2007.09.14 15:43:46
Kansas Corporation Commission
/S/ Susan K. Duffy

**BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS**

IN THE MATTER OF THE APPLICATION OF ATMOS ENERGY CORPORATION FOR REVIEW AND ADJUSTMENT OF ITS NATURAL GAS RATES	))))	**Docket No. 08-ATMG-280-RTS**

DIRECT TESTIMONY OF

DAVID ANGLIN

FOR ATMOS ENERGY CORPORATION

I. INTRODUCTION

Q. PLEASE INTRODUCE YOURSELF.

A. My name is David Anglin. I am the Director of Utility Operations in charge of several utility operations projects, including the automated meter reading program, for Atmos Energy Corporation ("Atmos", "Atmos Energy" or "the Company"). My business address is 5430 LBJ Freeway, Suite 1800, Dallas, Texas 75240.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I earned a Bachelor of Science degree in Business Administration from the University of Tennessee in Knoxville, Tennessee. I also completed the University of Tennessee's Management Development Program as well as the Executive Development Program.

I began my career with the Company in 1976 as a Sales Representative with United Cities Gas Company ("UCG"), which was acquired by the Company through merger in 1997. In 1980, I was promoted by UCG to assistant manager of UCG's operations in Columbia, Tennessee. In 1981, I was promoted by UCG to manager of the company's operations in Vandalia and Virden, Illinois. In 1986, I was promoted by UCG to Director of Marketing and relocated to the company's corporate offices in Brentwood, Tennessee. In 1987, I was promoted by UCG to Vice President of Marketing.

In 1995, I was promoted by UCG to Vice President and General Manager for the Georgia and South Carolina Division. I remained in my position as division Vice President of Operations for the Georgia service territory until 2001, when I moved to Colorado and became Vice President of Operations for the Colorado/Kansas Division of the Company in charge of operations in Colorado.

Q. WHAT WERE YOUR RESPONSIBILITIES AS AN OPERATIONS VICE PRESIDENT?

A. As an operations vice president for the Company (and formerly for UCG), I had responsibility for and oversight of meter reading, safety, operations, maintenance, construction, and customer service in connection with the Company's regulated utility operations within Georgia and subsequently in Colorado. My duties included developing, recommending, implementing and monitoring short and long-term strategic plans and initiatives to achieve profitability and growth for the Company's Georgia, and later Colorado, operations while maintaining safe and reliable natural gas service to our customers.

In July 2007, I was promoted to my current position as Director of Utility Operations in charge of special projects.

Q. AS PART OF YOUR OPERATIONS MANAGEMENT RESPONSIBILITIES, YOU INDICATED THAT YOU HAD OVERSIGHT OF METER READING IN YOUR GEOGRAPHIC REGIONS. PLEASE DESCRIBE THESE DUTIES IN MORE DETAIL.

A. The oversight of the Company's meter reading processes and functions in Georgia and Colorado required that I have extensive knowledge of these processes and functions. Part of my responsibilities included oversight of a meter reading workforce of approximately 13 employees in Georgia and 19 employees in Colorado. I was ultimately responsible for ensuring that customer meters were read accurately each month and the data was transmitted to the billing department and/or uploaded properly into the Company's customer information system to ensure accurate and timely billing. I was also charged with ensuring adequate staffing of the meter reading workforce and addressing employee issues relating to injuries, lost-time incidents and vehicle accidents. I was additionally responsible for addressing customer complaints or issues in my area of responsibility arising from meter reading inaccuracies, property damage or theft of gas service.

I have also served as a member of the Company's Utility Operations Council (UOC), which is responsible for reviewing and implementing common practices across the enterprise where feasible. The UOC's membership is comprised principally of operations vice presidents from the Company's various utility divisions, as well as representatives from technical services, legal, risk management, procurement and human resources. I was also a member of a UOCsponsored team that monitored and analyzed the Company's field operations workload and manpower plan for five years and I chaired that team for two years. The meter reading function was one of those functions analyzed by this team. As will be explained later in my testimony, in January of 2006, I was appointed by the UOC to chair an enterprise Automated Meter Reading (AMR) strategy team to begin seriously reviewing the Company's options with respect to simplifying the metering process as well as improving the accuracy of meter reads. My responsibilities with this team ultimately culminated in my appointment to my current position within the Company.

Q. WHAT ARE YOUR CURRENT JOB RESPONSIBILITIES AT ATMOS ENERGY?

A. I am principally responsible for and have oversight of the Company's AMI project including administering the overall budget for and implementation of the technology.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KANSAS CORPORATION COMMISSION ("KCC") OR OTHER REGULATORY ENTITIES?

A. No. I have never testified before the KCC. However, I have previously testified before the Georgia Public Service Commission in two rule-making dockets concerning main extensions and promotional practices. I also testified before the Georgia Public Service Commission on the Company's cast iron replacement program in Georgia. I subsequently testified before the Colorado Public Utilities

Commission in 2004 in connection with the Company's acquisition of a natural gas utility system in Buena Vista, Colorado.

