Nuclear Feedwater Flow Measurement Application Guide

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Nuclear Feedwater Flow Measurement Application Guide

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REPORT SUMMARY

This report is a summary of the technologies available to measure the feedwater mass flow rate in nuclear power plants. Differential pressure meters, three types of ultrasonic flow meters (UFMs) (external transit time, chordal transit time, and cross-correlation), and tracer tests are discussed. For each technology, the report describes operating principles, installation, maintenance requirements, measurement errors, uncertainties, and the results of an industry survey.

Background

Venturis and orifice plates used to calculate feedwater flow rates in nuclear power plants are susceptible to a “fouling” phenomenon that results in the calculated flow rate being greater than the true flow. Orifice plates might become bowed from use to the extent that the differential pressure produced is not representative of the true flow. As a result, a plant could be operated at a power level that is less than that allowed by its license (in the case of fouling bias), or, in other cases, plants might exceed their operating limits for reactor thermal power due to non-conservative flow measurement errors.

To offer utilities a way to correct flow measurement bias errors and optimize power generation, several companies have developed and marketed ultrasonic flow meters and chemical tracer testing services to calculate feedwater flow rates accurately.

Objectives

- To serve as a primer for utility engineers confronted with questions on feedwater flow measurement at their plant

- To clarify the guidance provided in PTC 19.1 for determining uncertainty in the feedwater flow measurements used to calculate reactor thermal power and primary loop flows

- To provide useful information on each of the various technologies available to calculate feedwater flow

Approach

The information in this report is based on technical papers, brochures, interviews with vendors, and an industry survey performed through the P^{2}EP office of the Electric Power Research Institute (EPRI).

Results

Five different feedwater flow measurements (differential pressure flow elements, chordal transit time meters, externally mounted transit time meters, externally mounted cross-correlation meters, and chemical tracer tests) were reviewed. The reviews covered operating principles, installation and maintenance requirements, reported uncertainties, potential errors, and a user survey. For meters other than venturis, vendor-reported uncertainties ranged from 0.2% to 1.0% per pipe. The methodologies used to determine these uncertainties were substantially different from vendor to vendor. The proprietary nature of the data and calculations upon which these uncertainties were based preclude a comprehensive critique of these methodologies within this report. However, it remains the obligation of the utility engineer to assess the validity of the uncertainty claims and ensure that these uncertainty analysis methodologies are consistent with the intent of ASME PTC 19.1.

EPRI Perspective

U.S. nuclear plants are licensed to operate at power levels up to a specified thermal power rating. A large component of the thermal power rating is calculated from the measurement of feedwater mass flow. Uncertainties in the measurement of this flow define the maximum allowable operating power. In Regulatory Guide 1.49, the U.S. Nuclear Regulatory Commission (NRC) provides guidance regarding the amount of margin required to account for flow measurement uncertainties.

Feedwater flow measurement technology has advanced considerably over the years. The most significant advancements have been in the use of ultrasonic technology to provide non-intrusive means of flow measurement.

Key Words

Thermal performance
Ultrasonic equipment
Calorimetry
Flow measurement
Feedwater flow

ABSTRACT

This report is a summary of the technologies available and in use to calculate feedwater mass flow rate in nuclear power plants accurately. Three methods—differential pressure meters, ultrasonic meters (chordal transit time, external transit time, and cross-correlation), and chemical tracer tests—are discussed. For each technology, the report describes operating principles, installation, maintenance requirements, measurement errors, uncertainties, and the results of an industry survey on reliability and performance.

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INTRODUCTION

Purpose of This Guide

Three measurement technologies are being actively used for calculation of feedwater flow rates in nuclear power plants to support calorimetric calculations of reactor power and coolant flow rate. These technologies are:

- Differential pressure flow elements
- Ultrasonic flow meters; transit time and cross-correlation meters
- Chemical tracer tests

In addition to understanding the fundamentals of each technology, performance engineers must consider several critical factors before selecting a measurement technology. These critical factors are uncertainty, design basis documentation, installation and maintenance requirements, and industry experience. This application guide is intended to assist utility engineers in these evaluations by summarizing the critical aspects of the measurement technologies.

Structure of This Guide

This guide contains one section for each of the technologies listed above. For each technology, the following topics are addressed:

- Principles of operation
- Physical description
- Maintenance requirements
- Installation requirements
- Sources of error
- Uncertainty

- Installed base
- Results of industry survey

Notes on Technology Descriptions

The descriptions in this guide are not intended as exhaustive technical explanations but as overviews that will help engineers to understand the basic operating principles of the technologies and the practical aspects of use of each technology. Ideally, the guide's descriptions will contain sufficient information to enable utility engineers to ask the vendors the key questions that are necessary to determine the suitability of a technology for their plant.

Notes on Uncertainty and Errors

Explanations of measurement uncertainty and procedures for calculating flow rate uncertainties are provided in several national and international standards [1,2,3]. When a measurement is to be used to set reactor power, regulations of the United States Nuclear Regulatory Commission (U.S. NRC) require that the basis for any uncertainty claims be thoroughly documented. These documentation requirements arise from U.S. Title 10 Code of Federal Regulation part 50.59 (10 CFR 50.59), which requires that owners maintain records of any design changes to the plant.

A change to the feedwater flow measurement technique and uncertainty might be considered a design change because 10 CFR 50, Appendix K, requires that plant safety systems be designed assuming that the reactor is generating 102% of its licensed power. The 2% is intended to cover the uncertainty of measurements used in calorimetric calculations. However, in some cases plants have been licensed with the calorimetric uncertainty less than 2%. In these isolated cases, the use of 2% would exceed the license basis of that plant.

Recently, the NRC has approved a topical report advocating the use of a specific ultrasonic technology to increase reactor thermal power by as much as 1%. The SER documents the NRC position that the technology is capable of feedwater flow measurement with accuracy sufficient to reduce the overall calorimetric calculation uncertainty [4].

Failure to consider wording in the Final Safety Analysis Report (FSAR) or other licensing basis documents, which can state explicitly how a feedwater flow is to be measured or fouling corrected, could be construed as a violation of the station's license. A detailed review of all documentation is, therefore, indicated prior to implementing any measurement techniques in this guide.

The following points should be considered in evaluating the reported uncertainty for a feedwater flow calculation. They are by no means all of the issues that should be addressed, but they do provide a starting point:

- **Uncertainty vs. observed variations.** Measurement uncertainty should be calculated from uncertainties assigned to each error. Use of "observed variations," calculated from the standard deviation of a data set, can be an appropriate method for estimating uncertainty only if the measurements are made over a range of conditions that allows the effects of all error sources to be included in the data set. This latter requirement makes it appropriate to use observed variations to estimate uncertainty for controlled measurements where there are few error sources, but very difficult to estimate for plant feedwater flow measurements where often complex, acoustic, hydraulic, and operational variables contribute to the measurement. In nuclear power feedwater applications, the end user is obligated to consider the extent to which data sets used for uncertainty calculations bound the range of plant installation variables when considering acceptance of the uncertainty analysis.

- **Measurement uncertainty vs. repeatability.** Measurement uncertainty is an interval that bounds biases and random variations that could occur over time for a given installation. The random portion of the uncertainty that applies to a given installation is often referred to as the "repeatability." Use of repeatability as the base measurement of uncertainty is incorrect if it ignores biases in the measurement technology and in the specific installation.

- **Level of confidence.** The level of confidence is the probability that the true flow rate will fall within the reported uncertainty interval. Current accepted practice is 2-sigma, a 95% confidence interval. However, several vendors use 1-sigma and, occasionally, a 3-sigma uncertainty analysis is reported.

- **Comparisons to other measurements.** The grouping of two or more measurements does not necessarily define the uncertainty of either measurement. Uncertainties should be calculated individually for each measurement by identifying all potential error sources. A hypothetical test where an alternative measurement produces a result within 0.001% of a "calibration standard" measurement that has a reported uncertainty of 0.5% does not indicate that the alternative measurement has an uncertainty of 0.001% or of 0.5%. The uncertainty of the alternative measurement should be calculated using a PTC 19.1 analysis methodology. It is possible, however, that the PTC 19.1 analysis might demonstrate that prospective biases between the alternative measurements and the calibration standard measurement are not significant and that the standard uncertainty is in fact bounding. For feedwater flow measurements, it is the obligation of the utility engineer to confirm that all potential biases are accounted for when basing a plant instrument uncertainty on prior measurements made against a standard.

Notes on Installed Base and Industry Survey

Information on numbers of installations, lengths of service, and regulatory acceptance are based on discussions with UFM vendors.

The industry survey results reported in this guide are from a voluntary survey of EPRI members conducted through the EPRI P^2EP center and from contact with utility members. The survey questions focused on experience with different technologies and the confidence in each technology used. The opinions expressed in the survey are those of the respondents and are not necessarily endorsed by the authors.

2

DIFFERENTIAL PRESSURE FLOW ELEMENTS

Overview

Differential pressure (DP) technology has been the industry standard for feedwater flow measurement throughout the development of the nuclear power industry. These instruments calculate flow from the measurement of differential pressure across a flow constriction and from the pressure and temperature of a flowing fluid. Types of differential pressure flow elements include venturis, flow nozzles, and orifices. Each of these elements is based on the same operating principle; however, they differ in the geometry of the flow restriction, the extent of irreversible pressure loss, and code acceptance.

DP flow meters can trace their origins to the 18th century and the works of Daniel Bernoulli and Giovanni Venturi. Industrial use of these meters became common in the early 1900s because the meters provided a relatively repeatable measurement with little mechanical maintenance required. Popularity of orifice flow meters prompted substantial research by the American Society of Mechanical Engineers (ASME) in the 1920s. This initial effort and subsequent work, including hydraulic testing, are the basis for the current understanding of the operation of the venturis and flow nozzles used in the nuclear industry today. Documents which describe industry standard practices for differential pressure flow elements are ASME Fluid Meters [5], ASME MFC-3M [6], ASME MFC-10M [7], ASME PTC 6 [8],ASME PTC 19.5 [3], ISO 5167 [9], and IEC 953-1, IEC 953-2 [10].

DP flow meters are relatively simple devices that provide continuous, fast-response measurements that are widely accepted throughout the nuclear power industry. The installed cost of a new venturi or flow nozzle is relatively high. However, most U.S. nuclear power plants were supplied with feedwater venturis or flow nozzles, while most Canadian deuterium/uranium (CANDU) plants were supplied with orifice plates for reactor feeder flow and uncalibrated nozzles in the feedwater system as original plant equipment.

Typically, a manufacturer that specializes in flow elements supplies the metering section and develops the associated discharge coefficient. The nuclear steam supply system (NSSS) or the plant architect/engineer supplies the impulse lines, instrumentation cabling, and interface with the plant computer.

Principles of Operation

DP flow meters reduce the flow cross-sectional area, resulting in an increase in fluid velocity through the throat of the flow element. The increased velocity causes a measurable difference in pressure between locations upstream and downstream of the flow element. The difference between the pressure upstream of the contraction and the pressure downstream of the contraction is measured with taps bored into the pipe or flow element. These taps can be located in a multitude of locations, determined by the particular style and method of determining flow. In a nozzle, the low-pressure measurement (downstream) can be measured at the throat or downstream of the throat, again determined by the style of device (for example, throat tap or wall tap).

The flow meter measures the differential pressure produced, and then flow is calculated using Equation 2-1, which is derived from the Bernoulli equation. If the discharge coefficient (C) is not included, the resulting flow is referred to as the "theoretical flow."

$$M = F \frac{\pi}{4} C d^2 \sqrt{\frac{2\rho \, \Delta P \, g_C}{1-\beta^4}} \qquad \text{Equation 2-1}$$

Where,

- M is the calculated mass flow rate.
- C is a "discharge coefficient" used to adjust for several factors that cause the actual flow to differ from the theoretical flow. These factors include the inlet fluid velocity profile, boundary layer effects, pressure tap effects, flow separation, friction, small differences in geometry, and manufacturing imperfections.
- d is the flow meter throat diameter, measured prior to installation.
- ρ is feedwater fluid density determined from a separate temperature measurement.
- ΔP is the pressure differential determined from measurements upstream and downstream of the flow element.
- β is the ratio of flow meter throat diameter to pipe diameter.
- g_C is a proportionality constant.
- F is the thermal expansion coefficient.

The discharge coefficient is determined experimentally by comparing the flow rate measured by the flow meter to the flow rate measured by a calibrated weigh tank. Such tests are usually referred to as "calibration" of the meter. To account for variations in flow element dimensions, such hydraulic tests are often performed for each flow element. If the flow element design conforms to a standard design, data from previous tests can be used to determine the discharge coefficient.

In this case, however, the discharge coefficient would not account for meter-specific factors such as manufacturing imperfections, pressure tap effects, or small differences in geometry; and a significantly higher uncertainty would exist. If the nozzle is built to ASME PTC-6 requirements and confirmed by flow testing to meet those requirements, the nozzle discharge coefficient can be extrapolated to the operating Reynolds number using the method outlined in the code. Care must be taken to use this extrapolation only for conforming ASME nozzles because not all flow section discharge coefficients will follow this curve shape.

Physical Description

A wide variety of meters have been designed that fall into the category of differential pressure meters. Among these are orifices, venturis, and flow nozzles. These meters share many common features but can differ significantly in their performance details.

An orifice plate is the most common flow restriction device for a differential pressure flow meter. The flow element consists of a flat plate with a carefully sized flow opening inserted between two flanges. Orifice meters are simple, but they have large irreversible pressure drops. Orifice flow meters are typically not used in main feedwater systems in the United States because of this pressure drop; however, in Canadian CANDU reactors, this is the primary flow measurement device for reactor feeder headers. (For detailed information on orifice meters, see Reference 11.)

The term "venturi" most accurately refers to flow meters that use a Herschel venturi, also known as a classical venturi tube, as a flow element. The venturi flow element minimizes irreversible pressure loss, but it is expensive and requires a significant length of straight pipe to install. Although much of the early hydraulic work in the 1930s was done on classical venturis, the sources reviewed for this report indicate that classical venturis are not installed at any U.S. nuclear power plants. However, it must be noted that the rough cast inlet classical venturi is widely used in the non-nuclear industry in the United States. In Europe, the rough cast, machined, and rough welded sheet iron inlet classical venturi is widely used. In addition, the ISA 1932 venturi, with or without a recovery cone, is widely used in Europe but seldom used in the United States.

The nozzle flow element is a compromise between a venturi and an orifice. Nozzles can be smaller and less expensive than venturis and generally result in lower pressure losses than an orifice. Figure 2-1 shows one type of flow nozzle commonly in use in the

United States. The design of this nozzle is specified in ASME PTC-6 and IEN 953-1 and 2. These are low beta ratio nozzles ($0.25 < \beta < 0.50$) with throat taps.

Flow nozzles are often modified by adding a divergent section after the flow nozzle. Such devices, shown in Figure 2-2, are sometimes referred to as venturi nozzles. They have lower pressure losses than standard flow nozzles, are less sensitive to downstream hydraulic disturbances, and are still less expensive than a classic venturi. When a venturi nozzle is calibrated, the full flow section, upstream piping, flow straightener, and downstream piping, including the divergent section, should be used in the calibration tests.

