Energy & Environmental Research Center (EERC)

SURFACE FACILITY VAPOR PRESSURE MODELING

Bakken Production Optimization Program (BPOP) 2.0

Task Wrap-Up Presentation

October 2018

Critical Challenges. Practical Solutions.

OUTLINE

- Surface facility modeling review
  - Fugitive emissions
  - Crude oil vapor pressure
- Winter 2017–2018 data collection
  - Site configurations and operating parameters
  - Oil samples and analysis
  - Model validation
- Cold weather scenario modeling
- Recommendations

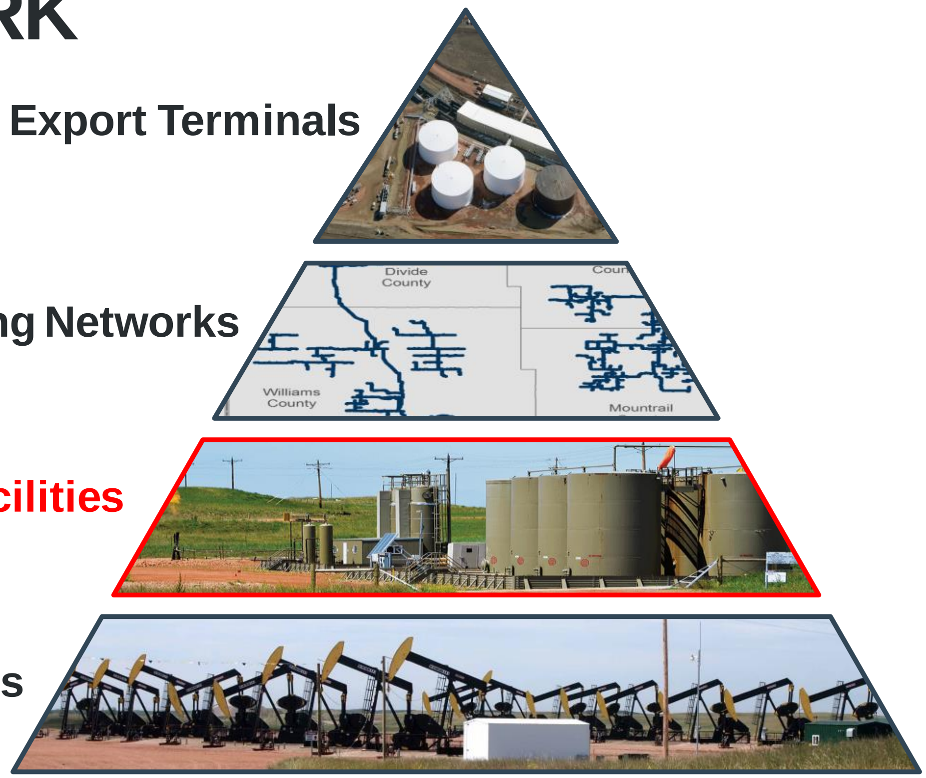
BAKKEN SURFACE PRODUCTION NETWORK

Regional Export Terminals

Gathering Networks

Surface Facilities

Production Wells



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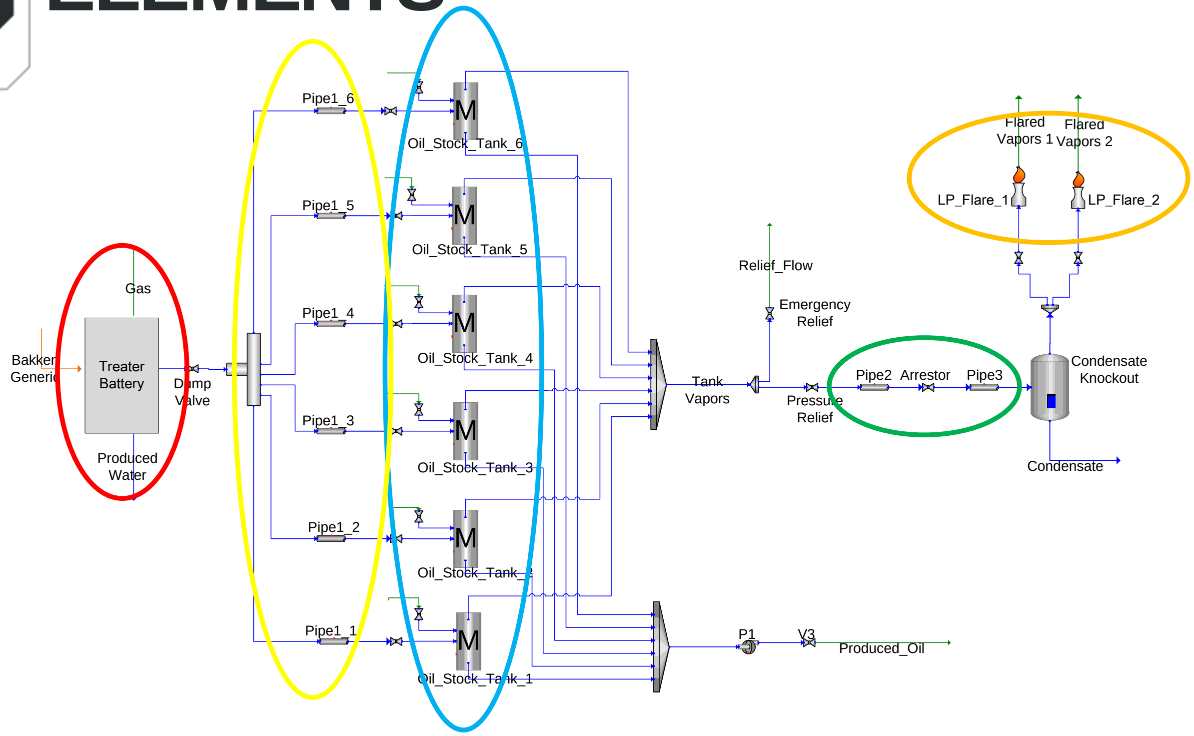
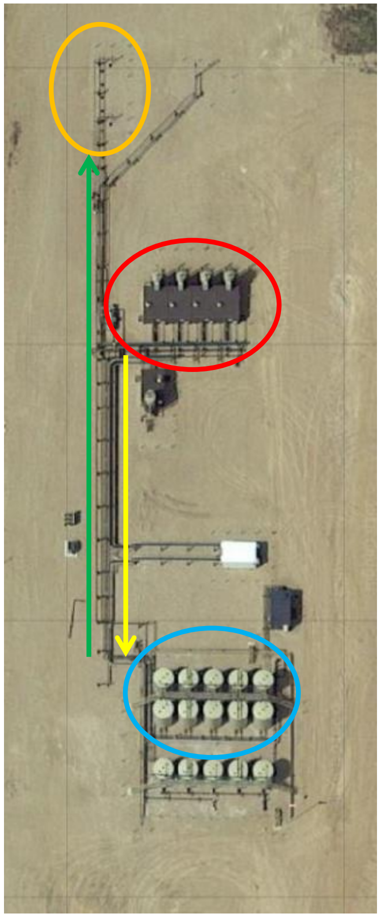
Critical Challenges. **Practical Solutions.**

This work focused on surface facilities, which is the point in the Bakken production network where the raw crude is initially separated and the sales oil properties are determined.

