

# Hydrocarbon Dew Point – Critical Considerations for Natural Gas Turbine Installations

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## Executive Summary

Natural gas fired turbine power plants and Cogen plants are required, by the turbine manufacturer, to provide the natural gas fuel to the turbine within certain specifications. Failure to do so can significantly increase emissions, void warranties, damage hot zone components and significantly increase maintenance costs. In addition to these out of pocket costs, there is also an associated loss of revenue incurred during an unplanned shutdown for burner section overhaul. To meet these specifications, conditioning the gas supply is necessary requires accurate and reliable gas analysis to ensure it is done properly. Overcompensation for poor analysis techniques or a less than optimum choice of instrumentation will significantly add to operational costs. Thus the focus of this paper is to identify the major factors that contribute to best practices for measuring the hydrocarbon dew point (HCDP) of the natural gas fuel supply. Reducing turbine maintenance and operational costs will be the result of implementing these best practices of good gas conditioning and measurement.

On-line Instrumentation is now available that provides reliable, accurate gas quality information upon which good operational decisions can be made resulting in a reduction of the liability for excessive emissions, turbine damage, unplanned shutdowns and operational costs.

## Why Measure HCDP

All turbine manufacturers generally specify that the incoming natural gas fuel meet several criteria. Some of those specifications call out particulate load maximums, chemical contamination limits, pressure and flow as well as temperature with the addition of the term 'superheat'.

## Superheat

When DLN (Dry-Low-NOx) turbines first started appearing in the 1990s, operators started experiencing problems that had never been seen in the older versions of gas fired turbines. Part of the reason was the gas being delivered to those older turbines was at a modest pressure of about 200 psig. This reduced pressure required no on-site pressure reduction and thus the fuel burned very predictably. Today with the gas fields aging and producing richer gas along with the higher pipeline gas pressures, a new mix of issues must be considered for proper operation of a turbine.

Generally, superheat is defined as an inlet gas temperature of 50°F (28°C) above the HCDP and water dew point (WDP) temperature. If the HCDP of the natural gas is measured at 15°F, the inlet gas temperature in this example must be elevated to 65°F minimum.

GE, a leading turbine manufacturer recommends the following:

“Liquid hydrocarbon carryover can expose the hot gas path hardware to severe overtemperature conditions and can result in significant reductions in hot gas path parts lives or

repair intervals. Owners can control this potential issue by using effective gas scrubber systems and by superheating the gaseous fuel prior to use to provide a nominal 50°F (28°C) of superheat at the turbine gas control valve connection.” (D. Balevic et al., *Heavy-Duty Gas Turbine Operating and Maintenance Considerations 2004 General Electric Company GER-3620K (12/04)*)

“GE Gas Fuel Specification GEI 41040E - in summary, this document defines for limitations on particulate matter size to no more than approximately 10 microns, calls for the elimination of all liquids at the inlet to the gas turbine control module and specifies the minimum and maximum requirements for fuel supply pressure. Other limitations and qualifications may also apply and the user is encouraged to review the details in this document.

A superheat temperature of at least 50 F/28 C above the moisture or hydrocarbon dew point is required to eliminate liquids. Meeting this requirement may require heating the gas if heavy hydrocarbons are present. Reasons for specifying gas superheat are:

- Superheating is the only sure method for eliminating all liquids at the inlet to the gas control module
- It provides margin to prevent the formation of liquids as the gas expands and cools when passing through the control valves

Why 50 F/28 C minimum superheat?

- It is an ASME-recommended standard (Reference 3) that 45 F to 54F (25 to 30 C) of superheat be used for combustion turbine gaseous fuel.
- Calculations show the 50 F/28 C minimum superheat requirement will prevent liquid formation downstream from the control valves and is verified by field experience
- Some margin is provided to cover daily variations in dew point
- Vaporization time for liquid droplets decreases as superheat temperature increases”

(C. Wilkes, “Gas Fuel Clean-Up System Design Considerations For GE Heavy-Duty Gas Turbines”, GE Power Systems, Schenectady, NY GER-3942)

### ***Protection of Turbine Burner Section***

If the fuel is not provided to the turbine at these conditions, serious and costly damage will occur to the burner/hot gas section of these installations. Once damaged, rebuilding these sections forces an unplanned shutdown with its associated loss of production/revenue.

