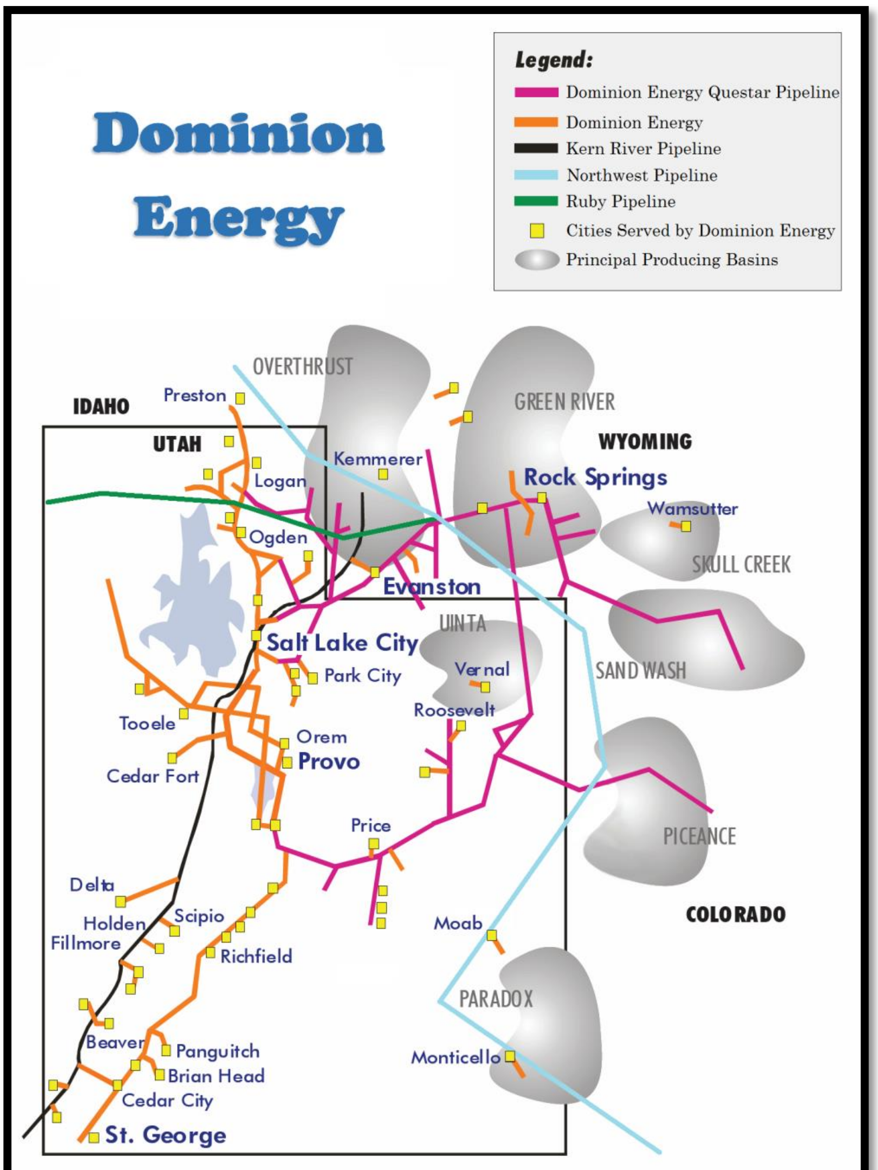
SYSTEM CAPABILITIES AND CONSTRAINTS

Dominion Energy System Overview

The Company's system currently consists of nearly 19,000 miles of distribution and transmission mains serving more than 1,000,000 customers. The system operates at pressures that range up to 1,000 psig and is separated into many subsystems in order to deliver the pressures and volumes that customers require. The Company builds system models annually to determine when and to what extent system improvements will be required. Figure 4.1 shows the Company's high-pressure (HP) system, its service area, connecting interstate pipelines, and adjacent producing basins.



Ongoing and Future System Analysis Projects

Master Planning Models

The Company creates gas network analysis (GNA) master planning models to more accurately predict impacts of system growth. The models are created using global growth projections as well as anticipated growth from specific planned developments in each area. The benefit of using this data is that the resulting system pressures will reflect the impact of the specific growth centers and provide improved projections of system impacts during a peak event.

System Supply Analysis and Joint Operating Agreement

The Company analyzes its gas supply contracts each year to determine if they will meet the coming year's demands. The Company carefully considers the upstream (interstate transmission pipelines) constraints and capabilities as well as the ability to acquire gas to deliver to its system on a peak day. The purpose of this analysis is to determine the amount of gas required on a peak day and if the current contracts (sales and transportation) facilitate this required delivery.

The Company and Dominion Energy Questar Pipeline work together each year to update a Joint Operating Agreement (JOA) as part of this analysis. The JOA includes details regarding the pressures and flows available at the jointly operated gate stations, as well as operational and facilities responsibilities. One objective of this agreement is to ensure that the Company receives adequate inlet pressures to these stations in order to maintain system reliability. This is a complicated process that requires detailed collaboration due to the fact that the flows at these stations fluctuate through the day to match the changing demands on the Company's system.

Interruption Analysis

A number of customers on the Company's system have chosen to purchase service on an interruptible rate utilizing any available system capacity. While the system is not designed for these customers, it is important to understand the temperatures at which an interruption would be expected. The Company performs an interruption test on an annual basis. The interruption analysis divides the system into interruption zones and determines the temperature at which interruption of a specific zone is appropriate to ensure reliable service to the surrounding firm customers.

Operational Models

The Company prepares for planned maintenance and construction work as well as unforeseen events that impact system capabilities by developing and maintaining operational models of the system. The Company maintains these models to represent current conditions that exist in the system. The Company's engineers review these models on an ongoing basis with The Company's Gas Control, Gas Supply, Marketing, Operations, and Measurement and Control departments in order to inform them of expected system conditions.

System Modeling and Reinforcement

The Company utilizes steady-state Intermediate High Pressure (IHP) gas network computer models to determine the required system improvements needed to maintain operational pressures throughout the distribution system to serve customer demand and growth. The Company uses these models to identify the required locations and sizing of new mains and/or regulator stations. The Company also uses the models to compare the required flow from the regulator stations to the maximum delivery capacity of the existing regulator stations. This analysis provides the Company with the information necessary to determine which reinforcements the Company should construct each year. Based on the modeling results, the Company constructs a number of IHP mains, new regulator stations and upgrades to existing regulator stations.

The HP system models have more variables than the IHP system models and are also used to design for customer demand and growth. Engineers consider gate station capacities, existing supply contracts, supply availability, line pack and the piping system in conducting HP analysis. Because HP projects typically take longer to complete than IHP projects, the Company must identify the need for HP improvements earlier than would be required for IHP projects. The Company and the interstate pipeline companies that supply its system collaborate to identify potential constraints to ensure that the Company's supply needs can be met.

Model Verification

The Company verifies the accuracy of the steady-state (24-hour period) GNA models using recorded pressure data and calculated demands. The Company's engineers built steady-state models to represent the system conditions that were present on Thursday January 5, 2017 using actual data from that day. Model settings were adjusted to match the actual temperatures and other conditions for this day. The model pressures were compared to actual pressures at 110 verification points and were found to be within 7% of the actual pressures on that day. One hundred and four of the pressures in the verification model were within 5% of the actual pressure. Based on this analysis, the Company has deemed the loads and infrastructure utilized in the GNA models are accurate, and the models can confidently be used for their intended purpose.

The Company verifies the unsteady-state (hourly results for a 24-hour period) models in the same manner as the steady-state models. The temperatures and the gate station flows and pressures are matched as closely as possible. The Central and Northern Regions are the largest of the Company's connected HP systems with seven gate stations and two primary maximum allowable operating pressure (MAOP) zones. There are other smaller isolated systems which also require unsteady-state model analysis included in the results (Figures 4.3 – 4.8). The unsteady-state model minimum pressures were found to be within 7% of the actual minimum pressures at 95 verification points on that day. Eighty-six of the pressures in the verification model were within 5% of the actual pressure. The results of these comparisons confirm the accuracy of the unsteady-state models.

Gate Station Flows vs. Capacity

The Company's system models must accurately emulate the physical pressure and flow limitations of each specific station. To ensure this, The Company completes a capacity study each year for each of the gate stations on the system. The Company calculated hourly and daily flow capacities for each station based on facility limitations, set pressures, and inlet pressures provided by the upstream pipelines. Some stations have specific minimum pressures based on contractual volumes. Other stations have fluctuating inlet pressures based on the changing flow on the Company's system. For the stations with changing inlet pressures, this analysis was based on the inlet pressures included in the JOA.