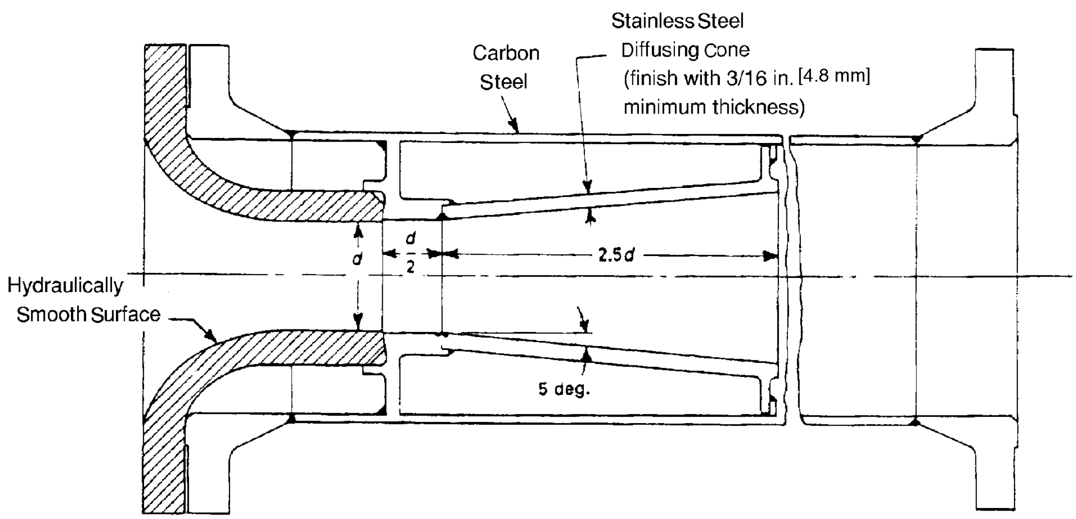

Figure 2-1
Cross Section of an ASME PTC-6 Nozzle

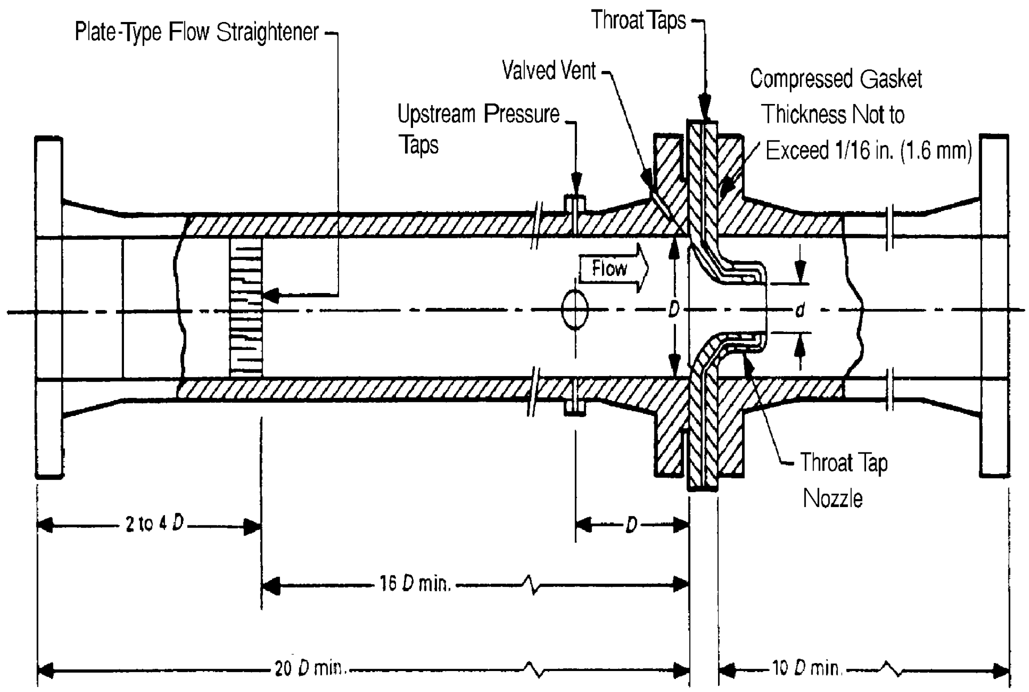

Figure 2-2
Cross Section of a Venturi Nozzle with Recovery Cone

In the 1950s, modified venturis that improved on the classical venturi in that they were shorter and produced greater pressure differentials were developed. In the early 1970s, Builders Iron & Foundry (BIF) developed the Universal Venturi Tube (UVT), a standard design based upon earlier modified venturis [12]. This design, shown in Figure 2-3, is used in many nuclear power plants.

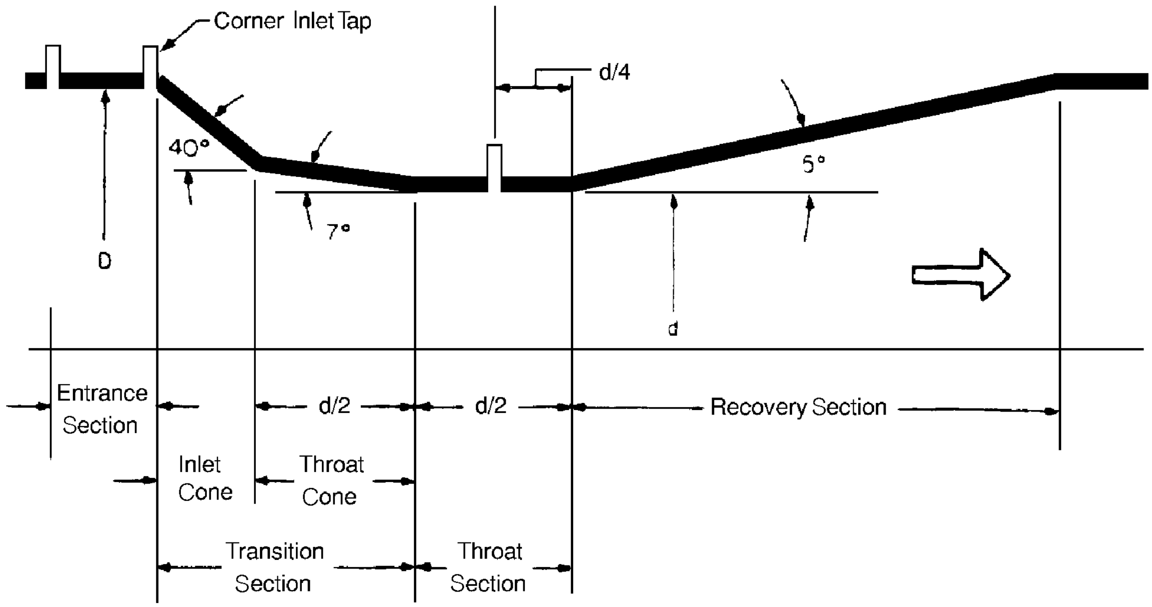

Figure 2-3
Cross Section of a UVT

In this section, the term “venturi” is used to collectively refer to universal venturi tubes and venturi nozzles. In general, the characteristics of these meters are similar, but where significant differences could exist, the differences are identified.

A venturi has relatively few components compared to other types of feedwater flow meters. A complete meter consists of the metering section, two impulse lines, a DP transmitter, and analog and digital devices for converting the DP signal into a digital mass flow rate that can be used by the plant computer. See Figure 2-4. Impulse lines are small diameter tubing routed from the pressure taps to the DP transmitter. The transmitter can be located in an instrument rack 100 to 200 feet away from the metering section. Plants vary in the method used to convert the analog DP signals into a flow rate indication, but all methods involve a combination of analog and digital devices, including the plant computer. A significant difference between the BIF UVT and the ASME nozzle is that the Cd of the ASME nozzle, wall, or throat tap varies with the operating Reynolds number while the BIF UVT Cd is nearly constant. Other types of nozzles have their own characteristic curves. See Reference 11, among others, for theoretical discharge coefficients.

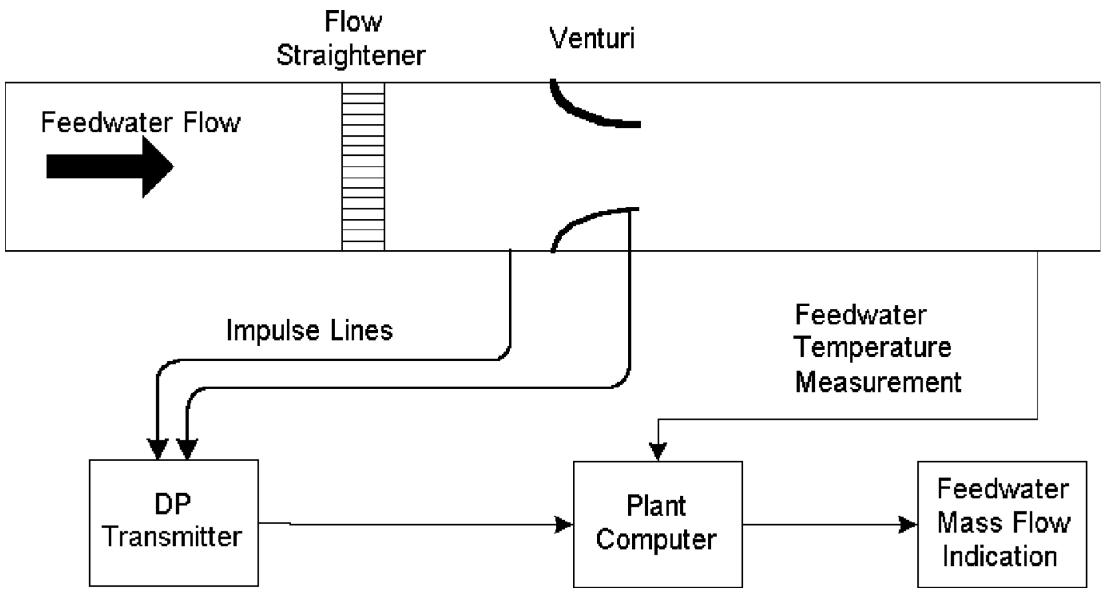

Figure 2-4
Venturi Measurement System Schematic

The metering section typically includes the pipe section with the flow element, an upstream pipe section with a flow straightener, and a straight piece of pipe downstream. This assembly can be welded or bolted in place. Typical straighteners are either plate or tube type. Flow elements are usually stainless steel, but they can contain carbon steel in transition pieces if they are welded to carbon steel pipes. When carbon steel pipes are found with stainless steel flow sections, thermal expansion rates are significantly different and have to be accounted for in the design. Because the discharge coefficient of a nozzle is sensitive to the surface finish of the flow element and the pipe upstream and downstream of the element, the nozzles are often polished to a smooth and controlled surface finish while the pipe internal diameter is machined.

Maintenance Requirements

Although venturis are relatively rugged instruments, experience has shown that careful maintenance is required to achieve low uncertainty in the flow measurement. PTC-6 does not give an uncertainty for the use of a flow section that has been placed in service and is used over a long duration of time. The end user is responsible for determining this uncertainty. However, experience has shown that a nozzle will usually degrade over time and will over-predict flow unless erosion has occurred. The principal maintenance activities are those used to calibrate the pressure transmitters and plant computer output. Calibration is typically performed at every refueling outage. This is considered routine maintenance and requires approximately one day to complete.

Inspections of the internal condition of a venturi are sometimes performed to check for the buildup of corrosion products, to identify erosion and damage in the vicinity of the pressure taps, and to investigate other deterioration, such as bypass flow around the flow element. Additionally, chemical or mechanical cleaning is sometimes performed to remove any buildup of corrosion products (referred to as fouling) that can produce erroneously high flow [13]. Extreme care is necessary when cleaning venturis to ensure that the geometry and surface finish are not altered. Other plants carefully monitor feedwater chemistry and add chemicals to reduce fouling. This effort varies from plant to plant and can become a large maintenance burden.

Installation Requirements

Because the discharge coefficient can be sensitive to upstream and downstream hydraulic conditions, several different standards exist that discuss the recommended separation between venturis and upstream and downstream hydraulic disturbances. Separation recommendations range from 5 to 40 pipe diameters upstream and 2 to 8 pipe diameters downstream. These values depend upon the specific meter design, the beta ratio of the meter, and the installation of flow conditioners such as straighteners. See Reference 11 for a list of the recommendations of several of these standards.

Potential Errors

Several errors, which can be grouped into the following categories, can impact a venturi's ability to produce reliable results with low uncertainties:

- Density errors
- Errors in differential pressure measurement
- Errors due to the plant computer
- Errors due to changes in the internal conditions
- Errors due to impulse lines condition
- Errors due to thermal expansion
- Errors in the discharge coefficient

Density Errors

The uncertainty in the mass flow result is directly affected by the uncertainty of the density used to convert volumetric flow to mass flow. Density is determined using temperature and pressure inputs from sensors that might be located near the metering section. In some installations, the pressure is assumed to be the saturation pressure at the measured temperature. The density uncertainty is due to the following:

- Errors in the temperature measurement (due to errors in the temperature sensor, the instrument calibration, any analog-to-digital conversion that is required, or temperature differences between the measurement and metering locations)
- Errors in the pressure measurement (due to errors in the pressure sensor, the instrument calibration, pressure differences between the measurement and metering locations, and use of saturation pressure to estimate the pressure at the metering section)
- Uncertainty in the density values given in the ASME steam tables as a function of pressure and temperature
- Uncertainty in any equation or interpolation technique used to determine the density at a temperature and pressure between those given in the ASME steam tables

Errors in Differential Pressure Measurement

Accurate measurement of the pressure differential across a venturi is critical to the accurate measurement of fluid flow. The error of the pressure transmitter is affected by calibration practices, ambient temperature compensation, instrument drift, and instrument degradation.

Plants typically calibrate the output of pressure transmitters to within a specified tolerance band with each refueling cycle using high accuracy pressure test equipment. This calibration should be conducted using the manufacturer's guidelines for calibration for operation at high static pressure. Specifically, the static pressure effect on the span and the zero of the device must be accounted for during calibration [14].

The ambient temperature can affect the measurement of differential pressure. Without compensation, the output of the transmitter can vary ±0.5% per 100°F (±0.9% per 100°C) change in ambient temperature. "Smart" differential pressure transmitters have embedded temperature compensation that allows the ambient temperature error to be neglected.

Unrelated to ambient temperature changes, the output of a pressure transmitter can be expected to drift over time. The rated stability of a pressure transmitter should be listed in the manufacturer's specifications. Stability of modern transmitters is typically ±0.2% over six months. For a smart transmitter, stability is typically ±0.1% over 12 months. Such ratings are for transmitters in good working condition. Pressure transmitter output can also vary due to degradation mechanisms such as oil loss or diaphragm leaks.

Errors Due to the Plant Computer

The plant computer can introduce errors in the indicated feedwater flow. Sources of these errors include signal conditioning and the equation used to convert differential pressure to mass flow. Signal conditioning devices such as analog-to-digital converters and analog summers and multipliers can introduce errors in the flow measurement. For equipment installed in most nuclear power plants, a typical uncertainty for an analog-to-digital conversion is 1% of the 4–20 mA current input. If this conversion is done on the input pressure signal, it will produce an error of 0.5% in the flow measurement for a single pipe.

Errors in the equation used by the plant computer to convert differential pressure into mass flow rate are considered here as plant computer errors. This category of errors includes errors in the actual equation and in the various equation inputs (including discharge coefficients for each set of pressure taps, flow element dimensions, and thermal expansion factors). Equation and input errors can be caused by human error. Verification by comparing the output of the plant computer to an independent calculation using direct DP transmitter output should ensure that such errors do not exist.

Errors Due to Changes in the Internal Conditions

Changes in the internal conditions of a differential pressure flow meter affect the accuracy of the feedwater flow calculation. Erosion, corrosion, corrosion product build-up, and cleaning can alter the internal condition of the meter. The internal condition is also altered when cleaning changes the pressure tap geometry, when a mechanical failure leads to a portion of the feedwater flow bypassing the throat, or when failure occurs in the tubes that supply the low-pressure signal to the transmitter.Ontario Hydro and Quebec Hydro nuclear generating stations have been affected by inaccurate flow measurements across orifice plates in the feeder headers. Fouling might not be the issue here as much as plate distortion, but due to the location, removal and inspection is not practical.

Note that PTC-6S Report-1970 does not give an uncertainty for a nozzle section or orifice plate that has been in extended use because it is impossible to predict what changes might have occurred. Duke Energy personnel report that wall tap nozzles in use at Duke facilities are relatively free of fouling problems. EPRI report TR-101388 should be considered as a resource for determining which type of differential pressure producer should be used.

Attention has been focused on the sensitivity of feedwater flow measurement venturis to fouling for a significant time, but, until the availability of UFMs, no practical method to correct for fouling was available [13]. Deposition of corrosion products in front of the throat, in the throat section, and in the recovery cone of the throat tap flow meter can increase the pressure drop across the meter. This will cause an erroneously high flow indication.

It has been observed that apparent errors from deposit accumulation can appear within hours of startup [13], or take as long as months to occur. A nozzle removed from service and tested at Alden labs with fouling deposition <0.0005” (<0.013 mm) thick indicates that the change in calculated flow due to the nozzle throat area reduction would be less than 0.003%, yet the tested flow difference was nearly 2%. However, the fouling that was on the nozzle was also on the upstream pipe, so the overall β ratio change was essentially zero. Thus, it is apparent that effects other than β ratio, such as boundary layer disturbance, contribute to the fouling error.

The use of full flow condensate polishers and secondary chemical treatment appears to have an effect on the extent or presence of nozzle fouling. For example, both Shearon Harris and Diablo Canyon plants use throat tap nozzles, yet only the Diablo Canyon Power plant reports significant fouling. Characterizing the mechanism of venturi fouling to allow accurate compensation for the flow measurement effects is difficult. Several methods have been used to determine the degree to which fouling can affect the feedwater flow measurement. Alternate flow measurement techniques, such as flow and energy balances around a low-pressure de-aerating feed tank, ultrasonic flow meters, and chemical tracer tests, have been used to quantify the bias introduced by fouling. Trending of feedwater flow measurement with other plant parameters such as steam flow or first stage turbine pressure has been used to identify a steadily increasing bias in feedwater flow measurement that would indicate the presence of fouling.

