

VERIFICATION OF PROCESS INSTRUMENTATION DATA

11.1 INTRODUCTION

Data verification is a necessity for a successful problem solver. This is true whether the problem solver is working to discover a cure for cancer or working to solve a process plant problem. In all cases, the verification involves use of both human resources and technical resources. While it may be possible to install multiple backup instruments, do frequent instrumentation calibrations, and install elaborate communication devices to avoid the concept of data verification, this level of sophistication is rarely justified in a process plant.

Data verification can take many different approaches. The purpose of this chapter is to elucidate some of the techniques the author has developed and/or used that are beyond the conventional “check out the instrument” approach. The approaches discussed in this chapter are certainly not all inclusive. They are given for two purposes:

1. To illustrate some of the techniques that are available to use to check out suspect data. As technology growth occurs, newer techniques will cause this list to require continual updating.
2. To serve as an encouragement to the problem solver to take full responsibility for the area of data verification. Often, the problem solver is

tempted to quit and say “I can’t do any more until someone fixes the instrumentation.”

11.2 DATA VERIFICATION VIA TECHNICAL RESOURCES

The first step in verifying any instrument is a careful review of the instrument specification sheet and a comparison of the specification sheet to the actual field installation. The instrumentation specification sheet will have such information as instrument range, process fluid density, pressure, and temperature. If these values are not correct, or if the range or zero point is set wrong in the field, the data cannot be expected to be correct.

A second area to consider when reviewing the instrument specification sheet is actual operating conditions compared to design conditions. That is, how close is the variable being monitored to the design level of flow, pressure, level, and so forth? Many instruments provide a measurement that is based on differential pressure. If the actual measured value is significantly different from the design level, there may be inaccuracy introduced by this deviation. This inaccuracy is often overlooked in the era of digital data acquisition where the measured variable may be shown in 4 or 5 significant figures regardless of what percentage of the range this is. An analog picture that may help in understanding this involves measuring the pressure of an automobile tire. The absolute accuracy of a pressure gage that is calibrated from 0 to 200 psig is much less than that of one calibrated from 0 to 40 psig. An error of 5% of maximum amounts to either 10 psig or 2 psig. This difference in accuracy is quite significant when measuring tire pressures of 30 psig.

This “percent of range” problem is particularly significant for an orifice flow instrument. With an orifice flow meter, the differential pressure across the orifice is proportional to the rate squared. Thus a flow rate of 50% of the maximum design flow rate only provides an output of 25% of the full meter range. The absolute meter accuracy at 25% of range will be much less than that at full meter range.

The concept of reviewing the instrument data sheet first follows the idea of doing the easiest thing first. If errors are found or if the operating conditions are found to be only at a low percentage of design conditions, these can almost always be rectified by simple adjustments of the instrument.

If the review of the instrument specification sheet fails to uncover any explanation for the suspected instrument being wrong, additional steps are required. In a continuous process plant, verification of instrumentation data is complicated by the fact that a shutdown of a process to verify an instrument is prohibitively expensive. Thus data verification must be done through techniques that do not require a shutdown.

Essentially, all instruments consist of both a primary element and a display element. The primary element senses a process variable such as pressure or differential pressure. The display element takes that reading and converts it

to the variable being measured such as flow rate, pressure, or level. The primary element is often not accessible without a partial or total plant shutdown. The display element can almost always be tested and replaced or adjusted while the process is in operation. For example, a flow instrument such as an orifice meter both creates and measures pressure drop. Since the orifice plate which creates the pressure drop is installed in the flowing fluid, it cannot be removed from service without at least a partial shutdown. However, the display element can be checked and adjusted or replaced without a shutdown. The emphasis in this chapter is on data verification when the primary element is in question and cannot be removed from service.

Table 11-1 summarizes the typical sources of instrumentation errors of the primary elements. As an example of the concepts in Table 11-1, the reader is referred to Figure 11-1, which shows a typical flow element and potential sources of errors. As shown in Figure 11-1 and Table 11-1, the flow meter can give erroneous results if one of the following occurs:

Table 11-1 Typical sources of primary element errors

Primary Element	Plugging in		Corrosion of Element	Condensation in Tubing
	Element	Tubing		
Flow	X	X	X	X
Level		X		X
Pressure	X	X		X
Differential pressure	X	X		X

X indicates that the primary element could likely be impacted by the condition shown at the top of the table.

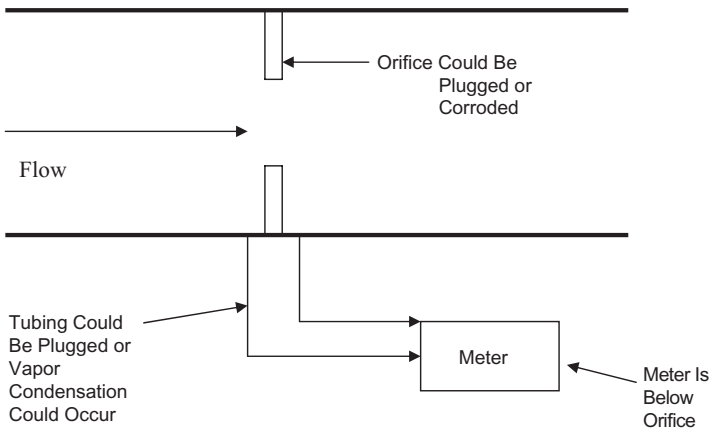


Figure 11-1 Potential flow meter errors.