In order to achieve the modeled system results, The Company assumed the capacity at Hunter Park to be 400 MMcfd. The Kern River Gas Transmission Company (Kern River) facilities are able to flow at this capacity and The Company is currently upgrading the Hunter Park gate station to meet this capacity requirement. The upgrade is planned to be completed prior to the 2017-2018 heating season.

There are a number of other gate stations that are near 100% utilization shown in Table 4.1. These stations will be upgraded as necessary in the coming years in order to accommodate their respective required flows. Each of these stations is either flowing at capacity in last year's JOA or is nearing the physical capacity of the station. Kemmerer and Altamont are the only stations that do not have a redundant feed to the same subsystem.

Table 4.1: Gate Stations Nearing Capacity in the JOA

Station	2016-2017 (MMcfd)	Station Capacity (MMcfd)	% Utilization	Upgrade Year
Altamont	0.39	0.39	100%	2018
Kemmerer	3.28	3.45	95%	2018
Island Park	7.30	7.30	100%	2018
Hyrum	145.63	151.90	96%	2019
Rockport (Heber Tap)	14.60	14.60	100%	2022
Central	44.95	47.50	95%	2024
Jeremy Ranch	27.82	28.20	99%	2025

In addition to these specific gate stations, the total gate station capacity[59] of the Northern HP system is approaching maximum capacity. Residential and commercial growth in Utah is increasing demand for natural gas along the Wasatch Front. In 2017, The Company determined that the system would benefit from a new gate station, served by Kern River, to feed Northern Utah within the next three years. This new gate station will provide the ability to bring additional firm gas to the Wasatch Front and enable the company to utilize more firm-peaking service to meet peak-hour requirements. In addition, when FL23 is replaced, there will be additional capacity available to the Wasatch Front through the Hyrum Gate Station.

System Pressures

Once the Company verifies the GNA models and properly sets contractual obligations and station capacities, it uses the models to analyze the gas distribution system to verify that it has adequate pressures in order to supply customers. The Company uses peak models for this analysis. Peak models include firm loads for sales and transport customers. The Company uses the daily contract limits for applicable customers and assumes that interruptible demands are curtailed during the peak day.

[59] Reflects station Capacity when combined with gas supply and upstream transportation contracts.

Northern

The Northern Region includes the distribution system throughout Salt Lake City and northern Utah, including Box Elder, Cache, Davis, Morgan, Salt Lake, Summit, Tooele, Utah, Wasatch, and Weber counties. The Company serves this region through interconnects with Dominion Energy Questar Pipeline at Meter Allocation Point (MAP) 164 using the Hyrum, Little Mountain, Payson, Porter's Lane, and Sunset stations. The Company also serves the region through Payson gate station from Dominion Energy Questar Pipeline's Main Line 104 (MAP 332), multiple smaller taps from Dominion Energy Questar Pipeline (MAP 162) and Kern River at Eagle Mountain, Lake Side, Hunter Park, and Riverton stations.

In the steady-state model, the calculated low point in the main portion of northern system is 264 psig, at the endpoint of a tap line off FL 28 in Lewiston. The lowest steady-state pressure is in the Summit/Wasatch system, in Woodland, which is 250 psig. These pressures remain higher than the Company's minimum allowable design pressure of 125 psig.

The steady-state pressures at some of the key locations in the Company's system are shown in Table 4.2. The locations on the system are shown in Figure 4.2. The Company models these pressures on a peak day at system endpoints and low points in the area and important intersections. The Company builds steady-state models using average daily flows that most closely represent average pressures for the peak day. The unsteady-state GNA models profile demands throughout the day, and represent the pressure fluctuations throughout the peak day.

Table 4.2: Dominion Energy High Pressure System Steady-State Peak-Day Pressures

Location	Pressure (psig)
Endpoint of FL 29 – Plymouth	272
Endpoint of FL 36 – West Jordan	298
Endpoint of FL 48 – Stockton	321
Endpoint of FL 51 – Plain City	306
Endpoint of FL 54 – Park City	327
Endpoint of FL 62 – Alta	290

Endpoint of FL 63 – West Desert	303
Endpoint of FL 70 – Promontory	276
Endpoint of FL 74 – Preston	264
Endpoint of FL 106 – Bear River City	296
Intersection of FL 29 & FL 23 – Brigham City	367

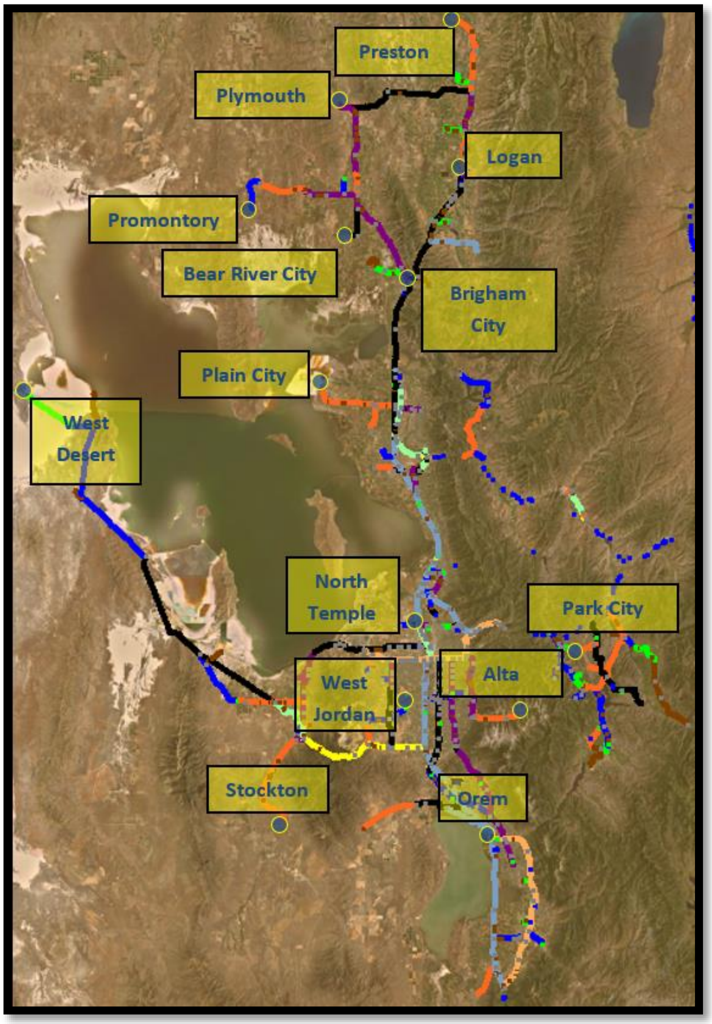


Figure 4.2: Northern Region Key Pressure Locations

The curves shown in Figure 4.3, Figure 4.4, and Figure 4.5 are the expected peak-day pressures for the Northern Region HP system. In the projected unsteady-state models, the low point in the Northern Region is West Jordan at 137 psig. The lowest predicted pressure in the Summit Wasatch subsystem is at the Woodland regulator station with 186 psig during the peak hour. In the past few years Plain City has consistently been one of the lowest pressures in the Northern System. However, due to a road project in the area, the Company upgraded a section of pipe from 8-inch to 12-inch which has significantly increased the pressures.

In the HP system north of the North Temple station, the minimum pressure occurs at Promontory Point with a minimum pressure of 250 psig. While these pressures are well above operational minimums, the gate stations in the North are all expected to reach their maximum capacities on a peak day. In order to maintain pressures in this area, the Company requires additional gate station capacity and pressure support by 2020. The one existing station in this area that is not at capacity due to upstream constraints is Hyrum Gate Station. Hyrum is constrained due to the size of FL23, which is scheduled for replacement as part of the Company's aging infrastructure replacement program. Increasing the diameter of FL23 not only increases pressures in the area, it is necessary to allow more gas to flow into the Northern system.