PROCESS-MODELING ELEMENTS

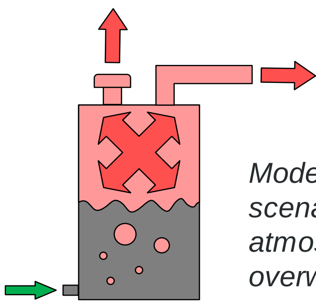




- Modeling was performed with VMG Sim v 10.
- This example process flow sheet highlights the unit operations used in the model to represent a typical surface facility.

FUGITIVE EMISSIONS MODELING RECAP

Infrared video image of thief hatch emissions. *U.S. EPA, 2015.*



Modeling used to evaluate scenarios where the atmospheric tank flash could overwhelm the flare vent.

- Modeling was used to identify design constraints and/or transient events that could lead to excessive tank pressurization.
- Analysis examples included:
  - Vent flow resistance
  - Condensate obstruction
  - Dynamic batch flow effects
- Results summarized in a white paper made available to members March 2017.
- Direct report link: https://www.undeerc.org/Bakken/pdfs/CLM-BPOP%20Process%20ModBrief%20R4-Mar17.pdf

- Initial surface facility modeling under BPOP 1.0 focused on the emission of storage tank vapors.
- With modeling, the effects of several scenarios on tank emissions were quantified for a generic surface facility.
- These findings were summarized in a white paper made available as a resource to Bakken producers.

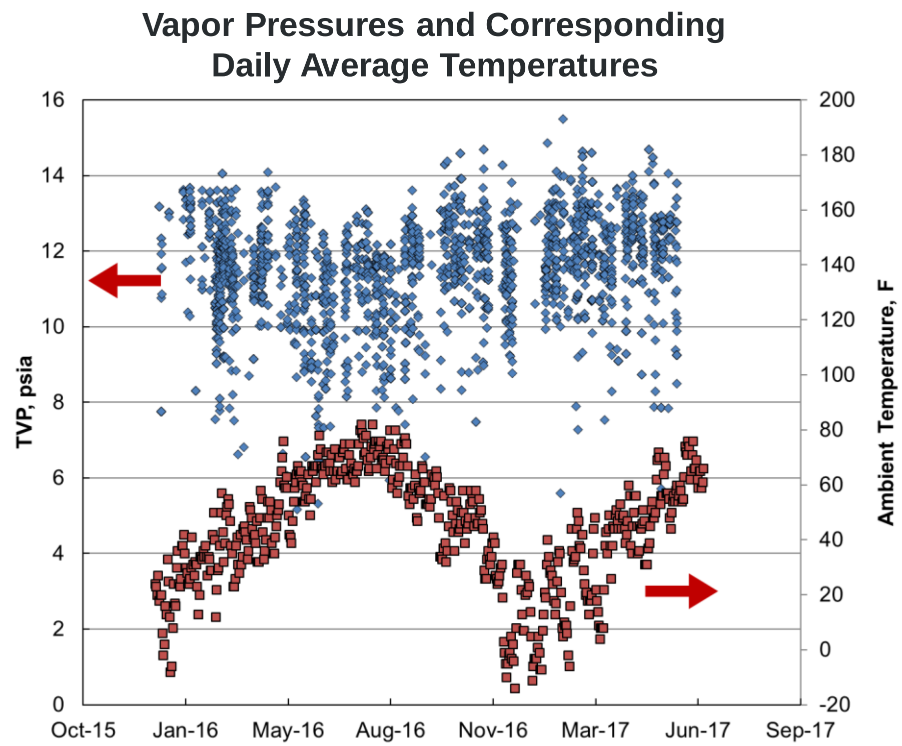
CRUDE OIL VAPOR PRESSURE

Regulatory Drivers

- Mandated by North Dakota's conditioning rule to be below 13.7 psia.
- Pipeline operators can have their own more stringent vapor pressure requirements.

The EERC convened a crude volatility meeting in May 2017 to discuss and coordinate producer activities.

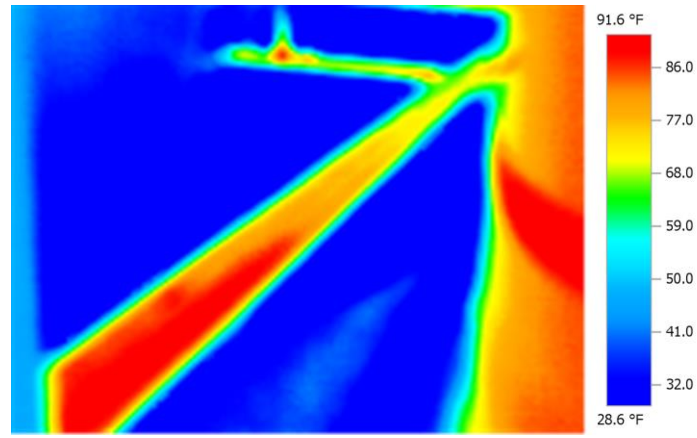
- Briefed attendees on the model's utility for this issue.
- Requested validation data and the opportunity to review field trials.



- Crude oil vapor pressure is a related issue for surface facilities since Bakken producers must comply with state-level directives and in some cases additional pipeline operator requirements.
- The EERC believed that process modeling could also provide insight to this topic and solicited feedback and information from Bakken producers.
- In the figure, quarterly vapor pressure measurements provided by a BPOP member (blue diamonds) are plotted along with corresponding daily average temperatures (red squares). These data support that vapor pressure is affected by ambient conditions, i.e., the highest vapor pressure readings occur during the coldest parts of the year.
- However, given the span of vapor pressures for any date of sample collection, other factors are clearly involved that need to be included in a model for accurate vapor pressure estimation.

2017–2018 WINTER ACTIVITIES

- Collected data from two BPOP member central tank batteries.
  - Site makeup (equipment type, sizes, distances, etc.)
  - Vapor pressure data corresponding to known conditions (i.e., production rate, temperature profiles, and ambient conditions)
  - Oil samples and follow-up analysis
- Created tuned models for each site.
- Extrapolated site performance as-tested and under additional parametric scenarios.