- *The orifice could be partially plugged.* This would create a greater-than-expected pressure drop for the given flow rate, and would result in the measured flow rate being higher than actual flow.
- *The orifice could be corroded.* This would create a lower-than-expected pressure drop for the given flow rate, since the orifice hole would be bigger than it was in the design. This would result in the measured flow being less than the actual flow. If corrosion of an orifice plate does occur, it might result in an orifice hole that is not uniform or is very rough, which might well create greater-than-expected pressure drop and a measured flow being greater than the actual flow.
- *One of the tubing lines leading to the display element could be partially plugged.* This would give a pressure reading at the display element that was different than the actual. The pressure sensors for the meter measure the pressure differential across the orifice. If the high pressure side tubing is plugged, the measured pressure differential will be lower than actual. This will cause the measured flow rate to be less than the actual flow. Conversely, if the low pressure side of the tubing is plugged, the differential pressure will be higher than actual and the measured flow rate will be higher than the actual flow. Possible sources of plugging are solids in the process fluid or freezing of the fluid in the tubing lines.
- *Condensation in the tubing lines can create a false differential pressure.* The comments here assume that the meter is located below the orifice so that condensation will accumulate in the tubing lines. If the meter is above the orifice, any condensation will normally drain back into the process flow by gravity. This condensation can occur when the orifice is in hot vapor service or when the ambient temperature is colder than the temperature of the flowing vapor. If this condensation occurs in the high pressure tubing line and not in the low pressure tubing line, the measured differential pressure will be higher than that created by the pressure drop across the orifice. This will result in the measured flow being higher than the actual flow. The converse is that if the low pressure tubing line has more condensation than the high pressure tubing line, the measured flow will be less than actual flow. If an equal amount of condensation occurs in both the high and low pressure tubing lines and the tubing lines have the same elevation change, then the impact on the measured variable is minimal. Since this is unlikely to occur in practice, the tubing lines are usually insulated and steam traced or sealed with either the process fluid or an instrumentation fluid that is not soluble in the process fluid. A similar situation can occur if the fluid is a liquid that can vaporize in the tubing lines.
- *It is possible for the flow measurement of a vapor stream entraining liquid droplets to experience a similar error.* In this case, the liquid droplets may accumulate in one or both of the tubing lines. While these droplets may vaporize over time, this vaporization will occur at a rate that depends on

Table 11-2 Data verification via technical resources

Type of Instrumentation	Repair Mode ^a	Data Verification Techniques
Flow measurement		
Primary element	Off-line	Insertable flow meters, ultrasonic flow meters, or process analysis
Display element	On-line	
Thermocouples with external wells		
Primary element	On-line	Thermometers, pyrometers
Display element	On-line	
Thermocouples without external wells		
Primary element	Off-line	Infrared pyrometers
Display element	On-line	
Pressure measurement		
Primary element with block valve	On-line	Pressure gage
Display element	On-line	
Level measurement		
Primary element	Both off-line and on-line	Gage glass, Geiger counter or X-Ray
Display element	On-line	

^aOff-line indicates that the process must be shut down to check or repair. On-line indicates that verification can be made while the process is in operation.

the ambient conditions. In addition, the rate of entrainment may also vary. Thus there is no way to know that the tubing lines are full of liquid or vapor. The preventative steps described above are usually provided by the instrument designer in this case.

A similar description could be provided for each of the types of instrumentation measurements shown in Table 11-1.

Table 11-2 shows possible techniques for validating instrumentation data. The emphasis in this table is verification without requiring a plant downtime. Thus the most obvious approach, replacing an “in-line” instrument, is not covered. The following paragraphs discuss verification techniques for the most common instruments.

11.3 FLOW MEASUREMENT

If a primary flow measurement device (an orifice plate or venturi meter) is suspect and cannot be removed from service, it must be verified by either, or both, a noninvasive external flow measurement device or process analysis.

Table 11-3 External flow measuring devices

Type of Device	Comments
Noninvasive ultrasonic instruments	These can be strapped onto a pipe and used to measure flow.
Transit time	Clean homogenous fluids. Accuracy has been reported from 10% to 70%.
Doppler shift	Used for suspended solids with concentrations from 200 ppm to the percentage level.
Invasive	These require a bleeder and a packing gland arrangement to insert them into the flow.
Pitot tube	Can be highly accurate if sufficient readings are taken across the flow path and integrated to obtain the average flow. Generally for clean fluids only.

The external flow measurement devices are generally not as accurate as the flow measurement devices installed in the process. There are some claims for high accuracy. However, this is usually based on devices that have been calibrated against a known flow rate of the suspect process fluid. If this field calibration against a reliable flow meter is not available, then claims of high accuracy are questionable. In addition, some external measurement devices (pitot tube) require insertion through a bleeder valve with a packing gland arrangement. This packing gland arrangement creates some safety risk, especially in high pressure service. Table 11-3 lists a few of the external devices that are available. This is not meant to be an exhaustive list; in addition, the changing technology world may well allow development of different and/or more accurate devices.