Several methods have been used to minimize the flow measurement errors caused by fouling. One approach has been to reduce the degree of fouling. Periodic cleaning of the flow element, such as hydrolazing, mechanical cleaning, or chemical rinses, has been performed to minimize the effects of fouling. Water treatment programs have been designed to reduce fouling. These programs include the addition of morpholine in pressurized water reactors (PWRs) and hydrogen and zinc in boiling water reactors (BWRs). The removal of copper-bearing alloys from the cycle has also been found to reduce fouling at some generating stations; while at other stations, no fouling reduction occurred [13].

Another approach has been to measure the flow bias caused by fouling and to correct the flow measurement. Several plants, such as Pickering Generating Station, have used this approach quite successfully. The key to the approach is to quantify the effect of the fouling with sufficient confidence to render the results viable. Typically, plants do this by measuring flow using an alternative technology believed to not be susceptible to fouling. Candu plants use nozzles located in low temperature (107°C) sections of the feedwater system for *in situ* calibration of feedwater nozzles, which in turn are used to provide a correction factor to the reactor calorimetric.

Quantifying the uncertainty due to fouling is often difficult because fouling is masked by other effects and because fouling varies over time and from plant to plant. Some power plants have reported feedwater flow biases as great as 2% attributed to fouling, whereas other feedwater flow elements at plants tested using UFMs and nozzle recalibrations are unaffected by fouling [13].

Fouling is not the only internal condition problem encountered by differential pressure meters. Changes in the geometry of the pressure taps will change the pressure indication [15]. Erosion of the taps, buildup of corrosion products, or scratches or gouges in the vicinity of the taps, as a result of mechanical cleaning or hydrolazing, for example, can result in a bias in the flow measurement. This biased error normally indicates increased flow.

Corrosion or erosion can create a leak path between the pipe section and the flow element. This allows fluid flow to bypass the flow measurement. Several flow element designs are susceptible to this error including those that contain an annular chamber at the throat that is welded to the feedwater pipe and to which the nozzle is welded and those that are manufactured from stainless steel when the pipe is carbon steel. This problem can be detected by periodic inspection of the flow elements and careful monitoring of flow data in comparison with other indicators of reactor power. Many UVTs are slip fit to the pipe on the inlet end while the outlet end is welded about 355°F (179°C), leaving small flow channels for bypass fluid. When carbon steel pipes are used, this bypass flow can erode pipe walls, increasing the bypass flow.

Errors Due to Impulse Lines Condition

Industry experience has shown that the condition of the pressure impulse lines can introduce uncertainty in the flow measurements. Noncondensables can collect in the impulse lines if blowdown practices are inadequate or if plant transients result in the release of noncondensables that collect in the stagnant lines. Plant procedures should include provisions to confirm that noncondensables are not trapped in the impulse lines. Thermal expansion and contraction have broken the low-pressure throat tap tubes of some nozzles. When this occurs, the nozzle will generally indicate a lower DP indicating less than the actual flow. In some designs, low-pressure tap connections internal to the pipe can also crack due to mechanical vibration and / or expansion. This allows an erroneous low-pressure value to be read as the throat pressure.

Errors Due to Thermal Expansion

Temperature increases will result in thermal expansion of the flow element, an increase in the flow area, and errors in the feedwater flow measurement. The flow measurement is corrected for the effects of thermal expansion based upon the thermal properties of the flow element material and the operating temperature. Errors in measurement of the element material properties and temperature contribute a relatively small uncertainty to the feedwater flow measurement.

Errors in the Discharge Coefficient

Errors in the determination of the discharge coefficient directly affect the flow measurement. Potential sources of error include the calibration of the nozzles, the extrapolation of the coefficient to plant operating conditions, and effects of the hydraulic profile.

Most feedwater flow nozzles in nuclear power plants were calibrated against a weigh tank prior to installation. The errors associated with this testing include the uncertainty in the weigh tank measurement and the uncertainty in the equipment used to measure the pressure differential across the flow meter. Typically, the uncertainty in this testing is ±0.25%.

Tests have shown that the discharge coefficient changes with the Reynolds number for certain types of nozzles [16]. Unfortunately, most hydraulic test facilities cannot achieve Reynolds numbers as high as those that exist in most nuclear plant feedwater systems. Some test facilities are limited to approximately Re = 6 million; typical feedwater systems have Re = 10 to 30 million. For some installations, an assumption is made that the discharge coefficient is constant at higher Reynolds numbers, and the test value is used for the plant flow measurements. Other installations use discharge coefficients that are determined by extrapolating from the test Reynolds numbers to the plant Reynolds numbers. For example, ASME PTC-6 describes a flow nozzle design and a curve that can be used to extrapolate the discharge coefficient of the nozzle [8]. The theoretical basis for this extrapolation is presented in References 17 and 18. The extrapolation uncertainty for some nozzle designs continues to be a point of controversy.

Early testing of classical venturis identified a dependency of the discharge coefficient on the velocity profile. To minimize this error, venturi measurement sections typically include an upstream flow straightener, or extremely long straight upstream sections, and a downstream pipe section. These elements are calibrated and installed as a unit. However, even with an upstream flow straightener, the velocity profile has been found to affect the flow measurement by up to ±0.1% [19]. Factors that affect the velocity profile include upstream piping configuration and pipe roughness.

Uncertainty

For most nuclear power plants, the uncertainty in the feedwater venturi measurement reported by the NSSS vendor or architect/engineer is approximately ±0.5% with the total uncertainty in the calorimetric ±1.5% to ±2.0%. For some generating stations, the reported uncertainty represents a 68% level of confidence (1-sigma) instead of the 95% level of confidence currently recommended in ASME PTC 19.1. When assessing flow uncertainties, engineers should consider the uncertainty in the indicated flow rate, not the uncertainty in the discharge coefficient. Some of the main components of the reported uncertainty are:

- Uncertainty in the differential pressure measurement
- Uncertainty in the discharge coefficient (also referred to as the calibration uncertainty of the flow element)
- Uncertainty due to the plant computer

At some plants, the uncertainty in feedwater flow may not be presented in an explicit calculation of feedwater flow rate uncertainty. Instead, the elements of the feedwater flow rate uncertainty are usually considered with other factors in a calculation of the overall calorimetric uncertainty.

Installed Base

Differential pressure flow meters are installed in every nuclear power plant in the United States and Canada for feedwater flow measurement.

Results of Industry Survey

Of the 14 responses to the P^{2}EP survey conducted on “Feedwater Flow Measurement Techniques,” six indicated satisfaction with the performance of their venturis or flow nozzles. The uncertainties of the instrument loop ranged from ±0.25% to ±1.5%. The most common problem associated with their use was fouling. The most significant maintenance effort was the calibration of the pressure transmitters.

In the P^{2}EP survey conducted for this report, one engineer reported that the output of his pressure transmitters was found to vary depending on the ambient temperature of the air where the transmitter was installed. This sensitivity has been removed or minimized by a new transmitter model that includes a resistance temperature detector (RTD) to measure ambient temperature.

Diablo Canyon Power Plant personnel reported that in unit one, BIF UVTs closely agree with ASME PTC-6 nozzles; in unit two, the difference between the ASME and BIF UVTs is about 1.2%.

Cost

The typical cost for two venturi flow elements is $125,000. This estimate includes two venturi nozzles, two flow straighteners, and calibration at a hydraulic lab. It does not include installation, pressure taps, impulse lines, pressure transmitters, and other installation costs that would likely exceed the cost of the venturi hardware.

3

CHORDAL TRANSIT TIME METERS

Overview

Chordal ultrasonic transit time meters measure the average fluid velocity along multiple chordal paths and combine the results to calculate the volumetric flow rate. The meter makes a temperature measurement that is used with an input pressure to determine density and to convert the volumetric flow rate into a mass flow measurement. Chordal meters provide a continuous flow measurement that can be updated faster than once per second if necessary. Chordal flow meters typically have lower uncertainties than external transit time meters, but because they require installation of a custom piping section, chordal meters are relatively expensive.

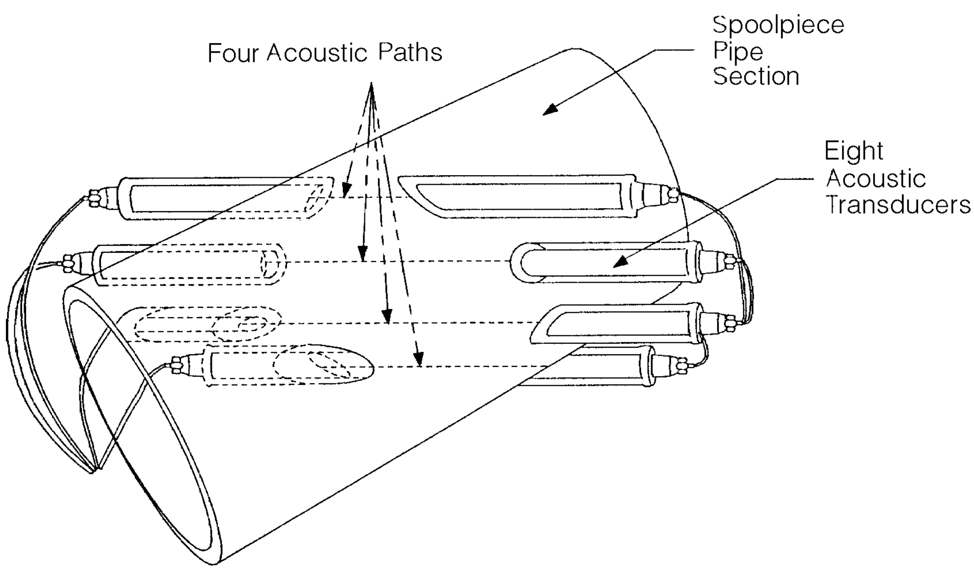

Figure 3-1
Diagram of a Four-Path Chordal Meter Piping Section

The ultrasonic transit time technology on which chordal meters are based was developed by Westinghouse in the early 1960s to measure flow velocities for the U.S. Navy. In the late 1960s, Westinghouse developed the integration techniques used by the chordal meters, and in the early 1970s, a chordal flow meter was installed in the reactor coolant system at Prairie Island. Subsequently, chordal meters were installed in the feedwater systems of several U.S., Japanese, and Korean PWRs. The chordal meter technology has been purchased and subsequently enhanced by the vendor who actively manufactures and markets four-path chordal meters for various applications where low uncertainties are required, including nuclear power plant feedwater systems. See Figure 3-1.

Principles of Operation

An ultrasonic transit time flow meter measures the time necessary for an ultrasonic pulse to travel across the pipe from one transducer to another along a chordal path that is diagonal to the fluid flow. The difference in times of flight for pulses traveling with and against the fluid flow is proportional to the fluid velocity. Fluid velocity is calculated from this measured time difference (Δt) and the known measured physical dimensions of the meter (the distance between the two transducers and the angle of the acoustic path).

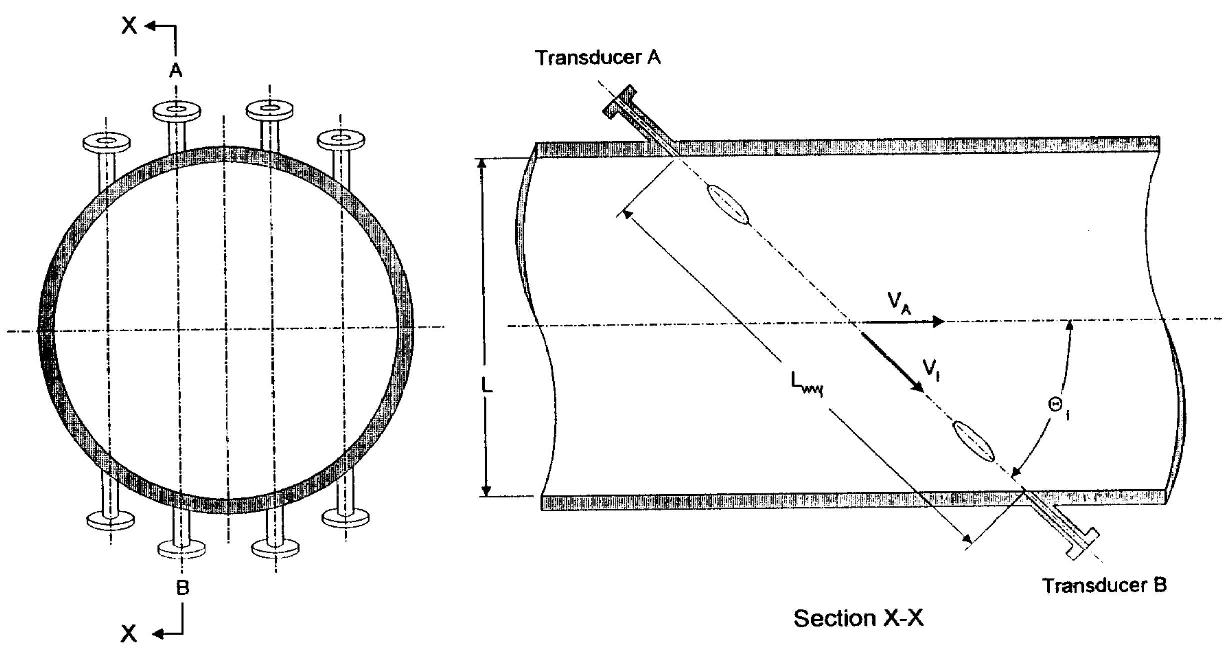

Figure 3-2
Chordal Meter Schematic

Chordal meters determine the volumetric flow rate by numerically integrating results from four acoustic paths. It is, therefore, a true volumetric flow meter, rather than a velocimeter as is the case for externally mounted ultrasonic flow meters. The approximate equations used by a chordal meter are provided below. These equations are provided to show the general approach used and the inputs required by the chordal meter. The derivation of the following equations is provided in other texts.

$$M = \rho \cdot PF \cdot \sum_{i}^{4} w_i \cdot v_i$$ Equation 3-1

Where,

M is the mass flow rate.

ρ is the fluid density calculated as a function of fluid temperature and pressure.

PF is a "profile factor" that adjusts for velocity profiles that are distorted or non-uniform or that contain swirl or cross flow. In such situations, the flow calculated using the standard numerical integration weighting coefficients would contain an error. This occurs because the numerical integration scheme is optimized for the velocity profile believed to exist with fully developed turbulent flow. If the fluid velocity profile were uniform, the PF would equal 1.00. The PF is a constant value for a given installation. It is determined from hydraulic test data and the upstream configuration of the piping. As discussed above, since the chordal meter is a volumetric flow meter, its calibration coefficient is within 0.5% of its theoretical value. Much larger corrections are required for externally mounted ultrasonic meters.

w_I is a weighting factor applied to the path velocities to calculate correctly the area average velocity. They are calculated using the mathematical theory of the Gaussian or Jacobian numerical integration techniques.

v_i is the average axial fluid velocity along path i. v_i is calculated as:

$$v_i = \frac{L_i \cdot \Delta t}{2 \cdot \cos\theta_i \cdot t_{down} \cdot (t_{down} + \Delta t)}$$ Equation 3-2

Where,

L_i is the distance between transducer pairs on path i. It is accurately measured during fabrication of the piping section.

θ_i is the angle of path i relative to the pipe centerline. It is accurately measured during fabrication of the piping section.

Δt is the difference in times of flight measured for signals traveling upstream and downstream. It is accurately measured by the flow meter electronics.

t_{down} is the time of flight for a signal received at the downstream transducer (that is, traveling with the flow). It is accurately measured by the flow meter electronics.

Δt is calculated by subtracting timing measurements made on upstream and downstream measurements. Each measurement is made by recording the time required for an ultrasonic pulse to travel from one transducer to another transducer on the opposite side of the pipe. The flow meter electronics detect the signal's arrival time. This process requires microseconds to complete, so several measurements can be made in a second.

Because of this, chordal meters obtain large amounts of timing measurements in a short period of time. This permits averaging of random fluid flow effects in a period as short as one second. Typical installations calculate flow rates every five seconds using the average timing measurements of the past five seconds. Longer averaging times and higher sampling rates increase the number of samples in each reported measurement and lower the uncertainty due to timing. This can lower the overall uncertainty depending on the relative magnitude of the other uncertainties.

A four-path chordal flow meter hardware includes a custom piping section approximately three diameters long (a "spool piece") that can be either welded or flanged into existing piping. Eight removable transducers are fastened into the spool piece and are connected by transducer cables to a remotely located electronics unit that processes ultrasonic signals and calculates the mass flow rate.