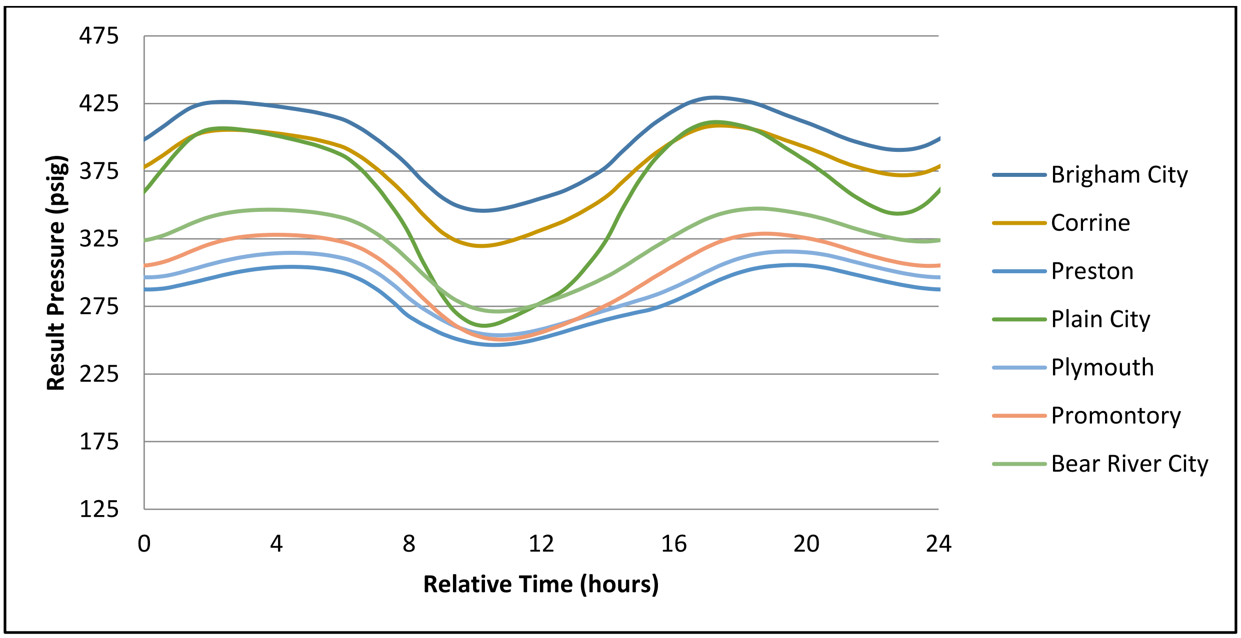


Figure 4.3: 2017-2018 Northern Unsteady-State Peak-Day Pressures (North of North Temple)

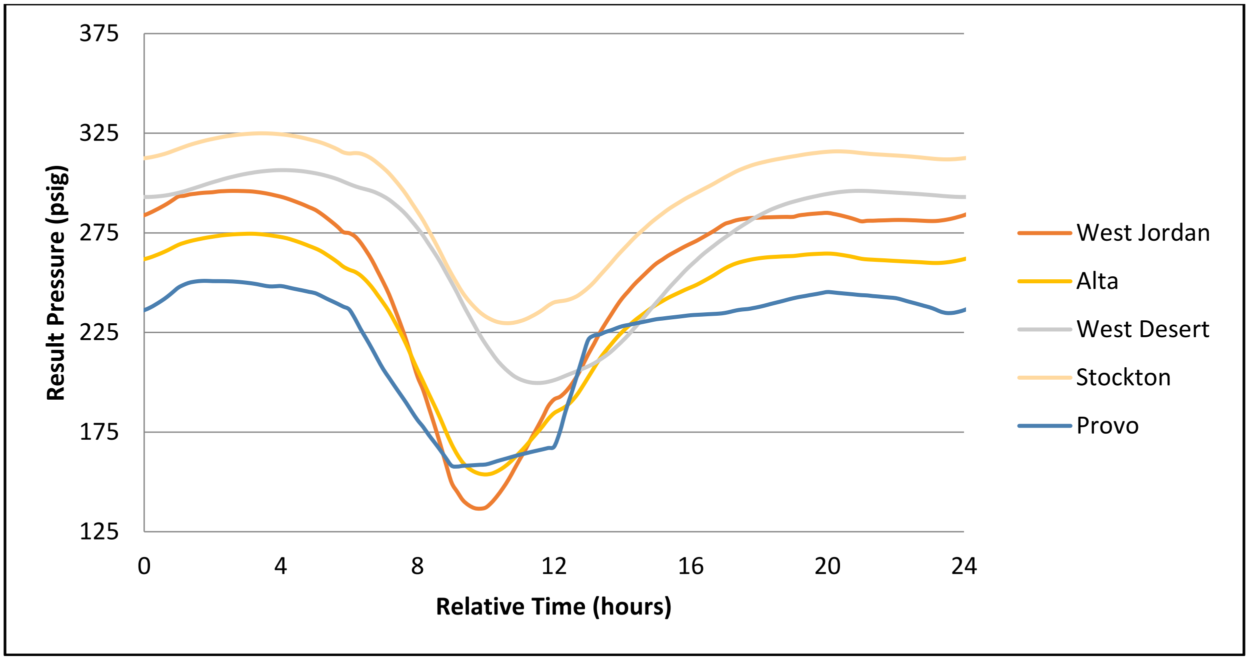


Figure 4.4: 2017-2018 Northern Unsteady-State Peak-Day Pressures (South of North Temple)

The pressures in the Summit Wasatch HP System have improved due to the tie from FL54 to FL99. In the 2016-2017 IRP, the pressure in Park City was near 125 psig. In this peak day model, the pressures in Park City do not drop below 300 psig due to the reinforcement of FL54 that will be completed prior to the 2017-2018 heating season.

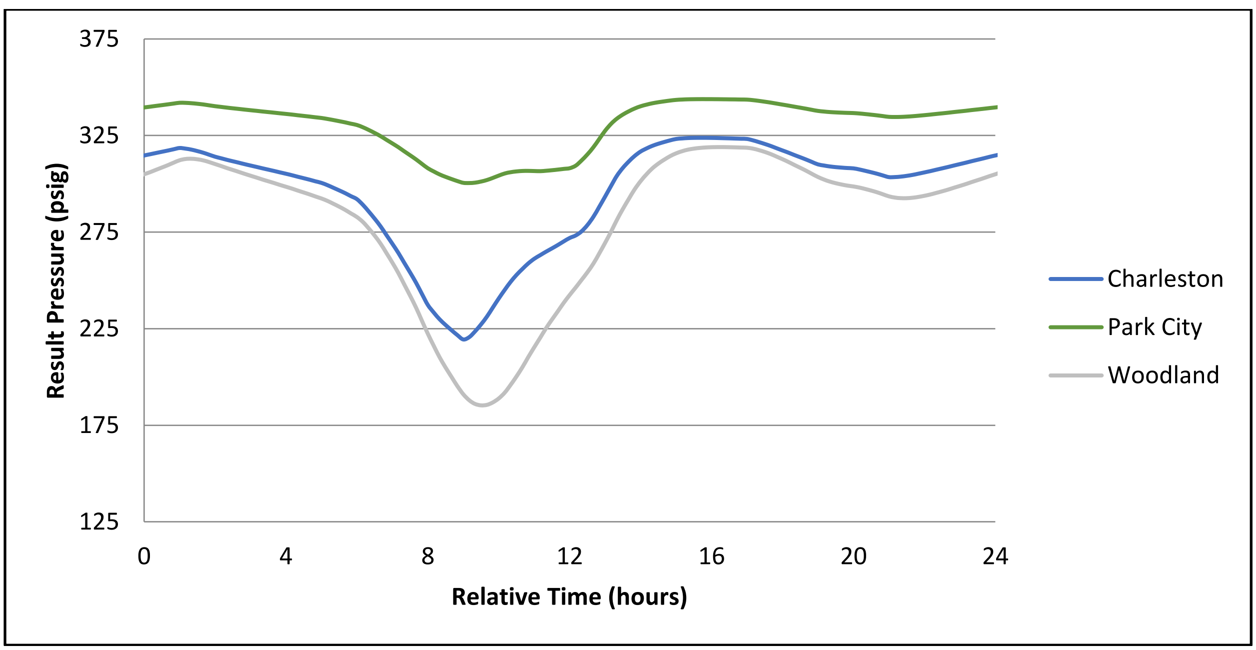


Figure 4.5: 2017-2018 Northern Unsteady-State Peak-Day Pressures (Summit and Wasatch Counties)

Eastern (North)

The Eastern (North) Region includes Duchesne, Uintah, Carbon, and Emery counties, including the cities of Price and Vernal. The Vernal area is served from Dominion Energy Questar Pipeline by two gate stations through MAP 163 and MAP 334. In 2016, the Company replaced FL 89 between Island Park (the gate station on the east side of Vernal) and the Diamond Mountain regulator station. The improvement increased both the pressure at the Vernal 1 regulator station as well as the take-away from Island Park. The results shown in Figure 4.6 reflect this improvement. Pressures in the Vernal system continue to decline, at Vernal 7 the minimum peak-day pressure reaches 168 psig.