Verification of a flow measurement by process analysis is a relatively simple, but often overlooked, technique. It involves the use of heat and material balances to confirm the validity of a suspect flow meter. It is probably best to consider it as a “one-sided” test. For example, if the heat and/or material balances appear to check, the flow meter is probably correct. If the heat and/or material balances do not check, the suspect flow meter or another flow meter is likely wrong. While these concepts are fundamental to all process engineering, some general guidelines are presented below to aid in the application of these principles.

- *Accumulation may cause a system to appear to be out of material balance.* Thus it may be necessary to expand the traditional concept to utilize the principle of accumulation discussed previously in Chapter 10. That is,

$$AD = I - O - RD \quad (10-1)$$

where

AD = rate of accumulation; this could be accumulation of anything: heat or material

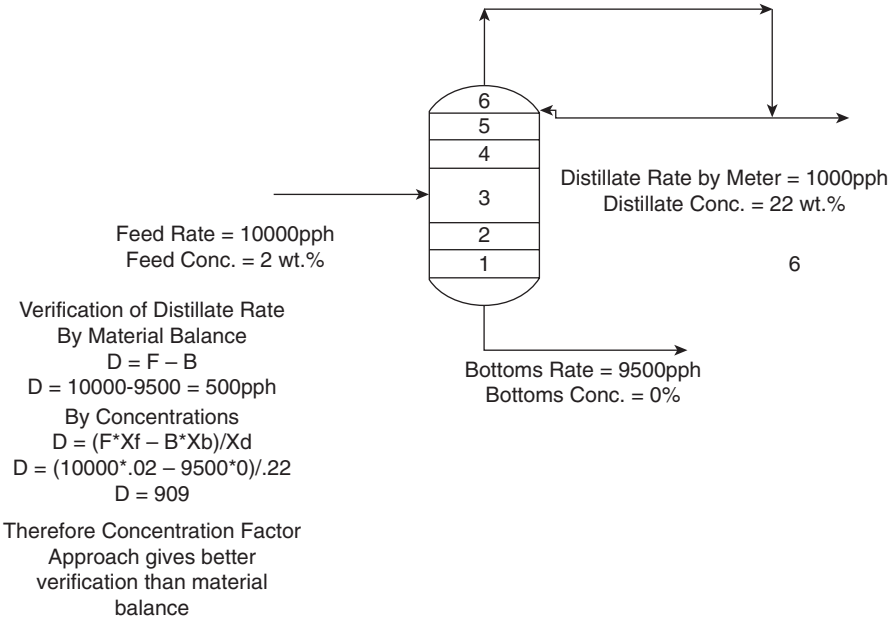


Figure 11-2 Estimating flow by concentration.

I = inflow of material or heat

O = outflow of material or heat

RD = removal of heat or material by reaction

- *Beware of determining flow rate as the difference between two large metered flows.* Using the concept of concentration factor provides more reliable answers. Figure 11-2 illustrates this point. As shown in this figure, if the overhead distillate rate is calculated as the difference between the feed rate and the bottoms rate, a value of 500lb/hr is obtained, compared to a metered value of 1000lb/hr. However, if concentrations are used to estimate the overhead rate, a flow rate of 909lb/hr is calculated.
- *Heat balances can be used to estimate the process or utilities flow to an operation.* For example, the steam rate to a reboiler for a simple fractionation column can be estimated knowing that the heat added by the reboiler and feed must be equal to the heat removed by the process streams and cooling water. Other examples are that the cooling water flow to a tower condenser can be determined knowing the heat removed in the condenser and the inlet and outlet water temperatures, and the “boil up” rate in an evaporator can be determined by the steam rate and the heat of vaporization of the process fluid.

11.4 TEMPERATURE MEASUREMENT

A suspect primary temperature measuring element can often be checked when removed from a thermowell which is installed in the vessel or pipe. However, in some instances, the primary device is not removable. An example of this is the tube metal thermocouples in a furnace. These devices are used to measure the temperature of the furnace tube metal. In order to obtain this measurement, the thermocouples are attached to the tube itself and shielded from the flame, as opposed to being installed in a thermowell. This shielding ensures that the thermocouple does not receive any radiant heat from the furnace flames. A high tube metal reading could be real, or could be associated with a failure of the device or shielding equipment.

In the case of furnace tube thermocouples that are suspect, infrared temperature measurement can be utilized to measure tube metal temperatures through a furnace port hole if it can be accessed safely. Infrared temperature measurement is a noninvasive technique used to determine the temperature of a small area. It can be used to measure reasonably accurately the temperature of a particular spot on a furnace tube. It can also be used to measure the temperature of a flowing solid, or to measure the temperature of a rotating part of machinery.

Infrared temperature measurement requires a great deal of expertise, particularly the measurement of furnace tube temperatures. For example, measurement of furnace tube temperatures may require that the infrared detector be cooled by liquid nitrogen.