Maintenance Requirements

The signal processing electronics are digital and require no calibration. A prudent measure is to annually check the transducer output in order to identify the transducers with reduced signal strengths and to improve the signals by adjusting gains or replacing transducers. If required, transducers can be replaced during plant operations.

Installation Requirements

Because installation of a chordal meter requires that a new section of piping be installed, chordal meters can be installed only when the plant is in an outage. Typically, plant personnel install the spool piece and the vendor installs the transducers and electronics. Time for installation should be about two weeks, depending on the number of pipe sections to be installed.

The installed location of a chordal meter spool piece is important for obtaining an accurate profile factor and low overall uncertainty errors.

The following categories of errors are critical in the uncertainty of chordal flow meter measurements:

- Spool piece dimensional errors
- Density errors
- Timing errors
- Profile factor errors

Each error category is discussed below, along with the specific errors grouped in that category.

Dimensional Errors

Uncertainty due to geometry measurements can be effectively controlled by careful manufacturing and the accurate measuring of the spool piece before installation. The measurement is generally equally sensitive to the following geometric measurements:

- Distance between transducer faces
- Spool piece inside diameter and area
- Angle of the transducer paths
- Location of the transducer paths from the pipe centerline
- Thermal expansion of the spool piece during operation

Dimensional uncertainty can be effectively eliminated if hydraulic testing is performed using the actual metering section to be installed in the plant.

Density Errors

The uncertainty in the mass flow result is directly affected by the uncertainty of the density used to convert volumetric flow to mass flow. This meter determines the density from a temperature measurement made by the meter at the metering section. Consequently, there is no uncertainty due to the location of the temperature measurement. The density uncertainty that does exist is due to the following:

- Errors in the measured temperature (due to errors in the measured sound velocity and to uncertainty in the correlation of sound velocity vs. temperature)
- Errors in the pressure measurement (due to errors in the pressure sensor, the instrument calibration, and pressure differences between the measurement and metering locations)
- Uncertainty in the density values given in the ASME steam tables as a function of pressure and temperature
- Uncertainty in the equation or interpolation technique used to determine the density at a temperature and pressure between those given in the ASME steam tables

Timing Errors

There are several errors in the timing measurements that can affect the measurement results. They include the following:

- Electronic noise in the signals received by the electronics unit from the transducers
- Difference in the time measured by a given transducer when sending and receiving an identical signal
- Variations of the speed of sound in the transducers, transducer housing, or cables from that entered into the meter
- Inaccuracies in the digital clock used to determine time
- Differences in the lengths of the transducer cables from that entered in the software
- Error in identifying the correct arrival time of a signal

Ultrasonic Parameter Errors

Systematic and random errors due to incorrect assumptions on beam angles

Transducer Well Errors

Hydraulic eddies that can form in the recesses where the transducers intersect the pipe wall will cause errors in the flow measurement. This effect is more pronounced in smaller diameter spool pieces. The vendor has modeled and quantified this effect. In most cases, the effect is reported to be negligible (about 0.02%). The effect is measured and bounded as part of model testing, and any error is accounted for with the profile factor.

Profile Factor Errors

The profile factor contains two types of errors: those related to the experimental uncertainty and those related to the ability to duplicate the exact velocity profile of the plant.

Profile Factor Errors Due to Experimental Uncertainty

The uncertainty of a profile factor calculated from weigh tank and ultrasonic meter results is limited, in part, to the uncertainty of its inputs. These uncertainties are:

- Weigh tank uncertainty. The "true flow" is typically measured using a weigh tank. The weigh tank used for nuclear feedwater flow calibration typically has a quoted 2-sigma uncertainty of ±0.25%.

- Ultrasonic meter uncertainty. The chordal meter used in the hydraulic tests contains random uncertainties from the timing measurements and the dimensions used to calculate flow.

Profile Factor Errors Due to Piping Configuration

When the meter location is relatively near an upstream disturbance, the upstream piping configuration can have a significant effect on the velocity profile. Upstream tees and elbows can introduce transverse velocities, swirl, and a severe skew to the flow profile. The hydraulic profile at the inlet of an upstream elbow can also have an effect. These effects dissipate as the flow proceeds downstream.

To determine the exact effects of the upstream disturbances and how much they are dissipated by the time they reach the meter location in the plant, hydraulic tests are performed. The hydraulic tests are designed to match the upstream configuration of the plant piping, but practical considerations usually require that hydraulic approximations be made using smaller diameter piping, flow straighteners, reducers, and no downstream disturbances.

These approximations can cause the velocity profile in the test to be different from that in the plant, and, consequently, an error will exist in the profile factor. This error can be increased when the profile factor is extrapolated from results of similar configurations or when flow velocities change as during power ramps. Note that local flow disturbances, such as welds, can also lead to errors if they are not included in the hydraulic tests.

Profile Factor Errors Due to Pipe Roughness

When the meter location is not near an upstream disturbance, the effect of pipe roughness becomes relatively more significant. Because the theoretical velocity profile of fully developed flow is a function of the pipe roughness, the distorted profiles developed in hydraulic tests depend on the roughness of the pipe used in the test. If the roughness of the test pipes is different from that in the actual installation, the test will not be based on the same velocity profile as in the plant. The effect of surface roughness on the correction factor can be difficult to quantify exactly, but it should be possible to bound the uncertainty of the effect by testing with pipes of various roughness. The vendor reports that the effect of wall roughness on fully developed flow measured by a four-path chordal meter is less than 0.1% over a range of Reynolds numbers from 10E4 to 10E8.

Profile Factor Errors Due to Reynolds Number Extrapolation

Velocity profiles are known to vary with the Reynolds number. However, because of test facility limitations, the temperatures and Reynolds numbers in hydraulic tests are typically less than experienced in the plant. Specifically, hydraulic tests are typically performed at Reynolds numbers of 3 to 4 million, while plant feedwater systems operate between 10 and 30 million. The profile factor must therefore, be extrapolated to the operating conditions. A difference between the true curve and the assumed curve used for the extrapolation would introduce an error into the profile factor used in the plant installation. This effect is considered relatively small for most extrapolations.

Miscellaneous Errors: Sensitivity to Transducer Equipment

Transducers manufactured to the same specification have a tolerance band. Based upon the limited transducer testing information available, it can be surmised that the uncertainty can be as large as 0.12%. These errors are included in the timing uncertainties and are not separately addressed.

Uncertainty

A typical uncertainty of ±0.5% for a four-path chordal meter is generally quoted. This uncertainty applies to a one-pipe mass flow measurement that is an average of measurements over a 5-second period.

For all installations, a report is issued that confirms uncertainty requirements are met. The report shows that the individual uncertainties based on plant-specific data are bounded by the uncertainties used in a "budget" uncertainty analysis. A typical uncertainty report shows a mass flow uncertainty of ±0.44% for a four-pipe, four-path chordal system performed in accordance with the vendor's QA program.

In Reference 4, the U.S. NRC approved a topical report that is the basis for the uprate of reactor thermal power by as much as 1% on the basis of improved calorimetric uncertainty achieved by use of the chordal Leading Edge Flow Meter (LEFM).

Repeatability of the 5-second average produced by a given one-pipe installation is estimated for the chordal meter to be 0.2% and is included in the uncertainty discussed above.

Installed Base

As of October 1998, chordal meters have been permanently installed in feedwater systems at 11 nuclear plants in the U.S where they are used for calorimetry. Chordal meter results are used to periodically adjust a "correction factor" applied to the venturi output, or they are used as the continuous and direct input for the calorimetric mass flow calculation.

Results of Industry Survey

Of the 14 responses to the P^2EP survey conducted on "Feedwater Flow Measurement Techniques," one reported to have a chordal meter installed that calculates total flow through two metering sections. This user reported that the utility was highly confident in the meter and no significant problems were reported. It was reported that the plant I&C staff expended 10 hours per year on maintenance of the meter.

4

EXTERNAL MOUNT TRANSIT TIME METERS

Overview

External mount ultrasonic transit time meters are similar to chordal ultrasonic transit time meters. Both types of meters determine the fluid velocity by measuring the times of flight of acoustic pulses traveling with and against the fluid flow. However, as shown in Figure 4-1, the transducers are mounted on the outside surface of the pipe, and the acoustic paths are along the pipe diameter rather than in "chordal" paths.

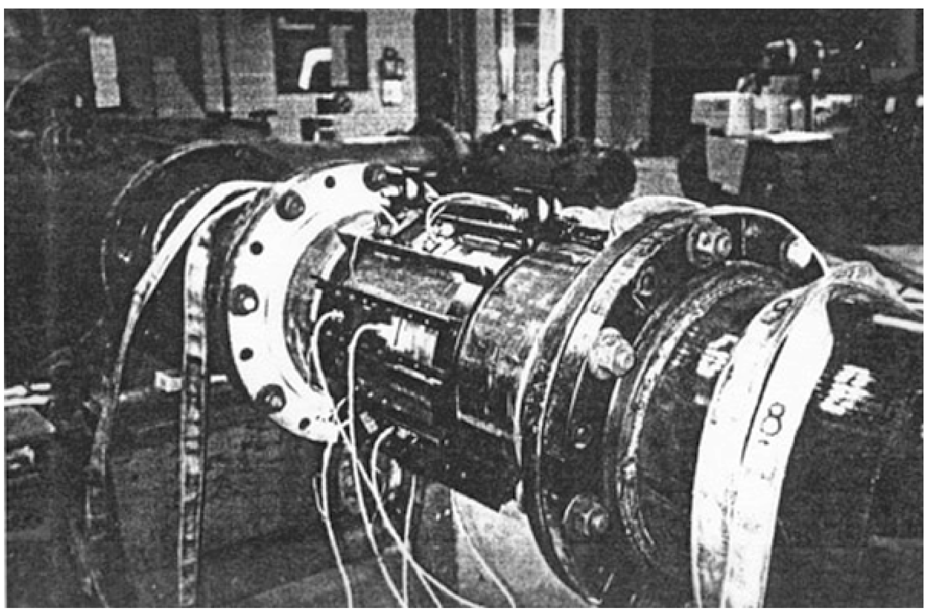

Figure 4-1
Photograph of External Mount Meter
(Courtesy of Caldon, Inc.)

External meters are noninvasive and do not require a custom spool piece. Installation of a two-pipe system can be performed in a week by trained technicians while the plant is running. The meter provides a continuous, fast response flow measurement.

External mount transit time meters were advanced significantly in the 1960s, perhaps as a result of the research and development projects in both the military and the space program. In 1964, the Japanese developed and patented a clamp-on transit time flow meter [20]. In the 1970s, additional work was performed and meters were marketed shortly thereafter by Controlotron, Inc. Several vendors are marketing similar meters. In the early 1990s, another vendor developed an external mount system, specially designed for low uncertainty and application to nuclear feedwater measurement.

Currently, external mount transit time meters are available from about a dozen companies, but only one is used in nuclear power plant feedwater systems on a permanent basis. To be suitable for this application, a system must withstand temperatures of approximately 400°F (204°C), account for flow velocity effects, and be carefully designed to meet the requirements of low uncertainty. The discussion in this section is based on the external mount system, which typically has four acoustic paths.

Principles of Operation

The external mount ultrasonic transit time flow meter uses the same principle as a chordal ultrasonic transit time flow meter. An ultrasonic pulse is introduced at an angle to the fluid flow. The difference in transit times for pulses traveling upstream and downstream is measured by the meter and is used to calculate the average velocity along the acoustic path.

The two main differences between the chordal and external mount meters are:

- With an external meter, the transducers are mounted on the outside surface of the pipe.
- With an external meter, the acoustic paths are diametrical (that is, they pass through the center of the pipe.

Mounting the transducers outside the pipe eliminates the need for a custom spool piece, but it complicates the measurement by affecting the path that the acoustic pulse travels as it passes through the pipe wall and an angular “wedge.” The second difference is that all external systems are velocimeters—they do not inherently integrate the flow as does a chordal meter. Therefore, a significant profile factor correction is required. Both differences result in a higher uncertainty for the external meter.

As shown in Figure 4-2, two types of transducers are used in the external transit time meter. The “cross path” transducers introduce a signal perpendicular to the pipe wall. They are used to measure the speed of sound in the fluid and any cross flows in the velocity profile. The speed of sound is also used to calculate fluid temperature and density. The “diagonal path” transducers introduce a signal at an angle to the pipe wall. These transducers are used to measure the Δt that is used to calculate the flow rate.

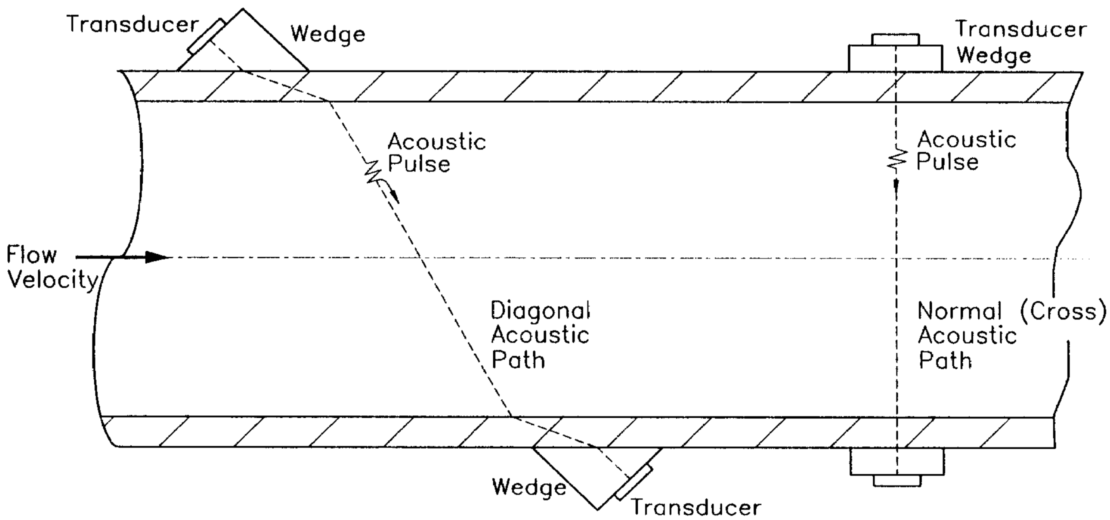

Figure 4-2
Diagram of External Mount Transit Time Flow Meter

The typical equation used by an external mount meter is provided below. This equation is provided to show the general approach and to show the inputs required by the meter.

$$M = \rho \, PF \; A V_{ax} \qquad \text{Equation 4-1}$$

Where,

M is the mass flow rate.

ρ is the fluid density calculated as a function of the fluid temperature and pressure. The meter makes its own temperature measurement using a "cross path" measurement and a correlation between the speed of sound, pressure, and temperature of the water. Other flow measurement methods, for example, venturis, cross-correlation meters, and tracer tests, use temperatures from external inputs.

PF is a "profile factor" that adjusts for the fact that the fluid velocity measured by the meter is the axial velocity averaged along a diametrical acoustic path. The relationship between this diametrical average velocity and the average velocity over the entire pipe cross-section is dependent on the shape of the velocity profile. If the velocity profile were uniform, the profile factor would be equal to 1.00. The profile factor is determined from hydraulic test data and the upstream configuration of the piping.

A is the flow area calculated manually and entered into the meter.

V_{ax} is the average axial velocity measured along the diametrial acoustic path. V_{ax} is calculated as:

$$V_{ax} = C^2 \Delta t \, / \, \left(2^* ID^* \tan(\theta)\right) \qquad \text{Equation 4-2}$$

Where,

C is the speed of the acoustic pulse in the fluid. It is calculated from the “cross path” timing measurement.

Δt is the difference in the transit times for the upstream and downstream acoustic pulses. It is measured by the meter.

ID is the inner diameter of the pipe. It is calculated from measurements of pipe outer diameter and wall thickness.

θ is the path angle of the acoustic pulse through the fluid calculated using Snell’s law at each interface. This requires accurate knowledge of the sound velocities in the pipe wall, fluid, and wedge.

The difference in transit times (Δt) is calculated by subtracting the timing measurement made for the downstream path from that made for the upstream path. Each measurement is made by recording the time required for an ultrasonic signal to travel from one transducer to the other transducer of the pair. The flow meter electronics filter noise, detect the incoming pulse, and record the time it took for the pulse to travel between the transducers. Because this process requires only milliseconds to complete, many measurements can be made each second. By averaging many measurements, an accurate average measurement can be obtained in a matter of seconds.

