2013 Western Gas Measurement Short Course
Reno, NV

MEASURING HYDROCARBON DEW POINT ACCURATELY AND ITS FINANCIAL IMPACT

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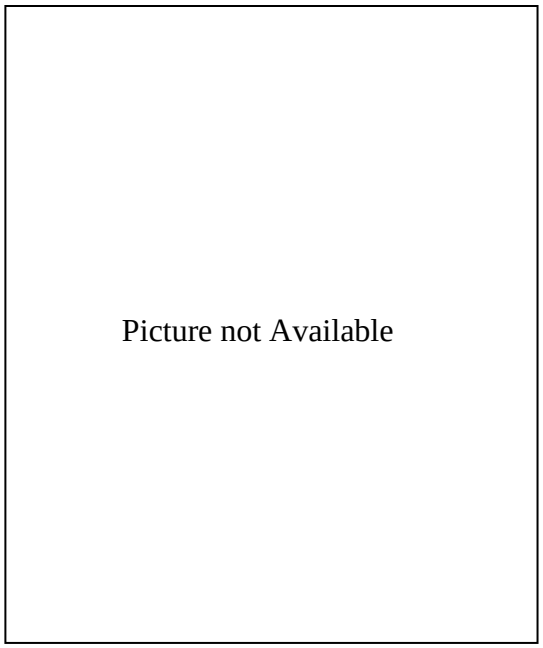

ABSTRACT

Natural gas fired turbines for compressing gas must burn clean fuel as specified by the turbine manufacturer. Failure to do so can significantly increase maintenance and operational costs. Condensate in the pipeline can damage equipment and risk contract violations and shut-ins. Poor analysis techniques or a less than optimum choice of instrumentation will significantly add to the risk associated with the operation. This paper focuses on identifying the costs, risks and major factors that contribute to best practices for measuring the hydrocarbon dew point (HCDP) of the natural gas fuel.

Instrumentation is now available that provides reliable, accurate gas quality information upon which good operational decisions can be made. Implementing these best practices of measurement will result in a reduction of operational costs, unplanned shutdowns, turbine damage and potential liability for excessive HCDP and shut-ins.

Installed cost is an important consideration in the choice of methods used to measure hydrocarbon dew point. But, even if the installed cost is slightly higher, choosing an accurate method will be shown to be a better value. Less expensive instrumentation techniques may under-report the dew point risking serious turbine damage. An inaccurate instrument choice can also add to the already high parasitic load by over-reporting the dew point temperature which would drive the control system to heat the incoming gas more than necessary. Reliable instrumentation producing an accurate measurement assists in controlling the costs of operating a gas processing plant, a pipeline or turbine compressors/generators as well as and protecting these assets.

Introduction

Measuring Hydrocarbon Dew Point (HCDP) accurately is critical to the profitability of producing/processing natural gas. End users want a quality product and for good reason. When HCDP limits are written into the gas contract the producer/processors and pipeline operators each play a role in delivering that quality product. Accurately measuring HCDP in order to satisfy the customer touches every link in this vital supply chain.

What is HCDP? What is involved in measuring HCDP accurately?

Hydrocarbon Dew Point Definition

The scientific definition for the hydrocarbon dew point is the temperature at which the first formation of liquid hydrocarbon in a gas at a specified pressure. This is not very workable since it could identify the temperature when the first two molecules find it irresistible to stay apart and connect to form a microdroplet of liquid that no longer obeys the gas laws which moments before governed their behavior.

Experience in the field proves this is not a practical definition for HCDP. The theoretical conditions above will not necessarily have an adverse impact on the operation of a turbine or create liquid drop-out in a pipeline that could damage turbine compressors. A more workable definition and one that generally practiced in North America, is the temperature when the first appearance of liquid hydrocarbon droplets form on a surface at a constant pressure. Under currently approved practices, the pressure for this measurement is the contract pressure. The de facto industry standard for observing the appearance of these droplets and measuring the temperature when it occurs is the Bureau of Mines device operated in accordance with ASTM D1142.

Hydrocarbon dew point is dependent on pressure, temperature and the composition of the gas. The heavier compounds will condense at higher temperatures. A good rule of thumb is the higher the BTU content, the higher the HCDP. The pressure and temperature pairs can be plotted where HCDP occurs for a specific gas sample. The resulting a curve, called the phase envelope, can be used to understand the behavior of the gas under specific conditions.

One point on the phase envelope for a given gas is called the cricondentherm. The derivation of the word cricondentherm is critical condensation thermal point and can be shown on the phase envelope curve. The cricondentherm is the maximum temperature where hydrocarbons can condense in that specific gas mixture at any pressure. This key point can tell us how the gas will behave as the pressure is let down at the processor or end user's location. Measuring the HCDP at this point can provide valuable information about the gas.