11.5 PRESSURE MEASUREMENT

A suspect pressure instrument can, many times, be removed and a gage installed to verify the pressure. However, if there is no way to isolate the pressure instrument or if the pressure tap is plugged, alternative methods of verifying the pressure instrument will be required. Fundamental process analysis can often be used to verify a pressure reading.

The classical chemistry phase rule can often be applied in this situation. This rule is as follows:

$$F = C - P + 2 \quad (11-1)$$

where

F = degrees of freedom (temperature, pressure, and composition)

C = number of components in the mixture

P = number of phases present

Thus for a single component system with two phases (liquid and vapor) present, the degrees of freedom equal one. This means if the temperature is known, the pressure is fixed. In a two-phase binary (two component) system, the degrees of freedom will be two. If the binary system has a fixed composition, fixing the temperature also fixes the pressure since the fixed composition eliminates one degree of freedom. While this may seem to be very basic chemistry/engineering, it is amazing how often this is overlooked in the data verification process. Example Problem 11-1 illustrates how this fundamental approach was used to solve a process problem rather than inventing more complicated theories.

11.6 LEVEL MEASUREMENT

The verification of a level instrument can often be done simply by utilization of a gage glass, if one is available. Other devices such as x-ray and Geiger counters can be used to determine the absolute level based on the fact that liquid is denser than vapor. Both of these techniques work in a similar fashion. A source of the radiation signal is located on one side of the vessel and a detector is located on the other side. The amount of radiation that reaches the detector is inversely proportional to the length of the flow path and the density of the material in the flow path. The material in the flow path includes both the vessel wall and the process fluids. Since the flow path and thickness of the vessel wall are fixed, the only remaining variable is the density of the material in the vessel. If the material is a liquid (higher density), more radiation will be absorbed and the reading on the detector will be lower than it would be if the material was vapor. The radiation absorption of the metal wall can normally be eliminated by a calibration technique. Thus the utilization of radioactive techniques can detect the interface between liquid and vapor. Key factors in the use of these techniques are as follows:

- *Difference in densities between the liquid and vapor.* As the density difference decreases, it is more difficult to measure the level with this technique.
- *Thickness of the vessel wall.* The thicker the vessel wall, the more difficult it is for a signal to penetrate the wall. If most of the radiation absorption occurs in the vessel wall, it will be difficult to utilize this technique to determine the presence of a vapor-liquid interface.
- *Diameter of the vessel.* At a fixed design pressure, larger diameter vessels require thicker walls. These thicker walls will absorb more of the radiation and, as indicated above, the determination of the vapor-liquid interface will be more difficult.
- *Strength of the radiation signal.* The stronger the source of the radiation signal, the easier it is to obtain a strong signal with the detector. However,

stronger signals increase the radiation hazards and the design consideration difficulties.

Again, process analysis can be used to verify the range of the level instrument. In order to verify the absolute accuracy of the level instrument, the zero point and range must be known. The zero point is the level in the vessel that corresponds to a zero reading on the level instrument. This may or may not correspond to an empty vessel condition. The range is the difference (usually in inches) between the zero point and the 100% indication of the vessel level. For example, a 6-ft-high vertical drum with a zero point set at the bottom tangent line of the vessel and a range of 72 in would cover the entire height of the vessel. Thus a reading of 50% on the level instrument would be expected to be 36 in above the bottom tangent line.

If the vessel level instrument is in question, it may be due to an inaccurate zero point or an inaccurate range. The zero point and instrument range can often be checked without taking the vessel out of service. However, some types of level instruments cannot be checked without taking the vessel out of service. In addition, inaccuracies of level instruments can also be caused by internal vessel connection plugging.

If accurate flow meters are available for the inlet and outlet flows, it may be possible to assess the accuracy of the range of the level instrument by accumulating in the drum or removing liquid from the drum and comparing the calculated inventory change from flow meters to the measured inventory change. The approach to be used depends on the orientation of the drum. If the drum is a vertical vessel, the inlet and outlet flows should be set so that there is a significant difference between the two. The measured inventory change should then be compared to the calculated inventory change based on the flow meters. If they compare well, this is a good indication that the range on the instrument is correct. However, the zero point could still be wrong. The zero point can be checked by reducing the inventory in the vessel until there is clear evidence that the drum is empty. The evidence could consist of "blowing through," as evidenced by the outlet flow meter or by a change in temperature which would indicate by the phase rule that there was only a single vapor phase present.

If the level instrument in question is on a horizontal vessel, the same technique can be utilized. However, determining the actual volumetric inventory change will be more difficult due to the curvature of the vessel walls. Tables and techniques are available to readily take this curvature into account. If an accumulation test is run with a horizontal vessel whose level zero point is in error, it is possible to conclude that the level meter is correct due to the curvature of the drum. For example, a change in the level instrument from 65 to 70 (5%) might be confirmed by the difference in flow meters. However, if the actual level were 10% instead of 65%, a 5% level increase would seem in error when compared to the difference in flow meters. To confirm the accuracy of the range of a level instrument on a horizontal vessel, it is best to run two tests at different vessel levels. If both of these tests indicate that, based on differences in flow meters,

the level changes appear correct, it can be assumed that the range of the level instrument is correct. The techniques discussed for determining the zero point for a vertical vessel can also be utilized for a horizontal vessel.