Natural gas fuel conditioning systems are often used to perform the function of heating the incoming gas and use many sources of heat for this process. All of these sources require energy, increasing operational costs. This issue is more costly when the dew point of the gas received at the plant is higher and/or when the temperature drops. These conditions require more heat to achieve the required superheat temperature.

When the fuel gas enters the plant at elevated pipeline pressures, it often must be reduced before entering into the turbine burner section. “Natural gas temperature drops 7°F for every 100 psig of pressure drop. So if the incoming pressure of the pipeline gas is 800 psig but the operating pressure of the turbine is only 350 psig, the fuel gas temperature will drop 31.5°F.” (C. Tiras, PE, Flowtronex International, “DLN combustors demand better fuel-gas conditioning”, Power, Mar-Apr 2001). If this Joule-Thompson (J-T) cooling takes the temperature down below the HCDP, then aerosols and liquids drop out inside the burner tubes. The cans and the nozzles coke up and lose their effectiveness resulting in significantly elevated NOx readings. If the liquid dropout condition is allowed to continue, in a short time the burner section will have to be rebuilt. This means a 3-5 day unplanned shut-down, a large crew on-site around the clock for the expensive rebuild and lost revenue and plant availability. This will dramatically impact the profitability of the plant.

Flashbacks are another symptom of excessive liquid dropout. “Condensation of liquid hydrocarbons in gas fuel have been

identified as one cause of flashback. Therefore, it is incumbent on the power plant operator to monitor the gas fuel supply to ascertain that it is meeting the requirements of the GE gas fuel specification.” (SEC Info - www.secinfo.com - Fran Finnegan & Company - 912057-0-4085). “Under certain transient conditions flashback can occur where flame “holds” or is supported in the recirculation zone downstream of the premixed gas pegs. This region is not designed to withstand the abnormally high temperatures resulting from the presence of a flame. In the event of a flashback, the metal temperatures increase to unacceptable levels and hardware damage occurs. In some cases, these events have caused forced outages and adversely impacted availability.” (GE Power Systems, GER-3568G, (10/00)). Preventing flashbacks is so critical to the healthy performance and availability of the turbine that it is partially the reason the 50°F superheat requirement was established. The turbine experiencing flashbacks must have the load significantly reduced and a recovery procedure must be followed to get the load back up to normal. More revenue and availability is lost. If a remedy for flashback is not implemented, the burner cans and nozzles will coke up, seriously impacting emissions.

### ***Emissions Control***

As liquid hydrocarbons, from under-processing or compressor lubrication system seal leakage, impact the turbine hot section there will be a proportionate increase in NOx emissions. If these entrained micro-droplets get to the turbine blades, they will burn at high temperatures and in severe cases have been known to burn off the blade tips decreasing the efficiency of the turbine overall. Compliance with EPA emissions restrictions is simple; keep the liquid hydrocarbons out of the turbine.

### ***Energy Conservation***

Overheating the fuel is not a trivial matter. “Because on-line dew point analysis typically is not conducted, the gas is often heated by 50°F continuously. For a GE Frame 7 gas turbine, 50°F of superheat amounts to about 740kW, which means energy costs can be as high as \$324,120 per year. But if the gas is well above its dew point under normal conditions, the additional heating is wasteful” (C. Tiras, PE, Flowtronex International, “DLN combustors demand better fuel-gas conditioning”, Power, Mar-Apr 2001).

## Current Methods Used for Measuring Hydrocarbon Dew Point

There are three primary methods used in North America - Gas Chromatography (GC) with Equations of State (EOS), Manual Dew Point Analysis and Automatic Dew Point Analysis.

