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<u>Hydrocarbon Dew Point Effects on Gas Flow Measurement</u>

Class 5115

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The hydrocarbon dewpoint (HCDP) of interest to the natural gas industry is simply an operating condition that causes liquids to condense out of the gas stream and form a liquid phase. Normal condensation occurs when increasing pressure or decreasing temperature causes liquids to form. Retrograde condensation occurs on a different portion of the phase envelope, wherein <u>increasing</u> temperature or <u>decreasing</u> pressure may cause the gas to cross the phase boundary and produce condensation. Both processes produce liquids condensing out of gas phase streams and are of interest to this presentation. Phase diagrams will not be discussed further in this paper, other than to mention that present correlations to predict phase behavior have proven to be inaccurate for relatively rich gas streams and typically predict HCDP temperatures well below the actual HCDP temperature. I will try to characterize "rich" gases, as referred to in this paper, by indicating those at or above 1050 Btu's per cubic foot and containing some C4 thru C6+ components (butanes thru natural gasoline).

It may be desirable or undesirable to produce these condensed liquids in a natural gas system. If, for example, a production lease operator wants to deliver natural gas directly into an interstate gas pipeline but the Btu content of the produced stream is too high, a wellhead liquid separation and/or recovery system may be used to remove the heavier components from the stream and lower the Btu content of the gas phase to be delivered to a point that it is acceptable for direct injection into the pipeline and will meet the necessary pipeline specifications. These wellhead systems are often associated with other equipment to dehydrate the stream (glycol and/or molecular sieve dehydration usually) and thereby reduce the likelihood of corrosion and freezing problems in the downstream processes and pipelines due to free water. At some locations, but usually at more centralized facilities, the stream may be treated to remove additional moisture, H_2S (hydrogen sulfide), COS (carbonyl sulfide) and other undesirable components in the gas stream.

Wellhead systems to control Btu content typically rely on simple separation if the gas is already a two phase natural gas/hydrocarbon liquid stream as it leaves the wellhead, and/or a simple refrigeration process to chill single phase gas or two phase produced streams to a level sufficiently below the hydrocarbon dewpoint of the stream so as to liquefy enough of the heavy components from the stream to make it marketable. The heavies removed are primarily butanes, pentanes and natural gasoline. The liquids produced are recovered from the bottom of a production separator or liquid storage vessel, then sold, transported and processed further.

Having compression facilities near the wellhead is likely to produce liquids as the gas is cooled between stages of compression and in the pipeline system downstream of the compressor station after the stream cools to ambient or soil temperature. This is especially true during winter months when ambient and soil temperatures are the lowest. Compression liquids are collected in the compressor discharge separators after being cooled by interstage coolers. Liquids condensing downstream of the compression systems may be gathered in downstream pipeline drip locations or removed from the pipeline by pigging operations that push the liquids thru the pipeline to a separation and collection point downstream.

From the measurement perspective, systems like those described above may produce several measurement problems. For example, any time pumps or compressors are used in close proximity to metering systems, the potential for pulsating or highly variable flows is greatly increased. It is easy to visualize that a gas compression system using a reciprocating compressor puts powerful pulses of gas into the downstream piping. Considering the high rpms of most compression systems and that most reciprocating compressors use double acting compressor cylinders, the frequency of the pressure pulses is very high – much faster than once per second - and will be referred to in this paper as pulsation. The amplitude of the pulsations can be very severe unless controlled by pulsation dampeners in the compressor discharge bottles or other dampening devices.

Systems experiencing significant pulsation and utilizing chart recorders will tend to exaggerate flow rates significantly. Systems with flow computers and significant pulsation will simply be wrong, but the severity and direction of the error is essentially unpredictable. The errors may be very large, such as 5 to 10%, or even higher. Turbine meters tend to over-register in the presence of pulsation or highly variable flows, since turbines tend to over-spin more than under-spin in the presence of highly variable or pulsating flows. Errors can easily exceed +5% of flow.

If orifice systems are coupled with Electronic Gas Meters (EGM's/flow computers), the direction of error due to pulsation is unknown, but one can be sure that the indicated volumes are not correct. Square Root Error Indicators (SREIs) may indicate a positive or negative error when they are used to analyze pulsations, but, at best, the indication is only true with the SREI inline and at the point where it is connected, which may not be relevant to the system after the SREI is removed and the harmonics of the system change. In addition to this, as engine rpms change, the harmonics of the system will change also.

