BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF	)	
SUMMMIT UTILITILIES OKLAHOMA, INC.,	)	
FOR APPROVAL OF ITS PERFORMANCE-	)	CAUSE NO. PUD 202200022
BASED RATE CHANGE PLAN CALCULATIONS	)	
FOR THE TWELVE MONTHS ENDED	)	
DECEMBER 31, 2021	)	

DIRECT TESTIMONY

OF

JOHN D. TRUE

CONTRACT SERVICES MANAGER

ON BEHALF OF

SUMMIT UTILITIES OKLAHOMA, INC.

Filed: March 15, 2022

TABLE OF CONTENTS

EXECUTIVE SUMMARY

My name is John D. True. I am a Contract Services Manager of Summit Utilities, Inc. ("SUI") for Arkansas and Oklahoma, testifying on behalf of Summit Utilities Oklahoma, Inc. ("Summit Oklahoma," "SUO" or "Company"). I am an engineer with over 18 years of utility work experience. I have previously filed testimony with the Oklahoma Corporation Commission ("Commission").

I am providing my testimony in support of the Company's investments in capital infrastructure. I will discuss the importance of and requirements pertaining to the Company's integrity management, public improvements, and customer additions. I am providing an overview of the types of capital additions made by the Company during the 2021 test-year and the drivers behind the Company's need to continually improve its natural gas distribution system for safe and reliable service. First, I address two of the main categories of capital additions: Mains and Services. Second, I address the Company's three most significant project types, which are System Improvement/Integrity Management, Public Improvement Relocations, and Customer Additions.

Relevant to the Company's system improvement/integrity management projects, as required by state and federal regulations, the Company is targeting replacement of assets containing certain material types and ages.

The Company has limited control over Public Improvement Relocations, which are required to remove conflicts with state and local facilities. Finally, costs incurred to add new customers to the system also contributed to the capital additions that showed an increase in 78% of main footage installation from the previous year and a 17% increase of customer service line additions over the same time period.

I recommend that the Commission approve the capital additions in the Company's PBRC Plan calculations.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is John D. True. I am the Contract Services Manager of Summit Utilities, Inc. ("SUI") for Arkansas and Oklahoma. In this proceeding, I am testifying on behalf of Summit Utilities Oklahoma, Inc. ("SUO" or the "Company"). My business address is 1400 Centerview Drive, Little Rock, Arkansas 72211.

Q. BRIEFLY STATE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE AND QUALIFICATIONS.

A. I received a Bachelor of Science degree with a major in Industrial Engineering from the University of Arkansas in Fayetteville, Arkansas, in 2003. In 2007, I received a Master of Business Administration degree from Arkansas State University in Jonesboro, Arkansas. In 2007, I also received my license as a Professional Engineer from the State of Arkansas.

Prior to the SUI asset transfer, I began my career with CenterPoint Energy, Inc. ("CNP") in 2003. Since that time, I have held various engineering and operations positions within CNP. My job duties have generally included the development of construction designs, drawings, and cost estimates for projects related to municipal, county, or state public improvement projects; the evaluation of new products and procedures for use in the various distribution systems comprising CenterPoint Energy Resources Corp.'s ("CERC") Southern Gas Operations and the analysis of failures of the components used in those distribution systems; providing staff support for code compliance, employee technical training, incident investigation, operating practices and procedures; and management of staff performing engineering and field measurement.

My position immediately before my current role was as an Engineering Manager with responsibility for Oklahoma engineering projects.

I am also the past Chairman of the Arkansas Gas Association, which promotes natural gas safety, fosters cooperation between industry and governmental agencies, provides educational programs, and increases public understanding about the benefits of natural gas. I have also worked to provide information concerning the Company's capital projects to the Oklahoma Corporation Commission's ("Commission") Public Utility Division as requested.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. Yes. I filed testimony before the Commission in prior years' Performance Based Rate Change ("PBRC") Plan proceedings, including Cause Nos. PUD 201900019 and PUD 202000028.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to present the Commission and parties with a view into the capital costs required to safely and reliably construct, operate, and maintain the Company's natural gas distribution system in Oklahoma. As part of this discussion, I provide an overview of the major categories of the Company's 2021 capital projects, including a discussion of types of projects that require the Company to invest in its distribution system: system improvement/integrity management projects, public improvement projects, and customer addition projects.

Additionally, the Joint Stipulation and Settlement Agreement ("Settlement Agreement") filed and approved in Cause No. PUD 202100054 requires SUO to include in its first post-transfer PBRC, the following, *inter alia*:

1) A discussion of SUO's procurement process and safeguards in place to assure projects are completed at the lowest reasonable cost while ensuring system integrity and maintaining customer service standards;

2) An outline of any changes made or to be made in the future to SUO's Distribution Integrity Management Plan ("DIMP") or Transmission Integrity Plan ("TIMP"); and

3) An analysis considering whether SUO is able to slow the timetable for certain improvement projects without affecting the safety and reliability of service to customers.

My testimony addresses these requirements, some of which are also discussed by SUO witness Steven Birchfield.