### *Gas Chromatography with Equations of State*

GC analysis is primarily used to determine the BTU content of the gas sampled. With the recent interest in HCDP, equations of state have been developed to predict the HCDP of the gas sample. "Hydrocarbon dew point is mainly influenced by C7 and above hydrocarbons." "Therefore, the traditional "C6 plus" analysis provides insufficient data for a valid hydrocarbon dew point calculation." (K. Ernst, D. Pettigrew, Emerson Process Management, "Hydrocarbon Dew Point Monitoring Of Natural Gas Using Field-Mounted On-Line Gas Chromatographs", Pipeline & Gas Journal, July 2005) "Using a C6+ characterization instead of a full characterization containing all known components of the gas was found to change the computed dew point by as much 70°F, and invariably led to under-prediction of the dew point." "Based on comparisons to date, however, the C9+ characterization most often appears to predict measured dew points to within  $\pm 25^\circ\text{F}$ . (D. George, Ph.D. et al., Southwest Research Institute, "The Need For Accurate Hydrocarbon Dew Point Determination", Pipeline & Gas Journal, September 2005). Bear in mind that the measurements you get can be affected by the pressure and gas composition of the sample.

Recently ISO published their newest standard 23874 (2006) 'Natural Gas – Gas Chromatographic requirements for hydrocarbon dew point calculation'. This standard states that the GC system requirements for analysis of higher hydrocarbons includes:

- "be capable of measuring alkenes up to and including dodecane"
- "be capable of measuring individual alkenes at a concentration of 0.000 000 1 (0.1 ppm)"
- "be able to distinguish and measure benzene, toluene, cyclohexane and methycyclohexane as individual components"
- "measure all hydrocarbons in the range C5 to C12".

GCs designed to meet these specifications are prohibitive in cost for most power plants. What currently is in place are generally C6+ and a few C9+ analyzers on pipeline gas and in end user turbine installations primarily to check the BTU of the gas they are selling/buying. Many users are applying equations of state to provide additional data including a calculated HCDP.

The table at the end of this paper sheds light on how the equations need the information that cannot be provided by the

field GCs in the installed base. Even with a C9+ with a 60-30-10 split, the HCDP value is underestimated by nearly  $29^\circ\text{F}$  at 400 psig. With the JT cooling effect to reduce the pressure to 200 psig, this is pushing the superheat issue by another  $14^\circ$  to a total of  $42.8^\circ\text{F}$ .

### *Manual Dew Point Analysis*

The Bureau of Mines device has been used since the 1930s to provide Manual Dew Point Measurements and has been considered by many as the de facto standard in the industry. This device 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. Since there is some subjectivity in the interpretation of the image involved, there will usually be some bias the readings.

### *Automatic Dew Point Analysis*

Automatic Dew Point Analyzers have been in commercial use for over twenty years and independent laboratory testing has shown them to have very good accuracies to  $\pm 1^\circ\text{F}$  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 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 the entire spectrum of species 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.

## Best Practices Required for All Measurement Techniques

The general methods required to produce good accuracy begin with proper sampling. Proper sampling begins 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

suffer. 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. Any required pressure reduction should be taken immediately before delivery to the measurement section of the analyzer itself.

### ***Additional Best Practices for GC Analysis with EOS***

GC best practices include using a C9+ GC as a start and then adding in data to C12 from periodic laboratory analysis to improve accuracy of the EOS calculations. These results should then be compared to actual Manual Dew Point 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 at conditions far different from those of the actual measurement.

### ***Additional Best Practices for Manual Dew Point Analysis***

In addition to the general best practices above, the Manual Dew Point 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 contract pressure or the approximate cricondenthem of the specific gas. The sample should be allowed to bleed through the device per the ASTM standard D 1142. Chilling the mirror down at “<2°F/min” until a visible condensate forms on the optical surface is the procedure (Chandler Engineering, “Condensables In Natural Gas”, Chandler Engineering Product Brochure). 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.

### ***Additional Best Practices for Automatic Dew Point Analyzers***

#### **Reliable Detection Method**

A reliable detector is a given for all instruments. Without the right sensor, discriminating a true HCDP has been tricky because without the appearance of its condensate is often

confused with other condensables. When hydrocarbons condense, they plate out as a shiny, transparent, somewhat iridescent condensate that is hard to distinguish from a mirrored surface. Rough or etched surfaces will be able to discriminate the HCDP from a WDP or a contaminated HCDP condensate layer because the condensate will make the optical surface more reflective and easier to discriminate.