Q. DO YOU HAVE ANY OTHER EXPERIENCE TESTIFYING?

A. Yes. In 1997, I was selected by the Lieutenant Governor of Georgia to serve on that state's Senate Study Committee for Natural Gas Deregulation. As part of my responsibilities in serving on that committee, I presented testimony before the Georgia Joint House and Senate Study Committee for Natural Gas Deregulation.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will testify with respect to the Company's Advanced Metering Infrastructure (AMI) initiative. In my testimony, I will provide an overview of AMI and compare it to the Company's historical and current meter reading practices. I will also discuss how AMI is superior to past and existing practices. I will talk about current natural gas industry trends regarding the implementation of AMI.

I will describe the evolution of the Company's decision to move forward with the implementation of AMI, how it will be implemented and the projected cost to the enterprise.

My testimony will also address some of the energy efficiency benefits of AMI for both the utility and the consumer. Finally, I will address the current national regulatory environment regarding AMI.

Mr. Mike DeArmond, who is also a Company witness in this proceeding, will further discuss the impact upon and benefits to Kansas ratepayers from the implementation of AMI, as well as the costs associated with the roll-out of AMI in Kansas. Mr. DeArmond also addresses the proposed rate treatment in Kansas for AMI costs requested by the Company in this rate proceeding.

III. OVERVIEW OF ADVANCED METERING INFRASTRUCTURE

Q. WHAT IS ADVANCED METERING INFRASTRUCTURE (AMI)?

A. AMI is a fixed based automated meter reading (AMR) network that will eliminate the necessity of manual meter reading because it essentially provides "real-time" consumption data that is electronically transmitted from a customer's gas meter to the Company's customer information system. AMI goes beyond AMR because it provides customer service and energy efficiency enhancements that do not exist in a system that performs only electronic meter reading.

Q. SO THE TERMS "AMR" AND "AMI" ARE NOT EXACTLY SYNONYMOUS?

A. Not exactly. AMR is more or less an electronic replacement of the manual meter reading process. It significantly enhances metering and billing accuracy. It also provides many of the other benefits of AMI that are discussed later in my testimony. However, in recent years, improvements and enhancements to AMR have led the industry to describe the improved technology as AMI. AMI provides numerous additional benefits to both the consumer and the utility. Moreover, the future holds many additional benefits as regulatory initiatives begin to unfold. As a result, the Company will be in a better position to implement such programs.

Q. HOW DOES AMI WORK?

A. An electronic transmitter will be installed on each customer's meter. The transmitter electronically "reads" the mechanical volumetric readings performed by the meter on an hourly basis with respect to natural gas that is flowing through the meter. The transmitter sends an electronic data feed, or "pulse", every six hours to a geographically proximate communications tower. Each pulse contains six hours of meter readings from a customer's meter and, over the course of twenty-four hours; the four combined pulses will provide information on the customer's consumption every hour during that entire twenty-four hour period. The pulse is received by an antenna mounted on the communications tower and then relayed to a tower gateway base station (TGB) situated at or near the bottom of the tower inside a small mechanical equipment building or similar structure. Depending upon its locations, size, geographical terrain and certain other technical criteria, a TGB can provide coverage for an area of between 75 and 300 square miles in size.

The pulse data that is received every six hours is then compiled by the TGB and transmitted via secure high-speed phone line or satellite feed to the regional network interface (RNI) located at the Company's corporate data center in Dallas, Texas. Data from an RNI will then be automatically processed and uploaded into the Company's customer information system through an interface. The data is used by the customer information system to generate a customer's monthly bill.

Obviously, the process I have described is a high-level overview and the actual process is much more detailed and complex. However, the description I have provided is essentially the process of how electronic information from a customer's meter travels to the Company's customer information system under the AMI infrastructure.

Q. HOW DOES THE COMPANY CURRENTLY ACCOMPLISH THE READING OF A CUSTOMER'S METER?

A. Once a month, a Company meter reader visits the premise of each customer on an assigned route to manually read the meter. Each morning, the meter reader's route assignments are downloaded into a handheld meter reading device (referred to hereinafter simply as a "handheld"). The handheld enables the meter reader to manually punch in the readings from a meter associated with a specific customer premise that is downloaded as part of his/her daily route assignment.

At the end of each day after performing the assigned meter reading routes, the meter reader will return to the local Company office and insert the handheld into a docking station. The electronically recorded information in the handheld is then uploaded into the Company's customer information system (CIS) for validation and exception processing. Basically, the handheld is an automated version of a meter book.

Q. WHAT IS A METER BOOK?

A. In the days of meter reading before the Company began using the handheld devices, meter readers took a meter route book with them to each customer premise on the route and manually wrote down the readings from the meter. The manual readings were then returned to the local Company office after completion of the assigned route for processing. The individual meter readings were then manually entered into the billing system to produce a customer bill.