II. CATEGORIES OF CAPITAL ADDITIONS

Q. PLEASE IDENTIFY THE MAIN CATEGORIES OF THE COMPANY'S CAPITAL ADDITIONS IN CALENDAR YEAR 2021.

A. Material 2021 capital additions are shown below in Table 1 – Major Categories of 2021 Capital Additions. Below, I address the two largest categories of 2021 capital additions, mains and services.

Table 1 – 2021 Major Categories of Capital Additions

Category	2021	% of 2021 Total Capital Additions
GRP - G37601 - MAINS	$7,726,573	48.6%
GRP - G38001 - SERVICES	$3,799,250	23.9%
SUBTOTAL OF CATEGORIES LISTED	$11,525,823	72.6%
Total Capital Additions in 2021	**$15,884,023**	**100.0%**

A. MAINS

Q. CAN YOU PLEASE EXPLAIN THE COSTS CAPTURED IN THE MAINS ACCOUNT?

A. Yes. This category, which accounts for 48.6% of the Company's 2021 capital additions, includes distribution main line replacements, relocations, and extensions. As discussed in further detail in Section III below, this capital cost is incurred as a result of (1) system improvements to the natural gas facilities, which include the Company's efforts to maintain a safe and reliable system that complies with pipeline safety standards as set out in its Integrity Management Programs, (2) relocation of mains for public improvements, and (3) extension of existing distribution facilities for customer growth.

Q. DID THE LEVEL OF CAPITAL ADDITIONS FOR MAINS INCREASE IN 2021?

A. Yes. As shown in Table 2 below, this category has increased to over $7.7 million from $7.5 million in 2020, which represents a 2.7% increase. In Section III below, I further discuss each of these categories and explain why the Company must engage in capital spending related to each type of project.

Table 2 -- Mains Category Breakdown by Job Type

	2020	**2021**	**% Change**
Customer Additions	$665,877	$1,921,191	186.4%
Public Improvements	$474,399	$754,523	23.9%
System Imp./Integrity Management	$6,386,619	$5,050,859	-24.5%
Grand Total	**$7,526,894**	**$7,726,573**	2.7%

Q. WHY WERE THE COMPANY'S 2021 SYSTEM IMPROVEMENT ADDITIONS 24.5% LESS THAN THE COMPANY'S 2020 SYSTEM IMPROVEMENT ADDITIONS?

A. As shown in Table 2, the Company spent $1,335,760 *less* on system improvements in 2021 than in 2020, but it spent $1,255,214 *more* on new revenue developments (customer additions) and $280,124 *more* on public improvements. These fluctuations are very natural in the course of gas utility work for several reasons, including the timing and needs of new development opportunities and the timing requirements of public improvement accommodation projects. The resulting numbers indicate that the Company managed its resources according to such timing needs, including shifting subcontractors across geographical areas and between types of work, while also managing its overall capital budget. I describe the nature of public improvements and customer additions and the variances that occur in those categories in more detail below.

Q. DID THE COMPANY DEFER ANY IMMEDIATELY-HAZARDOUS SYSTEM IMPROVEMENT WORK IN ORDER TO MEET THE DEMANDS OF CUSTOMER ADDITIONS OR PUBLIC IMPROVEMENTS?

A. No. The Company continued to follow its plans and procedures relating to recognizing, identifying, and remediating hazards through its daily operations and DIMP activities, as I described in detail above.

B. SERVICES

Q. CAN YOU PLEASE EXPLAIN THE COSTS THAT ARE COLLECTED IN THE SERVICES ACCOUNT?

A. Yes. Similar to mains, costs associated with services are incurred as a result of system improvements and compliance with pipeline safety standards, relocation of services for public improvements, and customer additions projects. As new mains are installed during replacement or extension activities, connected service lines are replaced or installed for the first time to new customers. This is consistent with industry practice to ensure service lines are replaced with the same modern materials as the gas mains.

Q. ARE SERVICE LINES REPLACED INDEPENDENT OF MAIN ACTIVITIES?

A. Yes. Existing service lines may be replaced – or new service lines may be installed – on existing distribution mains independent of main line replacement. When a leak is identified on a service line, the best solution may be to replace that line and make a connection to the existing main. If the gas main is replaced at a later time, this new service line will be connected to the new gas main. Similarly, when it is determined that existing facilities can serve new customer growth, a new service line is attached to the existing main for service.

Q. IS THE COMPANY PROACTIVELY ADDRESSING SERVICE LINES THAT HAVE METER LOCATIONS CLOSE TO A CUSTOMER'S PROPERTY LINE?

A. Yes. If a customer's meter is damaged by a vehicle or other outside force and is not in a location that provides protection from damage, the Company will do one of three things: 1) relocate the meter to the customer's building wall, which is a location protected from future outside force damage, 2) relocate the meter to a safe location further from the property line, as determined case by case, or 3) a barricade may be installed around the meter. These replacement activities may also occur as part of relocation or replacement projects, or independently of main activities if identified outside of main replacement project scoping through leak repair or integrity activities.