System pressures are also declining in the Fort Duchesne area and the declining pressure must be remedied in the coming years. Currently, the minimum pressure at Fort Duchesne is 150 psig, well above the minimum operational pressure. However FL 43, the pipeline serving Fort Duchesne, is a 20-mile line composed of mostly 4-inch pipe. In order to maintain pressures, the Company must loop or replace the line. One alternative being considered is to install a new gate station on the northern section of FL 43 which will increase pressures at Fort Duchesne until the line can be replaced. FL 43 is identified to be replaced as part of the Infrastructure Rate Adjustment Tracker and will likely be scheduled for replacement in the next five years.

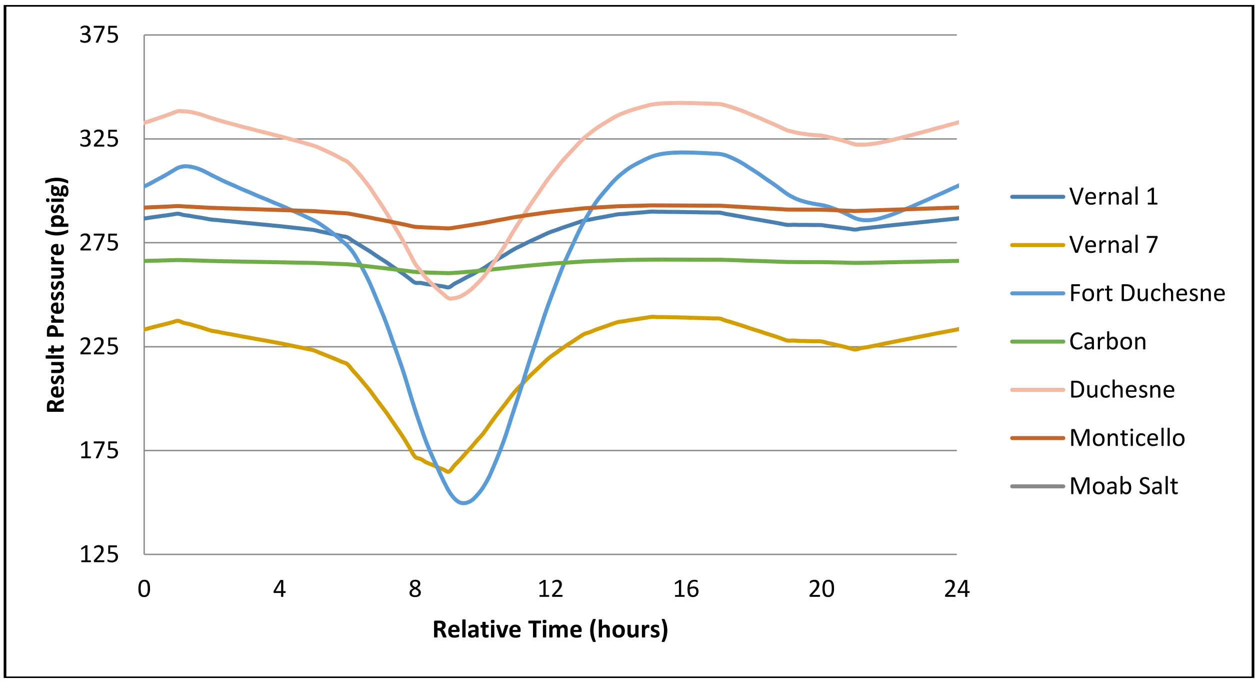


Figure 4.6: 2017-2018 Eastern (North) Unsteady-State Peak-Day Pressures

Eastern (Northwest Pipeline)

The Eastern (Northwest Pipeline) Region includes the cities of Moab, Monticello and Dutch John. The Company serves these areas from Northwest Pipeline with two stations in Moab, one station in Monticello, and one station in Dutch John.

The system in this area is comprised of separate subsystems with individual gate stations connected to Northwest Pipeline. All of the segments in this area have adequate pressures and do not require any improvements to meet the demand for the 2017-2018 heating season.

The HP system serving the Monticello system will be uprated prior to the 2017-2018 heating season. In the 2016-2017 IRP, modeled pressures in Monticello dropped slightly below 125 psig. The uprate will increase the MAOP to higher than 300 psig, which will bring modeled minimum system pressures up to 282 psig.

Southern (Main System)

The Southern (Main System) Region encompasses the areas served by the Indianola, Wecco and Central stations including Richfield, Cedar City, and St. George. The Company serves these areas from Dominion Energy Questar Pipeline at Indianola station through MAP 166 and from Kern River at Central and Wecco stations.

Using the steady-state model, the lowest modeled pressure on a peak day is 408 psig at the Brian Head regulator station. All segments in this area have adequate pressures and do not require any improvement to meet the existing demand.

The Southern System will require substantial upgrades within the next ten years. The Company has monitored the Southern System growth since the Central Compressor station was installed. Based on the current projections, it is estimated that a new feeder line will need to be installed from the Bluff St station east to the Washington 2 tap line prior to heating season 2022-2023 in order to maintain system pressures. In the years following this tie across the system, FL81 will need to be looped to increase gas flow from the Central tap to St George.

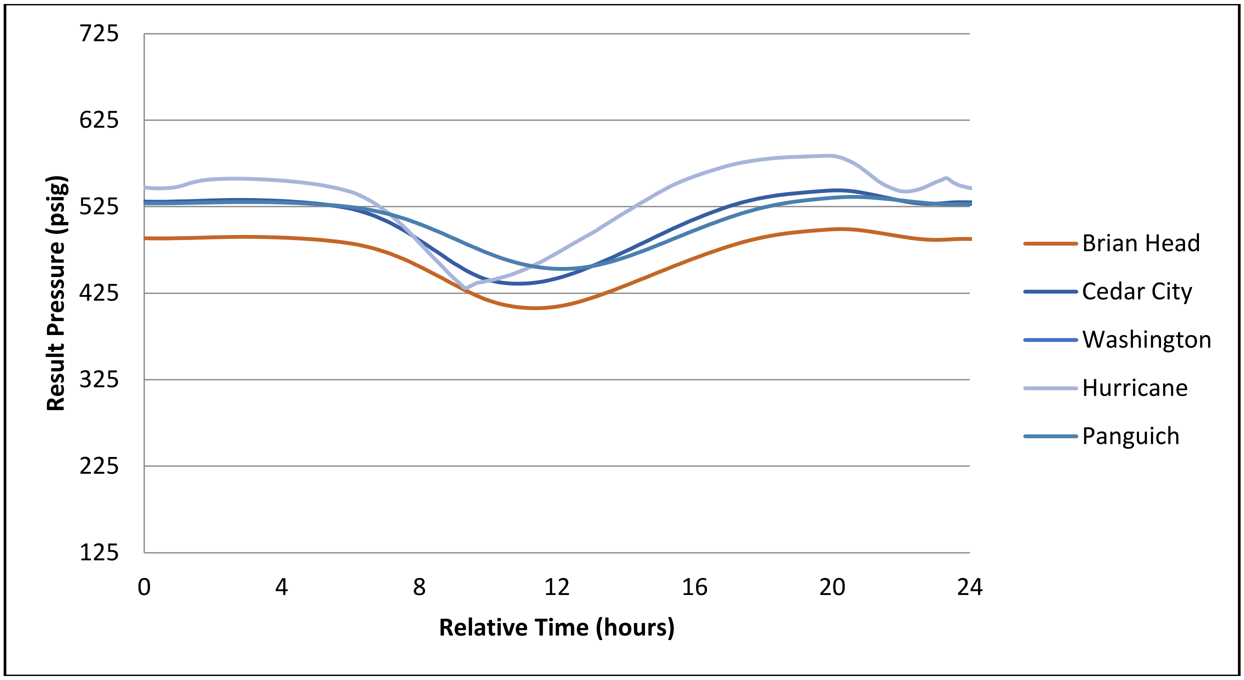


Figure 4.7: 2017-2018 Southern Unsteady-State Peak-Day Pressures

Southern (Kern River Taps)

The Southern Region includes towns in Juab, Millard, Beaver, Iron, and Washington counties. This includes all towns south of the Payson Gate Station that are not part of the Indianola/Wecco/Central system). These areas are all single feed systems served by Kern River.