Infrared image from Site 1; used to determine heat loss during sampling.

- In order to investigate the unique factors affecting surface facilities, two sites were modeled in detail with respect to cold weather performance.

CENTRAL TANK BATTERY COMPARISON

	Site 1—High-Flow, Low-Volatility Oil into Multiple Tanks	Site 2—Low-Flow, High-Volatility Oil with a Single Production Tank
Number of Wells	9	3
Oil Production	3000 bbl/day	110 bbl/day
Typical Treater Conditions Pressure Set Point Temperature Observed Downstream Temp.	 35 psig 125°F 122°F	 60 psig Off and 120°F 70°–90°F
Production Tanks	Five (400 bbl each)	One (400 bbl), either a standard noninsulated tank or an insulated tank with an immersion heater
Ambient Temperature	10°F during sampling, -1.5°F daily average	Average ranged -12° to 70°F

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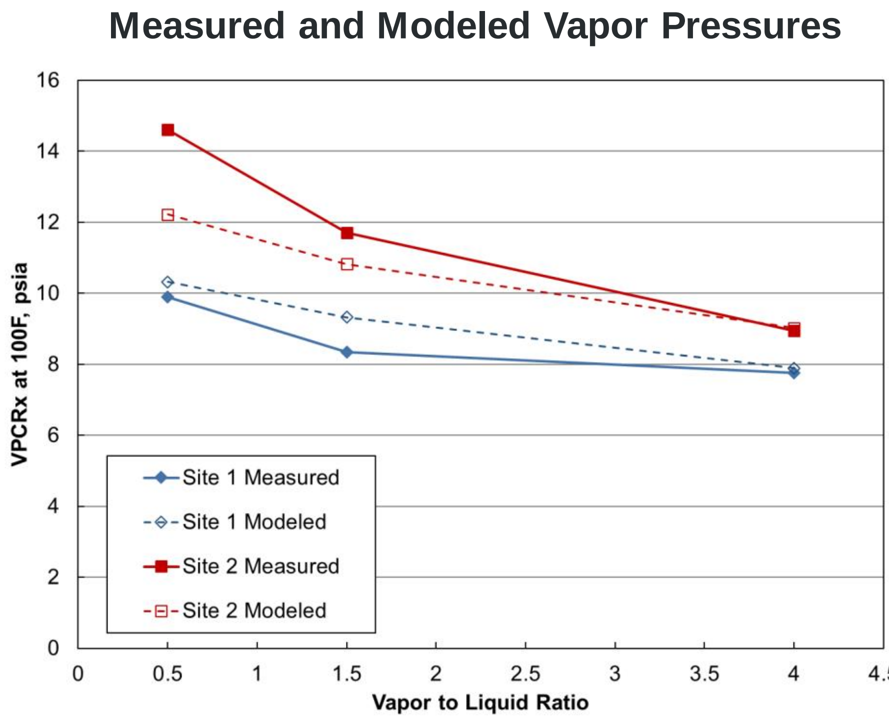
Critical Challenges. **Practical Solutions.**

- The table summarizes information about the two contrasting sites that were made available for detailed modeling by BPOP members.
- Data collection from Site 1 was limited to a single sampling event.
- Data from Site 2 consisted of multiple sampling events under differing conditions including treater burner status, production tank type, and ambient weather.

OIL COMPOSITION

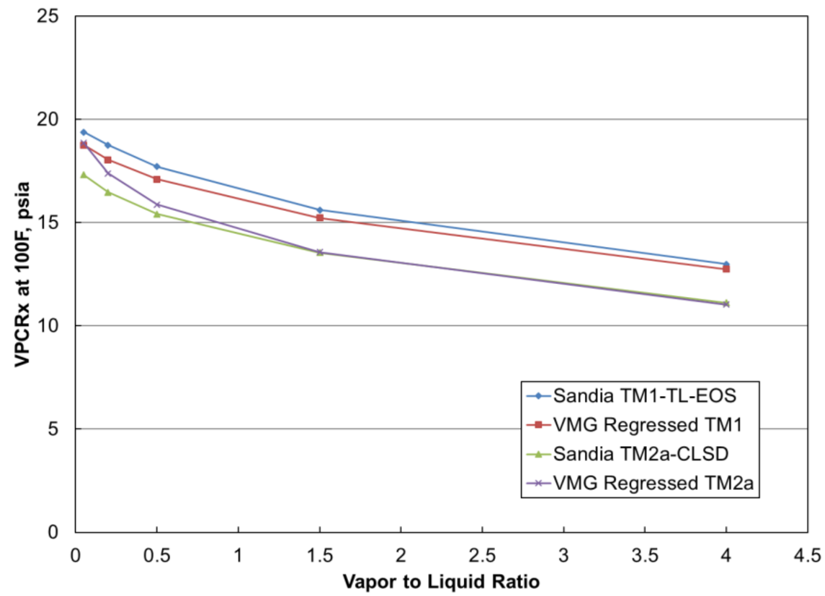
- Oil samples from both sites were analyzed using the methods below and combined mathematically into a sales oil composition.
  - ASTM D7169 (simulated distillation)
  - ASTM D7900 (light hydrocarbons)
  - GPA 2177 (N_2 and CO_2)
- Composition data were input in the simulator to produce vapor pressure estimates which were validated against lab-measured VPCRx values.
- Whole crude compositions were derived by incorporating treater and tank flash gases and produced water to match GOR and WOR targets.



- Detailed modeling began by defining the crude composition based on oil samples from each site. ASTM D7169 provided a simulated boiling point curve to characterize the approximate C10 to C100 distribution, while ASTM D7900 provides the distribution of light hydrocarbons to C9, and GPA 2177 determined light inorganic constituents including nitrogen and carbon dioxide.
- The figure compares laboratory-measured vapor pressures of EERC-collected oil samples and the calculated vapor pressure using a merged oil composition analysis.
- Agreement between the two is best at a vapor-to-liquid ratio of 4:1, which is less affected by measurement errors than smaller values. The 4:1 ratio is also the assumed basis for ND Conditioning Rule compliance.

OIL SAMPLING AND VAPOR PRESSURE MODELING

- Prior to modeling oil from Sites 1 and 2, the calculation procedure was established based on work by Sandia National Laboratory (SNL) into crude oil sampling and vapor pressure determination.
- Applicable points from SNL work:
  - Closed versus open sample containers can produce comparable vapor pressure values—for atmospheric-equilibrated oil samples, but not pressurized samples.
  - Equation-of-state modeling can generate reasonable estimates of vapor pressure provided that light ends, and inorganic gases are merged appropriately in the oil composition.
  - The repeatability and therefore the confidence in vapor pressure measurements generally improved with increasing vapor-to-liquid ratios.