11.7 DATA VERIFICATION VIA HUMAN RESOURCES

The role of an operator or mechanic in problem specification was discussed earlier. It was implied that it was imperative that he was cooperative and that all that was necessary was to solicit his data and/or the problem history. Obviously, an uncooperative worker can be a poor source of data by refusing to share his knowledge, presenting erroneous data, or simply acting as a “smoke screen.” For example, an instrument technician who was known to have acrophobia may not have checked out an instrument as he claimed, if it required him to be far above the ground.

While this book does not cover all aspects of interpersonal skills, the guidelines below will help the problem solver obtain the maximum assistance from the operating and mechanical workers.

- Respect the person that you are seeking information from as an equal.
- Learn people’s names and don’t forget them.
- Cultivate relationships by providing answers to questions, explaining your goals, reviewing the results of any tests, and listening to other’s thoughts.
- Don’t give others the impression that you are too busy to spend time with them.
- Be positive. Assume that people are always trying to do the right things. If a mistake has been made, assume that it was due to inadequate training or done accidentally. Don’t take the position that someone did it on purpose. You will be wrong on occasions, but you won’t destroy relationships.
- When it is necessary to look over someone’s shoulder as they perform their job, try to convince them that they are educating you on their skills.
- Realize that everyone has bad days. If you get an undeserved “chewing out” by an operating or mechanical worker, take your licks and back away from the conversation without becoming defensive. Defending yourself to someone who is irrational is not possible, and you will cut off a source of future data.

11.8 EXAMPLE PROBLEMS

The example problems below illustrate some of the approaches described in this chapter. The first problem illustrates the value of investigating and verifying conflicting data as opposed to simply assuming that one piece of the mysterious data is wrong. The second problem was solved by a careful review of the instrumentation specification sheet. The third problem is a fictitious problem that is included to illustrate how the technique of inventory change can be used to confirm a level instrument.

EXAMPLE PROBLEM 11-1

A vessel in an ethylene refrigeration unit, shown in Figure 11-3, served as a combination surge and knockout drum. Liquid ethylene flowed into the drum and out to various heat exchangers. The mixture of vapor and liquid ethylene leaving the exchangers was returned to the drum where it was separated into vapor and liquid streams. The ethylene refrigeration system was used to cool liquid propane to a temperature of -145°F . It was important to control the liquid level in the drum to ensure that minimal amounts of liquid were entrained with the vapor and to ensure that liquid ethylene was always available for feeding the heat exchangers. The drum operated under a slight vacuum and the normal temperature was -156°F .

Current conditions were an anomaly. The pressure was at normal conditions. This slight vacuum was confirmed by a second, independent pressure instrument. However, the temperature as measured by two independent thermocouples was $+10^{\circ}\text{F}$. Operating personnel believed that the thermocouples were both wrong. Management had asked that problem-solving resources determine what the real problem was.

The problem solver's approach to using the five-step problem-solving technique was as follows:

Step 1: Verify that the problem actually occurred.

Since there were two independent thermocouples that both indicated a much higher than expected temperature, it was obvious that something was wrong. This was a real problem.

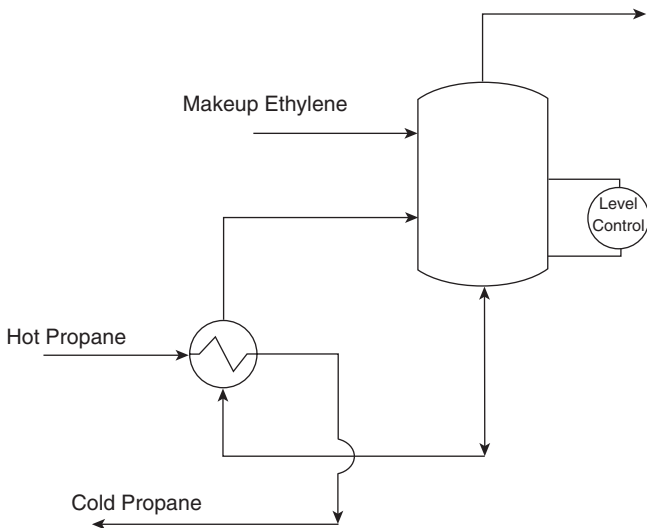


Figure 11-3 Ethylene surge/knockout drum.

Step 2: Write out an accurate statement of what problem you are trying to solve.

The problem statement that was developed was:

“The temperature on the ethylene knockout drum is reading much higher than normal. While the process appears to be operating normally, this higher temperature may be indicative of a potential problem that will occur in the future. Determine why the temperature on the ethylene knockout drum is reading much higher than the normal temperature of -156°F .”

Step 3: Develop a theoretically sound working hypothesis that explains as many specifications of the problem as possible.

Using the questions from Chapter 6, the problem solver developed Table 11-4. Based on the above questions, four hypotheses were developed, as follows:

1. There is a leak in the exchanger and the drum contains a mixture of propane and ethylene instead of pure ethylene.
2. The thermowell is so poorly insulated that the temperature instrument is really reading a mixture of the ethylene and the ambient temperature.