As with chordal meters, the determination of the profile factor for a specific installation is the most controversial issue in the use of external ultrasonic flow meters. The exact amount of the correction is critical to obtaining an accurate measurement. Compared to a chordal transit time meter, the external meter’s diametrical paths are not designed to provide as much information on the area average velocity. As a result, a greater adjustment is required, and it carries with it more uncertainty.

The profile factor is determined by conducting hydraulic testing of various piping configurations to develop a “library” of profile factors for various locations. The closer the meter’s location is to one of the testing configurations, the less uncertainty there is in the profile factor, and, consequently, in the overall measurement. If no tested configurations are sufficiently close, new hydraulic tests can be performed.

Physical Description

An external mount ultrasonic flow meter typically consists of one or more pairs of transducers and transducer cables, a clamp-type mount to attach the transducers to the outside surface of the pipe, and an electronics unit to process the signals and calculate the flow. Each electronic unit can control up to 16 pairs of transducers installed on one to four pipes. A typical two-pipe meter includes four transducer pairs per pipe (two diagonal pairs and two cross pairs), and it is controlled by a single electronics unit.

Installation Requirements

External mount meters require, at a minimum, a short section of straight pipe (approximately 36 inches [0.9 m]) for the installation of the transducer mounting fixture. Due to the effects of the flow velocity profile on the meter, it is necessary to install the meter in a hydraulic configuration that has been modeled in a hydraulically similar configuration in a flow lab. Where piping layouts, access, or interference make this impossible, additional model testing is required. The following is a partial list of locations that have been hydraulically tested by the vendor:

- Nine to 25 diameters downstream of a single 90 degree bend
- Nine to 25 diameters downstream of a close-coupled coplanar U-bend
- Six to 25 diameters downstream of close-coupled non-coplanar elbows
- Ten to 20 diameters downstream of a reducing header

For other locations, the vendor recommends additional hydraulic testing.

The outside surface of the pipe must be clean and smooth to ensure good acoustic coupling of the transducers to the pipe. Typically, the vendor will sand the pipe to obtain an acceptable surface finish. Trained technicians require approximately two days to prepare the pipe surface and install the transducers on a single pipe. One additional day is needed to set up the software inputs and complete the installation procedure. A two-pipe installation should require approximately one week to install, set up, and commission.

Maintenance Requirements

The signal processing electronics for an external meter are digital and require no calibration. The only maintenance recommended is a system verification check that should be performed during each refueling cycle. During this check, the clock calibration, cable continuity, alarm relays, signal strengths, and other system features are checked. The meter includes automatic troubleshooting features that generate messages when indications of weak signal strength are detected. Periodic maintenance and replacement of transducers are required.

Errors

The following categories of errors can be significant in the uncertainty of a measurement from an external mount transit time meter:

- Pipe area errors
- Errors in the application of Snell's law to determine the fluid angle
- Density errors
- Timing errors
- Profile factor errors

Each error category is discussed below, along with the specific errors grouped in that category.

Pipe Area Errors

The external mount transit time meter measures the flow velocity, and it requires an accurate input of pipe flow area to convert the velocity measurement into a volumetric flow measurement. This area is calculated from measurements of pipe outer diameter (OD) and wall thickness. Such a calculation includes errors due to pipes that are not perfectly round and errors in the diameter and thickness measurements used as input to the area calculation. With time, the pipe inside dimensions (ID) can change due to corrosion or erosion periodic assessments, and adjustments should be made.

Errors in the Application of Snell's Law to Determine the Fluid Angle

A number of factors go into the calculation of the fluid axial velocity in the pipe. Critical inputs to this calculation are those that are used to determine the angle of the acoustic paths in the fluid. These inputs are:

- The speed of sound in the pipe wall at the feedwater temperature
- The speed of sound in the feedwater at the appropriate temperature and pressure
- The speed of sound in the transducer wedge
- The temperature of the pipe wall
- The temperature of the transducer wedge

Density Errors

The uncertainty in the mass flow result is directly affected by the uncertainty of the density used to convert volumetric flow to mass flow. Because the density is calculated from a temperature measurement made by the meter at the metering section, there is no uncertainty due to the location of the temperature measurement. The density uncertainty that does exist is due to the following:

- Errors in the temperature measurement (due to errors in the measured sound velocity and uncertainty in the correlation of sound velocity vs. temperature)
- Errors in the pressure measurement (due to errors in the pressure sensor, the instrument calibration, and pressure differences between the measurement and metering locations)
- Uncertainty in the density values given in the ASME steam tables as a function of pressure and temperature
- Uncertainty in the correlation equation used to determine the density at a temperature and pressure between those given in the ASME steam tables

Timing Errors

The results of an external mount transit time meter are directly dependent on the timing measurements. When the meter is properly installed, several errors in the timing measurements can affect the measurement results. The most significant timing errors include:

- Electronic noise in the signals received by the electronics unit from the transducers
- Difference in the time measured by a transducer when sending and receiving an identical signal
- Variations of the speed of sound in the transducers, pipe wall, and cables from that entered into the meter

Timing errors that are typically relatively small include:

- Inaccuracies in the digital clock used to determine time
- Measurement errors in transducer cable lengths
- Errors in signal triggering and detection

Profile Factor Errors

The profile factor contains two types of errors: those related to the experimental uncertainty and those related to the ability to duplicate the exact velocity profile of the plant. The first type is relatively straightforward and is discussed in the section below. The errors in duplicating the exact velocity profile are varied and difficult to quantify. They are discussed in the sections following the one below.

Profile Factor Errors Due to Experimental Uncertainty

The uncertainty of a profile factor calculated from weigh tank and ultrasonic meter results is limited, in part, to the uncertainty of its inputs. These uncertainties are the following:

- Weigh tank uncertainty. The "true flow" is typically measured using a weigh tank. The weigh tank used for nuclear feedwater flow calibration typically has a quoted 2-sigma uncertainty of ±0.25%.

- Ultrasonic meter uncertainty. The external mount transit time meter used in the hydraulic tests contains random uncertainties from the timing measurements and the dimensions used to calculate flow.

Profile Factor Errors Due to Piping Configuration

When the meter location is relatively near an upstream disturbance, the upstream piping configuration can have a significant effect on the velocity profile. Upstream tees and elbows can introduce transverse velocities, swirl, and a severe flattening or skew to the flow profile. The hydraulic profile at the inlet of an upstream elbow can also have an effect. These effects dissipate as the flow proceeds downstream.

To determine the exact effects of the upstream disturbances and how much they are dissipated by the time they reach the meter location in the plant, hydraulic tests are performed. The hydraulic tests are designed to match the upstream configuration of the plant piping, but practical considerations usually require that hydraulic approximations be made using smaller diameter piping, flow straighteners, reducers, and no downstream disturbances. These approximations can cause the velocity profile in the test to be different from that in the plant, and, consequently, an error will exist in the profile factor. This error can be increased when the profile factor is extrapolated from results of similar configurations.

To quantify and bound modeling approximation errors so that they can be included in an uncertainty analysis, model sensitivity tests can be performed. Note that local flow disturbances can also lead to errors if they are not included in the hydraulic tests.

Profile Factor Errors Due to Pipe Roughness

When the meter location is not near an upstream disturbance, the effect of pipe roughness becomes relatively more significant. Because the theoretical velocity profile of fully developed flow is a function of the pipe roughness, the distorted profiles developed in hydraulic tests depend on the roughness of the pipe used in the test. If the roughness of the test pipes is different from that in the actual installation, the test will not be based on the same velocity profile as in the plant. The effect of surface roughness on the correction factor can be difficult to quantify exactly but may be bounded by testing with pipes of varying roughness.

Profile Factor Errors Due to Reynolds Number Extrapolation

Velocity profiles are known to vary with the Reynolds number. However, because of test facility limitations, the flow velocities and Reynolds numbers in hydraulic tests are typically less than experienced in the plant. Specifically, hydraulic tests are typically performed at Reynolds numbers of 3 to 4 million, while plant feedwater systems operate between 10 and 30 million. The profile factor must, therefore, be extrapolated to the operating conditions. A difference between the true curve and the assumed curve used for the extrapolation would introduce an error into the profile factor used in the plant installation. This difference is typically calculated by the vendor to be about 0.2% and is included in the profile factor uncertainty.

Uncertainty

A typical uncertainty of ±1% for an external mount meter is quoted. To ensure that this value is met, additional hardware can be installed for more measurement planes. The quoted uncertainty applies to a one-pipe mass flow measurement that is an average of measurements over a 5-second period.

For all installations, an uncertainty report that confirms uncertainty requirements are met is required. The report shows the individual uncertainties based on plant-specific data are bounded by the uncertainties used in a “budget” uncertainty analysis. A typical uncertainty report shows a mass flow uncertainty of ±0.9% for a one-pipe, four-plane external mount system. All uncertainties are calculated for a 95% level of confidence. The key components of the budget uncertainty in the report are the following:

- Uncertainty due to potential errors in the profile factor, ±0.6%
- Uncertainty due to potential errors in the flow area and other dimensions, ±0.6%

- Uncertainty due to potential errors in timing and electronics, ±0.37%
- Uncertainty due to potential errors in the density, ±0.2%

Repeatability of the 5-second average produced by a given one-pipe installation is estimated to be less than 0.3% and is included in the uncertainty discussed above. The variations in output of an actual feedwater flow meter will typically be greater than this value because of variations in the actual flow rate.

Installed Base

As of October 1998, external meters have been permanently installed in the feedwater systems at 13 nuclear power plants in the United States and five nuclear plants abroad. External meters have also been used for testing purposes at 17 other nuclear power plants. External meter results are used to periodically adjust a “correction factor” applied to the venturi output, or they are used as the continuous and direct input for the calorimetric mass flow calculation.

Results of Industry Survey

Of the 14 responses to the P^2EP survey conducted on “Feedwater Flow Measurement Techniques,” six reported to have or have had external mount meters installed. Two of the six respondents were not satisfied that the meters matched other installed instrumentation or with the meter’s reliability. The other four respondents were satisfied with the meters but reported problems with the transducer acoustic couplant and with the transducers themselves. The vendor reports that improvements in transducer and couplant design have substantially improved transducer life and reduced maintenance requirements.

5

EXTERNAL MOUNT CROSS-CORRELATION METERS

Overview

Cross-correlation meters use ultrasonic transducers mounted to the pipe to measure the velocity of random turbulence patterns that are part of the fluid flow. The measured fluid velocity is converted to a mass flow rate using a velocity profile factor, the pipe area, and a density calculated from a separate temperature and pressure measurement. The technology provides a continuous flow measurement. Installation of these meters is relatively easy and noninvasive.

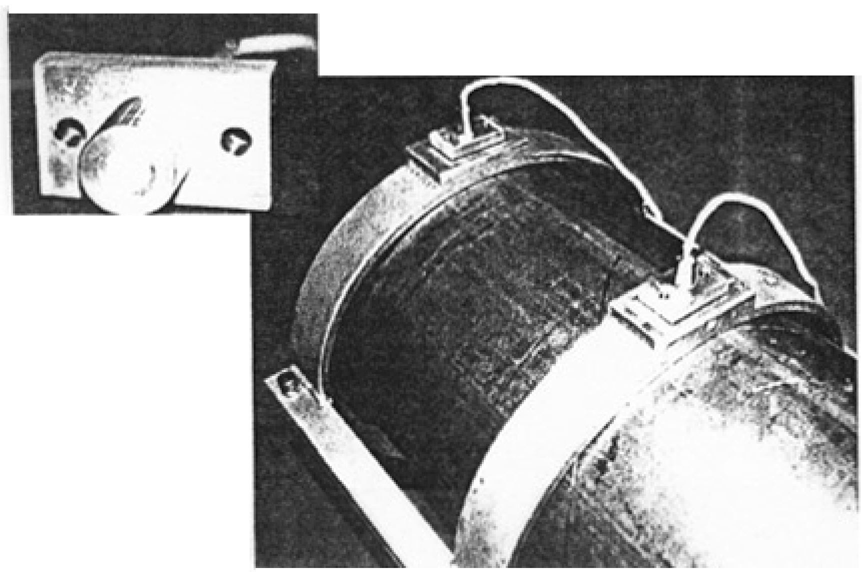

Figure 5-1
Photograph of an External Mount Cross-Correlation Meter
(Courtesy of ABB)

Cross-correlation meters are so named because they use a “cross-correlation” technique to identify common characteristics in two signals that indicate the presence of an individual turbulence pattern. Cross-correlation is a robust technology that has been used successfully for decades by radar and sonar detection engineers, and several researchers have worked to apply cross-correlation theory to measure gas and fluid flows using radiation, thermal, and other signatures [21].

The application of ultrasonics and cross-correlation to liquid flow measurement in pipes was pioneered by Canadian General Electric, among many others, in the mid-seventies [22] and further Refined by Ontario Hydro in the early eighties [23]. The axial distance parameter for clamp-on cross-correlation flow meters is simply the separation distance between the transducer sets. However, the cross-correlation meter tends to be slower due to digitizing, averaging, and the calculations involved [20].

Currently, only one company actively markets a cross-correlation flow meter for measurement of feedwater flow. That company is currently responsible for the technical development of a cross-correlation flow meter known as the CROSSFLOW meter. Note that the cross-correlation technique is also employed by various PWR primary loop meters that sense radiation signatures in the pipe. These meters are not applicable to feedwater flow and are not discussed here. The discussions in this section are applicable to the CROSSFLOW meter, which uses ultrasonic sensors.

Principles of Operation

The cross-correlation flow meter calculates mass flow rate using the following equation:

$$M = \frac{L}{\tau} \cdot CF \cdot A \cdot \rho$$

Equation 5-1

Where,

M is the mass flow rate.

L is the distance between transducer pairs.

τ is the time delay measured by cross-correlation.

CF is a "correction factor" applied to convert the measured velocity into the cross-sectional area average. It is based on the assumed turbulence patterns and velocity profile at the measurement location.

A is the flow area calculated manually and entered into the meter.

ρ is the fluid density, determined off-line from the ASME steam tables and plant measurements of temperature and pressure.

The ultrasonic cross-correlation flow meter measures the time delay, τ in Equation 5-1, as the transit time of turbulence patterns in the flow. A pair of ultrasonic transducers is mounted on opposite sides of the pipe at two axial locations approximately one foot apart. At each location, one transducer continually emits an ultrasonic signal that is received by the transducer on the opposite side of the pipe. The emitted signal frequency is set for each installation to maximize the strength of the received signal. The received signal is a combination of multiple signals including the relatively high-frequency "carrier wave" and a modulated signal that is caused by the turbulence in the fluid. The received signal is processed by a low-pass filter that removes the carrier wave and leaves the modulated signal.

The meter uses the existing eddies of the fluid, and a modulated received signal is caused by the turbulent eddies that travel at a speed related to the area average velocity of the fluid flow. The modulation has been described as a Doppler shift caused by the velocity field of turbulent eddies. Although eddies are created and dissipated relatively quickly, the experience of cross-correlation meter developers is that the turbulence pattern identified by the meter remains constant for a length of several pipe diameters. By uniquely identifying the same modulated signal at two locations on the pipe, the velocity of the causal turbulence pattern is calculated.

As shown in the flow calculation equation, the velocity of the turbulence pattern is calculated by dividing the distance between the two transducer stations by the measured time delay. The time delay is determined using the cross-correlation technique. This technique can be imagined as "overlaying" the two signals on top of each other until the signals match. When a match is found (that is, the signal is correlated), the delay required to make the signals match is the fluid travel time, or time delay, for the turbulence pattern.

The determination of the correction factor for a specific installation is the most controversial issue in the use of external ultrasonic flow meters. The exact amount of the correction is critical to obtaining an accurate measurement. The correction factor varies with the turbulence characteristics of the flow and with hydraulic configurations that change the fluid velocity profile. To determine correction factors, the relationship of Reynolds number and eddy velocities at various locations in the flow cross-section must be considered. This theory is described in Reference 24.

If a metering location is less than 15 diameters downstream of an elbow, the calculated correction factor is adjusted by a geometry factor. The geometry factor is based on a library of hydraulic tests performed at Alden labs where weigh tank results were compared to results of the meter at various distances downstream of a single elbow. In addition, numerical analysis simulations can be performed to verify the need for additional calibration in a nonstandard mounting arrangement.

Physical Description

An external mount ultrasonic flow meter typically consists of two pairs of transducers and transducer cables, a clamp-type mount to attach the transducers to the outside surface of the pipe, and an electronics unit to process the signals and calculate the flow.

Each electronics unit can control up to 16 pairs of transducers installed on up to eight pipes.