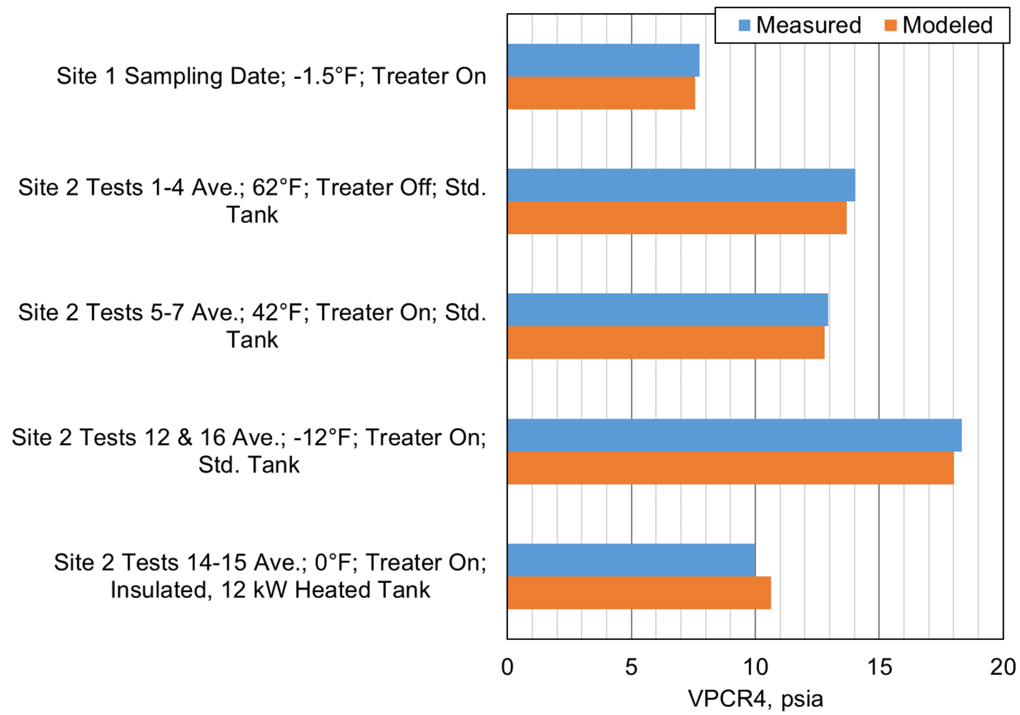


Comparison of SNL study results and those calculated using VMG Sim, the simulator used for surface facility modeling.

- Gaining agreement between measured oil vapor pressures and those calculated based on compositional data required the careful integration of multiple data sets. The team referred to recent work at SNL in order to establish the necessary procedure.
- The figure shows validation of this effort by comparing key data sets from SNL's work with vapor pressures calculated using the VMG Sim process simulator.

MODEL CALIBRATION

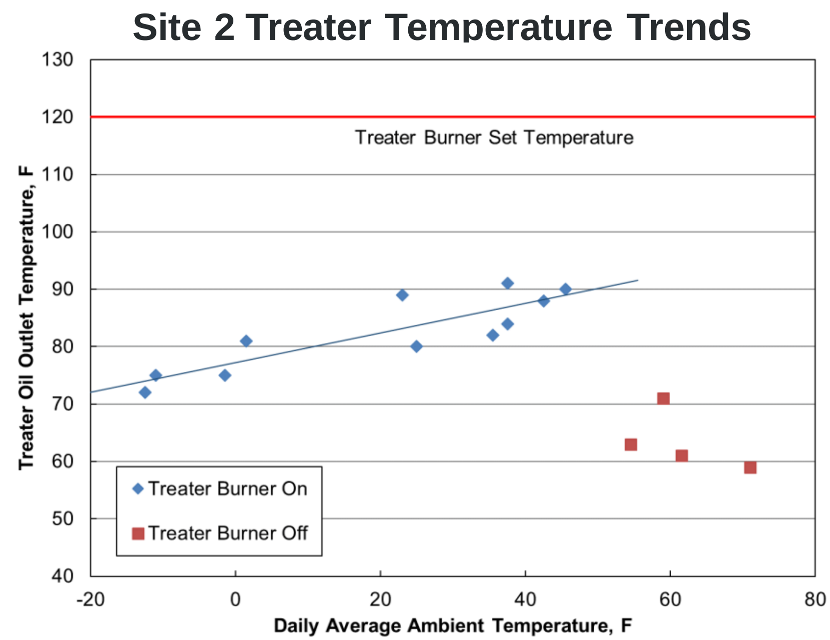
- Fine-tuned each model so the calculated heat loss from the modeled configuration matched observed temperature readings.
- Corroborated the model by inputting the whole crude composition and predicting the sales oil vapor pressure.



- With established oil compositions, the next step of model development was to calibrate the surface facility models using recorded operating conditions for each site.

TREATER TEMPERATURE

- At both sites, the treater oil outlet temperatures were used as a more reliable measure of treater flash temperature.
- The Site 1 treater operated near its temperature set point. Presumably, the high flow enabled better internal mixing and/or allowed more heat to be retained from the wellhead.
- Lower flow at Site 2 likely resulted in the opposite effects, i.e., poor mixing and heat loss.

