ABSTRACT

Heavy oil accounts for more than half the world’s total oil reserves. However, heavy oil as extracted from the reservoir has an extremely high viscosity and the transportation of these fluids in a pipeline requires the use of technologies to lower the viscosities of this oil. Among these technologies are heating or dilution of the heavy oil and sometimes a mixture of both of these methods. The majority of oil storage terminals contain pipes that are installed above ground and in northern countries are prone to experiencing cold temperatures during winter months. In part of the terminal where the fluid stays stagnant in the pipes (such as relief piping and manifold pipes) the cold weather can impact the viscosity of the fluid, even after it has been diluted. When the pumping system has to move fluid that has been stagnant in the pipe and has become colder, the pressure required to achieve this is very high. The transient surge pressures created in these cases can become extreme to the point of exceeding the maximum operating pressures of the pipe. When performing transient simulations, it is important to consider the fluid with higher viscosities that have been kept in the pipes and that will require higher pressures to pump them down the line, so that pressure surges can be more accurately calculated and mitigated.

This paper will present comparisons of how the transient pressures change between cases of heavy oils at different temperatures and viscosities. It will show that if heavy oil is kept stagnant in a pipe that is subject to cold temperatures, the pressures required to push this fluid down the pipe increases as the viscosity becomes higher. In particular, it will present the case where the relief piping has been installed above ground and when the fluid needs to be displaced, the surge pressures can become significantly higher than expected.

INTRODUCTION AND BACKGROUND

The definition of heavy oils most widely used is based on the API gravity of the hydrocarbon (Eq 1).

\[
API = \frac{141.5}{SG} - 131.5
\]  

(1)

Although no value has been standardized across the world, heavy oil API is commonly accepted as being somewhere between 10 and 22.3 °. Extra-heavy oils and bitumen have an API value of less than 10. [1, 2]

Another way of defining heavy oils is based on properties such as viscosity, low ratio of hydrogen to carbon atoms and presence of compounds such as asphaltenes, Sulphur, metals and nitrogen.

Heavy oils can present Newtonian behavior but are also characterized by their high viscosity, high pour point and high density. One of the most important aspects of heavy oil transportation is their high viscosity which can range from less than 100 cP to tens of thousands (at reservoir conditions). The unusual aspect of viscosity of oils and heavy oils is that although it varies with temperature; this variation is not the same for any two oils. Adding to this, the kinematic viscosity of any oil will also vary significantly from one mixture to another because the density can be different as well.

The one thing that is common for all types of oils is the effect of temperature on viscosity and density. With high temperatures, the viscosity and density of the fluid will be lower and the opposite also applies where lower temperatures will cause the viscosity and density to increase.

Most oil samples can be tested for viscosity at different temperatures and with this information, a curve is created that will show the dependence of viscosity on the temperature. In most cases of heavy oil, this variation can be expressed as a logarithmic function.
This behavior is commonly represented with the following equation provided by ASTM Standard D341

\[ \log_{10} \left( \frac{v}{cSt} \right) + 0.7 = A - B \times \log_{10}(T[\text{°C}] + 273.15) \]  

(2)

Where A, B are uniquely associated to each oil.

Figure 1 shows the dependence of viscosity with temperature and how these variables change from one type of fluid to another. [3]

Although heavy oils account for more than half the world’s reserves, transporting heavy crude oil and bitumen via pipeline is usually challenging due to their high density and viscosity. An increase in viscosity creates a higher pressure drop in the fluid most commonly transported under a turbulent flow regime. Higher pressure drop along a line requires more pumping capacity which consumes energy.

The heavy oil viscosity values that are required for pipeline transportation are not standardized throughout the world; therefore many ranges of viscosity are acceptable for different oil types and applications. Table 1 shows several viscosity values that have been proposed for pipeline transportation in different parts of the world. Consequently, there is an imperative need to use innovative technologies to lower the viscosities upon transport.