Q. IS THIS LEVEL OF CAPITAL ADDITIONS FOR SERVICES GENERALLY CONSISTENT WITH PRIOR YEARS?

A. Yes. There was an increase in capital additions for services from $3,796,333 in 2020 to $3,799,250 in 2021, which indicates this category of capital additions will remain a strong driver as the Company continues to invest in maintaining a safe and reliable distribution system by replacing both mains and services. The total capital cost associated with services will experience natural fluctuation year-to-year, largely based on the quantity of services associated with the main line projects. For example, a public improvement project involving a high-pressure main will likely not have many services directly connected, while a customer addition project to a new residential development may require service installations in double to triple digits.

III. <u>TYPES OF PROJECTS DRIVING CAPITAL INVESTMENT</u>

Q. WHAT ARE THE THREE TYPES OF PROJECTS THAT REQUIRE THE COMPANY TO INVEST CAPITAL IN ITS DISTRIBUTION SYSTEM IN OKLAHOMA?

A. A significant portion of the Company's capital additions fall into one of three types: 1) System Improvement/Integrity Management; 2) Public Improvement Relocations; and 3) Customer Additions. It is these projects that drive the Company's capital spending on mains and services as addressed above in Section II. In this section, I generally explain these types of projects.

A. SYSTEM IMPROVEMENT/INTEGRITY MANAGEMENT

Q. PLEASE PROVIDE AN OVERVIEW OF THIS SECTION.

A. In this section, I begin with a discussion of the federal and state requirements and guidance that together comprise what we refer to as "Integrity Management," and I discuss the Company's distribution integrity management plan ("DIMP") and transmission integrity management plan ("TIMP"), which are designed to ensure that the Company provides safe and reliable service to its customers. Next, I discuss a major component of the Company's DIMP that targets the replacement of certain types of assets based on material type. Finally, I address more specifically one project type that is driving capital cost in the 2021 test-year: risk mitigation associated with the Company's low-pressure systems.

1. FEDERAL AND STATE REQUIREMENTS – DIMP/TIMP

Q. DO FEDERAL AND STATE REGULATIONS IMPACT THE COMPANY'S CAPITAL EXPENDITURES?

A. Yes. The Minimum Federal Safety Standards in 49 CFR Part 192 for gas pipeline and distribution systems require the Company to identify, assess, evaluate, and correct damages to its gas transmission and distribution system, including damage from corrosion, third-parties, excavations, natural forces, and normal wear and tear. Part 192 was amended in 2003 to include the TIMP rules[1] and again in 2009 to implement the DIMP rules.[2] The State of Oklahoma subsequently adopted these rules.[3] In addition, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") and other industry organizations continually update their safety guidance and recommendations of best practices. Together, these rules and guidance require operators such as Summit Oklahoma to identify existing and potential threats to their transmission and distribution systems, evaluate and rank risks posed to their systems by those threats, and determine

[1] *See* 68 Fed. Reg. 69817 (Dec. 15, 2003).
[2] *See 74* Fed. Reg. 63934 (Dec. 4, 2009).
[3] *See* Part 5, Minimum Safety Standards for Gas 165:20-5-21 in the Oklahoma Corporation Commission Gas Hazardous Liquid Pipeline Safety Rules (Oct. 1, 2021).

and implement measures designed to reduce the risks from failure of its transmission and distribution system. These activities can generally be referred to as "Integrity Management" and are documented in the Company's DIMP and TIMP, as discussed below.

Q. IS SUMMIT OKLAHOMA REQUIRED TO PERIODICALLY UPDATE ITS INTEGRITY MANAGEMENT PROGRAM UNDER STATE AND FEDERAL LAW?

A. Yes. To comply with state and federal regulations, the Company must continue to re-evaluate its integrity management programs to ensure they are responsive to threats to its natural gas system. This means that the Company's integrity management programs must evolve as the threats to its system evolve and as technology improves to allow the Company to more accurately detect these threats. In short, Summit Oklahoma must be pro-active, instead of reactive, about inspecting, monitoring and taking measures to reduce or eliminate potential risks.

Q. PLEASE DESCRIBE THE COMPANY'S DIMP.

A. The Company's DIMP is required to validate the integrity of its natural gas distribution systems. This performance/risk-based plan is a comprehensive and systematic approach to meet the regulatory requirements of 49 CFR Part 192 subpart P and builds upon the integrity management activities that are used by the Company. The program uses performance metrics to determine activity effectiveness and the risk-performance combination to initiate root cause analysis to drive improvements and/or additions as necessary.

Q. CAN YOU DESCRIBE THE COMPANY'S FACILITIES THAT ARE INCLUDED IN THE TIMP?

A. Approximately two miles of 10" transmission main in the Lawton system are subject to the Company's TIMP. The Company is currently working on a project to allow for the replacement of this final segment of Oklahoma transmission main, which is located within Fort Sill. The Company has obtained easements with Fort Sill to allow the construction activities to begin in 2022. Due to advances in pipe manufacturing technology from the time of the original installation, the new gas main will operate below the stress thresholds that require the existing line to operate in transmission status. Once replaced, this segment will be managed within the Company's DIMP.