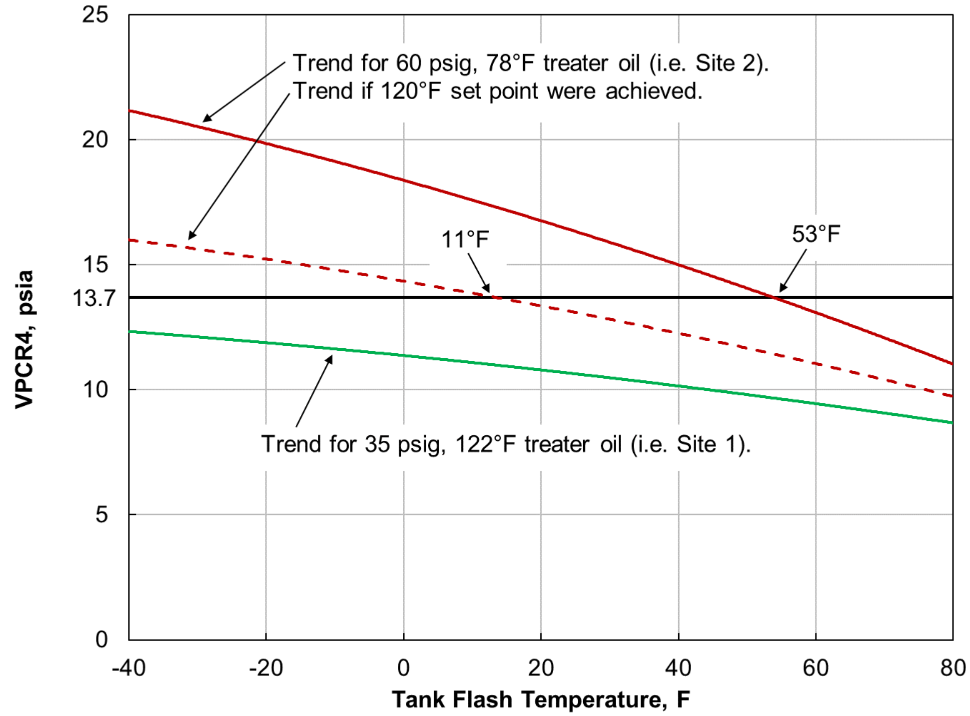


Site	Ave. Treater Flow, bbl/d/treater	Treater Pressure, psig	Ave. Ambient, °F	Treater Set Point, °F	Treater Actual, °F
1	330	35	-1.5°	125°	122°
2	110	60	-1.5°	120°	78°

- The most important assumption that was made for model calibration concerned the nonideal performance of Site 2's treater, data from which are shown in the figure.
- The treater set point was 120°F for all of the "Treater Burner On" data. However, based on the recorded treater outlet temperatures, it seems that the actual bulk fluid temperature in the treater was probably much lower.
- The trend line shown for these data was incorporated into the model as the actual treater flash temperature instead of assuming the burner set point temperature.

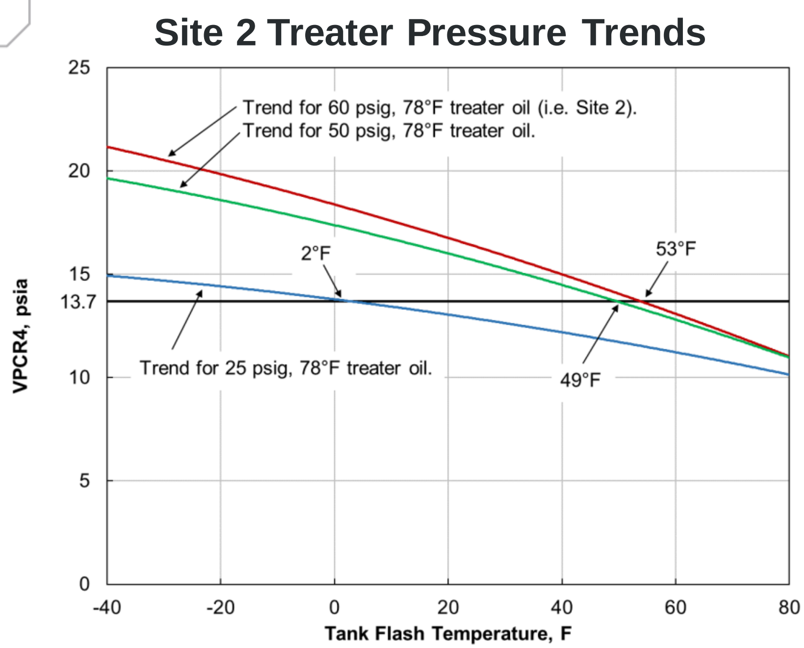
FLASHED TREATER OIL TEMPERATURE SENSITIVITY

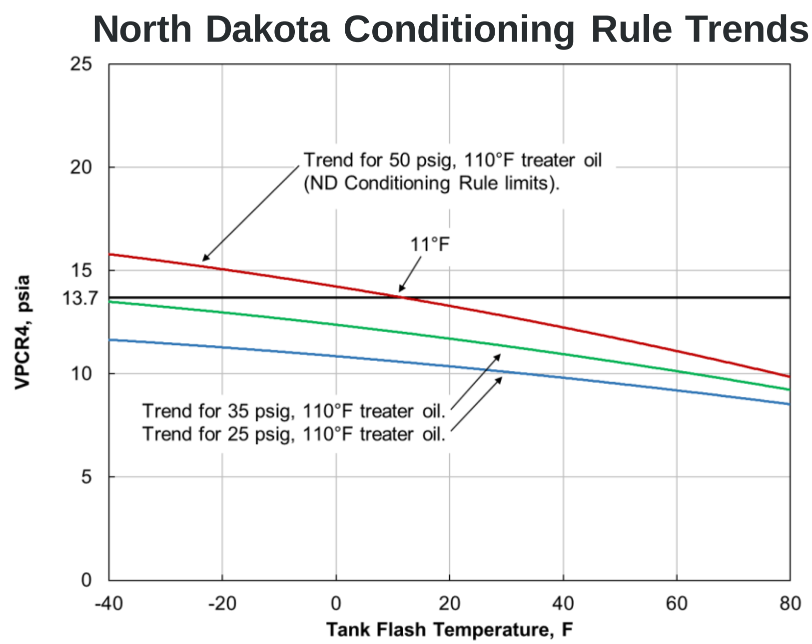
- Oil from Site 1 treaters was sufficiently flashed that it would not be expected to exceed 13.7 psia at any realistic tank temperature.
- Site 2 clearly represents a more limiting condition that could be improved with better treater heating or reduced-pressure operation (next slide).



- Calculated trends in the figure show the effect of treater performance on the resulting sales oil volatility for the two treater conditions outlined in the table on the previous slide.
- In addition, the Site 2 scenario was recalculated as if the treater were able to achieve its 120°F set point.
- Note that in this figure the temperature is the actual oil temperature in the tank, not the ambient temperature which will be included in subsequent slides.