Figure 1 below is a typical phase envelope for natural gas showing three HCDP curves at different stages of processing and one of water dew point. The three cricondentherm points are identified on the respective hydrocarbon dew point curves. Every field and producer/processors' gas will have a different curve due to differences in composition.

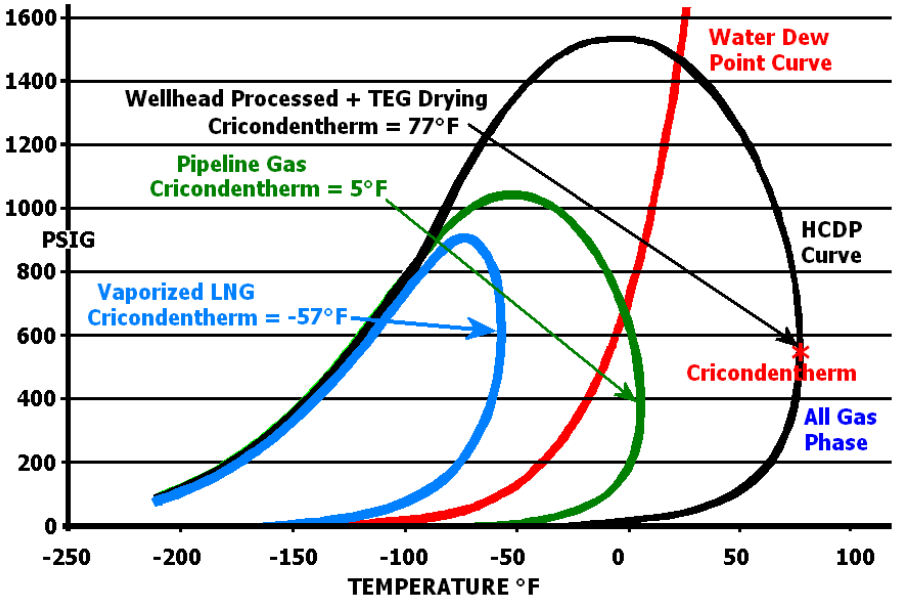

Figure 1[1]

Hydrocarbon Dew Point Measurement Methods

There are three primary methods used in North America –

- Manual visual dew point method
- Equations of state (EOS) method using gas chromatograph (GC) analysis
- Automatic optical condensation dew point method.

Each of these methods are described below with their advantages and disadvantages.

Manual Visual Dew Point Method

This is the most widely used method for measuring HCDP and requires the simplest hardware. It can also be used to measure water dew point (WDP) in natural gas. The Bureau of Mines device has been used since the 1930s to provide manual dew point measurements. This method is used for "spot checking" the dew point of a sample as extracted from a tap on the pipeline from any location in a gas processing facility, or point of use. It allows a trained operator to detect the dew point visually and interpret that image as a HCDP or a WDP or a contaminated dew point. It requires patience and training to be able to operate this instrument properly.

There are two chambers within the instrument. One is the sample chamber that is suitable for pipeline pressures to 5000 psig, containing a mirror visible through a window. There is also a method for measuring the temperature of the mirror. A second chamber allows a coolant to be conducted across the back of the mirror.

The operator connects the sample to the sample inlet port and begins purging the chamber with a flow of sample. A coolant, typically an expandable gas like propane, liquid carbon dioxide or liquid nitrogen is connected to the coolant inlet. The operator then throttles the coolant through a valve, cooling the polished mirror in contact with the sample gas until the dew point is observed.

This image is indicated by the first appearance of very small droplets of hydrocarbon condensate appearing on the mirror. The temperature is immediately read and the value noted.

Since the operator must interpret the image seen on the mirror, there will always be some subjectivity in this method. The proper procedure is described in ASTM D1142, but operator experience is critical for best accuracy. The condensate is a shiny, transparent coating that requires training to distinguish and interpret the image on the mirror.

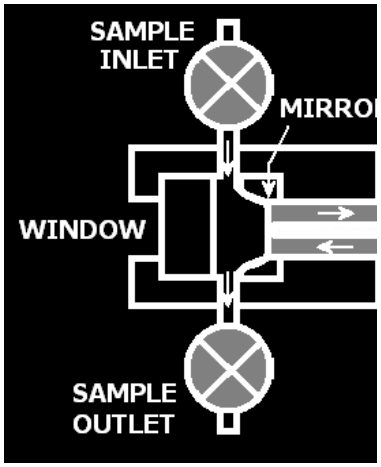

Figure 2

Bureau of Mines Device Schematic

Figure 3

Bureau of Mines Dew Point Tester[2]

Advantages of the Bureau of Mines Device:

- The most widely used measurement technique
- They are intrinsically safe
- Considered the de facto standard for hydrocarbon dew point measurement
- Require a low capital investment.