#### **Close proximity to pipeline sample point**

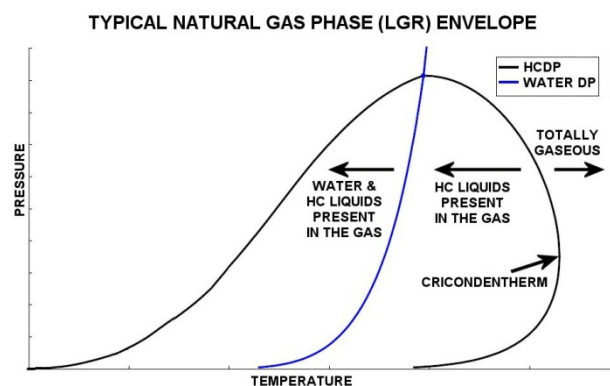
A unit that can be installed near the sample tap will produce faster information updates because there is less transportation time. Using a sample already piped to an instrument house may be convenient, but the resulting delay in the update may cause serious lag in reaction time for control purposes. Since each manufacturer has different operating temperature specifications, environmental conditions often dictate this choice.

#### **Blocking In 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. These heavier molecules are the first to condense as the temperature is decreased. If the flow is continuous throughout the measurement cycle, these heavier components build up disproportionately to their representative concentrations found in the sample. This will always bias the readings higher and the bias can be significant. Blocking in the sample during the measurement cycle will eliminate this bias producing more accurate readings.

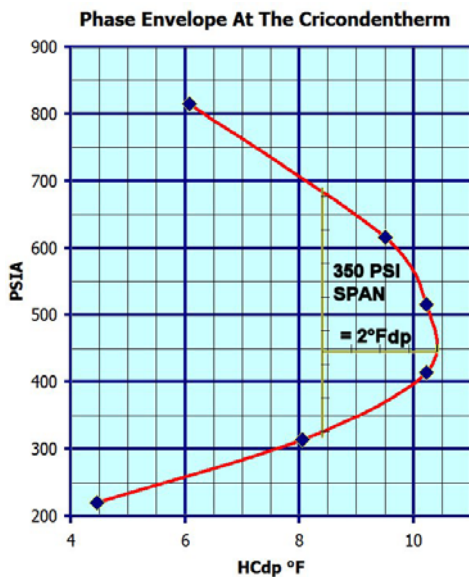
#### **Controlling pressure to the cricondenthem**

What is the derivation of the word cricondenthem? Critical condensation thermal curve – or “phase envelope” is the curve described by the pressure and temperature relationship which shows where the phase of the gas sample changes. The cricondenthem is the point on this curve where pressure and temperature indicate that the maximum HCDP is to be found (see diagram below). Many tariffs are written with this point as



the measuring point for the maximum allowable dew point in the contract. Tariffs written with the reference to the maximum HCDP at any pressure, are describing the same point.

The cricondenthem pressure is not as critical as may be anticipated. Since the profile of this region of the curve is nearly vertical, even a variance of fifty to a hundred psi either way can be shown to produce very little change in the accuracy of the measurement. The expanded graph below shows that a change of 100 psi in this sample will influence the HCDP a maximum of only 2°F. In contrast, missing just 1 ppmv of C10 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 cricondenthem illustrated by the graph below.



### Heating the optical surface between measurements

Once the sample has been blocked in and the measurement is completed, it will need to be refreshed for each subsequent measurement. The condensate will usually evaporate as the gas flow is restarted through the measurement chamber during a recovery after a measurement. If the surface does not totally clear, and the measurement cycle begins with hydrocarbon residue already on the optical surface, the result will always be a bias toward a higher reading. The sensing surface can be placed back into the measurement mode earlier by heating the optical surface which increases the evaporation rate of the condensate from the previous measurement.