IV. THE ROLE OF AMI IN ENERGY EFFICIENCY

Q. WHAT IS THE CURRENT VIEW OF STATE UTILITY REGULATORS REGARDING ENERGY EFFICIENCY?

A. The view of state regulators on energy efficiency can probably best be summed up by the National Action Plan for Energy Efficiency adopted by the National Association of Regulatory Utility Commissioners (NARUC) on July 31, 2006. This action plan provides five recommendations to state regulators as ways to overcome many of the perceived barriers that have limited greater investment by utilities to deliver energy efficiency to customers of electric and natural gas utilities. These recommendations include:

- Recognizing energy efficiency as a high-priority energy resource
- Making a strong, long-term commitment to implement cost-effective energy efficiency as a resource
- Broadly communicating the benefits of and opportunities for energy efficiency
- Promoting sufficient, timely and stable program funding to delivery energy efficiency where cost-effective
- Modifying policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency

Q. HAS NARUC RECOGNIZED THE IMPORTANCE OF AMI TO ENERGY EFFICIENCY?

A. Yes. In February of this year, NARUC adopted a resolution entitled "Resolution to Remove Regulatory Barriers to the Broad Implementation of Advanced Metering Infrastructure". Although the resolution is keyed to foster the deployment of AMI in the electric utility industry, many of the stated benefits and goals of AMI in the resolution are equally applicable to the deployment of AMI at gas utilities. NARUC recommends that regulatory commissions seeking to facilitate the implementation of cost-effective AMI technologies consider several regulatory options, including:

- Pursuing an AMI business case analysis, in conjunction with each regulated utility, in order to identify an optimal, cost-effective strategy for deployment of AMI that takes into account both tangible and intangible benefits
- Adopting ratemaking policies that provide utilities with appropriate incentives for reliance upon demand-side resources
- Providing for timely cost recovery of prudently incurred AMI expenditures, including accelerated recovery of investment in existing metering infrastructure, in order to provide cash flow to help finance new AMI deployment
- Provide depreciation lives for AMI that take into account he speed and nature of change in metering technology

In adopting this resolution, NARUC recognized many of the benefits of AMI to consumers including, among others, improved metering accuracy and customer service and expedited service initiation and restoration.

Q. REGULATORS HAVE CLEARLY RECOGNIZED THE BENEFITS OF AMI TO ENERGY EFFICIENCY IN THE CONTEXT OF ELECTRIC UTILITY SERVICE, BUT HOW DOES AMI PROMOTE ENERGY EFFICIENCY FOR GAS UTILITY SERVICE?

A. The AMI technology will facilitate energy efficiency for both Supply Side Management (SSM), the utility, and Demand Side Management (DSM), the customer. SSM entails a number of factors including forecasting supply requirements of customers for the gas commodity as well as delivering the commodity to the customer. DSM involves the ability of the customer to more closely monitor consumption and to make energy consumption choices or changes based upon information available to the customer.

Q. HOW DOES AMI FACILITATE SSM EFFICIENCY?

A. A gas utility such as the Company has two primary cost components in providing natural gas service to its customers – the cost of the commodity (which is recovered from customers through the Company's purchased gas adjustment clauses) and the cost of delivering the gas to the customers (the cost of service upon which state regulators determine the Company's applicable rates). With respect to the cost of delivering the gas to the customer, I have already discussed in greater detail earlier in my testimony some of the material benefits associated with the implementation of AMI through the reduction or avoidance of O&M expense that is inherent in manual meter reading processes.

With respect to commodity cost management, perhaps the overarching benefit of AMI is improved metering accuracy and the availability of real-time consumption data. Specifically, meter reading data is currently aggregated and used for purposes of system load forecasting in connection with gas supply planning purposes. More accurate metering data means that load forecasting will be more closely tied to actual consumption requirements. Another feature of AMI is that it will improve the accuracy of accounting for lost & unaccounted (L&U) gas and eliminate the cycle billing component of L&U, as well as giving the Company the ability to actually calculate rather than estimate unbilled revenue.

As for the customer's side of the meter, AMI is a customer empowerment tool. Ultimately, daily consumption information through AMI will be available to the Company's customers through a secure website. The ability of a customer to review his or her hourly or daily consumption patterns within any given month enables that customer to make informed choices regarding his or her energy consumption and allows them to utilize our services more efficiently.

Q. HOW WOULD THIS WORK?

A. Suppose that a customer received his bill at the end of the billing cycle in a spring month and noticed that it was unusually high for that period. Through the website, he could identify the days within that month where consumption had peaked, or, if he called the Company's customer contact center, a Company employee could assist the customer in identifying that same information through the same website. If, for example, there was a period of 3 or 4 days within that month when consumption spiked and the customer was using his gas-fired pool heater all day, then he would know why consumption increased during that particular 3 or 4 day period. Armed with this knowledge, the customer could implement consumption changes such as reducing the amount of time that his pool heater is running in subsequent periods.