Highly variable flows, with rate changes slower than once per second, may be the result of unstable control systems and will be considered as variation or variable flow in this paper. Any gas metering system associated with compression systems is going to have to deal with both pulsation and variation to one degree or another. Note that variable flow is generally produced by unstable control systems; such as flow control systems, temperature or pressure control systems, level control systems and/or engine speed control systems. They may also be produced by plunger lift systems or intermitters on production wellheads. These systems are intended to periodically shut in the well (usually for several minutes) to help the well build up sufficient wellhead pressure to allow the eventual flow from the well to clear liquids in the well bore and enhance production. They also produce highly variable flow rates that severely compromise the accuracy of chart recording systems and may cause some degradation in measurement accuracy in systems utilizing flow computers.

The advantage of EGM's is that if the variations in the flow are less than about once per second (highly variable but not pulsating flow), modern EGM's can still meter accurately. Any errors are likely to be a few tenths of a percent. However, if the rate of change is much faster than once per second, it becomes more likely that even flow computers cannot keep up with the rate of change and indicated volumes become increasingly inaccurate as the pulsation frequency and/or amplitude increases.

This is a good point in the paper to emphasize a key reason one should buy flow computers instead of chart recorders for significant volumes of gas in custody transfer applications, especially in the presence of highly variable flows. <u>Resolution!</u> The more variable flow rates become, the more important resolution becomes. An 8 day chart has an effective resolution of several minutes. This lack of resolution is the reason companies using chart recorders so often end up trying to integrate wide band charts, which is a very inexact combination of art and science, usually resulting in exaggerated gas volumes. On the other hand, a modern flow computer has an effective resolution of less than one second, so variations in flow are easily tracked.

If economics allow, consideration should be given to using EGMs in allocation measurement services as well, particularly when system balances are very poor due to the use of intermitters or plunger lifts on the wellheads. Chart recorders simply cannot provide measurement that is accurate under these conditions. This may be especially important when some producers in an allocation system are using intermitters and/or plunger lifts and others are not. In essence, if you use chart recorders throughout a system of this type, you'll end up paying the producers with the intermitters and plunger lifts for more than their fair share of gas.

Returning to the discussion of liquids being created near the wellhead, note that it may be <u>undesirable</u> to form these liquids. For example, if the well produces gas directly into a gas gathering system but the ambient conditions are cooler than the hydrocarbon dewpoint, the produced stream may eventually be cooled to the point that liquids condense from the stream and accumulate in the pipeline system. Eventually a substantial amount of liquids will form and create increased pressure drops thru the system. It will also increase the potential for internal erosion in the pipeline and increase the potential for operating problems in the pipeline and with associated compression and/or processing facilities downstream.

From the measurement perspective again, having liquids in the gas stream is always harmful to accurate measurement. Orifice meters are still the most common form of gas measurement in our industry and liquids in the gas stream do cause significant errors in measurement. Liquids may build up on the upstream side of the orifice plate and change the flow profile of the stream as it approaches the plate. Typically, small amounts of liquids that accumulate in this manner cause indicated volumes to be too low. If large amounts of liquids or slugs of liquids enter a gas metering system, errors are going to be severe and may be plus or minus, depending on the ratio of liquid to gas and the nature of the liquid. Note that this is true for any differential pressure device to one degree or another, but orifice meters are particularly susceptible to these errors. There are specialized plates with small holes near the bottom of the plate which allow the liquids to readily move past the plate, but they are not in wide use and their discharge coefficients are not well understood as liquid fractions vary (in my opinion).

Other types of meters routinely used in the field gathering and compression systems are also subject to varying degrees of error due to two phase flow. Turbine meters are not used in services of this type, since liquid slugs would severely damage them.

It should be noted that at some locations, particularly offshore where pipeline systems are very limited, the separated liquids and the natural gas stream may be recombined after they are metered. This recombination produces difficult operating conditions in the single pipeline that transports the mixed phase stream from location to location and eventually to shore or an offshore processing facility. Large slug catchers are necessary at the receipt points. Variable flows and large liquid slugs are the norm and facilities must be engineered and operated to handle these extremes. Pipeline monitoring must consider the possibility of erosion due to slugging and sloshing liquids inside the pipeline, particularly when solid contaminants such as sand are present.