Q. HAVE THE TIMP AND DIMP BEEN REVIEWED WITH THE COMMISSION'S PIPELINE SAFETY DEPARTMENT?

A. Yes. The last TIMP audit was performed October 24, 2018, and the last DIMP audit was performed on December 17, 2020, by the Commission's Pipeline Safety Department.

2. DIMP-TARGETED REPLACEMENT ACTIVITIES

Q. DOES THE DIMP IDENTIFY THE NEED TO REPLACE SPECIFIC MATERIALS?

A. Yes. Summit Oklahoma's DIMP targets the replacement of certain types of assets, specifically: 1) bare steel pipe; 2) legacy steel pipe (includes ineffectively coated pipe and/or pipe having little or no cathodic protection, mechanically joined steel pipe where the fitting provides no resistance to "pull out," and other legacy manufacturing, coating, construction and operating practices); and 3) legacy plastic pipe (which may include legacy manufacturing, construction, and operating practices).

Q. PLEASE DESCRIBE SOME OF THE TYPES OF FAILURES THAT CAN OCCUR WITH THESE SPECIFIC MATERIALS.

A. Bare and legacy steel are susceptible to corrosion failures; mechanically joined facilities are susceptible to gasket/seal/equipment failures. Additionally, legacy plastic prior to 1974 is susceptible to "low-ductility inner-wall" cracking failure caused by a deterioration of the material's ability to respond to a failure mode, and legacy plastic prior to 1984 is susceptible to slow crack growth.

Q. ARE THERE ALTERNATIVES TO REPLACING THESE SPECIFIC MATERIALS?

A. While there are other measures that can be taken to address factors affecting these assets (cathodic protection, fitting reinforcement on plastic squeeze points, etc.), such measures only effectively postpone the eventuality of failure at these weak points. Replacing these legacy facilities is the only way that the risk associated with these facilities can truly be addressed and mitigated, especially given the need to manage the increasing likelihood of risk as the asset or fitting is found to be defective or ineffective at achieving its original intended design as it reaches the latter portion of its useful life.

3. RISK MITIGATION ACTIVITIES ON LOW-PRESSURE SYSTEMS

Q. IN ADDITION TO THE IDENTIFICATION OF VARIOUS PIPE MATERIAL TYPES THAT SHOULD BE REPLACED, HAS INFORMATION IN THE DIMP LED TO THE TARGETING OF SPECIFIC *SYSTEM* TYPES FOR REPLACEMENT/RISK MITIGATION ACTIVITIES?

A. Yes. Low-pressure distribution systems present special challenges that have been recognized by PHMSA, the National Transportation and Safety Board ("NTSB"), and the Company. The Company has been careful to design and implement risk mitigation activities to continue to ensure customer safety and reliability. Incidents experienced by other utilities have emphasized how important the Company's efforts are in proactively targeting low-pressure systems for risk mitigation activities that require capital expenditures.

Q. CAN YOU PLEASE BRIEFLY DESCRIBE THE COMPANY'S LOW-PRESSURE SYSTEMS?

A. Approximately 42 towns served by the Company in Oklahoma contain systems defined by PHMSA as low-pressure systems. These systems serve approximately 16,000 customers. This is a reduction of approximately 3,000 customers from the previous year. According to PHSMA, a low-pressure distribution system is "a distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer."[4] The Company has evaluated all remaining low-pressure systems and is taking steps to mitigate any potential risk associated with these facilities. The reduction of the number of customers served by low-pressure systems is the result of low-pressure system replacements and installation of Ounce-to-Ounce regulators to provide overpressurization protection to customers.

Q. PLEASE DESCRIBE THE COMPANY'S CAPITAL-RELATED RISK MITIGATION ACTIVITIES IMPLEMENTED IN ASSOCIATION WITH LOW-PRESSURE SYSTEMS.

A. First, the Company reviewed its low-pressure systems to determine whether immediate construction activities needed to take place, and all immediate construction activities

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[4] https://www.ecfr.gov/cgi-bin/retrieveECFR?gp=1&ty=HTML&h=L&mc=true&=PART&n=pt49.1.192#se49.3.192_13.

were completed prior to 2020. Second, if DIMP-targeted replacement asset types are located in low-pressure systems, these assets are being prioritized for replacement if there are no other risk mitigation methods in place. Third, all remaining low-pressure customers will either have house regulators installed at the meter loop to protect against potential over-pressurization on house piping or will be converted to intermediate pressure systems through replacement and relocation projects. Costs associated with these regulators and replacement activity will continue to be a driver of capital costs in future years.

Q. CAN YOU PLEASE DESCRIBE THE COMPANY'S REPLACEMENT ACTIVITY ASSOCIATED WITH LOW-PRESSURE SYSTEMS IN 2021?

A. In 2021, the Company replaced or abandoned approximately 10.2 miles of low-pressure distribution piping on 23 projects. Active customers served by this low-pressure piping were converted to intermediate pressure systems or eliminated due to inactive status. In 2021, the Company installed 1,921 ounce-to-ounce regulators for customers served by low-pressure distribution piping, effectively mitigating the over-pressurization risk associated with the customer's meter set on said distribution piping.

