OTC 19525

Virtual Metering Technology Field Experience Examples

Prashant Haldipur, Ph.D., SPE; Gregory Metcalf, SPE; Multiphase Solutions, Inc.

Copyright 2008, Offshore Technology Conference

This paper was prepared for presentation at the 2008 Offshore Technology Conference held in Houston, Texas, U.S.A., 5–8 May 2008.

This paper was selected for presentation by an OTC program committee following review of information contained in an abstract submitted by the author(s). Contents of the paper have not been reviewed by the Offshore Technology Conference and are subject to correction by the author(s). The material does not necessarily reflect any position of the Offshore Technology Conference, its officers, or members. Electronic reproduction, distribution, or storage of any part of this paper without the written consent of the Offshore Technology Conference is prohibited. Permission to reproduce in print is restricted to an abstract of not more than 300 words; illustrations may not be copied. The abstract must contain conspicuous acknowledgment of OTC copyright.

Abstract

This paper discusses the recent advances made in virtual well metering technology and presents the experience gathered from deploying the technology in the Gulf of Mexico and various other locations globally over the last five years. Project execution best practices, including specifications, acceptance testing and commissioning procedures, are presented for deploying this advanced technology.

The paper presents field data comparison and shows that this technology has provided very reliable and accurate flow rate predictions over a variety of well configurations and reservoir characteristics (from gas condensate to black oil systems over a wide range of GOR/GLRs). The value of the dynamically estimated flowrate uncertainties in addition to real-time, continuous well flowrate estimates is described. These systems are equipped with real-time calibration programs that reconcile the total well production, on a daily or weekly basis, with the fiscal production and then back-allocate the production to the wells based on the calculated well flowrate uncertainties.

These well metering systems are easily integrated with real-time pipeline flow monitoring systems to provide real-time advisory capability to the operator. These systems have expanded in recent years to include leak detection/restriction detection capabilities, look-ahead/forecasting capabilities that offer flow assurance guidance on operational issues such as cool-down, warm-up and hot-oil circulation times, and the paper presents such examples.

Introduction

Multiphase flow simulation technology has matured to the point where it is frequently used to tackle flow assurance problems during design as well as day-to-day operation of oil and gas pipelines. Simulations are used, for example, in sizing pipes and thermal insulation; developing procedures for start-up, shutdown, and process upsets; and avoidance of wax and hydrate formation. An emerging application area is “online” simulators [Parthasarathy, P. et al., 2007] which are integrated with field data acquisition systems (DCS/SCADA). The demands on online systems differ considerably from design simulation tools [Llave S., 2005]. Design tools can assume idealized conditions, with precise knowledge of process parameters (inlet/outlet pressures and flowrates, fluid compositions, etc.). Corresponding measurements are often unavailable in the field. Numerical models must therefore be flexible to use such data as available. Models must handle instrument drop-out, noise, bias and drift, and incorporate filtering to stabilize the numerical model. Compositional uncertainties must be addressed by building in tuning factors so that predictions match the measured outlet phase rates. Online simulators are key to implementing model-based leak/restriction detection systems, which are the only viable systems for subsea multiphase pipeline networks [Scott, S.L and Barrufet, M.A., 2003].

Real-time readings from the gas and liquid export flow meters are usually available for export pipelines that extend from the offshore platforms to shore receiving facilities. These rates are used to feed online simulators via the field data acquisition systems (DCS/SCADA). These online simulators in turn provide real time information on pipeline holdup, pressure, flowrate, and temperature profiles; arrival slug size; pig tracking; and proximity to hydrate or wax formation. A powerful application is to combine field data and online model predictions to run look-ahead simulations. For example, safe pigging campaigns can be planned to ensure that the swept liquids will not flood the slug-catchers [Haldipur, P. et al., 2007].

For simulating infield subsea flowlines that extend from the wells to topsides, a common problem is the lack of real-time three-phase flowrates from the wells. One option is to install subsea physical multiphase flowmeters, but this is expensive; also, testing, calibration, and post-installation tuning of these meters are often problematic. Further, for subsea installations, it is not economically viable to remove these meters in order to carry out any type of maintenance if needed. Increasingly, operating companies are turning to software based solutions to estimate the well flowrates in real time.

This technology is known as virtual metering. Virtual Metering Systems (VMS) use the existing pressure and temperature measurements in and around the well to estimate the well flowrate. Multiphase Solutions (MSi) first deployed VMS in the