Once liquids have accumulated in a pipeline system, the potential for substantial liquid volumes being trapped in low points in the system is increased. Perhaps a river crossing or a natural low point for the pipeline, such as a valley or canyon, will cause very large volumes of liquid to be trapped. These liquids do not tend to flow out of these traps at a steady rate. Instead, they tend to slosh back and forth inside the pipeline, producing abrasion between any solids trapped in the liquids and the interior pipe walls, and periodically dumping liquid slugs out of the trapped volume into the downstream pipeline. Sudden pressure drops on the downstream side of these traps may cause very large slugs to be produced. Each trap increases the pressure differential necessary to move gas thru the pipeline, increases the potential for internal erosion of the pipeline and creates a higher potential for slugs of liquids moving toward downstream equipment and processes.

Two primary methods are used to remove these liquid accumulations. One method requires that collection vessels or drips be installed in the pipeline system, below the pipeline elevation, so that accumulated liquids can drain into the drips. The drips then have to be drained regularly, usually using transport trucks making runs to insure the pipeline itself is liquid free. The second method involves allowing the gas stream to force a device thru the pipeline that seals along the pipeline walls and forces any liquids in the pipeline to be pushed along the system to some convenient collection point. These devices are commonly referred to as “pigs”. There are many types and configurations of pigs, including poly pigs, scraper pigs and even smart pigs, but the simple pig discussed in this paper is simply a device that seals against the walls of the pipe and moves along the pipeline using differential pressure to push liquids ahead of it to a collection point.

Once the liquids arrive at a collection point, inlet separators must be designed with adequate internal volume to catch these slugs of liquid, or special "slug catchers" must be provided to collect them. Where inlet separators are typically either large volume, vertical or horizontal vessels designed to collect and separate the liquids from the incoming gas, the slug catchers are simply a large volume dedicated to holding the incoming liquids until they can be diverted for further processing. Slug catchers are typically large diameter pipes arranged parallel to one another and connected by header and piping systems. The liquids are collected in the slug catchers, and then delivered into a process system using pipeline pressure or liquid pumps, depending on operating conditions.

From the measurement standpoint, facility inlet metering systems have to deal with liquids contamination thru the metering systems unless slug catcher and separator systems are properly sized, well-designed and operated correctly. In addition, highly variable flows are almost guaranteed and the rangeability, resolution and accuracy of the metering system will become critical.

Orifice meters are typically capable of an accurate range of measurement that is fairly limited, with max flow rates typically only four or five times those of the recommended minimum flow. Turbine meters may be equally limited at lower operating pressures, but improve as gas pressure and density increase. Differential meters are generally limited in their rangeability relative to positive displacement and linear meters, but they are also fairly rugged, relatively easy to operate and maintain, and cost effective.

Although ultrasonic meters have great rangeability, most do not tolerate mixed phase and/or contaminated streams well and are widely used only in large volume, custody transfer quality applications, where they become very cost effective and accurate. Turbine meters tend to be limited to the same applications, and at lower volumes, may be cost effective choices.

Besides great rangeability, multipath ultrasonic meters are capable of great accuracy (better than 0.25%), they are very "intelligent" and can perform extensive self-diagnostic routines, and they are relatively tolerant of swirling and/or variable flow when coupled with modern flow computing systems and good flow conditioning. Like other meter types, they do not like pulsating flows and may even be damaged by severe pulsations in the stream. Pulsations are particularly damaging to accurate measurement if their frequency coincides with the operating frequency of the meter.

Turbine meters are very susceptible to swirl and often do not have adequate flow conditioning to eliminate the effects of swirl or to reduce the effect to an acceptable level. Turbine meters tend to over-register indicated volumes in the presence of pulsation. In addition, they do not tolerate contaminants passing thru the metering system very well. As a result, filter/separation systems are necessary to protect turbine meters from solids, oils, glycols and other contaminants that may be passing thru the metering systems. Another weakness of turbine meters is that their performance may degrade at any time due to friction, debris, contamination, etc., without any external indication of the problem unless the dual rotor types are used. With the dual rotor system, the relative performance of the two blades (equipped with different pitch and design) will generally give a good indication of operating problems due to damage, wear, increased friction, coatings, etc.