B. PUBLIC IMPROVEMENT RELOCATIONS

Q. WHAT IS A PUBLIC IMPROVEMENT RELOCATION?

A. A public improvement relocation is a replacement or relocation of the Company's existing utility infrastructure required by a construction project undertaken by federal, state, or local government. The Company typically has no choice but to undertake the relocation directed by the governmental project, at the Company's cost. The cost of these relocations underlies many of the capital additions I described earlier in my testimony. The Company had three of these projects each totaling over $100,000 in the test year.

Q. WHAT KIND OF PROJECTS RESULT IN THESE RELOCATIONS?

A. The governmental projects that cause these relocations can include any construction, reconstruction, improvement, enlargement, alteration, demolition, or repair of a highway, bridge, drainage system, water system, road, street, alley, sewer, ditch, sewage disposal plant, water works, and any other work constructed under the control of a governmental entity such as a state, county, township, municipal corporation, or other political subdivision of the state or federal government.

Q. WHY MUST THE COMPANY COMPLY WHEN REQUESTED TO RELOCATE SUCH FACILITIES?

A. There are health and safety concerns related to the need to relocate utility facilities located in the path of highway, road, street, bridge, or drainage construction. Utility facilities, if not relocated, could pose an obstruction in the completed street or bridge, causing a potential hazard for pedestrians or the motoring public. Additionally, in the Company's case, if the facilities are not relocated to a safe depth or location, the operation of heavy equipment and other construction activities on and around our facilities might result in gas leaks or main breaks, which may, in turn, result in property damage and/or personal injury to either construction crews or the general public.

Q. **ARE THESE PUBLIC IMPROVEMENT RELOCATIONS MANDATORY?**

A. Yes. All of the Public Improvement Relocation capital expenditures were reasonably incurred as a direct result of either requests to relocate made by the Oklahoma Department of Transportation ("ODOT") or the applicable county or municipality. In the case of the ODOT, the relocations were required pursuant to the provisions of the ODOT's "Right-Of-Way & Utilities Division Management Guide System Volume I Policy Manual," which requires a utility to relocate its facilities from a proposed construction area when the utility occupies a public right-of-way.

Q. PLEASE EXPLAIN HOW YOU TREATED ANY PROJECTS THAT WERE ELIGIBLE FOR REIMBURSEMENT BY ODOT OR THE APPLICABLE COUNTY OR MUNICIPALITY.

A. Under ODOT's "Right-Of-Way & Utilities Division Management Guide System Volume I Policy Manual," if existing utility facilities are located on private right-of-way, the relocation expenditures are reimbursable by ODOT. However, if the utility facilities are located on existing state highway right-of-way by permit or unwritten consent of the Highway Department, the expenditures incurred for the required relocation are not eligible for reimbursement. In the case of county and municipal jobs, the general rule is very similar. If the existing facilities are located on private right-of-way, the utility is entitled to reimbursement of the expenditures of the required relocation from the entity initiating the public improvement. However, if the utility facilities are located on county or municipal right-of-way, the utility is not entitled to reimbursement.

Q. ARE YOU ABLE TO PLAN PUBLIC IMPROVEMENT RELOCATIONS?

A. Only to some extent. ODOT does provide long term plans of their intentions of projects to be completed, but these plans may be delayed or accelerated based on ODOT funding. The Company works with municipalities to incorporate multi-year planning when possible. Some work related to municipalities may be reactive without much time to plan due to immediate hazards related to weather or other events not previously planned. An example of an immediate need from a municipality would include the need to relocate existing facilities that are preventing the clearing of drainage ditches to allow water to properly drain and avoid flooding.

Q. DOES THE PUBLIC IMPROVEMENT CATEGORY FLUCTUATE FROM YEAR TO YEAR?

A. Yes. Due to Public Improvements projects being driven by municipalities and ODOT funding, fluctuations between years can be experienced. For example:

- 2018 test-year had 23 Main projects at a total of $345,050;
- 2019 test-year had 20 Main projects at a total of $1,171,860;
- 2020 test-year had 17 Main projects at a total of $474,399; and
- 2021 test-year had 18 Main projects at a total of $754,523.

Although there was only a 6% increase in job counts from 2020 to 2021, the total capital required to complete these projects was a 24% increase due to larger project scale.

C. CUSTOMER ADDITIONS

Q. DESCRIBE HOW NEW CUSTOMERS ARE EVALUATED WHEN FACILITY EXTENSIONS ARE REQUESTED.

A. Extensions for new customers are based on factors identified in Rate Schedule No. 6 – Extension of Facilities. The estimated costs to serve new customers are based on the customer's requested capacity and pressure requirements and how they relate to the existing facilities in the area.

Q. DO NEW CUSTOMERS ALWAYS REQUIRE EXTENSION OF FACILITIES?

A. No. Customers requesting service located adjacent to existing facilities that meet the requested requirements may be connected to existing facilities.

Q. IS FUTURE GROWTH CONSIDERED WHEN EXTENDING FACILITIES FOR NEW CUSTOMERS?

A. Yes. If future growth is anticipated in an area of high growth, the Company may invest in a main size larger than required for the requested customer's need. This reduces the need to install additional main in the future to serve the projected growth.