<table>
<thead>
<tr>
<th>Oil Type</th>
<th>Viscosity (cSt)</th>
<th>Temperature (°C / °F)</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude Oil</td>
<td>200</td>
<td>15 / 59</td>
<td>North America</td>
</tr>
<tr>
<td>Crude Oil</td>
<td>25</td>
<td>50 / 122</td>
<td>Europe</td>
</tr>
<tr>
<td>Crude Oil</td>
<td>25</td>
<td>180 / 356</td>
<td>Venezuela</td>
</tr>
<tr>
<td>Heavy Oil</td>
<td>350</td>
<td>7 / 45</td>
<td>Canada</td>
</tr>
<tr>
<td>Heavy Oil</td>
<td>350</td>
<td>11 / 52</td>
<td>North America</td>
</tr>
<tr>
<td>Heavy Oil</td>
<td>150</td>
<td>37.8 / 100</td>
<td>North America</td>
</tr>
</tbody>
</table>

Table 1: Values of viscosity and temperature accepted for pipeline transportation of hydrocarbons [1, 2, 4]

Viscosity reduction for pipeline transportation can be achieved through several methods. The methods are: preheating of the heavy oil alongside heating of the pipeline, blending or dilution with light hydrocarbon fluids, heavy oil-water emulsification, partial upgrading and core-annular flow [5].

North American heavy oil transportation uses heating and dilution as the most common methods. The heating method involves increasing the temperature of the heavy oil to values that will achieve a low enough viscosity for proper pipeline transportation. The method consist of pre-heating the heavy oil at the storage or production location as well as heating the pipeline to maintain high temperatures along the length of it. Heat losses need to be considered along the pipeline and may require the installation of heating stations and proper insulation of the pipe [1]. Other issues that arise with this method are the high energy costs of heating and pumping, expansion and contraction of the pipeline, and internal corrosion due to the high temperatures [3, 5].

Dilution of heavy oils with lighter hydrocarbons creates a mixture that will have crude properties somewhere in between the two original fluids being mixed. Thus, diluting the heavy oil with a light fluid can decrease the viscosity of the resulting mixture in an exponential manner [5]. The light hydrocarbons used most commonly for this purpose are distilled petroleum products like gasoline, condensate, naphtha, and kerosene. The main disadvantage of using this method is the need to supply diluent in large amounts for the proper mixing ratio. The fraction of light crudes needed for the mixture could range from 30% to 50% in volume [1, 6].

Experiments have also shown that some additives can alter the physical properties of the heavy oil which may be detrimental to the future processing of such mixture [7].

Each of these techniques is aimed at reducing viscosity as well as the energy required for pumping, to enhance flowability of the oil via pipelines.

In northern countries the majority of oil storage facilities or terminals contain pipes that are installed above ground. Therefore, these above ground pipes are prone to experiencing freezing temperatures during winter months. This is more critical if the pipe is not insulated or heat traced. The decrease in temperature impacts the viscosity of the fluids contained within the pipes, even after implementing methods like dilution, emulsification or partial upgrading. Consequently, the pressure differential required to achieve flow through a pipe is increased.

In the case of a stagnant fluid in cold weather, the pressure is even higher because it will require a greater force to initiate the fluid movement. A concept used in fluid flow is the pour point of a substance which is the viscosity at which the fluid starts moving [8]. However, pour point is normally used for waxy compounds, which does not apply for most diluted heavy oils. If the temperature of heavy oil reaches extreme values (below freezing), the viscosity could increase in such a way that the behavior of this oil will imitate that of a non-Newtonian fluid. It is in this case that the pressures required for flow become much greater and the risk for overpressures appears.

Coincidentally, a relief pipe that is installed above ground is just the type of equipment that will contain a stagnant fluid prone to very low temperatures and will thus have the potential to require high pressures for its displacement. The transient surge pressures created in these scenarios can become extreme to the point of exceeding the Maximum Operating Pressure (MOP) of the pipe.

This paper presents the transient simulation results of a relief system that contains different types of fluids in the piping that is connected to the relief tank. When a relief valve opens, the...
stagnant fluid requires a certain amount of pressure to be transported downstream, and the properties of the fluid inside the relief piping can make this flowing pressure higher than expected. Several cases are simulated to show the effect of stagnant heavy oil inside the relief piping at different ambient temperatures, and the response of the relief system to this event.

**APPROACH**

In order to understand the effect of high viscosity in the relief lines, a model was created with a relief system inside an injection (initiating) terminal. In this paper, the term injection means the operation of pumping fluid from a tank into the main pipeline along a flowpath that contains a tank, a set of parallel booster pumps, a metering system, mainline pumps in series and the transporting pipeline.

Since the majority of the injection or initiating terminals are constructed with piping that has lower rating than the mainline, a relief valve is normally needed inside the terminal to protect this injection piping. In this model, the terminal or facility piping has a pressure rating of PN20 or ANSI150 which equates to a Maximum Operating Pressure of 1896 kPag (275 psig).