Even though the topic of this paper is hydrocarbon dewpoint effects, it would be a disservice to the reader to not mention hydrate formation, which can be a severe operating problem. Hydrates are crystalline structures that appear very similar to ice, but may form at temperatures well above freezing in high pressure pipelines. High pressure, free water and natural gas are the required ingredients. In a recent example, a high pressure pipeline had a hydrate formation temperature of 54F, well above mid-winter river bottom temperatures in the Mississippi River in Louisiana where this project was located. This is often very surprising to operators in warm climates who tend to assume freeze-ups can't happen.

Once hydrates form, they cause the same problems as ordinary ice in a pipeline system. They may block the line. They may move into operating equipment and cause damage. They may block valves, probes, relief systems and other critical components and, in general, be a very real hazard to the safety of pipeline employees and anyone else in close proximity to the pipeline. I will note that methanol will help prevent hydrate formation, but once large hydrate formations take shape inside a pipeline and block it, it may take days, weeks or months to clear the line.

Finally, we need to discuss HCDP prediction and measurement. During recent research into natural gas sampling, it became increasingly evident that current correlations to predict the HCDP are not accurate and often predict HCDP's as much as 30F lower than actual. This will result in gas samples that are contaminated with heavy components and not representative of the full flowing stream being sampled. Gas analyses that are too rich produce errors in calculated flow rates, flowing densities, Btu contents, compressibility, etc., so it is very critical that we develop more accurate correlations and/or actually measure the HCDP of the stream. The primary device for measuring the HCDP is the Bureau of Mines Chilled Mirror device, but online methods are being developed and are improving rapidly and may provide accurate and reliable means of continuously monitoring the HCDP.

For those of you not familiar with the chilled mirror device, I'll include a brief description. Typically the device is mounted on a tripod. It includes a small stainless steel chamber with a mirror inside. The chamber is chilled, usually using flashing liquid propane as the refrigerant. The temperature of the chamber is continuously monitored during the test. The chamber containing the mirror also has a viewport to allow visual inspection of the surface of the mirror to detect any condensation. Note that in gas streams with high moisture content, the chilled mirror can be used to detect the water or moisture dewpoint of the stream. If the product is dry enough, then it may be used to determine the hydrocarbon dewpoint we are addressing in this paper.

Some designs, such as the research grade chilled mirror device we used during the gas sampling research project, have a video camera trained on the mirror and on the temperature readout simultaneously. This allows a continuous recording of the condition of the mirror and the temperature of the mirror, so that should any dispute or inconsistent data arise, the images can be replayed until an accurate interpretation is resolved. The temperature at which hydrocarbons begin to cloud the mirror is determined visually, and then recorded. Repeat runs are made to insure the results are reliable. Operators with some experience with the chilled mirror device can readily obtain repeatable results within a couple of degrees. Manufacturer claims of accuracy are as good as +/- 0.2 degrees Fahrenheit, but that certainly would require a skilled operator.

Note that we really have to consider two different HCDP's. One is critical to our operations – one is not. Using the chilled mirror device, we determine what I'll call an operational HCDP – one that means enough liquid is condensing to produce some potential for operating problems due to liquid accumulations. A residential system using this gas might experience unstable flames or even flameouts due to liquids in pilot lights and regulators.

The other type of hydrocarbon dewpoint is what I would call a theoretical HCDP, meaning the temperature at which the first two gas molecules combine to form the first liquid droplet in the stream. This HCDP will not produce any operating problems, since the amount of liquid is so limited. The chilled mirror device is not effective for identifying this HCDP, and, in fact, this dewpoint is not really detectible with current technology outside a laboratory.

The API Chapter 14.1 Working Group which I chaired for 8 or 9 years collected a substantial amount of data on the operational HCDP and compared findings to the current correlations for predicting the HCDP. It became evident that current correlations for HCDP predictions are not accurate and may be 30F in error, with the actual HCDP much warmer than that predicted by Suave Redlich-Kwong (SR-K), Peng-Robinson and other correlations and their modifications.

The research also indicated that analyses thru C9+ are necessary to help accurately predict HCDP's, even with improved correlations.

Conclusion:

Liquids in gas measurement systems are a problem. They may lead to inaccurate measurement, non-representative samples, damaged analytical equipment, safety issues and a variety of other problems. I hope the reader will encourage additional work ongoing within the API and elsewhere to develop improved correlations for predicting hydrocarbon dewpoints and more accurate means of measuring two phase flow when economics dictate their use.