Table 11-4 Questions/comments for Problem 11-1

Question	Comment
Are all operating directives and procedures being followed?	All appeared to be correct and being followed.
Are all instruments correct?	The instruments had allegedly been calibrated.
Are laboratory results correct?	Not applicable.
Were there any errors made in the original design?	No. The process was an old one process that was returning to service after repairs.
Were there changes in operating conditions?	No.
Is fluid leakage occurring?	The propane being cooled could leak into the ethylene refrigerant and concentrate in the knockout drum.
Has there been mechanical wear that would explain problem?	The unit had been down for repairs. Repairing of the insulation on the drum might not have been completed.
Is the reaction rate as anticipated?	Not applicable.
Are there adverse reactions occurring?	Not applicable.
Were there errors made in the construction?	See comments above on mechanical wear. In addition, new thermocouples were installed.

3. The new thermocouples were calibrated incorrectly.
4. The level instrument is wrong and there is no liquid level in the drum.

Hypothesis 2 was ruled out by an inspection of the drum that showed the thermowells were well insulated. Hypothesis 3 was ruled out after discussions about the calibration techniques carried out by the instrument technicians.

The problem solver used the phase rule (equation 11-1) shown below to conclude that both hypotheses 1 and 4 were theoretically correct working hypotheses.

$$F = C - P + 2 \quad (11-1)$$

Based on the phase rule, he outlined the following three cases:

1. Under normal situations in the ethylene surge drum there would be a single component ($C=1$), two phases ($P=2$), and the degrees of freedom (F) would be equal to one. That is, the temperature in the surge drum would be fixed by the pressure and should be -156°F .
2. If there were two components ($C=2$) in the drum, then the degrees of freedom would increase to two and the temperature and pressure in the drum would be independent.
3. If there was a single component in the drum ($C=1$) but only a single phase ($P=1$), then the degrees of freedom would also be equal to two. Again, the temperature and pressure in the drum would be independent.

However, there are boundaries to the independence of temperature and pressure described in case 2. For example, if there are two phases present and an exchanger leak had occurred (hypothesis 1), the temperature in the drum cannot be warmer than the boiling point of propane. If the liquid level instrument is correct (two phases are present) and, as an extreme case, all of the liquid in the drum is propane, the following analysis could be made:

$C = 1$ (Nothing in the drum, but propane)

$P = 2$ (The level instrument is correct so there must be two phases)

Therefore:

$$F = 1 - 2 + 2 = 1 \quad (11-2)$$

The boiling point of propane at atmospheric pressure is -44°F . Thus even if the liquid in the drum were 100% propane, the temperature would be slightly below -44°F , not $+10^{\circ}\text{F}$.

As discussed in case 3, if there was no leak in the exchanger, but the level instrument were wrong and the drum was empty (hypothesis 4), the phase rule would indicate the following:

$C = 1$ (Nothing in the drum but ethylene)

$P = 1$ (Nothing in the drum but vapor)

Then:

$$F = 1 - 1 + 2 = 2 \quad (11-3)$$

In this case, the temperature of the ethylene vapor would be limited only by the amount of superheat added by the heat exchangers.

Therefore, the theoretically sound working hypothesis developed was as follows:

“It is theorized that the mysterious temperatures in the ethylene knockout drum are due to the absence of a liquid level in the drum. Since there is no liquid level in the drum, the vapor can be heated to temperatures above the boiling point of ethylene at the pressure in the drum. In addition, the absence of this boiling liquid results in a very low heat transfer coefficient between the phase in the drum (vapor) and the thermowell. The normal situation in the drum is such that the thermowells are covered with boiling ethylene. The heat transfer coefficient in the normal case is likely as high as 200 BTU/hr-°F-Ft². The heat transfer coefficient from vapor to the thermowell is likely as low as 10 BTU/hr-°F-Ft². With this exceptionally low coefficient, the heat gained from the atmosphere flowing through the insulation and heating the thermocouple may create an additional error source.”

Step 4: Provide a mechanism to test the hypothesis.

Although the hypothesis could have been checked by simply raising the liquid level in the drum, this was deemed too risky. Since the drum served as a knockout drum, there was a risk that a high level would cause liquid ethylene to be carried over into the compressors. The problem solver requested that the instrument technician (who had recently checked the level instrument and determined that the range and zero point were as they should be) accompany him to again check the instrument. He explained to the instrument technician why he thought that the level instrument was incorrect. When they jointly inspected the installation, they found that the steam tracing that was used to ensure that there was no liquid accumulation in the tubing lines was turned off. When this tracing was returned to service, the level instrument began to function correctly.

Step 5: Recommend remedial action to eliminate the problem without creating another problem.

In this case, the mechanism to test the hypothesis was the remedial action. In order to prevent future occurrences of this problem, a statement was added to the startup procedure that called for the operators to check that the steam tracing had been put into service.