The schematic from Figure 2 shows the equipment that was included in the model and the location of the relief valve connected along the path. The same model was used for all simulations, with fluid types being varied for the different cases analyzed.

DNV GL Stoner Pipeline Simulator was used. The model starts at a tank (with fluid levels maximized) and ends at the downstream pumping station with a 76 cm (30 inch) diameter pipeline of 40 kilometers (24.9 miles) in length. The system contains two booster pumps which transport the fluid from the tank discharge to the suction of the mainline pumps. There is a metering system located downstream of the booster pumps and the mainline pumps are connected downstream of the meters.

The basic layout of the terminal piping was as follows: Piping between tank and booster pumps is a 91 cm (36 inch) pipe with a length of 150 m (492 ft). The piping between the booster and mainline pumps was mostly 30 inches, with a few segments of 24 inch (61 cm) pipe. The total length between the two pumps is 550 meters (1804 ft) with the tie-in to the relief valve immediately upstream of the mainline pumps. The relief system consists of a 12 inch (30 cm) relief valve and a 16 inch (40 cm) relief line length of 300 meters (984 ft) from the valve to the relief tank.

The system has 3 mainline pumps installed in series and all are controlled by independent Variable Frequency Drive (VFD) elements. Table 2 shows some information for the pumps used in the model.

<table>
<thead>
<tr>
<th>PUMP</th>
<th>SPD (RPM)</th>
<th>PWR (KW)</th>
<th>HD @ BEP (m)</th>
<th>Q @ BEP (m³/h)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mainline 1</td>
<td>1780</td>
<td>4290</td>
<td>290</td>
<td>4000</td>
</tr>
<tr>
<td>Mainline 2</td>
<td>1780</td>
<td>4290</td>
<td>290</td>
<td>4000</td>
</tr>
<tr>
<td>Mainline 3</td>
<td>1780</td>
<td>4290</td>
<td>290</td>
<td>4000</td>
</tr>
<tr>
<td>Booster 1</td>
<td>1180</td>
<td>990</td>
<td>101</td>
<td>2250</td>
</tr>
<tr>
<td>Booster 2</td>
<td>1180</td>
<td>990</td>
<td>101</td>
<td>2250</td>
</tr>
</tbody>
</table>

Table 2: Pump Characteristics used in simulation model.

Where SPD is the rated pump speed, PWR is the pump break horsepower, HD is the pump differential head at its Best Efficiency Point and Q is the pump flow rate also at BEP. When performing transient simulations inside terminal piping, the scenarios that can cause the worst surge pressure is one that will block the flow in the shortest time of an event. Some of the transient event scenarios that can be simulated are the closure of Motor Operated Valves (MOV) or stopping of a pump. The MOV closing times are usually one to three minutes, while the ramp down of pumps is much faster. Therefore, the scenario that is most significant for creating transient surge pressures is the simultaneous shutdown of all mainline pumps during an injection event.

The paper consequently focused on the simultaneous pump shutdown scenario to evaluate the transient relief response. One item that was modeled constant in this paper was how fast the pumps spin down when they are stopped.

When a pump is suddenly stopped, the moment of inertia will have a significant impact on the stoppage of the fluid. The pump moment of inertia is the resistance of the pump to changes in angular velocity while rotating. Therefore, the higher the pump inertia, the longer it will take the pump to spin down or to reach full speed [9]. When the spin down is fast, the fluid stops more suddenly, thus increasing the surge pressures at this location.

As mentioned previously in the paper, the viscosity of oils can change significantly with the variation of temperature; therefore, Table 3 shows the fluids used in these simulations.

<table>
<thead>
<tr>
<th>Density (kg/m³)</th>
<th>Viscosity @ 10 °C (cSt)</th>
<th>Viscosity @ 30 °C (cSt)</th>
<th>Viscosity @ 8 °C (cSt)</th>
<th>Viscosity @ -10 °C (cSt)</th>
</tr>
</thead>
<tbody>
<tr>
<td>LIGHT</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>712</td>
<td>0.67</td>
<td>0.54</td>
<td>0.687</td>
<td>0.906</td>
</tr>
<tr>
<td>HEAVY</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>970</td>
<td>435</td>
<td>121</td>
<td>506</td>
<td>2522</td>
</tr>
</tbody>
</table>

Table 3: Properties of Fluids used in simulation model.
The table shows the density at standard conditions (pressure of 1 atm (14.7psi) and temperature of 15 °C (59°F)), the viscosity measured at two different temperatures which were used to obtain the A and B coefficients to create a viscosity curve that will help obtain viscosity values for any other temperature.