Moreover, consumption spikes could be indicative of old gas appliances that are wearing out and operating inefficiently or even leaks on the customer's side of the meter in customer appliances or piping. Access to timely consumption information will enable a customer to inquire of the Company regarding such matters that could facilitate a quicker investigation and remedial action. In short, in managing energy use timely, knowledge and information are essential tools. AMI will provide customers with those tools.

Another feature of AMI for purposes of DSM will be the ability of customers to select their preferred billing date, which will enable them to more effectively manage their budgets and costs.

In his direct testimony, Mr. DeArmond also explains some of the additional benefits of AMI for DSM through the enhancement of customer information sources and energy management tools that are already available to customers on the Company's website.

V. OTHER ADVANTAGES PROVIDED BY AMIT

Q. WHAT ADVANTAGES DOES AMI HAVE OVER HISTORICAL AND EXISTING METER READING PROCESSES?

A. In addition to promoting energy efficiency, which I will discuss later in my testimony, AMI presents a number of advantages including:

- "Real-time" meter reading
- Elimination of human error

- Elimination of "read and run" and re-read orders
- Reduced operating and maintenance (O&M) expense
- Enhancement of customer safety
- Early detection of meter measurement problems
- Elimination of most customer premise accessibility issues
- Reduction in potential for damage claims and lost-time incidents
- Reduction in theft of service

Q. WHAT DO YOU MEAN BY "REAL-TIME" METER READING?

A. Under historical and current processes, meter reads (unless subject of a separate service order such as a read and run) are typically taken once a month. Accordingly, customer consumption patterns are only available on a monthly basis and more frequent usage data is not available. Obtaining additional meter reading information requires the dispatching of a service technician to the customer premise to manually read the meter. With AMI, customer consumption data will be available at multiple intervals each day which, within certain predefined parameters programmed into CIS, will allow the Company to be in a position to determine as early as mid-month if there is a potential problem, such as a leak, which might correspond to an abnormal usage spike. Moreover, along with hourly consumption data, AMI records ambient temperature recordings which, once the applicable protocols in CIS are programmed, will facilitate the reduction of accidental service terminations during applicable regulatory cold weather rule periods.

Q. HOW WILL AMI ELIMINATE HUMAN ERROR?

A. AMI eliminates the necessity of the manual recording of meter reads. Even though a handheld is much more efficient and accurate than the old meter books, the monthly consumption data must still be entered manually into the handheld and is subject to human error, whether through the transposition of numbers, omission of a number indicated on the meter dial or otherwise. Although the Company has in place a back-office meter reading exceptions process which, when combined with the use of handhelds, improves the Company's meter reading accuracy rating, the use of AMI is expected to raise the enterprise-wide meter reading accuracy rate even further since it eliminates human error from the process. It should be noted that the Company prides itself on the accuracy of its current meter reading process that results in minimal errors. However, accuracy in meter reading is of paramount importance to both the Company and its customers and any improvement to accuracy yields additional benefits to both.

Additionally, mechanical meters may ultimately malfunction and begin registering zero-use. Such malfunctions may go undetected for a period of time because they may be assumed to be caused by customer vacancy. Reducing the number of malfunctioning meters and other metering issues will result in more accurate bills.

Q. WHAT ARE "READ AND RUN" ORDERS AND HOW WILL AMI ELIMINATE THEM?

A. A read and run service order is basically an out-of-cycle meter read performed by a Company service technician. It is often prompted by a customer move from one residence to another. If a customer calls the Company's customer contact center and requests a final bill because he or she is moving, then a special service order must be generated to send a service technician to the customer premise to perform a final meter read for the purpose of rendering a final bill for natural gas service to that specific premise under the customer's account. Often the Company is required to send a service technician to read the meter for a customer moving out one day and then return to the same premise within a day or so to read the meter again for a customer moving into the premise. Annually, the enterprise-wide O&M expense associated with performing read and run service orders is over $7 million. AMI will allow a final meter read to be performed through CIS from the Company's billing center without the necessity of dispatching a service technician to perform a manual meter read.

Q. HOW WILL AMI REDUCE O&M EXPENSE?

A. In addition to elimination of O&M expense associated with read and run service orders, additional O&M expense will be avoided through the eventual elimination of the meter reading function. Manual meter reading is a very labor-intensive function which requires considerable walking and driving by the Company's meter readers. Meter readers must deal daily with sometimes dangerous traffic and customer premise accessibility issues. Meter readers also typically have relatively high injury rates due to repetitive motion, high vehicle use and everyday work hazards, such as unrestrained dogs that are prone to bite.