Weaknesses of the Bureau of Mines Device:

- Periodic spot checking only
- 'Subjective', operator dependant measurement
- Labor intensive, high personnel costs

EOS Method Using GC Analysis:

Gas is sold based on its heating value and GC analysis is primarily used to determine that value. Since fiscal reporting is based on this heating value, there is a large installed base of field GCs in North America. Most of these analyzers generally analyze only through C_6+ with a few analyzing through C_9+ analyzers on pipeline gas and in end-user installations. Both buyers and sellers verify the heating content of the gas they are buying/selling but the sample used for analysis by the GC needs to be handled with care. Should the sample be allowed to cool below the HCDP, the measurement of the heating value would come under question.

Many users are now applying equations of state (EOS) to this data to calculate the HCDP value to ensure the sample lines are maintained above this temperature. Equations of state predict the HCDP of the gas sample, but are they really up to the task? Hydrocarbon dew point is mainly influenced by hydrocarbons C_6 and above, so here are a few comments:

- "the traditional C6 plus analysis provides insufficient data for a valid hydrocarbon dew point calculation."[3]
- "Based on comparisons to date, however, the C9+ characterization most often appears to predict measured dew points only to within ±25°F."[4]

This alert gives rise to the idea of designing any sample system for any method of detection of HCDP to maintain a temperature of at least 30°F above the highest projected dew point to prevent premature condensation and the errors that would result.

More research is being done on the EOS method for predicting HCDP of the natural gas sample. Standards have been written suggesting minimum requirements for producing good data. Recently ISO published their standard 23874 (2006) 'Natural Gas – Gas Chromatographic requirements for hydrocarbon dew point calculation'. This standard states that the GC system requirement for analysis of higher hydrocarbons includes:

- "measure all hydrocarbons in the range C_5 to C_{12}".
- "be capable of measuring alkanes up to and including *n*-dodecane;" (C_{12})
- "be capable of measuring individual alkanes at a concentration of 0.000 000 1 mole fraction (0,1 ppm[1]) or less;" (0.1 ppm_V ed.)
- "be able to distinguish and measure benzene, toluene, cyclohexane and methycyclohexane as individual components"

Component		C_6+	C_6+ 60/30/10 split	C_9+	C_9+ 60/30/10 split	C_{12}+	C_{14}	C_{16}
Helium mol	He	0.0137	0.0137	0.0137	0.0137	0.0137	0.0137	0.0137
Carbon dioxide	CO_2	0.1532	0.1532	0.1532	0.1532	0.1532	0.1532	0.1532
Nitrogen	N_2	0.8418	0.8418	0.8418	0.8418	0.8418	0.8418	0.8418
Oxygen	O_2	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Argon	Ar	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Hydrogen	H_2	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015
Methane	C_1	97.4699	97.4699	97.4699	97.4699	97.4699	97.4699	97.4699
Ethane	C_2	1.0471	1.0471	1.0471	1.0471	1.0471	1.0471	1.0471
Propane	C_3	0.3291	0.3291	0.3291	0.3291	0.3291	0.3291	0.3291
iso-Butane	iC_4	0.0487	0.0487	0.0487	0.0487	0.0487	0.0487	0.0487
Butane	C_4	0.0535	0.0535	0.0535	0.0535	0.0535	0.0535	0.0535
neo-Pentane	nC_5	0.001	0.001	0.001	0.001	0.001	0.001	0.001
iso-Pentane	iC_5	0.0107	0.0107	0.0107	0.0107	0.0107	0.0107	0.0107
Pentane	C_5	0.0081	0.0081	0.0081	0.0081	0.0081	0.0081	0.0081
Hexane	C_6	0.0117	0.00702	0.006	0.006	0.006	0.006	0.006
Benzene	C_6H_6		0.00351	0.0004	0.0004	0.0004	0.0004	0.0004
Heptane	C_7		0.00117	0.0035	0.0035	0.0035	0.0035	0.0035
Toluene	C_7H_8			0.0003	0.0003	0.0003	0.0003	0.0003
Octane	C_8			0.0007	0.0007	0.0007	0.0007	0.0007
m-Xylene	mC_8H_{10}			0.0001	0.0001	0.0001	0.0001	0.0001
Nonane	C_9			0.0007	0.00042	0.0003	0.0003	0.0003
Decane	C_{10}				0.00021	0.0001059	0.0001059	0.0001059
Undecane	C_{11}				0.00007	0.0001099	0.0001099	0.0001099
Dodecane	C_{12}					0.0001842	0.0000902	0.0000902
Tridecane	C_{13}						0.0000551	0.0000551
Tetradecane	C_{14}						0.0000252	0.0000252
Pentadecane	C_{15}							0.0000105
Hexadecane	C_{16}							0.0000032
Pressure	PSIG	400	400	400	400	400	400	400
°F HCDP @ Cricondentherm		-66.5	-60.3	-24.1	-7.8	20.3	36.5	49.1
		C_6+	C_6+ split	C_9+	C_9+ split	C_{12}+	C_{14}	C_{16}