The temperatures used in this model were 8 (46) and -10 °C (14 °F). The properties calculated for these two temperatures are also shown in this table. The A and B coefficients calculated from the ASTM formula were used to obtain the viscosity curves for these two fluids as shown in figure 3.

In order to maintain as many parameters equal as possible, the simulations were performed under isothermal conditions. This means that the temperature along the pipe is constant for the simulation time. The reasoning for this is that although the real system can have different temperatures along the lines, these changes are not significant in a short length of pipe like the ones involved inside the facility. Heat exchange between the ambient (or ground) is more significant when analyzing a long pipeline with kilometers in length, but not so important for pipes within the terminal.

The relief valve was simulated as a Danflo relief valve which is an element that is already coded in the software. The opening pressure setpoint was set to 1517 kPag (250 psig) and the closing pressure was set to 1296 kPag (188 psig) which is equivalent to 75% of the opening pressure. This is a typical ratio between opening and closing pressures provided by relief valves.

The flowrate used for all of the simulations was 4,000 m³/h (603822 Barrels Per Day (BPD))

### ANALYSIS

The model that was described above was used to simulate transient scenarios for injection cases from tanks to a pipeline. The methodology for simulating these events is explained in this paragraph. Initial states are obtained for each injection case analyzed and archived to be used for the transient events.

Starting from the steady state an upset scenario is launched which in this case is the simultaneous stopping of all mainline pumps while the booster pumps continue to operate. The simulation is then run for two minutes to observe the effect of this transient scenario on pressures within the terminal piping. The results from each transient scenario were saved and are analyzed in the next section.

The purpose of the paper is to determine the effect of low temperatures on the viscosity of crude oils, and the consequence of this change in the event of a relief case. The focus of the simulations is then to determine if the existence of viscous product that is stagnant in the relief line will behave differently than a relief line with a product that is not as viscous.

The initial cases created consisted of a combination of the two fluids described above (HEAVY, LIGHT) being injected from the tank into the pipeline all the way to the next downstream station. The two temperatures used for simulations were 8 and -10 °C.

Another variable was the fluid that filled the relief pipe simulated in the system, which could be the same or different from the fluid flowing in the facility. Several parameters were kept equal for all initial states such as the flow rate injected which was 4,000 m³/h. Another parameter that was kept the same was the number of booster and mainline pumps used for any of the initial states, as well as the tank levels for both the injection and the relief tank. The stopping time of the pumps, which was shown in the previous section to have a significant impact on the transient surges, was also kept the same for all cases.

For each temperature (8 and -10 °C) there were four initial states that were created based on the fluid that filled the injection piping and the relief piping. The table below shows the cases created for each temperature.

<table>
<thead>
<tr>
<th>Initial State</th>
<th>Fluid in Process Piping</th>
<th>Fluid in Relief Piping</th>
<th>Temperature (°C / °F)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>LIGHT</td>
<td>LIGHT</td>
<td>8 / 46</td>
</tr>
<tr>
<td>B</td>
<td>LIGHT</td>
<td>HEAVY</td>
<td>8 / 46</td>
</tr>
<tr>
<td>C</td>
<td>HEAVY</td>
<td>HEAVY</td>
<td>8 / 46</td>
</tr>
<tr>
<td>D</td>
<td>HEAVY</td>
<td>LIGHT</td>
<td>8 / 46</td>
</tr>
<tr>
<td>AA</td>
<td>LIGHT</td>
<td>LIGHT</td>
<td>-10 / 14</td>
</tr>
<tr>
<td>BB</td>
<td>LIGHT</td>
<td>HEAVY</td>
<td>-10 / 14</td>
</tr>
<tr>
<td>CC</td>
<td>HEAVY</td>
<td>HEAVY</td>
<td>-10 / 14</td>
</tr>
<tr>
<td>DD</td>
<td>HEAVY</td>
<td>LIGHT</td>
<td>-10 / 14</td>
</tr>
</tbody>
</table>

Table 4: Simulation cases used in study.

Based on this table, there were eight simulation scenarios in total for comparison of results. In each of these simulation scenarios the information analyzed consisted of the surge pressure along the pipes and relief valve as well as the flow behavior inside the relief piping.