The system in this area is comprised of separate subsystems with individual taps off Kern River. All segments in this area have adequate pressures and do not require any improvement to meet the existing demand.

Wyoming

The Wyoming Region includes Rock Springs, Evanston, Lyman, Kemmerer, Baggs, and Granger. The Company serves these areas from Dominion Energy Questar Pipeline through MAP 168, MAP 169, MAP 177, from CIG at Wamsutter and Rock Springs, and from Williams Field Services (WFS) at La Barge and Big Piney.

The Company has typically served the Rock Springs area with two gate stations off Dominion Energy Questar Pipeline. In the projected peak-day model, the HP system also requires supply from CIG's Foothill station in order to maintain operational pressure in the Reliance area at the end of FL 30. As discussed in the Gathering, Transportation, and Storage section of this report, the Company is evaluating options for firm capacity on CIG to serve this station.

The Company projects that the 2017-2018 peak-day pressures in North Rock Springs will be 151 psig (Figure 4.8) with the Foothill high-pressure station flowing with outlet pressures near

MAOP. The Company is scheduled to construct an extension of FL 111 to North Rock Springs in 2018 to maintain adequate operating pressures.

Kemmerer, Wyoming has experienced sporadic growth over the past few years. The Company has estimated that the gate station will need to be upsized and FL 91 will need to be uprated in 2018 in order to serve the Kemmerer demands on a peak day beyond the 2017-2018 heating season. Although Kemmerer pressures are relatively high in Figure 4.8, system pressures are expected to drop below 125 psig by the 2020-2021 heating season based on the historical average growth rate in Kemmerer. Eventually, the Company will need to replace the feeder line serving this area with a larger diameter pipe.

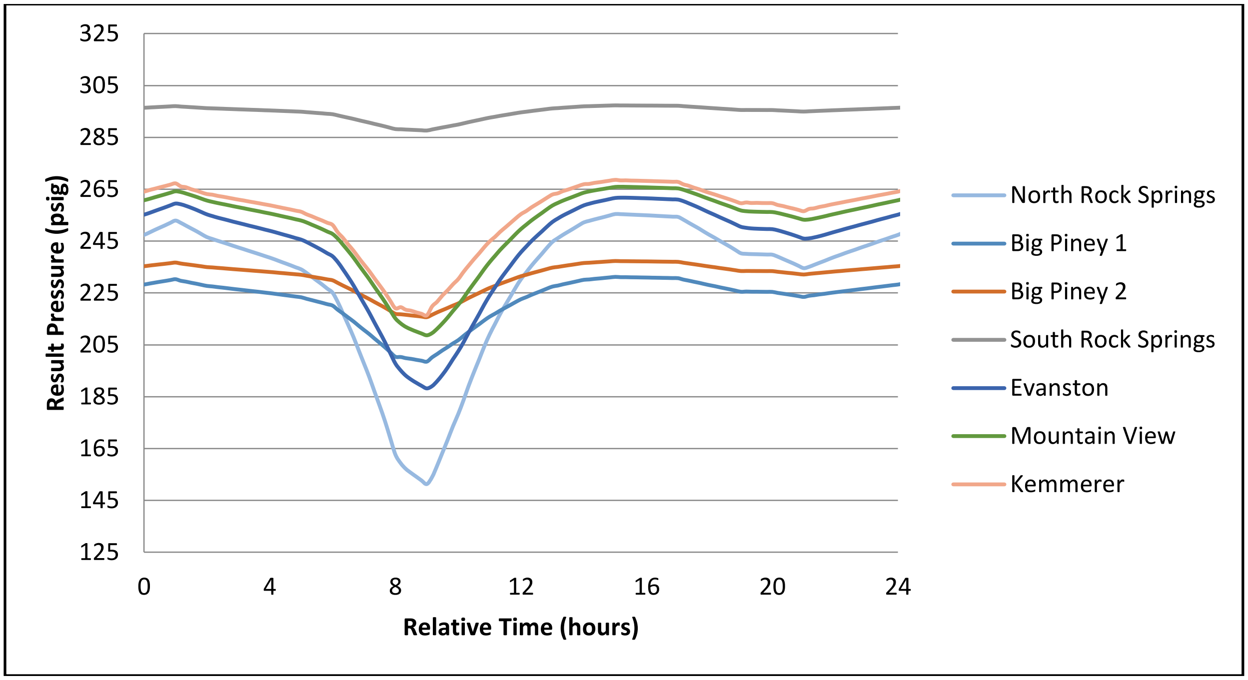


Figure 4.8: 2017-2018 Wyoming Unsteady-State Peak-Day Pressures

Facility Improvements to Meet Peak-Hour Requirements

Figure 4.9 shows the Wasatch Front peak-hour requirements with the system's ability to meet those demands. There are currently no options available to meet growing peak-hour demands on the Wasatch Front in the 2024-2025 heating season without a new gate station. Peak-hour demand requirements are discussed in detail in the Peak-Hour Demand and Reliability Section of this report.

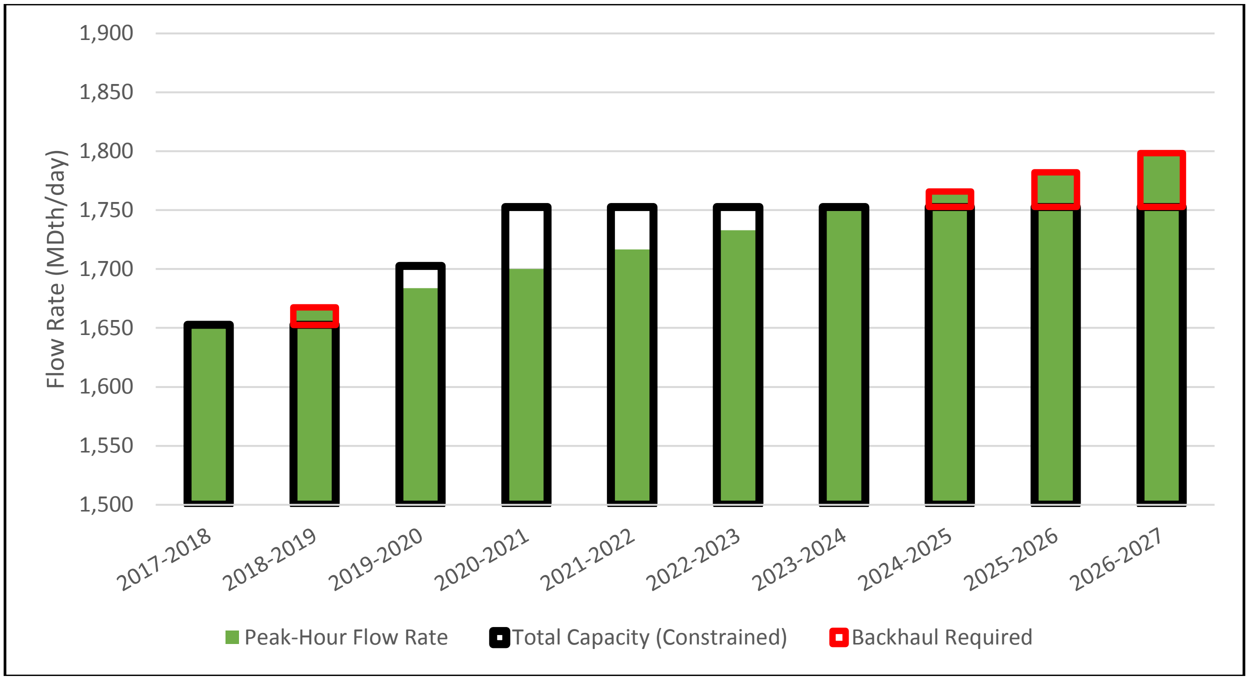
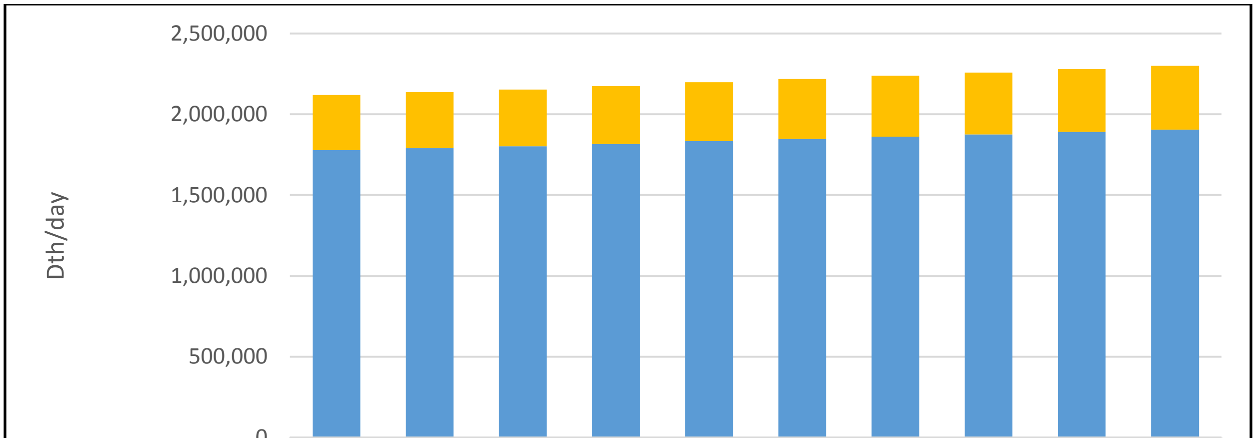