Over time, the implementation of AMI will eliminate the need for maintaining a workforce of employees whose primary function is performing only meter reading. Elimination of these positions also includes costs associated with labor, office meter reading routing and support, vehicles and associated fuel, computer hardware and software, equipment, uniforms and supplies. The eventual elimination of most of these positions and related ongoing costs, along with the associated injuries, accidents, lost-time incidents and property damage claims, is projected to yield up to $28 million annually in avoided operational costs on an enterprise-wide basis.

Q. HOW WILL AMI ENHANCE CUSTOMER SAFETY?

A. The real-time meter reading benefit of AMI is the ability to more quickly detect gas usage anomalies. For example, if there is a leak in a customer's piping or appliance, it is more likely than not that the resulting meter reading would increase over and above normal consumption indicated by the pre-set parameters of CIS. This would trigger an alert in CIS that would prompt a Company customer support associate to issue a field service order to investigate the cause. AMI would effectively enable the Company to detect anomalies such as gas leaks as much as one month faster than it does under current practices.

Q. YOU ALSO STATED THAT AMI WOULD REDUCE MOST CUSTOMER PREMISE ACCESSIBILITY ISSUES. PLEASE EXPLAIN.

A. Manual meter reading requires access to a customer's premise for purposes of performing a meter read at least once a month. Access to a customer's premise presents additional problems such as employee injury resulting from dog bites or other causes. Across the enterprise in 2006, there were 76 reported employee injuries to Company meter readers from a variety of causes such as dog bites, insect stings, sprains and strains, slips and falls and vehicle accidents. These injuries ranged from relatively minor to moderately serious. Although Company employees will still require periodic access to a customer's premise to inspect the meter and electronic data transmitter, the requirement for monthly access will be effectively eliminated. Less intrusion onto a customer's premise also translates into greater customer privacy.

Q. HOW DOES AMI REDUCE THE POTENTIAL FOR DAMAGE CLAIMS AND LOST TIME INCIDENTS?

A. The reduction in the potential for damage claims associated with customer property is attributable to the reduced requirement for access to a customer's premise. Additional reduction in the potential for damage claims also stems from the fact that the Company will have fewer vehicles on the road thereby decreasing the possibility of vehicular accidents involving meter readers. For example, in 2006, there were a reported 54 vehicular accidents involving Company meter readers across the enterprise.

Lost time incidents are incidents that result in lost work days attributable to on-the-job injury. Because meter readers must perform a great deal of walking, bending and other physical activities, they are more prone to on-the-job injuries such as sprains, strains and other injuries related to repetitive motion. In 2006, in addition to reported dog bite incidents and vehicular accidents, the number of lost work days attributable to on-the-job injuries suffered by meter readers across the enterprise was 242. Additionally, there were 96 reported restricted duty days.

Q. HOW WILL AMI REDUCE THEFT OF SERVICE?

A. A common method of theft of gas service is through meter bypass, which is typically effected by a customer turning a meter on, or back on, in an unauthorized manner and often times by breaking off the Company's lock. During calendar year 2006, 90+% of energy theft discovered by the Company was reported by meter readers, predominantly as a result of broken locks or tampering with a gas meter to affect the gas usage measurement. Using tamper alarms and analyzing hourly usage, the Company anticipates that these methods of energy theft can be greatly reduced, if not altogether eliminated.

Q. IS THE COMPANY THE ONLY GAS UTILITY TO IMPLEMENT AMI?

A. No. In fact, a number of major gas utilities across the country have already implemented, or are in the process of implementing, automated metering infrastructure. For example, South Carolina Electric & Gas began implementing the technology in South Carolina this year and expects to complete its entire roll-out of the technology in that state by 2011. SEMCO Energy implemented the technology in Michigan beginning in 1999 to over 228,000 gas customers. AGL Resources began implementing the technology in 2001 for its Atlanta Gas Light operations to over 1.3 million customers in Georgia and subsequently to the customers served by AGL's Virginia Natural Gas and Florida City Gas operations. Under a three-year roll-out, Mid-American Energy implemented the technology for both its electric and gas utility customers in Iowa, and Montana-Dakota Utilities Company implemented the technology for its 277,000 electric and gas customers. ONEOK began implementation of the technology in 2004 to its Oklahoma Natural Gas customers and LaClede Gas implemented the technology for its 630,000 gas customers in Missouri beginning in 2005. Alliant Energy announced the installation of AMI across its 1,000,000 electric and 400,000 natural gas customers in Wisconsin and Iowa beginning in the fall of 2007. Other utilities that provide natural gas service and which have implemented the technology, or are in the process of doing so, include NW Natural in Oregon, Piedmont Natural Gas in North Carolina and Tennessee, San Diego Gas and Electric Company in California, Equitable Resources in Pennsylvania, and the City of Pensacola, Florida.

According to a recent statistical study published in The Scott Report (10^{th} edition), as many as 79 million electric, gas and water meters across the United States have been enabled with and are using automated metering technology. Automated metering has already been or is being implemented by a number of the electric utilities in this country and implementation by gas utilities is quickly becoming the norm.