This heating cycle needs to be long enough to eliminate the condensate residue and prepare the sensor for the next measurement. A more consistent starting point for the

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

### Small internal volumes

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

### 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.

### Capability for Harmonizing With Historical Data

As HCDP research continues, new data has been incorporated into government regulations and commercial tariffs. Historically the definitions of HCDP have been slightly modified and standards have been rewritten to incorporate them. It is natural to assume that this trend will continue and as these changes come into effect, it is essential to have the ability to adjust the analyzer to align with historical data or comply with newly refined standards.

### Summary

Natural Gas Fired Turbine operation has become an efficient method for generating power and has found a niche in meeting peak demands. The investment in these plants is significant so they must be protected from damage. Turbine owners should consider the fuel requirements published by the manufacturer when contracting for natural gas. Once the contract is in place, accurate on-line instruments confirm that these contractual specifications are met. Reliable instrumentation becomes the only enforcement method available if contract quality is not being met.

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 can 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 operational cost by over-reporting the dew point temperature which would drive

the control system to heat the incoming gas more than necessary.

Reliable accurate measurement instrumentation assist in controlling the operation of the turbine and protecting this asset. Upsets in the supply of the gas will occur but using good instrumentation will prevent turbine damage and increase reliability of the plant to produce the power required.

Employing best practices in every case will enhance the protection and will also reduce the cost of heating the incoming gas to meet the superheat requirements of the turbine. Fully 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 protect the turbine.

## HCDP values calculated by SRK EOS at 400 psig of a fairly rich gas sample

Component			C14	C9+ 60/30/10 split	C9+	C6+ 60/30/10 split	C6+
helium	mol	He	4.9807	4.9807	4.9807	4.9807	4.9807
hydrogen		H2	0.9961	0.9961	0.9961	0.9961	0.9961
nitrogen		N2	183.2910	183.2910	183.2910	183.2910	183.2910
carbon dioxide		CO2	67.7380	67.7380	67.7380	67.7380	67.7380
Methane		C1	9298.0325	9298.0325	9298.0325	9298.0325	9298.0325
Ethane		C2	283.9018	283.9018	283.9018	283.9018	283.9018
Propane		C3	80.6879	80.6879	80.6879	80.6879	80.6879
I-butane		iC4	12.9499	12.9499	12.9499	12.9499	12.9499
n-butane		nC4	15.9383	15.9383	15.9383	15.9383	15.9383
I-pentane		iC5	3.9846	3.9846	3.9846	3.9846	3.9846
n-pentane		nC5	2.9884	2.9884	2.9884	2.9884	2.9884
cyclopentane		C5H10	0.2391	0.2391	0.2391	0.2391	0.2391
n-hexane		nC6	2.7892	2.7892	2.7892	3.41274	5.6879
cyclohexane		C6H12	0.1992	0.1992	0.1992		
benzene		C6H6	0.1692	0.1692	0.1692		
n-heptane		nC7	0.8965	0.8965	0.8965	1.70637	
toluene		C7H8	0.0598	0.0598	0.0598		
n-octane		nC8	0.7471	0.7471	0.7471	0.56879	
p-xylene		C8H10	0.0100	0.0100	0.0100		
n-nonane		nC9	0.3287	0.4901	0.8169		
n-decane		nC10	0.2889	0.2451			
n-undecane		nC11	0.1096	0.0817			
n-dodecane		cC12	0.0598				
n-tridecane		nC13	0.0199				
n-tetradecane		nC14	0.0100				
Temperature	F		60.0000	60.0000	60.0000	60.0000	60.0000
Pressure	psig		400.0000	400.0000	400.0000	400.0000	400.0000
HCDP	(F)		85.7	56.9	38.6	8.7	-18.4
Press	(psig)		400	400	400	400	400

As is shown above the gas is all the same and the calculations are all done for the same conditions but the results vary by over 100°F HCDP! The reason is that even small quantities of heavier compounds influence this calculation profoundly and we find the same occurs in the pipeline – heavier components condense first. These heavier components are the ones that cause turbine operators problems.