Q. ARE THERE OTHER BENEFITS TO EXISTING CUSTOMERS WHEN NEW CUSTOMERS ARE ADDED TO THE SYSTEM?

A. Yes. Installing larger mains allows the potential for all customers to benefit from added capacity and can allow existing customers to add additional appliances and generators. Installation of additional regulator stations can also provide additional feeds to customers to allow for continued service in the event service may be interrupted in another area.

Q. CAN YOU EXPLAIN THE SIGNIFICANT INCREASE IN THE CUSTOMER ADDITIONS CATEGORY SHOWN IN TABLE 2?

A. Yes. In 2020, the Company suffered from the effects of the global pandemic in ways that reduced project counts and associated capital expenditures. Due to the recovery of the economy in 2021, the Company experienced a significant increase of new development opportunities that were originally on hold or were being conceptualized during the onset of the global pandemic. The Company experienced a 189% increase over 2020 in Customer Additions activities due to these after-effects of a recovering economy. The Company continues to diligently work with developers and builders to capture these opportunities that help broaden the rate base across an increasing count of active customers. Details of these increases can be found in Table 3 below.

Table 3 – Customer Additions Breakdown by Category

Customer Additions	2020	2021	% Increase 2020-21
Total Additions	$665,877	$1,921,191	188.5%
Mains Footage	25,152	44,640	77.5%
Service Counts	457	535	17.1%

IV. ASSET SALE COMMITMENTS

Q. PLEASE DISCUSS SUO'S PROCUREMENT PROCESS AND SAFEGUARDS IN PLACE TO ASSURE PROJECTS ARE COMPLETED AT THE LOWEST REASONABLE COST WHILE ENSURING SYSTEM INGRITY .

A. SUO Company witness Steven E. Birchfield discuses the Company's procurement processes at a high level. I discuss below how Construction Services and Materials are purchased below.

Q. IS SUMMIT'S PROCUREMENT POLICY SIMILAR TO CERC'S POLICY?

A. Yes. Both policies have similar provisions governing the selection of construction vendors to ensure the integrity of the system is maintained. Additionally, both companies consider items other than pricing before assigning work to be completed. Pricing is an important factor, but maintaining a safe and reliable system using experienced, safe contractors is of the utmost importance. Some examples of the criteria used to evaluate contractors include: their Contractor Safety Manual, longevity of business, excavator damage metrics, and environmental violations.

Q. PLEASE DISCUSS THE PREFERRED SUPPLIER AGREEMENTS THE COMPANY PUTS IN PLACE.

A. A Preferred Supplier Agreement ("PSA") is a Contract between the Company and a third-party Vendor that defines the terms and conditions by which the parties will conduct business. Under a PSA, the Vendor typically offers their goods or services to the Company at a discounted rate or with other preferential conditions. The Procurement Department may arrange for the Company to enter a PSA when it benefits the Company, but it will do so only after evaluating the Vendor's price, service, availability, reduction of lead time, and ESG performance, etc. When engaged in a PSA, the Procurement Department will perform a biannual market analysis on the Company's top ten most frequently purchased items to determine if the vendor is providing competitive pricing.

Q. DO CURRENT REGULATIONS BY STATE AND FEDERAL AGENCIES HAVE REQUIREMENTS CONTRACTORS MUST POSSESS BEFORE WORKING ON THE COMPANY'S DISTRIBUTION SYSTEM?

A. Yes. To ensure system integrity, Title 49 CFR Part 192 Subpart N outlines operator qualifications of individuals performing covered tasks on a pipeline facility. For the purpose of this subpart, a covered task is an activity, identified by the operator, that:

(1) Is performed on a pipeline facility;
(2) Is an operations or maintenance task;
(3) Is performed as a requirement of this part; and
(4) Affects the operation or integrity of the pipeline

Summit Oklahoma has also added new vendors recently to Oklahoma to encourage competitive pricing between companies.

Q. DOES SUMMIT OKLAHOMA HAVE POLICIES THAT ENSURE THE COSTS OF PURCHASE MATERIALS ARE PRUDENT?

A. Yes. Similar to CERC's policy, the Company seeks Vendors offering the best price, quality, service, availability and lead time. However, the Company is also committed to responsibly sourcing the Goods and Services it uses in its business, and consideration is also be given to ESG performance criteria, such as anti-corruption, diversity, health and safety, and environmental and labor practices. Other considerations include invoicing proficiencies, stocking ability, and the historic capability, capacity, and performance of Vendors.

Q. DOES SUMMIT HAVE CRITERIA FOR GETTING MULTIPLE QUOTES FROM MULTIPLE VENDORS FOR MATERIALS?

A. Yes. Summit's Procurement Department strives to obtain at least three quotes for the desired Goods and will evaluate pricing, lead time, quality, and ESG performance criteria described above.

Q. PLEASE OUTLINE ANY CHANGES MADE OR TO BE MADE IN THE FUTURE TO SUO'S DIMP OR TIMP.

A. Based on current and pending PHMSA guidance, the Company foresees a number of potential future integrity management projects. As the transition continues, the existing DIMP will evaluate the same materials addressed by the CERC DIMP. Two changes that are currently anticipated are the transition to a Probabilistic Risk Model for Oklahoma assets and legacy cross-bore inspections.