VI. EVOLUTION OF THE COMPANY'S DECISION REGARDING AMI

Q. WHEN DID THE COMPANY FIRST BEGIN EVALUATING AMR OR AMI?

A. The Company began looking at AMR some time around 1999 or 2000. The technology that I now refer to as AMI was either not available or adequately reliable at that time.

Q. WHAT PROMPTED THE COMPANY TO EVALUATE AMR?

A. The meter reader position within the Company, as with most utilities, typically has the highest attrition rate. Although the Company was not experiencing significant attrition within its meter reading workforce at that time, the Company elected to move forward with some interim pilot programs to test the AMR technology that was available at the time.

Q. WHAT TYPES OF AMR SYSTEMS WERE EVALUATED?

A. There were basically two such systems - fixed-based systems and mobile systems. The fixed-based system (although now substantially updated and more technologically reliable) is the one the Company is currently implementing. It uses the meter-mounted transmitter to pager tower technology. The mobile system is one where a meter-mounted transmitter sends a signal to a receiving device installed in a Company vehicle. As the vehicle drives by, the system in the vehicle sends a "wake-up" signal to the radio transmitter on the customer's meter. The meter transmitter receives the signal and begins sending meter reading data back to the receiver in the vehicle. Once the data is collected, it is then supplied to the utility's customer billing system where it is matched to the customer's account number. Most gas utilities that have already implemented or are in the process of implementing automated metering technology have installed either or a combination of both of these types of systems.

Q. DID THE COMPANY ELECT TO TEST EITHER AVAILABLE SYSTEM?

A. Yes. We decided to test both systems beginning around 2001. The mobile system was installed on approximately 200 of the Company's gas meters in Steamboat Springs, Colorado and the fixed-based system was installed on approximately 200 of the Company's 60,000 gas meters in Columbus, Georgia.

Q. WHY WERE THESE AREAS SELECTED FOR THE TWO SYSTEMS?

A. The altitude and extreme mountain cold of Steamboat during the winter is not particularly conducive to outdoor activity such as meter reading. Accordingly, Steamboat was selected for testing one of the systems. We decided to test the mobile system there because the area is a more remote service location with a smaller number of customers. The area experiences heavy snowfall that makes it difficult to remove snow from the meters each month in order to read them.

Columbus was selected because it was one of the few areas served by the Company at that time that had any reasonable degree of customer density coupled with reasonably available pager tower coverage. Therefore, we decided to test the fixed-based system there.

Q. HOW LONG WERE THE TESTS CONDUCTED AND WHAT WERE THE RESULTS?

A. The Company started each program with the intent of using and testing the equipment for about one year. The mobile system used in Steamboat proved to be very accurate and reliable. In fact, the results of that testing program were satisfactory enough to prompt the Company to subsequently install mobile system transmitters on the remainder of the meters in Steamboat Springs as well as the mountain towns of Durango, Gunnison, Salida and Buena Vista, Colorado. Approximately 2,000 mobile transmitters were also installed on irrigation customer meters in West Texas and on 200 irrigation customer meters in Southeastern Colorado, all of which are spread out over hundreds of square miles. These systems are still used to this day. The irrigation meters are read each month via fly-over by a contracted aircraft equipped with a receiver similar to what has been used in trucks in Steamboat.

Although the results of the fixed-based system tested in Columbus were satisfactory, the system presented various challenges. The challenges associated with that particular fixed-based system arose primarily from the way the technology worked, which was on a direct sequence spread spectrum unlicensed frequency. Essentially, only those customer meters that were located within a zone triangulated by three communications towers could be effectively read electronically. Any data transmitted by a meter outside the triangulated zone may or may not have reached the receiver that relayed the data to CIS. Because the frequency was unlicensed, we could not be assured that other users of this same frequency would not interfere with the communications from our customer meters.

The testing programs in Steamboat for the mobile system and in Columbus for the fixed-based system ended in 2002.

Q. IF THE RESULTS FROM THE MOBILE SYSTEM TESTING WERE SATISFACTORY, WHY DID THE COMPANY NOT PROCEED TO IMPLEMENT THAT FORM OF AMR?

A. Until late 2004, the majority of the Company's service areas across the twelve states in which it operates consisted of rural towns and areas. Installation of a mobile system would have meant that the Company would have to retain a fairly large meter reading workforce that would transition from foot to vehicle for most meter reading. The rural nature of our service territory presented additional challenges ranging from meter accessibility on a customer's property beyond the range of the receiver in the vehicle to increased vehicular driving by Company meter readers. Implementation of mobile systems of AMR in urban areas is much more feasible because the meter reader can drive an entire meter reading route and the receiver in the vehicle will take readings from meters as the vehicle is driven down the street or alley. Airplane flyover meter reading for all residential and customer meters, similar to that done for irrigation meters in West Texas and Southeastern Colorado, was too expensive and worked best in rural service areas. One of the shortfalls of the mobile system AMR is that it remains dependent upon human labor. In order to obtain many of the same advantages of AMI's fixed-based system that is being implemented by the Company (such as real-time meter reads), a mobile meter reader would have to drive by a customer's meter multiple times each week, if not each day. Another shortfall inherent in the mobile system is the persistent issue experienced from continuously removing and reinstalling the truck mounted computer system. Many times it would take longer to get the system operational than it did to read the meters with the system. Although the mobile system showed great promise, it did not really fit the existing or future needs of the Company or its customers.