Lessons Learned While it is true that an experienced engineer would not need to use the phase rule to analyze this problem, that is only because he knows by experience and intuition how to analyze similar situations. In applying his experience and intuition, he is using the phase rule whether he knows it or not. This problem might be considered too simple for a detailed analysis; however, it does illustrate two important points. In the first place, there is great value in doing a fundamental analysis instead of making the assumption that the first analysis (the thermocouples are both wrong) is correct. It would be unlikely that both thermocouples were incorrect unless there was an external circumstance such as if they were incorrectly calibrated or the heat transfer to the thermocouple was not what it should have been. As indicated, this could be due to excessive heat loss from the thermowell due to poor insulation or poor heat transfer (caused by the absence of liquid) from the vessel contents to the thermowell. The application of the phase rule was very helpful in indicating that the level instrument which had been checked out was truly in error.

The problem also indicates that it is often necessary to get an operator or mechanical personnel to recheck something that has already allegedly been checked. This requires tactfulness and a good working relationship. This good working relationship is developed by the principles indicated in Section 11.7. In this example problem, it was enhanced by the problem solver going with the instrument technician to look at the level instrument for a second time.

EXAMPLE PROBLEM 11-2

A new polymer was to be produced in a test run in a commercial polypropylene plant. This new polymer was to be a copolymer produced by using ethylene as a comonomer in reactors normally polymerizing only propylene. Careful preparations were made for the test run, including reviews of batch and pilot plant operations producing the copolymer. This data indicated that the ethylene conversion should be about 85% during the planned operation. The test run plans called for careful monitoring of all variables, especially the ethylene conversion. The ethylene conversion was to be monitored using the propylene and ethylene flow meters, the ethylene content of the polymer, and the ethylene content of the unreacted gases. Because of the reliance on feed flow meters, these were carefully checked out by the instrument technicians prior to beginning the operation.

After the test run was started and steady state was established, the calculated ethylene conversion based on flow meters and the ethylene content of the polymer was essentially 100%. This was in contrast to the ethylene content of the unreacted gases, which indicated that the ethylene conversion was significantly less than 100%. While the unit ran well, the problem solver was greatly concerned about the deviation from the anticipated conversion based

on calculations made using the feed meters. He convinced management that even though this discrepancy between the anticipated conversion and the apparent actual conversion did not seem to be a problem on this run, that it might be a problem on future runs. They agreed that he should spend some time investigating the problem.

The problem solver's approach to using the five-step problem-solving technique was as follows:

Step 1: Verify that the problem actually occurred.

Since the test run had been carefully planned and the instruments had been checked out ahead of time, there was no doubt that there was a problem. There was some doubt about whether the problem merited attention. The problem statement developed by the problem solver had to address the incentive for working the problem.

Step 2: Write out an accurate statement of what problem you are trying to solve.

The problem statement that was developed was:

“The calculated ethylene conversion based on the ethylene feed flow meters and the ethylene content of the polymer is about 100%. This is in conflict with the pilot plant data and with the analysis of the unreacted gases, which shows the presence of ethylene. If the flow meters are correct, then either the ethylene content of the polymer or the ethylene content of the unreacted gases is wrong. The process control strategy requires that all three variables (feed flow meters, ethylene content of the polymer, and ethylene content of the unreacted gases) be measured correctly. Determine why the ethylene conversion is significantly higher than anticipated based on feed flow meters.”

Step 3: Develop a theoretically sound working hypothesis that explains as many specifications of the problem as possible.

Using the questions from Chapter 6, the problem solver developed Table 11-5. Based on the questions in the table, four hypotheses were developed as follows:

1. There was a design mistake in sizing the ethylene flow meters.
2. There was an error made in the installation of the ethylene flow meters.
3. The unreacted gas analyzer had been incorrectly calibrated for ethylene, or else the installation or design of the analyzer made it unacceptable for ethylene monitoring.
4. The technique for analyzing for ethylene in the polymer was either incorrect or being done incorrectly.

Table 11-5 Questions/comments for Problem 11-2

Question	Comment
Are all operating directives and procedures being followed?	All appeared to be correct and being followed.
Are all instruments correct?	The instruments had allegedly been calibrated. The ethylene flow meters and the analyzer for measuring the ethylene content of the unreacted gases were being used for the first time.
Are laboratory results correct?	The technique for measuring the ethylene content of the polymer had been closely cross checked against known standards.
Were there any errors made in original design?	Since this was the first time that the ethylene meters and analyzers had been used, their design could be in error.
Were there changes in operating conditions?	Not applicable.
Is fluid leakage occurring?	Not applicable.
Has there been mechanical wear that would explain problem?	Not applicable.
Is the reaction rate as anticipated?	Higher-than-anticipated ethylene conversion might explain the apparent discrepancies.
Are there adverse reactions occurring?	Adverse reactions are highly unlikely.
Were there errors made in the construction?	Since both the ethylene flow meters and the ethylene analyzer were being used for the first time, this had to be considered.