The results in the next section show how the transient scenario of a simultaneous pump trip causes a surge pressure inside the terminal piping that requires the activation of the relief valve and creates a pressure profile that will vary based on the fluid that fills the pipe. Results also show how the fluid that fills the relief pipe, which is initially stagnant, requires high pressures to initiate the movement of the liquid to the relief tank, and how the viscosity of such fluid affects the required pressure for this.
RESULTS

Maximum Pressures in Terminal Piping:

Upon simulation of transient scenarios, the pressure profile was obtained and analyzed for each case, and one example is shown in figure 4. This pressure profile shows the initial and maximum simulated pressures along the terminal piping obtained for Case A, two minutes after the upset. Since the booster pumps continue to operate when the mainline pumps shutdown, the cumulative effect of these two opposite flows gives way to a rise in pressures somewhere along the piping between the equipment. Due to the presence of the relief valve, some flow is extracted into the relief tank but it is not enough to avoid the pressures from rising above the Maximum Operating Pressure (MOP) allowed in the system. Since this is Case A, both the terminal and relief piping are filled with light fluid at 8 degrees Celsius. If we want to decrease the surge pressures to an acceptable value, we can lower the opening setpoint of the relief valve to 1034 kPag (150 psig). Figure 5 shows these pressures before and after mitigation for Case C.

Different fluids in relief piping:

If we only simulated these two cases, we could assume that the surge pressures are mitigated to within acceptable levels but when we include different fluids in the relief piping and at lower temperatures, we can see that the surge pressure is much higher and the mitigation solution for this case is to lower the relief opening setpoint to 1034 kPag (150 psig). Figure 5 shows these pressures before and after mitigation for Case C.

This table shows that when the relief piping is filled with a heavy fluid, at either temperature, the surge pressures result in higher values than when the relief piping is filled with the light fluid. Also, the lower temperature results are all higher than the ones for 8 °C, confirming that at lower temperatures and at higher viscosity, the fluid flow is more difficult and will require more pressure to make it happen.

However, these are the surge pressures happening in the terminal piping which also have the booster pump fluid accumulating inside and increasing the surge pressures. The next step is then to look at the relief piping to see what is happening with the fluid flow in this section.

Pressures and Flow at Relief Valve:

When isolating the information of the relief piping two factors were considered: pressure and flow along the line. The first step was to compare the pressures and the maximum flow rate observed at the relief valve location. Table 6 shows these values for all cases run and figures 6 and 7 show plots of the flowrate through the relief valve as a function of time for all simulation cases.

<table>
<thead>
<tr>
<th>Case Simulated</th>
<th>Pressure at Relief Valve (psi)</th>
<th>Flow Rate at Relief Valve (BPD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>2076 / 301</td>
<td>2916 / 440,186</td>
</tr>
<tr>
<td>B</td>
<td>2126 / 308</td>
<td>2278 / 343,876</td>
</tr>
<tr>
<td>C</td>
<td>2227 / 323</td>
<td>2740 / 413,618</td>
</tr>
<tr>
<td>D</td>
<td>2154 / 312</td>
<td>3239 / 488,945</td>
</tr>
<tr>
<td>AA</td>
<td>2359 / 299</td>
<td>2576 / 388,861</td>
</tr>
<tr>
<td>BB</td>
<td>2415 / 319</td>
<td>1983 / 299,345</td>
</tr>
<tr>
<td>CC</td>
<td>2273 / 330</td>
<td>2386 / 360,180</td>
</tr>
<tr>
<td>DD</td>
<td>2170 / 315</td>
<td>2873 / 433,695</td>
</tr>
</tbody>
</table>

Table 6: Maximum Surge Pressures upstream of relief valves and maximum flow through relief valve.

Almost all cases at lower temperatures (-10 ºC) show higher pressures at the valve and lower flow rates through it. This can be verified by looking at Figures 6 and 7 where the flow rate at the valve is higher for the higher temperatures. This can be explained with the fact that a fluid that is less viscous can flow easier than one with higher viscosity. Table 6 shows that even though the pressure is higher at -10 ºC, the flow rate achieved is lower for all cases compared to the temperature of 8 ºC. Also, the cases where the light fluid is stagnant inside the relief pipe are the ones showing less pressure required to push the fluid and higher flow rates achieved at the relief valve.

Another interesting fact from Figures 6 and 7 is that when light fluid is in the process line, it takes more time for the relief system to activate and the flow to start along the relief
line. Figure 6 shows that flow starts moving 0.3 seconds after the initiating event. This could be due to the fact that the surge pressures in the light fluid take longer to reach the relief setpoint but also it takes more time for this light fluid to force the movement inside the relief line, compared to the heavy fluid when it is used as the process fluid (Figure 7).