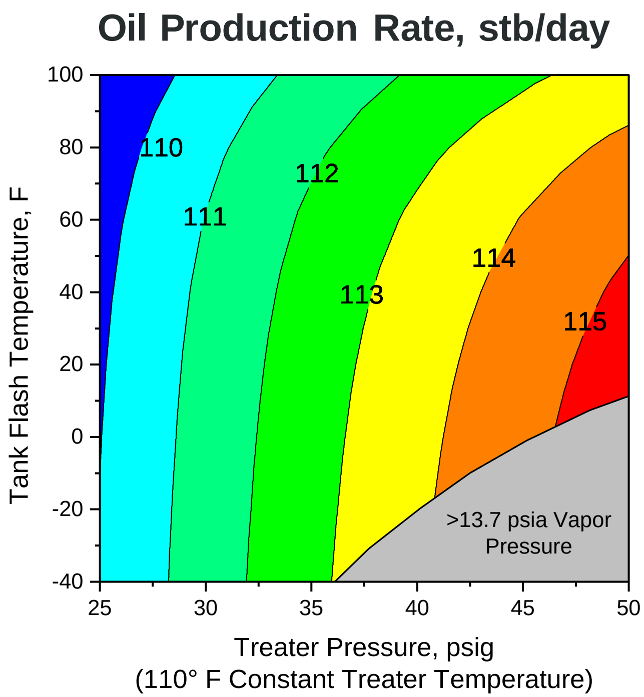
TREATER PRESSURE REDUCTION

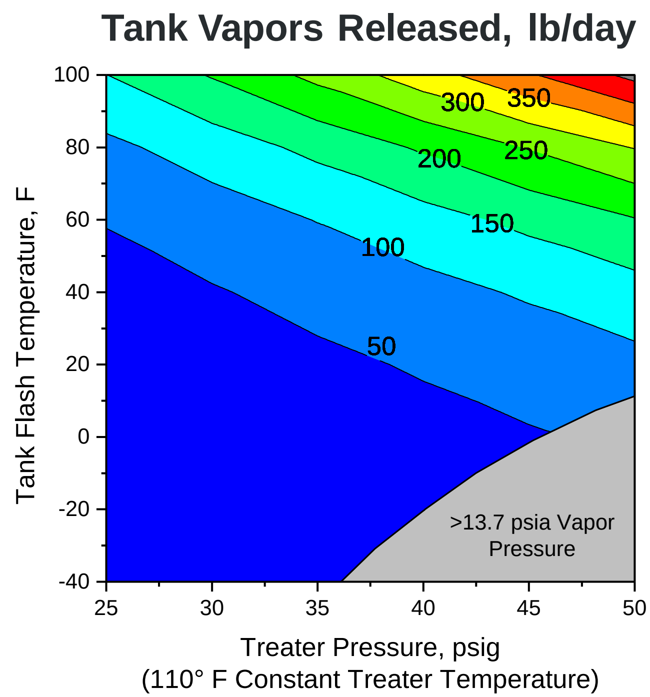




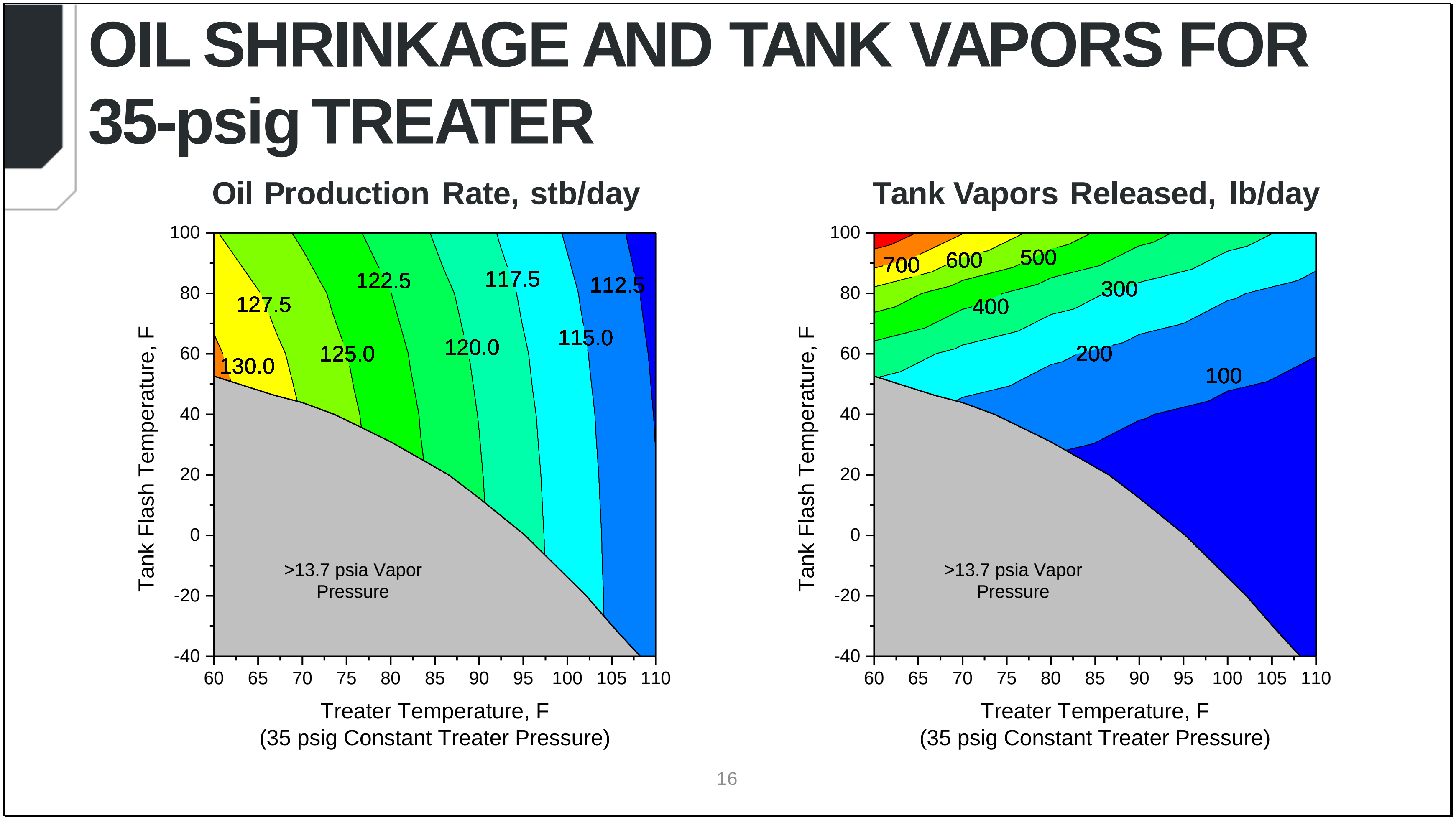
- While the previous slide showed the effect of Site 2's treater temperature (78° vs. 120°F), the figure on the left evaluates a reduction in treater pressure at a 78°F temperature.
- For reference, the right-hand figure shows pressure trends for a higher treater temperature specified by North Dakota's Conditioning Rule.

OIL SHRINKAGE AND TANK VAPORS FOR 110°F TREATER





- The previous slide indicated that with treater operation at 110°F and 35 psig, the oil would be sufficiently flashed that it would not retain 13.7 psia vapor pressure down to a tank flash temperature of -40°F.
- However, at higher tank flash temperatures more volatiles than necessary would be flashed away, resulting in lost oil production (shrinkage) and increased tank vapor production. Figures on this slide show both shrinkage and tank vapor trends as a function of treater pressure and tank flash temperature.
- These figures suggest that there is some incentive to optimize treater conditions to meet the 13.7-psia requirement while avoiding excessive flashing and lost oil volume/revenue.