Installation Requirements

External mount meters require, at a minimum, a short section of straight pipe (approximately 12 inches [30 cm]) for installation of the transducer mounting fixture. Due to the effects of the flow velocity profile on the meter, it is desirable to install the meter in a long, straight section of pipe. It is recommended that the location be 10 diameters or more downstream from a single elbow. For locations that do not meet this specification, additional hydraulic testing may be required.

The outside surface of the pipe should be clean and smooth to obtain a good acoustic coupling of the transducer to the pipe. Typically, the vendor will remove the scale from the pipe to obtain an acceptable condition. For a typical two-pipe installation, the vendor will install all necessary equipment, including the software, and complete the installation procedure in less than two days.

Maintenance Requirements

Most of the signal processing electronics for the cross-correlation meter are digital and require no calibration. The cross-correlation meter includes a diagnostic function that, when requested, automatically tests the signal processing circuits. Periodic transducer maintenance or replacement is required.

Errors

The following categories of errors are critical in the uncertainty of cross-correlation flow meter measurements:

- Pipe area errors
- Transducer spacing errors
- Density errors
- Timing errors
- Correction factor errors, which include flow profile errors and miscellaneous errors due to assumptions on the distribution and signal interaction effects of turbulent eddies

Each error category is discussed below, along with the specific errors grouped in that category.

Pipe Area Errors

The external mount cross-correlation meter measures the flow velocity, and it requires an accurate input of pipe flow area to convert the velocity measurement into a volumetric flow measurement. This area is calculated from measurements of pipe outside diameter (OD) and wall thickness. Such a calculation includes errors due to pipes that are not perfectly round and errors in the diameter and thickness measurements used as inputs to the area calculation. With time, the pipe's inside dimension may change due to corrosion or erosion periodic assessments, and adjustments should be made.

Transducer Spacing Errors

The flow result is directly dependent on the value that is input as the axial spacing of the transducer pairs. An accurate measurement of the distance between the effective centers of the transducer elements is required.

Density Errors

The uncertainty in the mass flow result is directly affected by the uncertainty of the density used to convert volumetric flow to mass flow. Density is calculated from the ASME steam tables using indications from plant temperature and pressure instruments. The density uncertainty that does exist is due to the following:

- Errors in the temperature measurement (due to errors in the temperature sensor, the instrument calibration, any analog-to-digital conversion that is required, or temperature differences between the measurement and metering locations)
- Errors in the pressure measurement (due to errors in the pressure sensor, the instrument calibration, or pressure differences between the measurement and metering locations)
- Uncertainty in the density values given in the ASME steam tables as a function of pressure and temperature
- Uncertainty in the interpolation equation used to determine the density at a temperature and pressure between those given in the ASME steam tables

Timing Errors

The correlation analyzer produces a cross-correlation plot that is used to determine the degree of correlation between two received signals. A peak-to-RMS ratio selection criterion is used to minimize the standard deviation of the timing error. The user can alter the selection criterion, and the shape of the cross-correlation plot can influence the standard deviation of the flow measurement. Errors associated with measurement of time are typically less significant for cross correlation than transit time meters due to the longer time base upon which the cross-correlation meter timing uncertainty is based.

Correction Factor Errors

The correction factor is determined analytically from first principles and can be modified based on profile data established at a hydraulics lab. Errors that should be considered in the correction factors are:

- Uncertainty in the hydraulic calibration facility (typically 0.25%); geometric
- Acoustic and timing errors present in the ultrasonic meter used at the calibration facility
- Uncertainties in the theory relating to the distribution and turbulent eddies and their interaction with the acoustic beam

Correction Factor Errors Due to Analytic Theory or Experimental Uncertainty

The equation used to determine the effect of the turbulence pattern on correction factor is described in Reference 24. Details of the technical basis for the correction factor are proprietary to the vendor.

Profile Factor Errors

When the meter location is relatively near an upstream disturbance, the upstream piping configuration can have a significant effect on the velocity profile. Upstream tees and elbows introduce transverse velocities, swirl, and a severe flattening or skew to the flow profile. The hydraulic profile at the inlet of an upstream elbow can also have an effect. These effects dissipate as the flow proceeds downstream.

To determine the exact effects of the upstream disturbances and how much they are dissipated by the time they reach the meter location in the plant, hydraulic tests are performed. The hydraulic tests are designed to match the upstream configuration of the plant piping, but practical considerations usually require that hydraulic approximations be made using smaller diameter piping, flow straighteners, reducers, and no downstream disturbances. These approximations can cause the velocity profile in the test to be different from that in the plant, and consequently, an error will exist in the profile factor. This error can be increased, when the profile factor is extrapolated from results of similar configurations.

To quantify and bound modeling approximation errors so that they can be included in an uncertainty analysis, model sensitivity tests can be performed. Note that local flow disturbances can also lead to errors if they are not included in the hydraulic tests.

One approach that has been used to determine if a velocity profile is fully developed downstream of a flow disturbance is to mount a second meter further downstream. If the readings from the two meters are within the uncertainty of the measurement, it can be assumed that the flows are fully developed. This approach has the added advantage of an *in situ* verification under actual operating conditions—something that cannot be achieved in laboratory tests.

Profile Factor Errors Due to Pipe Roughness

When the meter location is not near an upstream disturbance, the effect of the pipe roughness becomes relatively more significant. Because the theoretical velocity profile of fully developed flow is a function of the pipe roughness, the distorted profiles developed in hydraulic tests depend on the roughness of the pipe used in the test. If the roughness of the test pipes is different from that in the actual installation, the test will not be based on the same velocity profile as in the plant. The effect of surface roughness on the correction factor can be difficult to quantify exactly but may be bounded by testing with pipes of varying roughness.

Profile Factor Errors Due to Reynolds Number Extrapolation

Velocity profiles are known to vary with the Reynolds number. However, because of test facility limitations, the flow velocities and Reynolds numbers in hydraulic tests are typically less than experienced at the plant. Specifically, hydraulic tests are performed at Reynolds numbers of 3 to 4 million, while plant feedwater systems operate between 10 and 30 million. The profile factor must, therefore, be extrapolated to the upper operating conditions for some installations. A difference between the true curve and the assumed curve used for the extrapolation would introduce an error into the profile factor used in the plant installation.

Miscellaneous Errors: Sensitivity to Transmit Frequency

A variable frequency feature allows measurements to be made over a range of frequencies and then averaged to minimize the effect or error of any single frequency. As discussed in Reference 21, the frequency response is expected to be related to the size of the eddies: lower frequencies by larger eddies and higher frequencies by smaller eddies. The system analyzes the lower frequencies only (that is, response produced by the larger eddies).

Miscellaneous Errors: Sensitivity to Transducer Equipment

Reference 25 describes measurements taken in a hydraulic laboratory to determine the sensitivity of the cross-correlation meter to variations between transducers manufactured to the same specification. Results varied by 0.12%, depending on which transducer set was used.

Uncertainty

A typical uncertainty of less than ±0.7% per pipe is quoted. Often, the uncertainty calculated using actual pipe dimensions and observed variations is as low as ±0.5% per pipe. These uncertainties have a confidence level of 95% at 2-sigma. Purchasers of permanent installations are provided an installation-specific uncertainty calculation prepared in accordance with the requirements of the vendor’s QA program [3].

The key components of the analysis, with mention of areas of reportedly lower uncertainty, are:

- Uncertainty due to errors in the correction factor, ±0.25%
- Uncertainty due to errors in density, ±0.2%
- Uncertainty due to repeatability, ±0.1%
- Uncertainty due to errors in the flow area, ±0.3%
- Uncertainty due to transducer spacing, ±0.05%

Testing performed at the Everest Flow Lab of Electricité de France has demonstrated the capability of the cross correlation meter to closely match the flow measured by an independent reference standard over a range of flow Reynolds’ numbers, while considering the effects of installation repeatability.

Installed Base

As of December 1998, cross-correlation meters have been permanently installed at five plants in the U.S. In addition, the meter has been used for tests at 10 plants in the U.S. and at 20 plants in Canada. External meter results are used to periodically adjust a "correction factor" applied to the venturi output.

Results of Industry Survey

Of the 14 responses to the P^2EP survey conducted on "Feedwater Flow Measurement Techniques," four reported to have experience with a cross-correlation meter. Two had meters permanently installed, and two had tested the meter but not installed it permanently. All four reported installations were performed in either 1996 or 1997.

The responses indicate that the utilities were reasonably satisfied with the meter. The utilities where tests were performed reported no problems with the cross-correlation meter. At the permanent installations, one reported some mechanical problems with the probe housing, and the other reported a requirement for periodic tuning to maintain signal strength.

The permanent installations also provided estimates of annual maintenance requirements. One site reported that approximately 40 hours is required annually to replace probes; the other site reported that approximately 7 hours is annually for transmitter frequency tuning. All reportings are based on early designed systems. The probe replacements were performed by the plant I&C staff, and the transmitter tuning was performed by plant engineers. One utility pointed out that the system was "less demanding, simpler, and much quicker."

6

TRACER DILUTION TESTS

Overview

The tracer dilution method has been used since the mid-1800s to measure the flow rate of streams, pipes, canals, etc. [26]. Two variations of the method have been developed: one-time “slug” injection and constant injection. For measurement of nuclear power plant feedwater flow, the constant injection method is typically used. With this method, a known concentration of a chemical tracer is injected into the pipe at a constant and measured rate. The dilution of the chemical tracer at a downstream location is used to determine the flow rate. The use of tracer dilution tests to measure volumetric flow rate is discussed in ISO 2975, “Measurement of Water Flow in Closed Conduits—Tracer Methods” [27].

Tracer tests can be performed while the plant is running. The uncertainty of the measurement does not depend on pipe geometry measurements, such as pipe diameter and pipe wall thickness, but it does depend on several other factors associated with measuring the dilution ratio of the tracer. Tracer tests require a significant length of pipe not interrupted by major components, such as pumps and heat exchangers, that could introduce a leak path and provide an opportunity for tracer hideout. The choice of locations and sample points should consider the need to ensure complete mixing of the tracer into the feedwater flow. Because the tracer dilution test does not produce a continuous flow indication, in nuclear power plants the tests are typically used to periodically assess the uncertainty of other feedwater flow measurement equipment.

In the past, three vendors have provided tracer dilution tests to nuclear power plants. The methods used by all of these vendors are sufficiently similar that the discussion in this section applies to all three.

Principles of Operation

Tracer dilution tests determine mass flow rate using the principle of conservation of mass. See Figure 6-1. A solution containing a known mass concentration of a chemical tracer (either radioactive such as sodium 24 or non-radioactive such as lithium, potassium, or rubidium) is injected into the flow stream at a known rate. Constant injection of the tracer continues until the concentration of the tracer at the measuring cross section is stable. The feedwater flow is then sampled at a location sufficiently downstream to allow for complete mixing of the injected solution and the feedwater.

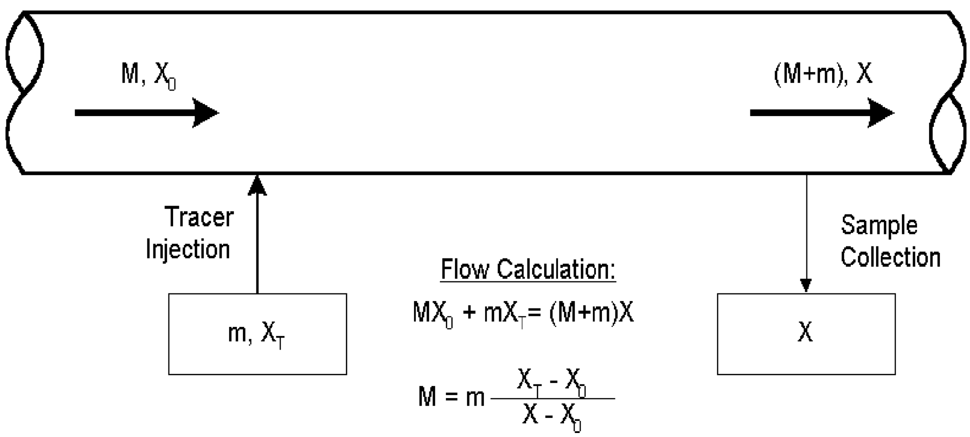

Figure 6-1
Tracer Test Schematic

Constant injection of the tracer continues while several samples are collected. The samples are then analyzed to determine the concentration of the tracer in the mixed feedwater. The feedwater mass flow rate can then be determined from the following equation, which is derived from a mass balance on the tracer chemical:

$$M = m\frac{X_T - X}{X - X_0} \qquad \text{Equation 6-1}$$

Where,

M is the mass flow rate upstream of the tracer injection point.

m is the mass flow rate of the injected tracer, measured by a metering pump as the tracer is injected.

X_0 is the mass concentration of the tracer upstream of the injection point. It is nominally zero but should be measured.

X_T is the mass concentration of the tracer in the injected solution. This is a known quality of the injected tracer.

X is the mass concentration of the tracer in feedwater at the sampling point. This is determined by evaluating fluid samples withdrawn at the downstream location.

Three key assumptions are made in deriving Equation 6-1. First, no leakage into or out of the system between the injection point and sample point is assumed. Second, no loss of tracer between the injection point and sample point due to chemical reaction, deposition, ion exchange, etc. is assumed. Third, complete mixing of the tracer into the flow is assumed to have occurred before the sample point. When planning a tracer test, these three assumptions should be considered in choosing the injection and sample points.

A successful tracer dilution test requires complete mixing of the tracer between the sampling points, a steady feedwater flow rate during the sampling period, and flow loop times long enough to prevent the injected flow from returning to the injection point before the sampling is completed. To ensure complete mixing, the injection and sampling points must be located sufficiently far apart. A typical mixing distance is 220 pipe diameters [28]. Valves and other components that increase the flow turbulence will decrease the distance required to achieve adequate mixing.

Ideally, the injection and sampling points can be set with the required length of pipe between them but with no locations between where fluid can be either added or removed. If fluid is added between the points, an accurate measurement can be made if the added fluid is completely mixed with the main flow at the sampling point. For this situation, the calculated flow is the flow at the sampling point. An accurate measurement can also be made if fluid is removed between the sampling points, but this requires that the fluid be completely mixed before any fluid is removed. The resulting flow rate is the flow rate at the injection point.

Various tracers can be used to perform a flow test. Radioactive tracers are advantageous for good accuracy because they typically enable more accurate measurement of the mixed tracer concentration [29]. However, radioactive tracers require special handling procedures to limit personnel exposure, involve more complicated sample analysis, and are more expensive than nonradioactive tracers. Most tracer tests performed have used nonradioactive tracers, such as lithium, potassium, and rubidium.

Physical Description and Test Procedure

To perform a tracer dilution flow test, the vendor provides injection and sampling equipment. The injection equipment includes an injection metering system and a reservoir of the tracer. The sampling equipment includes equipment to cool the samples, control valves, and sampling containers.

The tracer is typically injected and sampled from the pipe through existing vent and drain penetrations. A pump on the injection cart delivers a known flow rate of the concentrated tracer solution. This solution is then diluted with feedwater and injected into the feedwater system.

Sampling begins when the tracer concentration has reached steady state at the sampling location. The time required to reach steady state is approximately the transport time of the tracer from the injection point to the sampling point and can be calculated by dividing the mixing length by the feedwater flow velocity. This is typically several minutes. Samples are then withdrawn from the system. Feedwater is admitted to the sampling equipment where it is first cooled and then portioned into sample containers for storage. One vendor indicated that the sampling process takes one to three minutes. Another vendor indicated that sampling may require up to an hour or more. The effect of tracer traveling around the loop back to the injection point is minimized by using tracers that do not carry over with the steam and by measuring concentrations upstream of the injection point. For a typical test, 40 samples are taken.

Radioactive tracers are measured using gamma spectrum analysis. Reference 30 describes one standardized method to perform this analysis. Nonradioactive tracers are measured using atomic absorption spectrometry. Reference 31 describes the use of atomic absorption spectrometry to measure lithium and potassium.

Installation Requirements

Tracer dilution tests can typically be performed using existing drains and vents for tracer injection and sample collection. If appropriate pipe taps are not available, then they must be installed during an outage before the test can proceed. This is a fairly simple procedure that should be performed by plant personnel.

With the connection points installed, it is a fairly straightforward procedure to perform the flow test. The vendor provides the carts and performs the test while the feedwater system is producing a steady flow rate. Changes in flow rate will affect the uncertainty in the measurement.

Maintenance Requirements

Tracer dilution tests are not permanent installations. However, at some plants, isokinetic sample injection probes that can be stored in the retracted position exist. These probes should be verified to be retracted when not in use. Because they use gaskets and packing, minor leaks can develop that need attention. Other than that, no maintenance is necessary. Any tracer remaining in the system after the test is removed in the steam generator blowdown for PWRs or the reactor water cleanup (RWCU) system for BWRs.