Table 1
HCDP values calculated by Equation of State on 1020 BTU Gas

A major turbine manufacturer went a step further with this statement. “Small quantities of heavy hydrocarbons above C_6 raise the dew point significantly. …Using a standard analysis can result in an artificially low dew point determination. Instead, an extended analysis should be used except where no C_6+ compounds are present. (An extended gas analysis to C_{14}) checks for the presence of the heavy hydrocarbons and quantifies their amounts to the level of C_{14}. The extended analysis is more complicated and expensive than the standard analysis, and not all laboratories can provide this service. It is, however, the only type of analysis that will result in an accurate dew point determination. An analysis procedure for C_1 through C_{14} is described in GPA 2286-95.”[5]GCs designed to meet this set of specifications are laboratory GCs, not yet adapted for field installation and are prohibitive in cost for custody transfer points and processing plants. The calibration gases are also very costly to properly operate such a GC. It should be noted that such a system will produce much better HCDP data than the C_9+ characterization.

The reason is simple. The equations of state need information that simply cannot be provided by the field GCs in the currently installed base. Table 1 illustrates why. The heavier components in the Standard Analysis to C_6+have been simply lumped together as would be done by the field GC. The results speak for themselves with over a 115°F difference for the same gas.

The difference is that even small quantities of heavier hydrocarbons strongly influence this calculation. These heavier components are the ones that cause problems inside the pipeline too. While it may be of interest to know the concentration of liquids from assumptions from the data above, the HCDP is generally the parameter given in most tariffs and contracts. Due to the large total volumes of gas transmitted in a pipeline and the variation in the topography along its route, any liquid will gather at the lowest points and can cause serious transmission problems.

Advantages of using EOS from GC data:

- Potential to combine a number of gas quality/fiscal metering parameters into one analyzer
- Possibility to provide a theoretical phase envelope curve
- Adding software to an existing measurement technology may have a lower installation cost.
- The components contributing to a high dew point level may be identified and help to determine the reason or source of these components.

Weaknesses of using EOS from GC data:

- It is an indirect method relying on the correct application and suitability of the equation of state being used.
- The accuracy of extended analysis is dependent on correct and regular use of special reference gases.
- The limit of analysis sensitivity and compositional changes especially of aromatics, e.g. benzene and toluene, can produce large measurement errors.
- Staff specialists are required to operate/maintain the instrument performance.
- There is a high initial outlay for a GC with C9 capability, installation costs (analyzer house) and operating costs (personnel and reference gases).
- When extended analysis cannot be performed on-site and samples must

be sent to a laboratory the added uncertainty in the results can reduce the confidence in this data.

- When extended analysis is performed there is also a significant time loss to see the results. This forces back-calculations and adjustments for billing purposes.

Automatic Optical Condensation Method

Automatic Optical Condensation HCDP Analyzers have been in commercial use for over twenty years. Independent laboratory testing has shown them to have very good accuracies (better than "±1°F"[6]) when compared to the Bureau of Mines manual dew point method. They can also provide the user with up to six measurement cycles per hour.

An optical detector is chilled until a thin layer of condensate forms on that surface. Measuring the detector temperature when that occurs gives the HCDP temperature. Automatic Dew Point Analyzers are not influenced by individual operators and include all gas constituents in their analysis. They are available in field installable units that can be mounted very near the sample tap, providing a fast response to any change in the properties of the gas.

The dew point method of chilling a mirror until the condensate formation is observed is one of the oldest methods of measuring HCDP (manual method) accurately and is also the oldest method for measuring WDP. It has long been thought that the same technique could be automated to eliminate the subjectivity of the manual method. The benefit would be an increase in accuracy and repeatability. But hydrocarbon condensates do not behave as water condensates do.

Water condensates disturb a light path in both the liquid and solid phases. For example they can be seen as dew or frost on the windshield of a car when the ambient conditions are right. This is due to the unique high surface tension of water - a single molecule with very well documented characteristics. Hydrocarbon condensates only marginally disturb a light beam due to their low surface tension and transparency. This makes it difficult to see the first formation of the condensate on a chilled mirror. The very low surface tension of these HC condensates is also affected by the fact that natural gas is a mixture of compounds. Because the mixture of components cascade sequentially on a surface as it is chilled, the HCDP will occur gradually across a small range of temperatures. This is one reason that automating the manual method dew point technique needed a new approach.