At the relief valve, the flow rate increases and decreases within the first two seconds. Then the flow rate increases again at 2.5 seconds in a smaller amount. This behavior is similar to a surge absorber response where the initial surge lasts for a short period of time and can be repeated at a lower degree until the system pressures decrease into a new steady state.

Flow Rates into Relief Tank:
Another area of interest is the flow coming into the tank because this will allow us to understand if the stagnant fluid inside the relief pipe is actually being displaced by the surge event. For this section, Figures 8 and 9 were created which show the flow rates entering the tank. Both figures show that fluid movement starts approximately 0.25 seconds after the relief valve opens. Also, unlike figures 6 and 7, the flow rate shown in figures 8 and 9 does not decrease in the same manner as the flow rate at the relief valve. At the tank location, the flow rate decreases in a steadier manner and the burst of flow rate seen at the relief valve is not so obvious. Therefore while the flow rate at the relief valve changes drastically, the flow rate into the tank does not do so in the same manner. This could be caused by the accumulation of fluid inside the relief piping and the fluid being pushed along the relief pipe in a steadier manner.

These two last figures also show that the temperature of the fluid will have a significant influence in the flow rate and that when a stagnant fluid is left inside the relief piping the pressure required to move the liquid is higher and the flow rate along the relief system is lower, which also causes the higher surge pressures.

These results show that in the case of transient simulations, it is very important to include the correct fluid inside the relief piping to make sure the surge pressures simulated are the most conservative and include the worst case possible for relief flow rates and pressures. This is particularly true in the case of terminal piping in the Northern areas of the world where cold temperatures could make a significant impact on the relief system behavior.

**CONCLUSIONS**

In northern countries, if the pipe of the relief system is not insulated, heat traced or buried underground, the cold temperatures will significantly affect the fluid properties of the liquid that is left stagnant in the relief pipe. This will potentially make it very difficult to move the stagnant fluid when a transient even occurs and the relief valve activates.

This paper shows that when performing a simulation for transient scenarios, particularly in terminal piping, it is of utmost importance to include the proper fluids in the relief piping and to consider the temperature effects on this stagnant fluid.

It also shows that if the terminal system operates with various types of fluids, the relief line should not contain stagnant liquid that can become very viscous during cold periods of time. The high viscosity of the stagnant fluid could make it very difficult for the process fluid to push the flow out of the relief pipe, causing an increase in the surge pressure above the desired values.

All the fluids and potential temperatures need to be modeled in transients studies to confirm that the mitigation chosen will be valid for any combination of operations.

**REFERENCES**

AUTHOR BIOGRAPHY

Emma C. Perez, Emma Perez graduated as a Chemical Engineer at Universidad Simon Bolivar in Venezuela and obtained a Master’s Degree in Mechanical and Environmental Engineering at the University of California at Santa Barbara specializing in thermos-fluid sciences. She has worked in various areas of from Reservoir Simulation to Water Filtration and Process Engineering. She is currently a Hydraulics Engineering Specialist at Enbridge Pipelines where she has been working since 2011. She performs hydraulic transient simulations and provides support for pipeline and terminal hydraulic related operational issues. She has presented several papers at pipeline conferences in an effort to bring attention to transient simulations in facilities or terminal piping.

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FIGURES

Figure 1: Variation of viscosity with temperature for various hydrocarbons [3]

Figure 2 – Schematic of Injection System Modeled

Figure 3 - Viscosity curves as a function of temperature for Light and Heavy fluids used in the simulation model.
Figure 4 – Pressure Profile for Case A. Green line shows initial pressures and blue line shows maximum surge pressures obtained after the transient scenario. Red line shows MOP values for lower rated piping.

Figure 5 – Pressure Profile for Case C. Blue line shows maximum surge pressures obtained after the transient scenario with a relief opening pssetpoint of 1517 kPag (220 psig). Red line shows MOP values for lower rated piping. Green line shows mitigated surge pressures with relief valve setpoint lowered to 1034 kPag (150 psig)
Figure 6 – Flow rate through the relief valve for various simulation scenarios at 8 and -10 °C and all with light fluid in the process piping.

Figure 7 – Flow rate through the relief valve for various simulation scenarios at 8 and -10 °C and all with heavy fluid in the process piping.
**Figure 8** – Flow rate into relief tank for various simulations scenarios with light fluid in process piping.

**Figure 9** – Flow rate into relief tank for various simulations with heavy fluid in process piping.