Potential Errors

A number of potential errors can affect the uncertainty of a tracer dilution flow measurement, including the following:

- Errors in determining the tracer concentration in injected and sampled flows
- Errors in sampling to determine the tracer concentration
- Errors in measuring the tracer injection rate
- Errors due to adsorption and reaction of the tracer
- Errors from incomplete mixing
- Errors from feedwater flow rate fluctuations

Each error category is discussed below, along with the specific errors grouped in that category.

Errors in Tracer Concentration Analysis

Errors in the reported tracer concentration of a given sample directly affect the uncertainty of the feedwater flow measurements. The uncertainty in the concentration analysis greatly depends upon the equipment and practices used to perform the analysis. A process-specific uncertainty of the concentration analysis should be part of the flow test uncertainty evaluation. The uncertainty should consider:

- The sensitivity and repeatability of the analysis equipment in the range of the sample concentration
- Biases from analytical interference, errors in the preparation of reference standards
- Errors in the dilution of samples and standards

To reduce systematic errors and correct for interferences in the analysis method, a portion of the injected solution should be retained and diluted to make calibration standards. The use of two independent laboratories in performing the concentration analysis aids in quantifying any systematic errors in the analysis [27].

Errors in Sampling the Tracer Concentration

There is an error associated with the use of random sampling to estimate the true tracer concentration. Variations exist in the true tracer concentration of the samples. These variations may be caused by the following factors: feedwater flow rate fluctuations, tracer injection rate fluctuations, and incomplete mixing of the tracer and feedwater. These are discussed below. Except for incomplete mixing, these variations will be random and normally distributed. Based on this assumption, the true tracer concentration may be estimated by the mean of the sample concentrations. The uncertainty in using this mean is calculated from the standard deviation and the number of samples. Because an increased number of samples decrease this uncertainty, a sufficient number of samples will make this error a minor uncertainty contributor.

Errors in Tracer Injection Rate Measurement

Any biases or uncertainties in the tracer injection rate are transferred directly into the final measurement. The metering pump should, therefore, be calibrated and its uncertainty included in the feedwater flow rate uncertainty. A typical uncertainty for metering pump flow is ±0.1% to ±0.3% of metered flow [27].

Errors Due to Tracer Adsorption and Reaction

If the injected tracer reacts with the feedwater or is adsorbed on pipe surfaces, the concentration of tracer in the samples collected will be reduced, producing a bias in the feedwater measurement. The feedwater flow rate will appear to be greater than it actually is, thus overestimating reactor thermal power. This effect has not been fully quantified by research and could be significant in some applications.

To minimize the effects of adsorption, injection of the tracer into any components with large surface areas, such as feedwater heaters, should be avoided. If the tracer displaces other metals that were on the pipe surfaces (ion exchange effect), then tracer adsorption might be detected by analyzing the feedwater samples for increasing metal concentrations during the tracer dilution test. However, tracer adsorption can occur without displacing other metals.

Errors from Incomplete Mixing

The tracer dilution test assumes that the tracer and feedwater are completely mixed at the sampling location. The biggest variable affecting this mixing is the distance between the injection and sampling points, the “mixing distance.” Too short a mixing distance results in incomplete mixing.

Reference 28 estimates that 220 pipe diameters may be required to reduce uncertainty from mixing variations to less than ±0.5%. The required mixing length can be shortened considerably by using multi-orifice injectors, increasing the injection velocity, and injecting the tracer upstream of pumps, bends, valves, and other obstructions.

Errors from Feedwater Flow Rate Fluctuations

The tracer dilution test assumes that the feedwater flow rate is constant. Fluctuations in the true flow rate cause variations in the dilution of the tracer and, consequently, in the sample concentrations. Although these variations do not represent a true error in the measurement process, they increase the uncertainty in the reported flow rate. This uncertainty can be reduced to insignificant levels by maintaining a steady feedwater flow during the test.

Installed Base

No data were available on the number of tracer dilution tests performed at U.S. nuclear power plants. Tracer dilution tests of feedwater flow are primarily used to assess the biases of other feedwater flow measurement devices. Some vendors also measure steam generator moisture carryover and moisture separator/reheater (MSR) moisture removal using tracer methods.

Uncertainty

Vendors report typical uncertainties of ±0.25% to ±0.5%, but they also report that for specific tests the uncertainties have been as low as ±0.2% [29]. These reported values are consistent with ISO 2975, which gives a typical uncertainty of ±1% but allows that more accurate measurements may be obtained [27].

During the writing of this report, two different vendors were contacted to discuss the basis of their reported uncertainties. Both vendors stated that their uncertainties had a 95% level of confidence and were based on detailed uncertainty analyses that considered all known potential errors.

Vendor uncertainty analyses are typically proprietary information, and a typical analysis was not available. Based on discussions with vendors, a typical analysis is expected to include the following components:

- Observed variations that account for several random errors, typically in the range of ±0.3%
- Uncertainty due to metering the tracer injection rate, typically ±0.1%

Note that no apparent allowance has been made for adsorption (that is, hideout).

A concern about application of tracer technology and other one-time flow tests is that an uncertainty allowance must be provided for changes in the differential flow element, such as those caused by fouling and other dynamic effects, between calibrations.

Results of Industry Survey

Of the 14 survey responses, seven had experience with the tracer dilution method. At five of the sites, the tests were performed using lithium as the tracer. The remaining two sites used sodium 24 as the tracer. Included in the seven sites was one site that had used both methods. The reported uncertainties ranged from ±0.25% to ±1.5%.

Four of the respondents stated that they were satisfied with this method. One respondent indicated that the test results may have been over-conservative due to leakage-type bypass flow around the feedwater pumps. One other response indicated that the results were questioned.

Two of the seven respondents had used the results of the tracer test to calculate a correction that was applied to the primary feedwater flow measurement. At one site, a tracer dilution test identified transmitter drift, which was corrected. One site performed PTC-6 testing in conjunction with chemical tracer testing. One site used the results to determine which steam generator to inspect based upon high carryover. Severe degradation of the wrapper sheet was found.

Cost

The cost for a tracer test depends upon the tracer used, the number of pipes, and the location of the plant, but the approximate cost for a two-pipe test is $50,000 to $80,000.

7

SUMMARY

Three different technologies are currently in use by nuclear power plants for calculating feedwater flow rates. Table 7-1 summarizes the significant features of each technology. Two of these technologies, differential pressure meters and UFMs, can provide continuous on-line measurements. The other provides a one-time test for calibrating other on-line measurements. While each of the measurement methods has a sound technical basis, the potential for significant error exists in all cases. Accordingly, it is the obligation of the plant engineer to ensure that all potential errors (including those specific to plant applications) are considered and properly quantified in the uncertainty analysis.

The ability of the utility engineer to satisfy this obligation is complicated by the differing uncertainty analysis methodologies used by the manufacturers and the proprietary data upon which uncertainty claims are based. The recommended approach for assessment of these uncertainty claims include:

- Obtain all available documentation upon which uncertainty claims are based.
- Compare the uncertainty analysis approach used by the vendor with the guidance provided in PTC19.1 and other applicable standards. Particular emphasis should be placed on those areas discussed in Section 1 of this report (Notes on Uncertainty and Errors).
- Explore with the vendor each of the elements of uncertainty discussed in this report including those which may be considered proprietary by the vendors. Ensure that a sound technical basis exists for the approach for bounding these potential errors.

Table 7-1
Summary of Available Technologies for Feedwater Flow Measurement

	Venturi/Flow Nozzle	Chordal Transit Time	External Transit Time	Cross-Correlation	Tracer Test
Continuous?	Yes	Yes	Yes	Yes	No
Reported uncertainty (Note 1)	±.25% to 2.0% (Note 2)	±0.5%		±0.5 to 0.6%	±0.5%
Pipe cutting required?	Yes	Yes	No	No	Usually No. May need to install taps.
Maintenance and plant support	Minor	Moderate	Moderate	Moderate	Minor
Used for direct input to calorimetric calculations?	Yes	Yes	Yes		No

Notes:

1. The uncertainties in this table are typical 2-sigma uncertainties for mass flow rate through a single pipe, as reported by the vendor. Uncertainties for a specific installation may vary from those in this table. **Because vendors use different assumptions and methods to calculate these uncertainties, users are strongly advised to carefully review the analytic or statistical basis of any reported uncertainty before accepting it for use in their plants.**

2. The uncertainty assigned to venturi and flow nozzle measurements can vary significantly from plant to plant. Many BWRs use a GE uncertainty analysis that provides a 1-sigma value that is less than that listed in the table above.

3. The values in this table are for the chordal transit time meter.

8

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A

RESULTS OF INDUSTRY SURVEY

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PLANT SUPPORT ENGINEERING

P²EP Survey #98-006

9/25/98

Feedwater Flow Measurement Techniques

Personnel at EPRI are preparing a feedwater measurement application guide that will aid utility engineers in evaluating feedwater flow measurement techniques by conveniently providing descriptions of the operating principles, accuracy, and installation and maintenance requirements of the most prevalent measurement technologies. The purpose of this survey is to gather information regarding the industry use of these technologies to include in the application guide. Contact person for this survey is Ramesh Shankar (I&C) at (704) 547-6127. The following questions were asked in this survey:

1. Which flow measurement is used in the calorimetric calculations at your site?

   [ ] feedwater flow [ ] steam flow

2. What is the overall uncertainty of your measurement technique?

3. Which of the following feedwater flow methods have been employed at your site?

   [ ] Venturi/Flow Nozzle [ ] Wetted transducer ultrasonic transit time meter

   [ ] Chemical tracer tests [ ] Strap-on ultrasonic transit time meter

   [ ] Strap-on ultrasonic cross correlation meter [ ] Other

Please describe your experience with each of the following technologies:

4. Venturi/Flow Nozzle Technology

4a. For your venturis/flow nozzles, please list the name of the vendor that supplied them and the make, model, nominal rating, and pipe size.

4b. What is the make and model of the pressure transducers that are used?

4c. How long have they been installed?

4d. On average, how much time is required to maintain these devices per year, what maintenance is performed, and who performs it?

4e. What is the accuracy of this method as stated by the vendor?

4f. How were these meters calibrated prior to initial installation?

4g. Have these meters been recalibrated since installation, and if so, how?

4h. How would you describe your overall satisfaction and confidence with this method?

4i. What problems have you experienced?

5. Chemical Tracer Tests Technology

5a. Which vendor or supplier performed the tests?

5b. When were these measurements made?

5c. Was a correction applied to the primary flow measurement on the basis of the results, and if yes, how was this correction applied?

5d. How many times have these tests been performed?

5e. What is the accuracy of these methods as stated by the vendor?

5f. Which tracer chemical was used?

5g. What method was used to determine the tracer chemical concentration?

5h. How would you describe your overall satisfaction and confidence with this method?

5i. What problems have you experienced?

6. Wetted Transducer Ultrasonic Transit Time Meter Technology

6a. Which vendor supplied the meters, and what is the make and model?

6b. How many meters are installed at your site?

6c. How long have they been installed?

6d. What is the accuracy of these methods as stated by the vendor?

6e. How were these meters calibrated?

6f. If this is used as an alternate measurement, is a correction applied to the primary flow measurement on the basis of the results, and if yes, how is this correction applied?

6g. On average, how much time is required to maintain these devices per year, what maintenance is performed, and who performs it?

6h. How would you describe your overall satisfaction and confidence with this method?

6i. What problems have you experienced?

7. Strap-On Ultrasonic Transit Time Meter Technology

7a. Which vendor supplied the meters, and what is the make and model?

7b. How many meters are installed at your site?

7c. How long have they been installed?

7d. What is the accuracy of these methods as stated by the vendor?

7e. How were these meters calibrated?

7f. If this is used as an alternate measurement, is a correction applied to the primary flow measurement on the basis of the results, and if yes, how is this correction applied?

7g. On average, how much time is required to maintain these devices per year, what maintenance is performed, and who performs it?

7h. How would you describe your overall satisfaction and confidence with this method?

7i. What problems have you experienced?

8. Strap-On Ultrasonic Cross Correlation Meter Technology

8a. Which vendor supplied the meters, and what is the make and model?

8b. How many meters are/were installed at your site?

8c. When were the meters installed?

8d. For how long were they used?

8e. What is the accuracy of these methods as stated by the vendor?

8f. How were these meters calibrated?

8g. If this is used as an alternate measurement, is a correction applied to the primary flow measurement on the basis of the results, and if yes, how is this correction applied?

8h. On average, how much time is required to maintain these devices per year, what maintenance is performed, and who performs it?

8i. How would you describe your overall satisfaction and confidence with this method?

8j. What problems have you experienced?

9. Is there any other comment or experience that you would want to share with other utility engineers on this subject?

As of September 25, 1998, the following utilities had responded:

Carolina Power & Light, Harris Plant

Kim Thomas, 919-362-2937
Kim.Thomas@CPLC.com

1. Feedwater flow

2. Precision calorimetric uncertainty is approximately 1.5%.

3. Venturi/Flow Nozzle, chemical tracer tests, strap-on ultrasonic transit time meter, and strap-on ultrasonic cross correlation meter

4a. Vendor: Permutit

Make: 16" Venturi with pressure recovery section

Model: N/A

Nominal rating: 4.27 MPPH

Pipe size: 16" - Schedule 120

4b. Make: Honeywell; Model: STG170 Press., STD130 dP

4c. 11 Years

4d. Excellent reliability and recalibration history and essentially no maintenance time required - inspected once per fuel cycle; On-site calibration laboratory calibrates static pressure and differential pressure transducers once per fuel cycle in a laboratory controlled environment.

4e. Venturi maximum tolerance is +/- 0.5% over the full range of application.

4f. Alden Lab flow tests

4g. Yes; Alden Lab flow tests for the three installed venturis in 1997.

4h. Excellent

4i. None

5a. ABB

5b. 1996

5c. No

5d. Once

5e. +/- 0.5%

5f. Lithium Hydroxide

5g. Atomic Absorption (AA)

5h. Very satisfied

5i. None

6a. na

7a. Caldon; Dual- Path

7b. Currently none. The single uncalibrated unit installed in 1993 and the 3 calibrated units installed in 1995 were removed within months of installation.

7c. na

7d. Approximately +/-0.83% (1995 installation).

7e. Hydraulic calibration was performed at Alden Laboratory.

7f. na

7g. na

7h. Reliability was not acceptable and flow rate was different from tracer, correlation ultrasonic and installed calibrated venturis (Reference INPO OE HNP97002).

7i. Numerous repairs and signal grooming were required.

8a. AMAG

8b. 2

8c. 1996

8d. One day demonstration

8e. Unknown - units not calibrated.

8f. Units not specifically calibrated for CP&L installation.

8g. na

8h. na

8i. Installation was less demanding, simpler and much quicker.

8j. na

9. Is there any other comment or experience that you would want to share with other utility engineers on this subject? Fully understand the company (capabilities, track record, etc.), its product and the technology at hand (limitations, installation requirements, etc.) before installing any flow measurement device. Also, EPRI/Utility should consider installing a calibrated magnetic flow meter(s) for feedwater flow measurement.

Consumers Energy, Palisades

Steve Handlovits, 616-764-3262
smhandlo@cmsenergy.com

1. Feedwater flow

2. 1.01%

3. Venturi/flow nozzle and strap-on ultrasonic cross correlation meter

4a. Vendor: Badger Meter, Inc.

Make: Badger Meter, Inc.

Model: PMT-F

Nominal rating: 0→219.35 inches water for 0→6E6 16m/hr

Pipe size: 18"

4b. Unknown

4c. Inservice date 12/31/71

4d. None

4e. Unknown

4f. Unknown

4g. Not sure. Potentially recalibrated 2/11/83.

4h. Not very satisfied. Venturis are in containment building in a fairly inaccessible location.

4i. Believed to have been fouled for many years before Palisades implemented the AMAG crossflow system.

5. Have not used tracer test, wetted transducer UT transit time, or strap-on UT transit time technology.

8a. AMAG 1.2 MHz and 0.8 MHz probes.

8b. 2 sets of probes

8c. 8/96

8d. Starting approximately 9/97 to the present.

8e. Better than 1%

8f. At Alden Labs

8g. Used as off-line measurement, correction factor applied to calorimetric in the plant process computer which will immediately change "calculated" heat balance power up or down.

8h. Approximately 40 hours, replacement of probes, Instrument & Control techs perform maintenance.

8i. Pretty satisfied with system and reasonably confident. Considering buying AMAG's new system which doesn't require probe replacement.

8j. Galling of brass probe housing in aluminum frame.