In the mid-1980s, researchers found that since hydrocarbon condensates have a very low surface tension and were shiny, the condensate deposit could be used as the mirror in an automatic system. A chemically etched dry sensor, with a strong light illuminating it, would diffuse the light instead of reflecting it. Then condensing a hydrocarbon dew layer onto the surface by cooling it will focus the reflected light producing a strong image that can be detected easily. It was also discovered that a conical depression on the optical surface dramatically improved the repeatability.

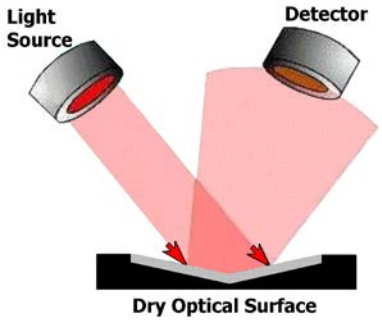

Figure 4
With no condensate, the detector ‘sees’ an image of just diffused light.

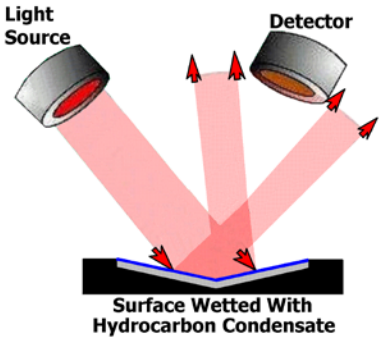

Figure 5
With HC condensate present, the detector ‘Sees’ an image of focused light as a ring with a dark spot in the middle.

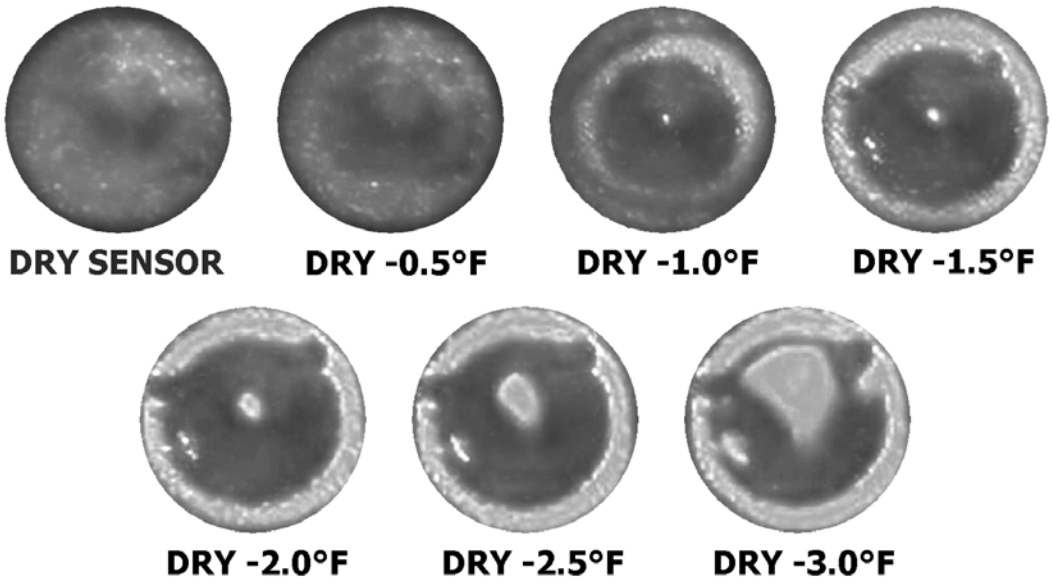

Figure 6
Actual "Dark Spot" optical surface images shown in black and white

The detection of this image is very sensitive, allowing the sensor to 'see' an image of the HCDP as it begins to condense. This same image quality can be repeated over and over again eliminating the subjectivity of the operator. A detector signal with this wide sensitivity can be adjusted to align with the currently accepted industry practices, contractual or historical data.

In addition, since the heavier components do indeed condense out first, it is important that the sample being measured be trapped within the measurement chamber. This blocking-in of the sample prevents an over-reporting of HCDP caused by continued build up of the heavy components in a continuously flowing sample.

Slow cooling, analogous to the best practices for manual visual chilled mirror method is also achievable. The condensate requires some time to form and be identified by the detector. With PLC control and digital memory, the automatic HCDP analyzer should have the ability to mimic the operator of a manual dew scope. This slow cooling does not have to impact the duration of a measurement cycle significantly. It should ramp the optical surface temperature down rapidly to within a few degrees of the previously measured dew point temperature, then slow the cooling rate to achieve the final dew point.

Heating the optical surface between measurements is also desirable. The optical surface is heated after each measurement forcing the evaporation of all condensate and preparing the surface for the next measurement cycle. Thermoelectric coolers are quite capable of performing this task by simply reversing the current to the device. Heating the optical surface while the fresh sample is purging the measurement chamber in preparation for the next cycle provides a stable optical baseline. A combination of the PLC control of the cooling rate and the heating between

measurements shortens the measurement cycle to as little as 5-10 minutes.