Figure 4.9: Wasatch Front Available Gate Capacity during a Peak Hour

The peak-hour required flow rate into the Company's system will continue to increase as system demand increases. Figure 4.9 contains an estimate of the minimum amount of peak-hour volume the Company's system will require through 2026-2027.



	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027
Peak Hour Requirement	340,375	346,466	352,556	358,647	364,737	370,828	376,918	383,009	389,099	395,190
System Total Firm	1,778,408	1,789,511	1,801,218	1,816,015	1,833,050	1,847,123	1,860,737	1,875,345	1,890,414	1,904,962

Figure 4.10: System Projected Peak-Hour Requirements

System Capacity Conclusions

The Company's HP system is capable of meeting the current peak-day demands. The Company bases this assessment on GNA modeling that indicates that the gate stations and feeder line systems have adequate capacity to meet average-daily (on a peak-day) and peak hourly demands and the supply contracts are adequate. All system models show that pressures should not drop below the design minimum of 125 psig. As discussed below, the Company has plans to address any areas with projected pressures near the 125-psig minimum. The system will continue to grow along with the demand and the Company will conduct an analysis annually and address concerns to ensure that the system continues to meet the peak day needs.

The Company will discuss project options in the distribution action plan (DNG Action Plan) for these identified constraints and concerns:

- Increasing demand and limited supply in the Northern and Central Regions
- Low pressures at the endpoint of FL 51 near Plain City
- Low pressures in the Vernal HP system
- Low pressures in Fort Duchesne
- Demand growth in Monticello
- Demand growth in the Southern HP System
- Demand growth in Rock Springs
- Demand growth in Kemmerer

Distribution System Action Plan (DNG Action Plan)

The Company is currently planning, designing, and constructing several reinforcement and replacement projects on its system. The following is a brief description of the major planned projects for 2017 and beyond.

High Pressure Projects:

Station Projects:

1. <u>SQ0003 District Regulator Station, Santaquin, Utah</u>: The Company first discussed this project on page 4-14 of the 2015/2016 IRP. Additional information on the scope of this project is provided on page 4-13 of the 2016/2017 IRP. This project is currently under construction with an anticipated completion date of August 2017.

   The updated estimated cost for this project is $3,019,000 with a first year revenue requirement of $430,000.

2. NO0001 District Regulator Station, North Ogden, Utah: The Company first discussed this project on page 4-13 of the 2015/2016 IRP. The Company also provided an update on the status of the project on page 4-14 of the 2016/2017 IRP. At that time, the Company was still in negotiations for the purchase of the regulator station site. Consequently, the full scope of the project was still in development.

   The Company has since purchased the property and completed the redesign of this project. The revised project scope includes installation of approximately 17,000 lf of 8-inch HP main and new district regulator station. The route selected for this extension starts at the intersection of US-89 and Pleasant view drive (tap location) and then runs southeasterly along Pleasant View drive to Lomond View Drive. The route then heads east along Lomond View Drive to the regulator station site.

   The project is currently under construction with an anticipated completion date of October 31, 2017.

   The updated estimated cost for this project is $4,983,000 with a first year revenue requirement of $690,000.

3. LG0012 District Regulator Station, Nibley, Utah: The Company first discussed this project on page 4-14 of the 2016/2017 IRP. The project is currently in the design phase, and the Company anticipates construction in 2018.

   The estimated cost for this project is $3,255,000 with a first year revenue requirement of $460,000.

4. TG0006 District Regulator Station, Lehi, Utah: The Company is considering the construction of a new district regulator station in Lehi, Utah. This station is required to reinforce IHP pressures near proposed residential and commercial developments in west Lehi. The Company is purchasing property north of 2100 North Street and west of 3600 West Street in the Holbrook Farms Subdivision for the regulator station.

   The Company's IHP Region Engineer has indicated that a 2 x 3 district regulator station is required to serve to increased load. Preliminary sizing analysis indicates that an 8-inch diameter HP tap line would be required to serve the regulator station.

   There are two potential corridors for the construction of the HP tap line. The first option would tap the Company's FL 85 approximately 2.1 miles south of the proposed regulator station site. However, FL 85 does not have enough free capacity in this location to serve this regulator station.

The second option for serving the new regulator station is for the Company to extend its existing tap line for district regulator station HR0002 approximately 6.9 miles to the proposed regulator station site. This route would largely follow Redwood Road near Camp Williams in the south end of the Salt Lake Valley.

The last option for serving the new station is for the Company to tap its existing FL 25 approximately 1.5 miles to the east of the regulator station site. While this is the shortest of the three options, it presents challenges. The proposed route crosses the Jordan River as well as a rail corridor. Both of these crossings will likely need to be installed using directional drilling. Even with the challenges, this route is preferred.

The Company is evaluating each alternative. Once an alternative is chosen, the Company will provide updates and a corresponding cost estimate as part of the IRP Variance Report process. Based on current projections, this station will be in service prior to the 2018-2019 heating season.

5. <u>North Temple HP Regulator Station, Salt Lake City, Utah</u>: In 2018, the Company plans to relocate its HP regulator station WA0085 located at approximately 2000 West Street and North Temple Street in Salt Lake City. This station was installed in 1930 and is used as an MAOP break between the Company's Northern System (471 psig MAOP) into its Central System (354 psig MAOP). It is a critical HP regulator station on the Company's system. Typically, gas flows south on the Company's 20-inch FL 33 into the regulator station. From there the gas flows into FL's 55 and FL 12 at reduced pressures. In the event of an emergency on the Northern System, gas can flow from south to north if the pressure in the Northern system is low enough to accommodate the flow.

   There are several reasons why the Company decided to relocate this station instead of remodeling it at its current location. First, the existing site is extremely constricted. I-15 borders the east; the south property line is directly adjacent to North Temple Street; and the west property line is directly adjacent to a restaurant. Second, the existing building housing the equipment is an old, unreinforced masonry building. Due to the critical nature of this facility, the building would need replacement to ensure the safety of personnel and equipment during a seismic event. Third, the Company's technicians have had myriad problems with the large diameter valves within the station. At high flows these valves experience abnormally high vibrations. These vibrations have caused the control valves to shut-off on several occasions, effectively shutting off a significant amount of gas flow from north to south. Last, the existing bypass line for the station is located outside of the station building. Accessing and operating the large diameter valves is very difficult for the Company's personnel.

The Company considered a complete remodel of the existing station, but given the challenges with the restricted site, the Company's Engineering and Operations departments opted to relocate the station to a larger site. Not only would a larger site provide better and safer access, it would also allow the Company to construct a pig launcher and receiver at the site to facilitate inline inspection of FL 33.

In 2014, the Company secured a new parcel of property approximately 1.6 miles north of the existing site. This site is large enough to allow for the construction of the following:

- A new code-compliant building housing the required regulation and metering equipment;
- An IHP regulator station and line heater to serve the Salt Lake City belt main system; and
- Piping and valves to facilitate the future construction of pig launchers and receivers on FL 33.