Duke Power, Oconee Nuclear Station

Greg Lareau, 864-885-3275
galareau@duke-energy.com

1. Feedwater flow

2. 0.54%

3. Venturi/Flow Nozzle

4. Venturi/Flow Nozzle Technology

4a. Vendor: BIF & PERMUTIT

Make: Universal Venturi Tube & 24 Inch Venturi Flowmeter

Model: 24

Nominal rating: 1290 psia, 475 F, 6 E 06 lbm/hr

Pipe size: 24 inch Sch 80

4b. Rosemount 3051

4c. Since 1986

4d. Cleaning - 6 Mech Maint once per cycle ~8 hours. Precision Calorimetric Tests - 1 Mech System Engin once per cycle ~20 hours.

4e. +/- 0.25% of true flow.

4f. Alden Labs calibration traceable to NIST.

4g. No

4h. Poor, but conservative.

4i. Venturi fouling and correction determinations

Entergy Operations, Waterford-3

Lawrence Bergeron, 504 739-6797
lberger@entergy.com

1. Steam flow
2. Less than 2%
3. Venturi/Flow Nozzle, Chemical tracer tests, Strap-on ultrasonic transit time meter

4a. For your venturis/flow nozzles, please list the

Vendor name:

Make: Permutit

Model: Venturi Element

Nominal rating: 37.89" x 24.00" Beta Ratio - .6334

Pipe size: 40.5"

4b. 1153 Rosemont

4c. 13 years

4d. 2 man days

4e. 0.25% before installation after Alden Research Lab calibration

4f. Alden Research Lab calibration

4g. No

4h. Very satisfied

4i. Transmitter drift

5a. CE

5b. 1987

5c. No, but identified transmitter drift, which was corrected.

5d. 2

5e. <0.5%

5f. Li

5g. No answer

5h. Satisfied but aware of industry problems associated with proper mixing of tracer

5i. None

6a. na

7a. Caldon

7b. None, used for testing

7d. <1.0%

7e. Alden Research Lab

7f. na

7g. na

7h. Satisfied and confident the results were accurate

7i. Couplant problems while the meter was installed

8a. na

First Energy, Davis Besse

Gene Matranga, 419-321-8369
Eugene_C._Matranga@FirstEnergyCorp.com

1. Feedwater flow

2. <2%

3. Chemical tracer tests, strap-on ultrasonic transit time meter, and strap-on ultrasonic cross correlation meter

7a. Caldon LEFM

7b. A flow sensor was installed on each of the two MFW pipes and indication was provided by a common read out.

7c. Installed for about a day.

7d. <1.0%

7e. Independent laboratory tests.

8a. ABB CE

8b. A flow sensor was installed on each of the two MFW pipes and indication was provided by a common read out.

8c. Feb 97

8d. About One day as part of a system demonstration. Cost benefit did not support purchase.

8e. <0.7%

8f. Independent laboratory tests.

8i. Both demonstrated systems matched plant instrumentation within 0.3%

9. I came across another subtile factor associated with feed flow errors and that is that older Rosemount 1153 transmitter output is a function of the transmitter ambient temperature. The newer transmitters have an internal RTD to compensate for ambient temperature affects. The effect is sometimes positive and sometimes negative, it is transmitter specific but doesn't appear to change too much over time. We found this out in some Rosemount literature and I think other at work may have talked with Rosemount some time ago. We just never put 2 and 2 together for this specific application until recently.

Northern States Power, Prairie Island

Tom Verbout, 651-388-1121 x4724
tom.verbout@nspco.com

1. Feedwater flow

2. 1.6%

3. Venture/flow nozzle and Caldon cordal system on one unit (not used in calorimetric)

4a. Vendor: BIF

Make: BIF

Model: A-187151

Nominal rating: O-4.47 x 10^6 P/# O-376.4” WTR

4b. Honeywell ST 3000 STD 130

4c. Since 1986

4d. 4 hours I&C Tech 5

4e. No answer

4f. The venturis were calibrated at Alden Labs

4g. Xmtrs have been calibrated; venturis have not, but Unit 2 has been inspected and seems to be in good shape.

4h. Highly confident, but there are unknown biases like venturi fouling that worry me.

4i. None

5a. ABB

5b. 1995

5c. No, results questioned by performance engineer.

5d. Once that I know of.

5e. 1.5%

5h. Skeptical, since I was not involved. Method seems to be good.

6a. On Unit 2 Caldon cordol flow measurement system.

6b. 1 meter

6c. 2 years

6d. 0.5%

6e. Alden Labs and on site.

6f. No, because both the Ultrasonic and the venturis read within their respective tolerances.

6g. I&C 10 hours

6h. Highly confident in the method.

6i. Correction factors changing over time.

7a. Tried Caldon’s

7b. None

7c. Had them installed 6 months

7d. 1.5%

7e. By Caldon on site

7f. No

7g. ?

7h. Not satisfied

7i. Error in measurement, which showed a bias that, did not exist.

Ontario Hydro, Darlington

Jim Sherin, 416-592-5597
jim.sherin@hydro.on.ca

1. Feedwater flow

2. Total feedwater flow uncertainty as documented for regulatory consumption is ±1.25% at a 95% confidence level.

3. Venturi/flow nozzle and strap-on ultrasonic cross correlation meter

4a. Vendor name: Donlee Precision Ltd.

Make: ASME flow nozzle with wall taps

Model: Special order

Nominal rating: 0-35 kPa deltaP

Pipe size: 14 inch

4b. Rosemount 1152DP4N

4c. 10 years

4d. Annual calibration callup on four transmitters per unit performed by station control maintenance technicians (estimated time:48 man-hrs per unit). Annual verification of flows against strap-on ultrasonic cross correlation meter performed by Corporate Nuclear Engineering staff (estimated time: 48 man hrs per unit).

4e. No guaranteed accuracy for flow nozzle and no easy method of inspection. Estimated accuracy $\pm$3%. After correction to ultrasonic flow meter results, accuracy is $\pm$1.5% for each individual feedwater nozzle (4 per unit).

4f. No calibration was performed prior to installation.

4g. In-situ calibration is performed annually against strap-on ultrasonic cross correlation meter.

4h. Method accuracy sufficient to meet regulatory requirements but MW production may be suffering because of the present uncertainty band.

4i. 1. Feedwater flow measurements are also used for boiler level control necessitating a wider transmitter range then would be desired for best accuracy. Transmitter calibrations must be performed with care to avoid incorrect flow indications. Shifts of up to 1% have occurred simply due to the precision of the transmitter calibrations.

2. Changes in flow nozzle correction factors between annual ultrasonic flow meter checks have usually been less than 1% but there have been a few occasions when correction factors change by as much as 1.4%. The reason for the changes has not always been explainable.

8a. Ultrasonic cross correlation flow meter built by Ontario Hydro. (AMAG CrossFlow meter originally based on Ontario Hydro design.)

8b. One meter and four transducers are installed on unit 2 only.

8c. February 97

8d. Still in use

8e. Experience from online system shows improved repeatability compared to annual measurements. Overall accuracy is now estimated to be ±1.0%.

8f. Original meters calibrated at Ontario Hydro Technologies on full scale hot pressurized loop using ASME PTC6 nozzle as standard. ASME nozzle was originally calibrated at Alden labs before installation. Newer meters have been qualified by extensive comparisons to original meters with additional measurements at Alden labs, NIST, Ontario Hyrdo's own weight tank facility and in-situ comparison against PTC6 turbine acceptance test method of determining total feedwater flow.

8g. Correction is applied by a multiplication factor on each individual flow measurement within the calorimetric calculation.

8h. Transducers have not been touched since installation. Transmitter frequency tuning performed by Corporate Nuclear Engineering staff to optimize signal strength prior to periodic data collection for comparison to station flow nozzles. Overall maintenance would total less than 7 hours since installation.

8i. Online system has performed well but is still being used in a batch mode.

8j. Signal strength will degrade somewhat without periodic tuning of the transmitter frequency increasing scatter in flow meter results.

PECO Energy, Peach Bottom

John Cihak, 717- 456-7014
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1. Feedwater flow

2. 1.70%

3. Venturi/flow nozzle and chemical tracer tests

4. Venturi/Flow Nozzle Technology - Does not appear to foul over time.

4a. Vendor that supplied them: General Electric

Make: Permutit

Model: Type-TG

Pipe size: 18"

4b. Rosemount model 1151DP5E22B2

4c. Since ~1993

4d. I&C flushes the sensing lines once per cycle (24 months) - requiring 12 man-hours for the 3 lines. I&C calibrates the transmitters once per cycle - requiring 48 man-hours for the 3 lines.

4e. We have calculated the uncertainty of the plant instrumentation to be 1.11%

4f. By Weigh Tank at Alden Labs. After the meters were put into operation, GE notified PECO that the throat tap should be moved to the wall behind the nozzle and that no calibration change would occur. The tap change was made, but because the meters were contaminated, it was not possible to recalibrate them at Alden Labs. Subsequent tracer testing showed the meters to be indicating ~1% low.

4g. Yes, to Na tracer tests in August of 1992.

4h. We believe we may be able to improve our accuracy by using one of the ultrasonic flow measurements.

4i. There is a belief that the 9 MWe difference between the 2 Peach Bottom units may be due to errors in feedwater flow measurement.

5. Chemical Tracer Tests Technology

5a. NWT Corporation of San Jose, CA

5b. August, 1992

5c. Yes, feedwater flow coefficients in the process computer were changed

5d. Once

5e. 1.28%

5f. Na-24

5g. Dilution Method - A known activity of Na-24 solution was injected to the feedwater at a known mass flow rate and samples were taken downstream at a point where the solution was thoroughly mixed with the feedwater. These samples were counted and the feedwater flow rate calculated from the dilution formula.

5h. The tracer test may have been inaccurate and over-conservative due to leakage-type bypass flow around our feedwater pumps. We recently became aware of this bypass flow. The tracer test is relatively complicated compared to the new UT methods.

6. Wetted Transducer Ultrasonic Transit Time Meter Technology - N/A

7. Strap-On Ultrasonic Transit Time Meter Technology - We are currently entertaining a proposal from Caldon for use of their leading edge flow meter for a flow test.

8. Strap-On Ultrasonic Cross Correlation Meter Technology - We are currently entertaining a proposal from ABB/AMAG for use of their Crossflow technology for a flow test.

Rochester Gas & Electric, Ginna

John Walden, 716-771-3588
john_walden@rge.com

1. Feedwater flow

2. Uncertainty is aprox. 1.72%. The limit is < 2%.

3. Venturi/Flow nozzle, and wetted transducer ultrasonic transit time meter

South Texas Project

Dan Sicking, 512 972-7678
dcsicking@stpegs.com

1. Feedwater flow

2. 1.3% overall (this value is conservative since it is based on old transmitter accuracy); 0.5% for venturi alone.

3. Venturi/Flow Nozzle

4. Venturi/Flow Nozzle Technology

4a. Name of the vendor: Westinghouse

    Make: Permutit

    Model: Serial #s N-1533, N-1534, N-1535, N-1536

    Nominal rating: 440 Degree F.; 1210 PSIA; 5,557,000LB/Hr each; 15.25"*8.063" (nominal size); 0.5287 (Beta Ratio)

Pipe size: 18"- SCH. 120

4b. Rosemount Model # 3051PD3A22A1AB4

4c. 3 years

4d. Since we have the new Rosemounts very little maintenance is required. The instruments are calibrated once per 18 months. I&C Craft perform calibration.

4e. 0.5% for venturi

4f. Weigh Tank at Alden Labs

4g. No

4h. Good with minor problems as stated below.

4i. We experience small amount of fouling 0.2-0.4% during the cycle.

Southern Nuclear, Vogtle

Clay Chastain
e.c.chastain@snc.com

1. Feedwater flow

2. 0.5% with Barton transmitter

3. Venturi/flow nozzles

4a. Stainless steel, no experience with fouling. Visual inspection every outage (18 months). Will now go on 36 month inspection cycle.

4b. Barton, MD&CL, # not known

4c. 1987 (Unit 1) and 1989 (Unit 2)

4d. 1 shift per calibration. No other maintenance.

4e. 0.5%

4f. Same

4g. Every quarter since 1987 (Unit 1) and 1989 (Unit 2)

4h. Does not foul; no MW loss; repeatable. Very satisfied.

4i. None other than industry problems. Attribute this to careful chemistry control on the secondary side; SG sludge removal shows very minimum content.

5a. Not applicable

9. Good chemistry control and steady operation.

Tennessee Valley Authority, Sequoyah

Richard Mooney, 423-843-7293
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1. Feedwater flow

2. 1%

3. Venturi/flow nozzle, chemical tracer tests, strap-on ultrasonic transit time meter, and radioactive tracer (1984). Recently started evacuating “non-throat tap” nozzle flow indication.

4a. Make: BIF

Model: 0183, Universal venturi tube

Pipe Size: 18”

4b. Process: Foxboro E13DM. Precision: Rosemount 3051

4c. 15 years

4d. 8 hr/year each, calibration, instrument mech.

4e. 4 loop “as left” total NSSS uncertainty; +0.54%

4f. Alden Research Lab (hydraulic lab)

4g. Yes, same ~1990

4h. Except for venturi fouling – OK.

4i. Venturi fouing

5a. ABB C.E. Themtrac (French)

5b. 1990, 1991

5c. Yes, correction to constant in process computer to correct FW flow

5d. 2

5e. <0.5%

5f. Lithium

7a. Caldon 8300 LEFM

7b. 2, 1/unit

7c. 6 years

7d. +0.93%

7e. Alden Research Lab

7f. Yes, correction is applied equally to each of the four loop flow calculations in the process computer.

7g. 16 hrs/cycle/unit, recoule/verify calibration of electronics, Caldon

7i. Non repeatability (but within accuracy band) with old model non-PFT transducer. New zinc pad/PFT transducer appeared to have 6 month burnin of ~-0.5%, otherwise very repeatable.

9. Include in this survey "non-throat tap" nozzle results when compared to throat tap BIF venturi that are actually fouling. Our comparisons during one fouling event (post copper removal, post ETA usage) was promising! (Fouling was 0.5% -0.75%, estimated from ΔT, impulse pressure, LEFM and non-throat tap nozzle.) Has anyone made corrections for fouling based on a combined statistical value from various power indicators (without ultrasonics)?

Tennessee Valley Authority, Watts Bar

Charlie Wood, 423-365-8969
cewood@tva.gov

1. Feedwater flow

2. +1.2%

3. Venturi/flow nozzle and strap-on ultrasonic transit time meter

4a. Vendor: BIF/General Signal

Make: Universal/venturi tube

Model: 0183-18-4956

Nominal rating: 3.973 x 10^6

Pipe size: 18 inch

4b. Don't use transducers, use transmitters (Rosemont)

4c. Since startup (~3 years)

4d. We calibrate loops every outage.

4e. 1.2%

4f. Vendor calibrated off site.

4g. No recall since installation.

4h. Rely on venturis when not fouled. Use ultrasonic to calculate a multiplier when fouled.

4i. Fouling

5a. Westinghouse

5b. After startup at 100% power

5c. Na_{24} test performed to determine steam quality. Steam quality accounted for in calorimetric.

5d. Twice

5e. Don't know but very accurate.

5f. Sodium (Na_{24})

5g. Chemical sampling, radioactive decay or carryover.

5h. High confidence.

5i. None

6a. N/A, ours are not wetted.

7a. LEFM

7b. One

7c. 3 years

7d. $\pm$1%

7e. Vendor

7f. Correction is applied as a multiplier to the feedwater flow in the calorimetric calculation.

7g. One to two visits per year by vendor.

7h. Good

7i. Transducers failing, transducer gel replacement.

8a. Not applicable

9. We are getting rid of copper, which should significantly reduce our venturi fouling. Increasing ETA concentrations also appear to slow the fouling rate.

Virginia Power, Surry

Bernard Sloan, 757-365-2731
Bernard_Sloan@vapower.com

1. Feedwater flow

2. 2.7%

3. Venturi/Flow Nozzle, Chemical tracer tests

4a. Name of the vendor:

Make:ALL WELD

Model:

Nominal rating:1550 psig @ 650F

Pipe size:14"

4b. Rosemount 1152DP5

4c. 7 years

4d. Inspection and cleaning performed every 36 months by Mechanical Maintenance

4e. None stated. It is assumed that measurements taken within tolerance guarantee acuracy.

4f. L&N Flow Test, Special Test to confirm L&N using Chemical Tracers

4g. No

4h. Satisfactory

4i. None

5a. CE

5b. 1991 & 1995

5c. No

5d. Twice

5e. 0.25%

5f. Lithium Nitrate

5g. No answer

5h. Excellent

5i. None

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