While any of the four hypotheses could be selected as a “theoretically sound working hypothesis,” the problem solver elected to do some further investigation prior to proposing a working hypothesis. Since the easiest and quickest thing to do was to review the instrument specification sheets, he elected this route. In addition, he recognized that the pretest instrument check by the instrument technicians did not involve a review of the instrument specification sheet. A review of the specification sheet indicated the following:

Table 11-6 Specification and actual data

Variable	Specification Sheet	Actual Data
Pressure, psig	735	735
Temperature, °F	90	75
Critical pressure, psig	735	735
Critical temperature, °F	50	50
Compressibility (Z)	1.0	0.6
Density, lb/ft ³	3.56	6.10

The original instrumentation design used a density that was significantly less than the actual density because the gas compressibility that occurs at high pressures was not considered. In theory, the influence of pressure on gas density should be adequately calculated based on a ratio of actual pressure to atmospheric pressure. However, at high pressures, the gas is more compressible than would be indicated by this ratio alone. Thus a compressibility factor must be included. This compressibility factor is available in tables and handbooks. This factor was not considered in the instrument design. There was also a difference in actual and design temperatures, but this was not significant. These calculations led to the following theoretically sound working hypothesis:

“It is theorized that the discrepancies between the actual ethylene conversions and the indicated ethylene conversions are due to the fact that the density for the ethylene flow meters was calculated assuming that the compressibility was 1. This resulted in a calculated density that is 40% below actual density. Since the measured flow rate is directly proportional to the square root of the density, this error results in a measured flow rate that is 30% below the actual flow rate. This single error explains the discrepancies observed.”

Step 4: Provide a mechanism to test the hypothesis.

The mechanism for testing the hypothesis was very simple. Since the error was in the calculations, it was easily corrected by changing the range on the flow instrument to correct for the incorrect density. After this correction was made, the flow rates, ethylene content of the unreacted gases, and ethylene content of the polymer were all consistent with the anticipated results.

Step 5: Recommend remedial action to eliminate the problem without creating another problem.

In this case, the testing mechanism was the permanent solution. It should be noted that in this problem, there was a temptation to simply modify the process control computer with a “fudge factor” to adjust for the error. This was easy to do, but it brought with it the risk that at some future time, the factor that was used in the computer would be removed because someone did not understand what it was. It was much more fool proof to change the instrument range and revise the instrument specification sheet.

Lessons Learned It should be noted that the error in the instrument specification sheet was only discovered after the problem solver realized that the pretest instrument checkout done by the instrument technicians only included a physical check of the instruments against the range given on the instrument specification sheet. They had no way of knowing that the density used in calculating this range was incorrect. The problem-solving lesson to be learned is that the problem solver needs to know the boundaries of the

mechanics or operators when they are asked to check out a piece of equipment. If they are starting with an incorrect calculated setting, they can only confirm that the instrument or piece of equipment is set to that value.

While it could be argued that the effort taken to resolve this discrepancy was not justified, the discrepancy was a particular concern since the flow meters were a key to changing grades. In addition, some grades produced at high ethylene contents could cause process shutdowns if control were lost. As a general rule, discrepancies in data or things that we do not understand will almost always cause future problems.

This example problem also illustrates again the value of doing the easiest calculation or data review first. While it seemed hard to believe that the design team would ignore the compressible nature of ethylene at high pressures, a simple review of the instrument specification sheet showed that this in deed was the case. Other hypotheses described earlier would have been more involved and taken longer to pursue.

EXAMPLE PROBLEM 11-3

This problem is included to show the calculation technique discussed earlier. The 5-step problem-solving approach is not considered. In addition, the tables that show liquid volume as a function of level in a horizontal drum are not included. For simplicity, the head volume of the drum is not included. In order to illustrate the calculation technique, it is assumed that the bottom connection of the differential pressure type level indicator is partially plugged so that the indicated level is 15% greater than the actual level.

A pump taking suction from a horizontal vessel continued to experience intermittent periods of operating below the pump curve. At times, it operated well. After an extensive problem-solving analysis, it appeared that the level instrument was incorrect. The level instrument was checked by instrument technicians and the range and zero point appeared to be correct. The problem solver decided that the only way to confirm the accuracy of the level instrument was with a plant test using the inlet and outlet flow meters. He planned to use the flow meters to calculate the level change in the drum. He would then compare this change to the measured change to try to determine if the level instrument was correct.

A summary of the test is shown in Tables 11-7 and 11-8.

Table 11-7 Summary of test basis

Drum size	
Diameter, ft	10
Length, ft	30
Fluid density, lb/ft ³	30.6
Inlet flow – outlet flow, lb/hr	10000
Test time, min	30
Volumetric flow, ft ³	163.3

Table 11-8 Test run results

	Test 1	Test 2
At Test Start		
Indicated level, % ^a	25	65
Actual level, %	10	50
Actual contained volume, ft ³	123	1178
At Test Completion		
Actual contained volume, ft ³	286	1341
Actual level, %	17.9	55.5
Actual level change, %	7.9	5.5
Measured level change, %	6.1	5.8
Error, %	23	5

^aThe problem description indicated that the level instrument showed 15% higher than the actual level.

An examination of Table 11-8 indicates the risk of running an accumulation test at only one level. If the test is run at a starting indicated level of 65%, it would be easy to conclude that the actual level change and calculated level change were very close. However, if the test run is started at an indicated level of 25%, the conclusion would be that there is a significant difference between the actual level change and calculated level change.

NOMENCLATURE

- F* Degrees of freedom (temperature, pressure, and composition)
- C* Number of components in the mixture
- P* Number of phases present