The Company is designing the station improvements. This station will still serve as the MAOP break between the Northern and Central HP systems. Once the design is complete, the Company will provide an update on anticipated costs as part of the IRP Variance Report process.

6. Westport Tap Station, Salt Lake City, Utah: The Company anticipates growth in the north-west quadrant of Salt Lake City. Two sizeable facilities will be constructed in the area in the near future, along with the remodel and expansion of the Salt Lake City International Airport and other business and industrial development. The Company does not have any HP facilities in the area and evaluated options for extending HP service. To serve growth and development in the area, the Company proposes to construct a new interconnect with Kern River and to extend a 6-inch HP pipe from the proposed tap location to the area. A portion of the cost will be offset with customer contributions. The Company estimates its portion of project costs will be approximately $3,200,000. The Company is working to acquire property, and plans to construct the project in 2017 and 2018. The Company will provide updates, as needed, as part of the IRP variance report process.

7. North Salt Lake Kern River Gate Station, North Salt Lake City, Utah: The Company's gate stations along the Wasatch Front are nearing capacity. As a result, the Company has been analyzing alternatives to provide additional feeds into its HP system. The Company's most economically feasible option is to construct a new gate station off the Kern River Pipeline in North Salt Lake. The Company has formed a team to pursue

property acquisition, develop cost estimates and develop project drawing and specifications for a new 400 MMcfd gate station near FL 21 in North Salt Lake.

This project is scheduled for completion prior to the 2019-2020 heating season. The Company will provide updates to this project as part of the IRP Variance Report process.

8. TG0007 District Regulator Station, Saratoga Springs, Utah: The southern end of Saratoga Springs is developing rapidly. Currently, plans exist for the near-term construction of over 800 new residential units in this section of the city. Additionally, Saratoga Springs has recently annexed an additional half mile of property along its southern border, increasing the amount of developable property in the area. In order to maintain IHP pressures in this portion of the system, the Company has begun analysis on constructing a new district regulator station in the south portion of Saratoga Springs. The Company is currently reviewing routes to accommodate the high-pressure main extension, as well as possible regulator station sites.

   The Company anticipates constructing the project in 2019. The Company will provide updates on the status of this project (schedule and estimated costs) as part of the IRP Variance Report process as well as in the 2018-2019 IRP.

Feeder Line Projects:

1. FL 54 Extension, Park City, Utah: The Company first discussed this project on page 4-16 of the 2015/2016 IRP. This project is required to reinforce the Company's HP system in Park City. The Company has analyzed system models for the area and determined that the system receives the most benefit by connecting existing FL 54 and FL 99. To do this, the Company is constructing approximately 9,200 lf of 8-inch HP pipeline. The HP pipeline starts at the Company's existing WA1562 district regulator station located near the intersection of SR-40 and Kearns Boulevard in Summit County. From there the route heads west, along Kearns Boulevard to its termination point near the Company's PC0004 district regulator station, near Park City High School.

   This project is currently out to bid. The Company anticipates starting construction in June 2017, with a completion date of August 2017. The estimated cost for this project is $3,900,000 with a first year revenue requirement of $520,000.

2. FL 111 Extension, Reliance City, Wyoming: The Company first discussed this project on page 4-16 of the 2015/2016 IRP. The project is required to reinforce the Company's

HP system in the North Rock Springs/Reliance Area. The Company examined two route variations for this project.

The Company first analyzed extending 8-inch HP steel pipeline from its existing RS0039 district regulator station, north along Foothill Boulevard approximately 2.9 miles to the intersection with Yellowstone Road. At this intersection, the pipe route heads northwest along Yellowstone Road another 0.7 miles to the tie-in point at the Company's existing SC0011 district regulator station.

This route is the most direct route between the two regulator stations. However, finding a suitable running line within Yellowstone Road proved to be a challenge as the roadway has several existing utilities in place. Additionally, the roadway borders many residences and businesses. This would complicate construction activity in this area, as maintaining driveway access would be costly and time consuming.

The Company analyzed a second route that was very similar to the first. The first 2.9 mile portion of the route directly mirrored the route discuss in the first option. However, instead of turning northwest at the intersection of Yellowstone Road, the pipeline route continues north approximately 0.5 miles until it intersects with the Company's existing FL 30. At this point, the route turns west following the route of FL 30. Instead of looping FL 30 however, the Company proposed to replace this section of FL 30 with the 8-inch HP pipe. The route terminates at the Company's existing SC0011 district regulator station. While this option is slightly longer, due to the difficulties constructing within Yellowstone Boulevard, the cost estimate for this route is the least expensive. The Company selected this route.

The Company is finalizing design documents and plans on bidding and constructing this line in 2018. The estimated cost for this project is $4,850,000 with a first year revenue requirement of $590,000.

3. <u>Feeder Line Replacement Program</u>: Pursuant to the Utah Commission's Order approving the Settlement Stipulation in Docket No. 09-057-16, on November 15, 2015 the Company filed an infrastructure replacement plan detailing the planned projects, the anticipated costs and other relevant information.

Preliminary Timeline Summary:

High Pressure Project Summary Table (Excluding Feeder Line Replacement)			
Year	Project	Estimated Cost	Revenue Requirement
2017	SQ0003 District Regulator Station	$3,019,000	$430,000
	NO0001 District Regulator Station	$4,983,000	$690,000
	FL54 Extension	$3,900,000	$520,000
2018	FL111 Extension	$4,850,000	$590,000
	LG0012 District Regulator Station	$3,255,000	$460,000
	TG0006 District Regulator Station	TBD	TBD
	North Temple HP Regulator Station	TBD	TBD
	Westport Tap Station	$3,200,000	$460,000
2019	North Salt Lake Kern River Gate Station	TBD	TBD
	TG0007 District Regulator Station	TBD	TBD

Plant Projects:

1. On-System LNG Facility: The Company is taking necessary steps to obtain the required approvals to build an on-system LNG storage facility. Details on this facility are discussed in the Peak-Hour Demand and Reliability section of this report.

Intermediate High Pressure Projects:

1. Belt Main Replacement Program: The Company continued its Belt Main Replacement program in 2017. Pursuant to the Settlement Stipulation of Utah Commission's Order Approving the Settlement Stipulation, in Docket No. 13-057-05, on November 15, 2015 the Company filed an infrastructure replacement plan detailing the planned projects, the anticipated costs and other relevant information.

2. Eastern Utah System Replacements: The Company acquired the distribution systems in Moab, Vernal, and Monticello from Utah Gas in 2001. After careful consideration and analysis, the Company determined that these systems were in need of replacement.

   In 2009, the Company began a replacement program. The Company has completed replacements in Monticello and Moab and work is underway in Vernal. The Company plans to complete the work as described below.

   Vernal Replacements: The Company will replace approximately 50,000 lf of main and 525 services in 2017. Of the 50,000 lf of main, about 15,000 lf will be replaced with 2-inch plastic pipe, about 25,000 lf will be replaced with 4-inch plastic pipe, and about 10,000 lf will be replaced with 6-inch plastic pipe. The total estimated project cost for 2017 is $2,400,000 with a first-year revenue requirement of about $350,000. The Company plans to complete the Vernal replacements in 2017. There are no viable alternatives for this replacement.

3. Aging Infrastructure Replacement: The Company is reviewing the replacement rate of its aging infrastructure relative to its expected life and may propose to accelerate replacement in the future. At the end of 2016 there was approximately 4,300 miles of pre-regulatory (pre-1971) steel main and service lines, some dating back to 1929, that are not currently in the Infrastructure Replacement Tracker.

   The Company also has approximately 7,000 miles of Aldyl-A pipe, which is early vintage plastic that has a higher than average leak rate. Because of the higher leak rate, many utilities have targeted programs to replace this type of pipe. The Company is concerned that the current rate of replacement may be inadequate.

Activities and Associated Costs for Transmission Lines and Distribution Systems

Transmission Integrity Overview

The Company continues to implement integrity activities defined in its Transmission Integrity Management Plan for transmission lines as originally mandated by the "Pipeline Safety Improvement Act of 2002" and later codified in the Federal Regulations (49 CFR Part 192, Subpart O). The transmission integrity management regulations require the Company to identify all high consequence areas (HCA) along the segments of feeder lines that are defined as transmission lines.[60]

Once the Company identified these HCAs, it calculated a risk score for each segment located in the HCA. These risk scores established the initial priority for when the Company initially assessed each HCA. The Company verifies each HCA and calculates the risk score on an annual basis. Subsequent to this initial assessment, federal regulations require the Company to reassess each HCA at intervals not to exceed seven calendar years from the initial or previous assessment, or sooner based on results of the previous assessment.