- Similar sensitivity results for treater temperature show that operating the treater at a cooler temperature is another way to minimize shrinkage.

SITE 1 VRT CONSIDERATION

- Site 1 was equipped with an insulated vapor recovery tower (VRT) upstream of the tank battery, but it was not in service during sampling.
- Modeling the VRT for the high-flow baseline resulted in a further vapor pressure reduction from 7.6 to 7.3 psia.
- At a lower flow rate, the VRT acted as a dedicated, near-atmospheric flash vessel and offered improved flashing compared to the parallel filling of all five tanks.
- However, without a supplemental heat source, the VRT must rely on residual heat from the treater, which is likely to decrease at lower flow rates (as at Site 2).

Site 1 VRT Modeling Results

Common Conditions:

-1.5°F ambient temperature
122°F treater temperature
Five production tanks

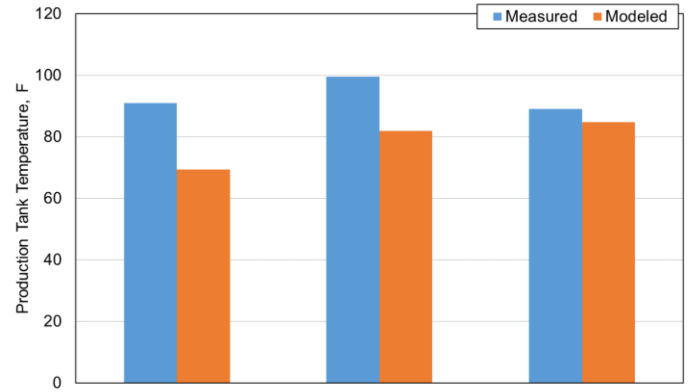
Flow bbl/d	VRT Active	LACT T, °F	VPCR4, psia
3000	No	102°	7.6
3000	Yes	101°	7.3
300	No	43°	10.3
300	Yes	41°	9.1

- Each site had unique features not included in the previous discussion.
- Site 1 had a vapor recovery tower, but it was not included in the model because it was not online during sampling.
- However, the effects of adding it were modeled for a few scenarios shown in this table.

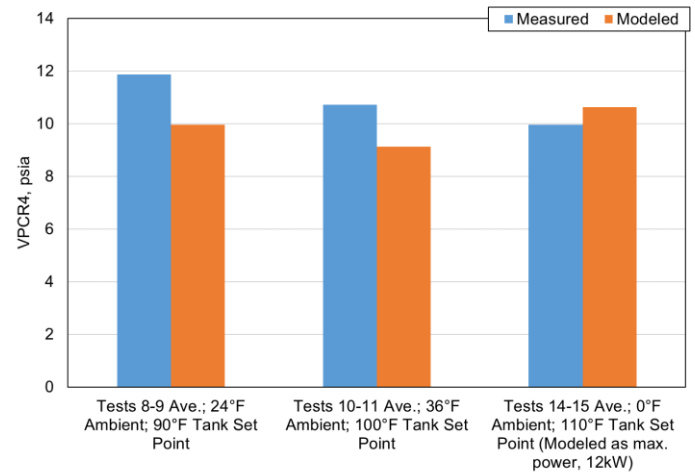
SITE 2 HEATED TANK CALIBRATION

- Site 2 included multiple conditions of the insulated and heated production tank, but only the full-power condition resulted in a reasonable match for both temperature and vapor pressure (Tests 14 and 15 average).
- The heater was at partial load at the other set point conditions, but the set point temperature does not appear to correspond with the measured and modeled vapor pressures.
- In all likelihood, the bulk temperature of the tank was lower than the heater set point. This may have implications regarding the appropriate temperature and set point to use for feedback control.

Modeled to Match Vapor Pressure



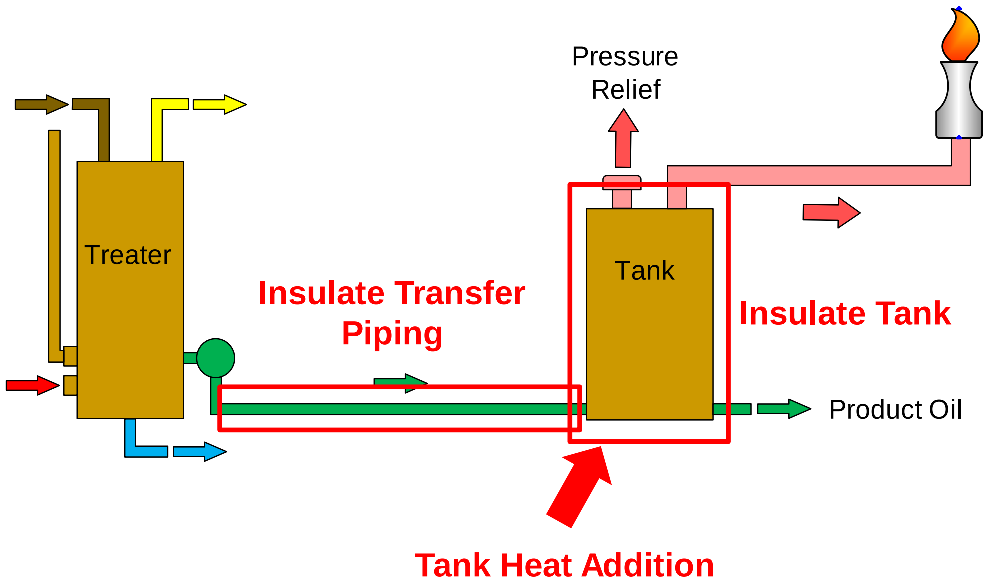
Modeled to Match Tank Temperature



- Site 2 included additional data points when the insulated tank heater was in operation.
- These data points were modeled two ways: by running the model at the tank heater set temperature and by adjusting the tank temperature to match the measured vapor pressure.
- As shown in the figures, only the maximum power condition (in which a power input was specified rather than a tank temperature) provided a reasonable match in both cases. This result suggests that when the heater is partially loaded and cycling, its set point temperature is not indicative of the overall flash conditions in the tank.