Q. WHY DID THE COMPANY NOT PROCEED WITH THE IMPLEMENTATION OF A FIXED-BASE SYSTEM AT THAT TIME?

A. Primarily due to the limited success associated with the testing in Columbus and the fact that the communications network infrastructure in the United States was still developing. For example, in 1999 there were an estimated 74,000 communications towers in the United States and the cellular phone boom was just beginning. Installing a fixed-based system in 2002 would have required the construction of separate towers to operate the system, making the project excessively expensive. Since then, the number of wireless customers in the United States has reached over 200 million and is expected to reach almost 270 million people, or about 87% of the U.S. population, by 2010. As a result, the number of communications towers across the country had increased to an estimated 130,000 by the end of 2006. Moreover, although wireless service has expanded dramatically, many of the Company's rural services still have limited wireless coverage. As a result, pagers (the same fundamental system upon which the Company's AMI system operates) are still heavily used in these areas.

Q. AFTER THE TESTING PROGRAMS WERE COMPLETED, DID THE COMPANY CONTINUE TO MONITOR THE TECHNOLOGY?

A. To some degree, but any major evaluation for implementation was tabled for the time being. That subsequently changed, however.

Q. WHAT IS THE CHANGE TO WHICH YOU REFER?

A. In October of 2004, the Company purchased TXU Gas Company. As a result of this purchase, the Company almost doubled in size by acquiring approximately 1.5 million additional customers and, for the first time in its history, began serving an area with a high population density. Almost 1 million of the Company's customers served by its Mid-Tex Division (the former operations of TXU Gas) are in the greater Dallas/Fort Worth metroplex.

This was a significant event for the Company and presented a multitude of operational challenges, including meter reading. For almost a year after the acquisition, TXU Electric performed meter reading services for the Company's Mid-Tex Division pursuant to an agreement entered into in connection with the acquisition transaction. In the latter part of 2005, the Company hired an entire meter reading workforce from TXU (over 150 additional employees) as part of the in-sourcing of the Mid-Tex Division's meter reading function and transition away from TXU. During that time, the Company's real-world experience with operating a utility property in a densely populated metropolitan area led it to once again seriously begin consideration of AMI. Operational issues such as meter reading errors and accuracy, meter reader training and re-training as a result of high attrition, and meter reader safety were seen as problems inherent with operating a large urban utility that could be alleviated or altogether eliminated through the implementation of AMI.

Q. WHEN DID THE COMPANY AGAIN BEGIN REVIEWING AMI?

A. In or around January of 2006, the Enterprise AMR Strategy team was formed and I was selected by the UOC to chair it. Additional members for the team were selected from different disciplines within the Company including operations, meter reading, information technology, procurement and measurement. Several of the team members, including myself, also had prior experience with or exposure to automated metering technology.

Q. WHAT HAPPENED AFTER THE TEAM WAS SELECTED?

A. The team began reviewing the latest available AMR technology and solicited requests for proposals from six different vendors in February 2006. The prospective vendor list was narrowed to two and the Company received presentations from both of them in May 2006. After reviewing and considering the presentations from both vendors, the team made a recommendation to the Company's senior management in mid-2006 that the Company proceed with the implementation of the fixed-based AMI technology.

In November of 2006, the team made an updated recommendation to the Company's senior management and, in February of this year, formally requested approval for an AMI pilot program. In addition, the vendor selection was completed and the Company elected to utilize the services and technology offered by Sensus Metering Systems ("Sensus"), one of the premier vendors of automated metering technology and infrastructure. The name of the AMI technology that the Company will be implementing is known as FlexNet.

VII. IMPLEMENTATION OF AMI

Q. WILL THE COMPANY REQUIRE ANY NEW INFRASTRUCTURE IN CONNECTION WITH THE IMPLEMENTATION OF AMI?

A. Yes. AMI requires that each customer meter have an electronic transmitter installed on it. As transmitter installations are made, existing meters will be inspected to determine whether replacement is required. However, the Company has projected that less than 10% of total meters across the entire enterprise will require replacement.

In connection with the implementation of AMI in any given area, Sensus will first perform a study to determine what towers can best serve a particular area. The triangulation issues inherent in the Columbus test study and discussed earlier in my testimony have been rectified by advances in fixed-based system technology and extensive expansion of wireless infrastructure, and should no longer present the problems previously encountered in Columbus.