Advantages of Automatic Optical Condensation Analyzers:

- Provides a direct, fundamental, highly sensitive and repeatable measurement that is objective.
- Requires only AC power and a gaseous sample at line pressure for proper operation
- No specialized training or skill requirements for operation and maintenance staff
- Can produce direct measurement phase envelopes rather than those based on theoretical estimations
- Sensitivity may be harmonized with contractual measurement techniques, practices or historical data
- Low operating costs.

Weaknesses of Automatic Optical Condensation Analyzers:

- High initial investment (but less than a C9+ GC)

Best Practices For HCDP Measurement

Best Practices - All Measurement Techniques

In general, methods required to produce good accuracy begin with proper sampling. Proper sampling begins right at the sample tap. The sample should be drawn upwards from a region sufficiently away from the inner walls and five diameters downstream of any components, elbows, valves and etc., which might modify the flow profile within the pipeline. This sample must be drawn off through heat traced tubing from the point of extraction through to the analyzer. This is a critical issue since all surfaces contacting the sample gas must be maintained at a temperature higher than any dew point or the accuracy will be compromised. Fast or speed loops should be used for maximum speed of response. Sample filtration must remove all particulates and liquid aerosols. This can sometimes be done as part of the sample extraction probe. However, any required pressure reduction should be taken after the fast loop and before delivery to the measurement section of the analyzer to furnish the analyzer with the freshest possible sample.

Best Practices - Manual Visual Analysis

In addition to the general best practices above, the manual visual method requires a well trained operator and patience. The optical device must be clean before starting any measurements. The sample pressure should be at the approximate cricondentherm of the specific gas or the contract pressure. The sample should be allowed to bleed through the device per the ASTM standard D1142. Chill the mirror down gradually at a rate no greater than 1ºF (0.6ºC) per minute, per the recommendations of ASTM Standard D1142 (ASTM, 1995)[5] until a visible condensate forms on the optical surface. Once this image is identified as the HCDP, the thermometer should read the HCDP temperature. The mirror temperature should then be allowed to elevate slightly and then cooled again to “home in” on the actual reading. These readings should be repeated a minimum of three times with reasonable agreement to qualify as being accurate.

Best Practices - GC Analysis with EOS

HCDP using EOS calculated from GC analysis best practice includes using a C_9+ GC and then adding data to C_{12} from periodic laboratory analysis to improve accuracy of the EOS calculations. These results should periodically be compared to actual manual visual measurements to further enhance predictability. Using multiple EOS may also provide data comparison review over time that will determine the historical significance of one formula over another for a specific field or supplier. Keep in mind that field GC installations may not comply with all of the above general best practices and may produce less accurate results. GC samples are analyzed at very low pressures compared to pipeline pressures and are predicting values by measurements at conditions far different from those of the actual pipeline.

Best Practices - Automatic Dew Point Analyzers

An automatic HCDP analyzer must incorporate a number of elements into the device to be as reliable and repeatable as possible. Below is a list of the critical components and why they need to be part of the analyzer package.

1. Reliable Detection Method

A reliable detector is a given requirement for all instruments. Rough or etched surfaces will be better able to discriminate the HCDP because the condensate will make the optical surface more reflective and the image easier to detect. It will also nearly eliminate any interference from other condensates.

2. Close Proximity To Pipeline Sample Point

Automatic units should be mounted near the sample tap with internal heaters and insulated housings. Using a sample already piped to an instrument house may be convenient, but the resulting delay in the update may cause serious lag in reaction time for control purposes. Since each manufacturer has different operating temperature specifications, environmental conditions often dictate this choice.

3. Trap The Sample During The Measurement

A sample that is allowed to flow continuously creates an abnormal build up of the heavier hydrocarbons on the optical surface. Blocking in the sample during the measurement cycle will produce more accurate readings.

4. Controlling Measurement Pressure

Measuring at the cricondentherm has many benefits such as identifying how the pressure can be safely let down to avoid the Joule-Thompson cooling to create condensate. It also has the biggest sweet spot for this measurement and thus is very repeatable. But the measurement pressure is not always driven by what is most useful but it is always driven by what is in the tariff or contact between the buyer and seller. So the measurement pressure must be controlled at this specified value.

Many contracts are written with the cricondentherm point as the measuring point for the maximum allowable HCDP in the gas. Contracts written with the reference to the maximum HCDP at any pressure, are describing the same point.

The cricondentherm pressure is not as critical as may be anticipated. Since the profile of this region of the curve is nearly vertical, a change of fifty to a hundred psi either way can be shown to produce very little change in the accuracy of the

measurement. In the expanded graph example below, a change of over 100 psi results in influencing the HCDP a maximum of only 2°F. In contrast, just 1 ppm_V of a C_{10} component in the sample can change the HCDP by as much as 10°F! It is however, always good practice for the measurement to be performed at the contract pressure which is often the cricondentherm pressure.