COLD WEATHER MODIFICATION STUDY

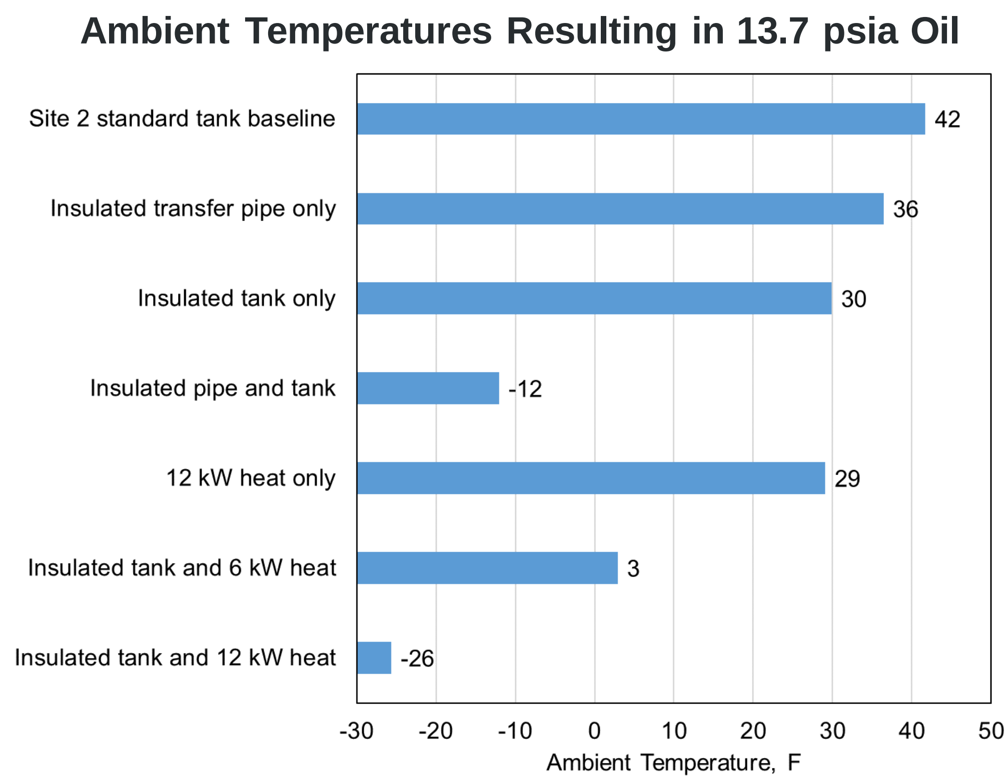
- Different upgrade scenarios were modeled to estimate cold weather resiliency.
- Evaluated cold weather tank battery modifications using Site 2 conditions.
- Nominally 110 bbl/day/tank.



- Site 2 was selected for the cold weather modification study since the conditions at Site 1 were unlikely to result in a vapor pressure greater than 13.7 psia.
- The three indicated changes were considered, both individually and in selected combinations.

COLD WEATHER MODIFICATION RANKING

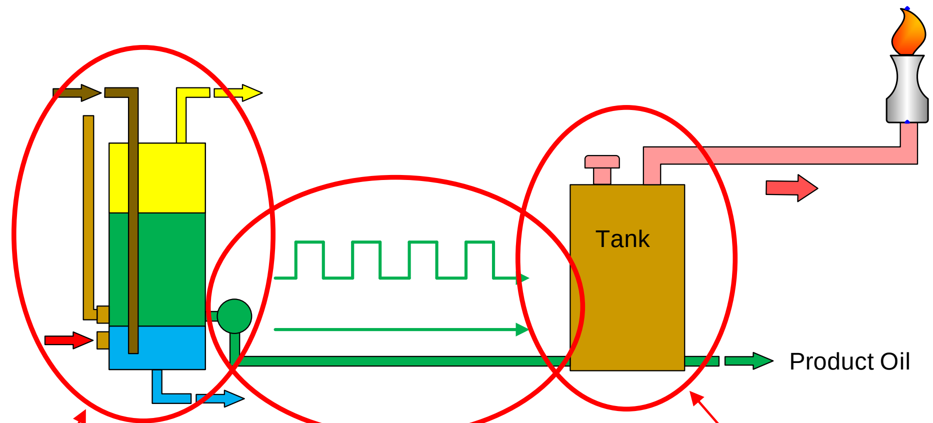
- Insulation of either the tank or piping alone did not show much added resilience. Instead, they are needed in combination to preserve heat from the treater and maintain it in the tank.
- An alternative that offers more design flexibility is the combination of a heater with an insulated tank.



- The cold weather modifications were ranked by computing the ambient temperature required to produce an oil with 13.7 psia vapor pressure.
- Lower temperatures indicate more resiliency against forming a high vapor pressure oil.
- Note that these ambient temperatures will generally be lower than corresponding tank temperatures that were specified in previous figures.

ADDITIONAL STRATEGIES AND TRADE-OFFS

- Strategies to alleviate crude vapor pressure can either complement or work against other site functions.
- **Synergistic actions**
  - Increase treater efficiency
- **Mixed actions**
  - Batch versus continuous flow to tanks
  - Produce into a single tank or dedicated flash vessel



Flashing vapors in the treater means less product lost to the low-pressure flare.

Discrete pulses of oil reduce piping heat loss but increase peak discharge of tank vapors to the flare.

A single production tank or dedicated flash vessel conserves heat but will also have a smaller headspace "cushion" before relief vents open.

- Improvements made to alleviate vapor pressure will also need to be considered for their effect on other processes.
- For instance, the mixed actions outlined on this slide presents concepts that could improve tank oil flashing and reduce oil vapor pressure, but they would also result in peak loading of vapors into the flare vent which would tax the vent and tank pressure relief.
- On the other hand, improving treater efficiency appears to be completely synergistic since vapors removed in the treater can be gathered and sold and are not available to become fugitive emissions from the tank.

MODELING LESSONS LEARNED

- Input oil composition is critical for the accurate prediction of oil vapor pressure. Since no common, single method measures the entire inorganic and hydrocarbon distribution of crude, this determination relies on merging separate analyses.
- Modeling results should represent trends at most Bakken surface facilities; however, site-specific modeling is necessary to estimate numerically accurate vapor pressure values.
- Oil throughput was a key distinguishing factor between Sites 1 and 2. Nonideal treater performance was an important consideration for Site 2, which had a low production rate.

RECOMMENDATIONS SUMMARY

Two general approaches seem possible to alleviate wintertime vapor pressure issues:

1. Address the low-flow performance of the treater to prevent high-vapor-pressure oil from reaching the tank battery.
   a) Improve mixing and temperature uniformity within the treater.
   b) Alternatively, preheat the fluid entering the treater and minimize its heat loss.
2. Modify the tank battery to maintain an effective atmospheric flash under all expected weather conditions.
   a) Produce into a single tank or dedicated flash vessel to minimize storage heat loss.
   b) Insulate this tank and add a heating mechanism for maximum resilience.
   c) Weigh year-round performance to avoid excessive flashing during warm weather that could lead to unneeded product loss and increased emissions.

- Approach 1 seems to offer a performance advantage since it could enhance product sales and help reduce the potential for fugitive emissions.
- However, facility decisions must of course also weigh the cost of implementation against the potential benefits identified through modeling.

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