Q. WHAT HAPPENS AFTER THE APPROPRIATE TOWERS ARE IDENTIFIED AND SELECTED?

A. The Company will then negotiate leasing rights to install and maintain data reception/transmitting equipment on the towers. Sensus will then install a TGB that will send meter reading data to the RNI. Sensus currently holds the Federal Communications Commission licenses necessary to operate this system and the Company's contract with Sensus will enable the Company to utilize those frequencies. Through an interface with the Company's CIS, the RNI will upload customer premise meter reading data into CIS. The interface, and any appropriate modifications to CIS, are being constructed by the Company's information technology team in tandem with consultation from Sensus. In connection with all of this, the implementation of AMI will also require the one-time purchase of a computer system that will be housed in the Company's corporate offices in Dallas, Texas.

Q. WHAT WILL AMI COST?

A. The Company has projected that its total capital investment to completely implement AMI across the entire enterprise will be approximately $220 million.

Factored over approximately 3.2 million customers, the average per customer cost will be approximately $68. Depending upon the service area, the per customer cost could be higher as a result of lack of customer density resulting in farther installer travel time between customer locations, communications tower licensing or leasing costs (which vary by geographic region or tower owner), number of TGB units required, meter replacement, etc.

Q. WILL THERE BE ANY ONGOING O&M EXPENSE ASSOCIATED WITH AMI ONCE IMPLEMENTED?

A. Yes. Projected annual O&M attributable to AMI after complete implementation is projected to be approximately $3,000,000 enterprise-wide.

Q. DOES THIS MEAN THAT THE COMPANY WILL LAY OFF ITS METER READING WORKFORCE?

A. No, the Company does not intend to implement any wide-spread or wholesale lay-offs. The Company recognizes the value of its employees and has developed an approach to manage labor force impacts as effectively and efficiently as possible. Although the Company expects AMI may eliminate certain functions, any workforce reductions are expected to be achieved through normal attrition and the Company anticipates re-training displaced employees to fill areas of work already existing or new areas of work created by AMI.

Q. HAS THE COMPANY IMPLEMENTED AMI IN ANY OF ITS SERVICE AREAS?

A. The Company is currently implementing AMI on a pilot basis for its operations in the West Bank area of Jefferson Parish, Louisiana, which is just outside of New

Orleans. This pilot program entailed installing AMI for approximately 1,050 customer meters.

Q. IS THE COMPANY IMPLEMENTING AMI ELSEWHERE WITHIN ITS SERVICE AREAS?

A. Yes. During its 2008 fiscal year, the Company plans to implement AMI for its operations in and around Monroe, Louisiana, which will affect approximately 50,000 customers, and in and around McKinney, Texas, which will affect about 20,000 customers.

Q. HOW LONG WILL IT TAKE THE COMPANY TO IMPLEMENT AMI?

A. The Company has projected that it will take 5 years to completely implement AMI across the entire enterprise.

Q. WHEN DOES THE COMPANY ANTICIPATE IMPLEMENTING AMI IN KANSAS AND HOW LONG WILL IT TAKE?

A. Other than those areas where implementation is already underway or approved, the Company has not definitively established an implementation schedule by state or service area. The Company would welcome the opportunity to work with the KCC staff to cooperatively develop a roll out schedule for Kansas customers. We estimate that it will take approximately three years to complete the Kansas AMI installation. The roll-out of AMI to Kansas, however, could be accelerated if the KCC approves the implementation of the Company's tariff requested in this rate proceeding, which is discussed in more detail in the testimony of Mr. DeArmond.

VIII. CONCLUSION

Q. WOULD YOU LIKE TO OFFER ANY CLOSING REMARKS?

A. Metering is a crucial function for both the gas utility and its customers. Advancements in metering technology like AMI should be recognized by state regulatory commissions as an enhancement to a crucial function that provides a wide array of benefits to all stakeholders. Among these benefits is that AMI clearly promotes energy efficiency by providing actual, real time data that empowers both the customer and the utility to make informed choices for both demand and supply side energy management. Ultimately, the achievement of energy efficiency goals is dependent upon the decisions made by both the utility and its customers. Educated choices cannot be made without access to current, accurate and reliable information provided by AMI.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

VERIFICATION

STATE OF TEXAS)
) ss.
COUNTY OF DALLAS)

David L. Anglin, being duly sworn upon his oath, deposes and states that he is Director of Utility Operations for Atmos Energy Corporation; that he has read and is familiar with the foregoing Direct Testimony filed herewith; and that the statements made therein are true to the best of his knowledge, information, and belief.

David L. Anglin

DAVID L. ANGLIN

Subscribed and sworn to before me this 10th day of September 2007.

Ethel Z. Taylor

NOTARY PUBLIC

My appointment Expires:

August 13, 2010

NOTARY PUBLIC STATE OF TEXAS
ETHEL Z TAYLOR
My Commission Expires
August 13, 2010