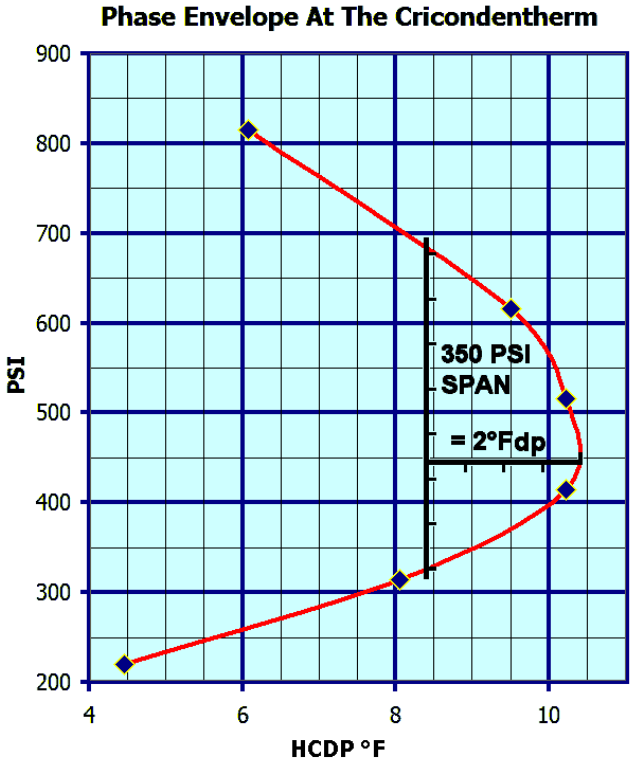

Figure 7

5. Heat The Optical Surface Between Measurements

Without sensor heating the total cycle time can be three times that of the heated one and result in lower reliability of the measurement.

6. Keep Internal Volumes Small

When the volume of sample in the measuring chamber is reduced, it will speed the measurement and allow faster purging of the measurement chamber.

7. Frequent Sampling

Many of the above practices will allow automatic dew point analyzers to make more frequent measurements. Frequent measurement cycles provide for better response to changes in the gas conditions and allow control functions to be implemented in a more timely fashion.

8. Capability For Aligning With Contract Data

Historically the working definitions of HCDP have been slightly modified and standards have been reviewed with consideration to incorporate them. If this trend will continues and changes come into effect, it is essential to have the ability to adjust the analyzer to align with newly refined standards.

What Is At Risk When HCDP Is Not Measured Accurately?

When measuring the heat content of natural gas that governs all fiscal transactions of gas purchasing, certain practices have become industry accepted for proper sampling and conditioning to ensure accurate measurements. The hydrocarbon dew point is perhaps the single most important property to consider in natural gas sampling. If the sample temperature drops below the hydrocarbon dew point temperature, a significant loss in hydrocarbon content can occur, resulting in errors in volumetric flow rate, heating value and other gas property calculations. It of vital concern for all parties to the transaction to follow these same procedures to have the same results and eliminate disputes over billing for gas delivered.

End User Risks

Large gas utilities simply cannot tolerate liquid hydrocarbons in their gas. They go to great lengths to prevent liquids from entering their distribution system. The potential for home fires is just to treat to risk on the hope that they will regasify as pressure is let down.

Large natural gas consumers using natural gas for firing aeroderivative turbines are becoming more aware of the impact they can feel if the HCDP is out of specification. Gas fueled turbine power generation plants have been hit with high exposure risk of fines for NOX emissions which become excessive as the HCDP climbs over the contract limits.

Turbine manufacturers specify a superheat of the gas of 50°F – the gas temperature must be 50°F higher than either the HCDP or the WDP whichever is greater. This is to protect against condensate formation as the pressure is let down from pipeline pressure to burner operating pressure caused by the Joule-Thompson coefficient. If liquid hydrocarbons condense out during the pressure letdown, flashback can occur. "For a GE Frame 7 gas turbine, 50°F of superheat amounts to about 740 kW, which means energy costs can be as high as $324,120 per year."[7] This retail energy value converts to 2.27 MMBtu/hr corrected or ~$9.00/hr @ $4.00/MMBtu or $78,840/yr. If HCDP is maintained at contract levels this parasitic load to heat the gas can be dramatically reduced, increasing the power available for sale.