Q. CAN YOU EXPLAIN THE DIFFERENCE BETWEEN A PROBABILISTIC RISK MODEL AND CERC'S DIMP MODEL?

A. As recommended by PHMSA in the "Pipeline Risk Modeling Overview of Methods and Tools for Improved Implementation" released in February of 2020,[5] SUO is currently moving away from the more common Relative Assessment/Index model utilized historically to implement the industry best practice Probabilistic methodology. The new risk model will have the capability to model several scenarios and solutions, allowing SUO to make the best decision with project dollars to improve safety and system reliability long term.

Q. MOVING ON TO LEGACY CROSS-BORE INSPECTIONS, WHAT IS A CROSS-BORE?

A. Cross-bores are defined as an intersection of an existing underground utility or underground structure that compromises the integrity of either utility or underground structure. For example, a cross-bore occurs when a new natural gas line is installed using a trenchless method and intersects an existing underground utility, such as a sewer line. This example may pose no problem initially and can go undetected for months or years. However, if the sewer line becomes blocked and mechanical equipment, such as a rotating auger, is used to clear it, the intersecting gas line can be damaged, resulting in a gas leak. The leaking gas can migrate into buildings via the sewer line, resulting in a potentially dangerous situation.

Issues with cross-boring were identified as early as 1972; thus, this is not a new problem. The occurrence of cross-bores has become more prevalent as the installation of gas distribution facilities using trenchless technology becomes more popular.

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[5] Pipeline-Risk-Modeling-Technical-Information-Document-02-01-2020-Final_0.pdf (dot.gov).

However, there is limited data on the number of cross-bores found per mile of sanitary sewer inspected. Typically sanitary sewer laterals belong to the property owner and are not marked by local municipalities in response to locate requests. Sewer laterals are often not identified on maps due to a lack of requirements and/or technology available at the time of their installation, and they are not locatable using conventional methods since they are commonly non-metallic pipe.[6]

Q. HOW DOES SUMMIT OKLAHOMA PLAN TO PROACTIVELY ADDRESS CROSS-BORES?

A. Proactive Legacy Cross-Bore Inspection Programs have been identified as a leading practice in the industry. Tools the company is currently evaluating utilize both internal and external data sets to identify areas with a higher likelihood of cross-bore and then trains the model using inspection results to further refine predictive capabilities. A proactive legacy cross-bore inspection program is under development pending the results of this model. The company will utilize existing data and provide new information to the predictive model to continue to improve its effectiveness over time.

Q. HAS SUO ANALYZED WHETHER SUO IS ABLE TO SLOW THE TIMETABLE FOR CERTAIN IMPROVEMENT PROJECTS WITHOUT AFFECTING THE SAFETY AND RELIABILITY OF SERVICE TO CUSTOMERS?

A. Yes. As mentioned above, the Company will continue on the path of using data-driven decisions to steer its integrity management programs. The Company's management of pipeline integrity prior to the implementation of 49 C.F.R. 192 subparts (O) and (P) was

[6] Gas Distribution Integrity Management Program: Resources | PHMSA (dot.gov).

consistent with applicable regulations and was based on sound engineering practices and standards. For many years, the Company has been replacing higher-risk facilities. The integrity management programs discussed in my testimony represent an acceleration of pipeline integrity expenditures in order to comply with the new regulations based on the Company's knowledge and experience from designing, constructing, operating, and maintaining its system.

Q. HAS THE COMPANY INCREASED REPLACEMENT ACTIVITY IN RECENT YEARS?

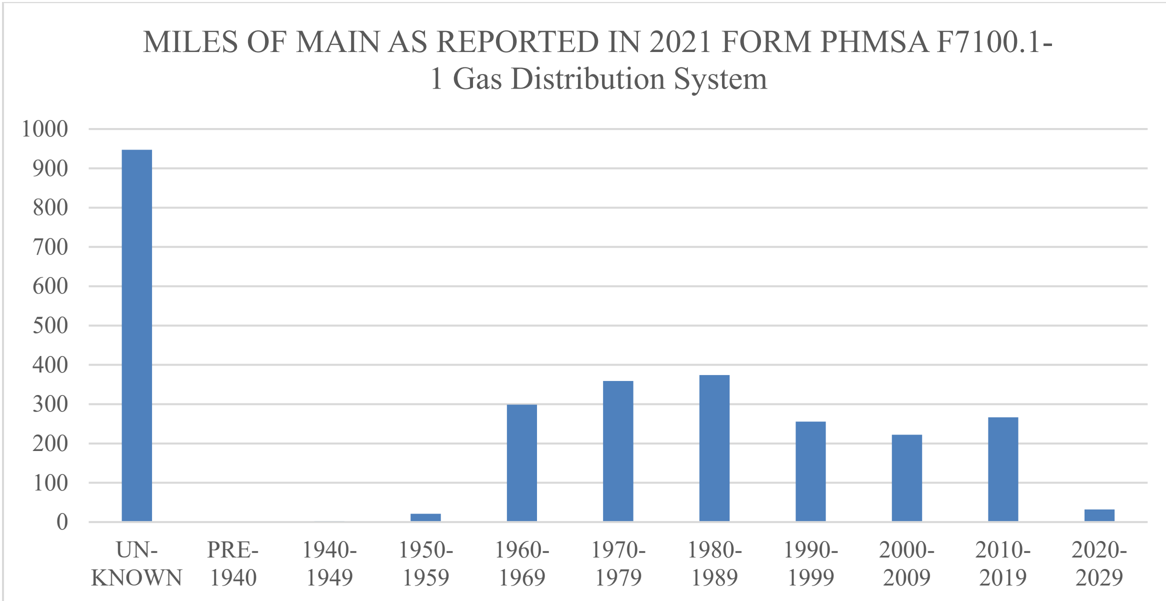
A. Yes. The largest contributing factors for increased replacements are as follows:

1) The Company has a significant amount of facilities installed in the 1960s and prior that have surpassed 50 years of age in the current decade and are reaching the end of their useful lives; and

2) Continued analysis of assets through the Integrity Management Plans discussed previously, paired with the aging infrastructure discussed above, allows the Company to identify and target replacement areas more effectively.

As shown in Table 4 below, for gas pipes with known installation dates, the majority were installed between 1960-1990. This data is also provided in "Form PHMSA F7100.1-1 Gas Distribution System" and demonstrates that the Company must continue to replace its aging facilities.

Table 4 – Miles of Main



Facilities installed in the 1960s are reaching 50 years of age in the current decade and are reaching the end of their useful lives. As discussed below, this will continue for the foreseeable future.

Q. HOW DOES THE COMPANY ADDRESS THE "UNKNOWN" VINTAGE PIPE IN ITS SYSTEM?

A. In the current risk model, an increased weighting is given if the pipe is unknown, which increases the likelihood that an area of unknown pipe may be included in replacement recommendations. The Company is currently vetting processes that evaluate these mains based on legacy industry practices and known data relative the surrounding systems.

Q. HOW LONG WILL THE COMPANY'S MAIN REPLACEMENT ACTIVITY CONTINUE?

A. The Company will continue to use system behavior analysis and a portfolio of risk evaluation tools to address the risks associated with assets targeted for replacement.

While there is no fixed period for this activity, when these targeted assets are no longer in the system, the Company can begin to scale down replacement activities while continuing to monitor for other areas of risk to the system. It is important to note that, similar to the risk mitigation measures currently being taken on low-pressure systems as discussed below, ongoing analysis of all active facilities may identify other/new risks that may lead to other replacement or mitigation activities.

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. Summit Oklahoma's System Improvement/Integrity Management programs and projects are reasonable and necessary to provide safe and reliable service to its customers. The Company replaces these aging assets at a rate necessary to improve system safety and reliability. Additionally, the costs incurred by the Company to address its low-pressure systems contribute to the safety and reliability of the system and, as such, are also necessary.

Pipeline safety regulations require the Company to develop and implement an integrity management program for its transmission and distribution system. The regulations require that the integrity management program include specific elements, that the Company assess threats to pipeline integrity and that the Company take action to remediate or mitigate such threats. The Company has developed such a plan, continues to conduct required assessments in a manner consistent with the regulations, and has undertaken specific projects to manage pipeline integrity. All of this has been performed under the oversight of, and in cooperation with, the Commission's Office of Pipeline Safety.

Costs related to public improvement projects are required by the Company due to existing agreements with the Oklahoma Department of Transportation and municipalities that allow the use of existing rights-of-way. These agreements are advantageous to the Company and protect citizens by maintaining specific corridors for utilities to safely operate. As ODOT and municipalities improve infrastructure, the Company is required to relocate facilities in conflict. Costs related to extensions for new customers are also reasonably incurred and allow the Company to serve new customers.

The costs associated with these programs and replacements are directly related to the safe and reliable operation of the natural gas system in compliance with state and federal law. A modern system helps with customer satisfaction through safety and reliability.

Related to asset sale commitments, Summit has procurement processes and safeguards in place that assure projects are completed at the lowest reasonable cost while ensuring system integrity. Like CERC, Summit has provisions governing the selection of construction vendors to ensure the integrity of the system is maintained and consideration of items other than price. Summit also ensures that the costs of purchased materials are prudent.

Concerning changes in the future to SUO's DIMP and TIMP, I discussed the transition to a Probabilistic Risk Model and the implementation of a legacy cross-bore inspection program.

Finally, I discussed whether SUO can slow the timetable for certain improvement projects without affecting the safety and reliability of service to customers.

I discuss the Company's approach, which is to continue to use system behavior analysis and a portfolio of risk evaluation tools to address the risks associated with assets targeted for replacement on the Company's aging distribution system.

CERTIFICATE OF SERVICE

I hereby certify that on the 15th day of March, 2022, a full, true, and correct copy of the above and foregoing instrument was served on the following persons by **ELECTRONIC MAIL** and by **UNITED STATES CERTIFIED MAIL**, postage prepaid to:

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