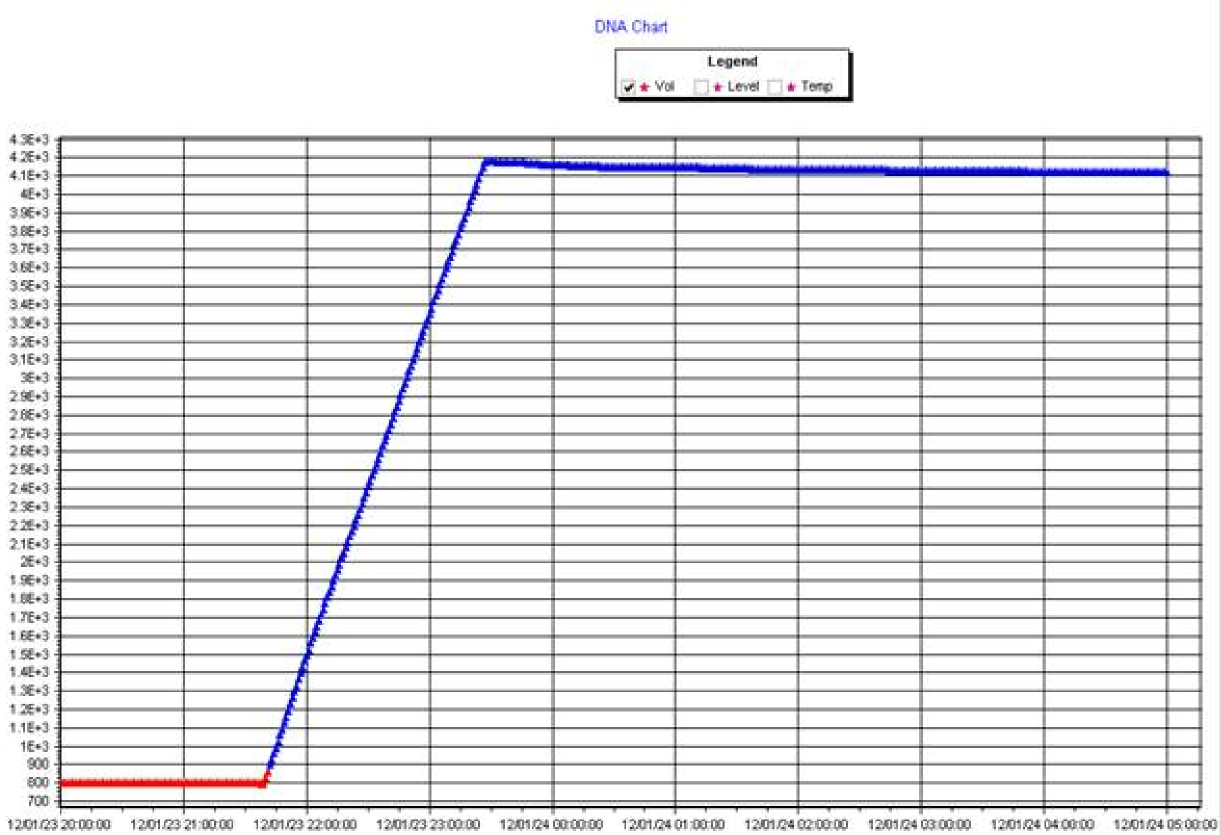
This Level Trend contains the Tank 121 level trend from a time prior to the receiving of crude oil in Tank 121 on 23 January 2012 to a time after the leak was found and stopped by the field technician in the morning of 24 January 2012. Note the time reported on this trend is Mountain Standard Time (MST) and times referred to in this investigation report are PST.

Tank 121 Level Trend

Volume Trend from the Test System

The volume trend from the Test System that was viewed by the night shift CCO during the incident. Note the time reported on this trend is Mountain Standard Time (MST) and times referred to in this investigation report are PST.

Tank 121 Volume trend from the Test System



Volume Trend from the Legacy System

The volume trend from the Legacy System that was viewed by the night shift CCO during the incident. Note the time reported on this trend is Mountain Standard Time (MST) and times referred to in this investigation report are PST.

Tank 121 Volume trend from the Legacy System