Excessive HCDP causes turbine flashback where the flame front reverses and moves toward the source of the gas instead of the turbine. "This is known as flashback and can lead to significant damage to the gas turbine within seconds of it occurring."[8] Often, the operator must reduce power on the turbine to sustain consistent power output at a lower level or risk continued flashbacks. "Flashback can be a significant issue during combustion turbine operation, as it can reduce combustor life and, in extreme cases, cause combustor damage and extensive repairs."[9]

Long term effects of high HCDP are excessive maintenance costs as the heavier hydrocarbons damage burner sections and even the turbine blade tips of this expensive equipment. Rebuilding just the burner section is a $2.5 - $3 million direct cost in addition to lost production for this unscheduled outage. These unbudgeted costs seriously impact the profitability and potentially the viability of these operations. This risk drives this critical gas quality measurement where compliance to the fuel specification is not optional.

Pipeline Operator Risks

The demand for quality gas shifts upstream to the pipeline operators who have a custodial function in addition to the transportation function of the gas. Obviously, their delivery of good quality gas is dependent on their receipt of good quality gas. Thus the responsibility for measuring and recording their receipts are the only way their custodianship can be verified.

If their gas receipts do not comply with the contract, there is a resultant shut-in risk for these operators. They only get paid as long as the gas is moving to the end users.

If this measurement is inaccurate and liquids build up in their pipelines, their investment in turbine compressors is put at risk. Turbine compressors do not do well with multiphase flow. When liquid in the gas is detected the increased frequency of pigging operations, adds to the cost of moving the gas effectively.

Turbine compressors need good clean fuel to operate reliably. If HCDP is maintained at contract levels this parasitic load to superheat the gas can be dramatically reduced, increasing the gas available for sale.

Producer / Processor Risks

Finally, the producer/processor has the initial control over this resource. If they do not comply with the gas contract, they will be shut-in. Their operation comes to an abrupt halt and another vendor will often step in to fill the end users' demand. In any business, allowing a competitor to fill your customers' need is a huge risk for that operation to remain viable. More and more, shut-ins carry contractual penalties as the additional cost for changing over to a competitive supplier impacts the end user as well.

The unprocessed gas also has many recoverable compounds that can bring added income to the producer/processors' operation. These NGLs currently have significant value to drive their recovery to the limit of the processors' capability. The economics of their recovery will fluctuate as market conditions change but NGLs will always have value and recovering them adds to the security of not experiencing shut-ins.

Some of the costs are identifiable but impossible to quantify. One example is the legal costs when there is a dispute over shut-ins driven by gas quality measurement by the end user. These can be avoided when the producer/processor and pipeline operator accurately measure the HCDP along with the water content and encourage their customer to do the same. Accountability is always preferable to litigation.

Some of these costs can be quantified as in the case of the cost of a shut-in as illustrated in Table 2 below:

Shut-in Revenue Loss for 1100 Btu/CF Gas + NGL Recovery					
Flow	$4.00/MMBtu			NGL @ $65/Bbl	
MMcfe/d	One Hour	One Day	One Week	Bbl/Day	One Week
0.25	$46	$1,100	$7,700	10	$4,550
0.5	$92	$2,200	$15,400	15	$6,825
1	$183	$4,400	$30,800	25	$11,375
2	$367	$8,800	$61,600	50	$22,750
4	$733	$17,600	$123,200	100	$45,500
8	$1,467	$35,200	$246,400	250	$113,750
16	$2,933	$70,400	$492,800	500	$227,500
32	$5,867	$140,800	$985,600	1000	$455,000
64	$11,733	$281,600	$1,971,200	1500	$682,500

Table 2

These substantial costs are not the total picture. In addition to costs above there are other costs, e.g. the cost of litigation.

Conclusion

Gas contracts are more restrictive now as the market demands continue to tighten. Accurate data is the only enforcement method available for contract quality issues. Accurate on-line instruments are now available that confirm these contractual specifications are met.

In the choice of methods used to measure hydrocarbon dew point, installed cost is an important consideration. Less expensive instrumentation techniques may under-report the dew point risking shut-ins and lost revenue. Even if the installed cost is somewhat higher, choosing an accurate method has been shown to be a better value. An inaccurate instrument choice can also over-report the dew point temperature which would drive the control system to over-process incoming gas. This would significantly add to the operational cost while cutting profits.

Reliable accurate HCDP instrumentation assists in controlling the gas processing operation thereby enhancing the profitability in this complex business. Full-featured automatic HCDP analyzers will produce the best results and will often have a ROI that will pay for their installation in just a few months of operation. Should an upset in the gas supply occur, these analyzers will certainly pay for themselves on the first occurrence by alerting operations to such an event in time to prevent a shut-in.

Acknowledgment

The author would like to thank Andy Benton, Michell Instruments, Ltd., Ely, Cambridgeshire, U.K. for his body of work on the topic of measuring HCDP. He has written and presented many papers upon which much of this document is based. With over 25 years of experience in the technology and application of this measurement, his input has been invaluable. He has presented at ISHM, ASGMT and NGS Tech as well as several other schools and conferences globally.

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