Additionally, the Company is required by the transmission integrity rules to conduct additional ongoing preventive and mitigative measures on feeder lines in HCAs and in class 3 and 4 locations.[61] These additional measures include monitoring excavations (excavation standby) near these feeder lines and performing semi-annual leak surveys.

Distribution Integrity Overview

On December 4, 2009, PHMSA issued its final rule titled: "Integrity Management Program for Gas Distribution Pipelines." This final rule became effective on February 12, 2010, with implementation required by August 2, 2011.

The distribution integrity management rule requires the Company to develop, write and implement a distribution integrity management program with the following elements:

> Knowledge; identify threats; evaluate and rank risks; identify and implement measures to address risks; measure performance, monitor results, and evaluate effectiveness; periodically evaluate and improve program; and report results.

The Company continues to implement activities defined in its Distribution Integrity Management Plan for the distribution system. It implements the activities to mitigate the threats that are identified in the plan.

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[60] Transmission Lines are those feeder lines (or segments of feeder lines) that are operating (i.e. Maximum Allowable Operation Pressure (MAOP) at or above a pressure that produces a hoop stress of 20% of Specified Minimum Yield Strength (SMYS)).
[61] Class location as defined by 49 CFR Part 192 (§192.5).

Transmission Integrity Management

Costs

Table 4.3 details the anticipated costs associated with transmission integrity management.

Baseline Assessment Plan

The Baseline Assessment Plan prescribes the methods that the Company will use to assess the integrity of each HCA. The Company determines these methods based upon the known or anticipated threats to these segments. The most common threats on the pipeline include corrosion and third party damage. The Company has used multiple assessment methods in the past to address these threats, including external corrosion direct assessment (ECDA), internal corrosion direct assessment (ICDA), direct visual examination, pressure testing, and inline inspection. The Company has completed the Baseline Assessment Plan for all segments of pipe.

External Corrosion Direct Assessment

ECDA is an assessment method that evaluates the integrity of the pipeline segments for the threat of external corrosion, including segments of cased gas transmission pipelines. Refer to Figure 4.10 for an overview of the ECDA process.

The ECDA methodology is a four-step process. The four steps of the process include:

Pre-Assessment - This step utilizes historic and current data to determine whether ECDA is feasible, identify appropriate indirect inspection tools, and define ECDA regions. ECDA regions are areas along the pipeline that have similar characteristics. There may be multiple regions along a single pipeline segment. Examples of ECDA regions include segments in casings or segments with different types of external coatings.

Indirect Inspection - This step utilizes above-ground inspection methods such as close interval survey, pipeline current mapper or DC voltage gradient survey, to identify, and quantify the severity of coating faults and areas of diminished cathodic protection. The analysis of this data can help identify areas along the pipeline segment where corrosion may have occurred or may be occurring. The Company uses a minimum of two indirect inspection tools over the entire pipeline segment to provide improved detection reliability across the wide variety of conditions encountered along a pipeline right-of-way. The Company categorizes indications from indirect inspections according to severity. A third indirect inspection tool is required for initial assessments of the segment.

Direct Examination - This step includes excavations of the pipe for direct examination to determine if there is corrosion occurring on the pipeline. For initial assessments (i.e. first time assessments for an HCA), a minimum of two excavations are required for each ECDA region and a minimum of four excavations in total for the ECDA project. The ECDA project may contain more than one pipeline and more than one ECDA region. Reassessments require a minimum of one excavation per ECDA region and a minimum of two excavations in total for the ECDA project. The Company selects excavation sites based on a review of the data collected during the pre-assessment and the indirect surveys.

The Company uses this information to identify the areas on the pipeline within each region where external corrosion is most likely. The Company must also excavate at a location where it has not identified any indications. The Company uses the information gathered at this site to help validate the effectiveness of the ECDA process. When corrosion or other pipeline damage or coating damage is found during the direct examination step, the Company repairs the pipe or coating. The Company may select additional sites for examination based on the findings of the required direct examinations.

Post-Assessment - This step utilizes data collected from the previous three steps to assess the effectiveness of the ECDA process and determine reassessment intervals and provide feedback for continuous improvement.

Internal Corrosion Direct Assessment

ICDA is a process used to predict the most likely areas of internal corrosion, including those caused by chemical and microbiologically induced corrosion. ICDA focuses on directly examining locations at which internal corrosion is most likely to occur.

The basis of ICDA is the detailed examination of the most susceptible locations along a pipeline where liquids, if any, would first accumulate in the pipeline. If the locations most likely to accumulate liquids have no indications of internal corrosion, all other locations further downstream are considered to be free from internal corrosion. ICDA relies on the ability to identify locations most likely to accumulate liquids.

The ICDA methodology is a four-step process that is intended to assess the threat of internal corrosion in pipelines and assist in verifying pipeline integrity.

The initial baseline assessment plan included ICDA. The Company was able to eliminate internal corrosion as a threat of concern going forward based on the fact that internal corrosion was not found at the conclusion of completing ICDA on the entire pipeline system as well as the implementation of the Company's ongoing internal corrosion plan.

Visual Examination of Aboveground Pipe and Pipe in Vaults

The Company assesses aboveground piping (e.g. spans and valve assemblies) and piping in vaults by visual examination when the piping is located in an HCA and the Company cannot assess the pipe utilizing other methods.

Inline Inspection

When a pipeline has been constructed and configured, or retro-fitted in such a way to allow for inline inspection, the Company assesses the pipe using inline inspection tools commonly called “smart pigs.” These tools are equipped with sensors that collect data as the tool travels through the pipeline and can reveal areas of wall loss and dents that may require repair or cutout. The Company has 132 miles of transmission piping (16% of the Company’s transmission system) that can be inspected using smart pigs. As the Company replaces aging infrastructure, it designs and builds the new pipelines to accommodate inline inspection tools. Recent advancements in technology allow some limited application of inline inspection tools for non-piggable pipelines. The Company has helped fund these advancements through its research and development program. The Company has used these advanced tools to assess locations of its system that it previously could not.

The inline inspection tools provide specific data on the condition of the pipeline segment being inspected. The Company analyzes data that it collects along the pipeline segment for defects and areas of concern (e.g. wall loss or dents) and excavates for further evaluation and repair or cut out, if necessary.

High Consequence Area Validation

Each year, the Company conducts a field survey of all transmission line segments to validate the current HCA as well as identify any new potential sites that may trigger a new HCA. Sites that may trigger a new HCA include the following: office buildings, businesses, community centers, churches, day care centers, retirement centers, hospitals, and prisons.

The Company maintains this information in its mapping system and uses it to calculate HCAs on an annual basis.

Distribution Integrity Management

Costs

Table 4.4 details the anticipated costs associated with distribution integrity management.

Implementation

The Company implemented its written Distribution Integrity Management Plan in August of 2011. Implementation included identifying the threats associated with the distribution system within each operating region as well as calculating a risk score for each identified threat. The risk scores are calculated by subject matter experts (SME) for each operating region utilizing known infrastructure data and leak history. The threats and the associated risk scores are validated by comparison to a second geographic information system (GIS) risk model. Once the Company identified the threats and calculated the risk scores for each threat, each operating region identified possible measures that could be implemented or are currently being implemented that would help mitigate the risks on the distribution system. The process of identifying threats and calculating the risk for each threat is ongoing and is evaluated on a biennial basis.

Key Performance Integrity Metrics

Table 4.5 details specific performance metrics associated with the transmission integrity management program.

New Regulations

The following regulations may have significant impact on the Company:

Safety of Gas Transmission and Gathering Lines (Mega Rule)

PHMSA initially published an advanced notice of proposed rulemaking (ANPRM) for the Mega Rule on August 25, 2011. On April 8, 2016, PHMSA published a notice of proposed rulemaking (NPRM) in the Federal Register. The Mega Rule is intended to increase the level of safety associated with the transportation of gas by imposing regulations to prevent failures like those involved in recent incidents. The Mega Rule also seeks to clarify and enhance some existing requirements and address certain statutory mandates and National Transportation Safety Board (NTSB) recommendations.

If adopted, the proposed rule would require additional pipeline integrity management measures for pipelines that are not in HCAs, as well as clarifications and selected enhancements to integrity management activities related to pipelines within HCAs.

The proposed Mega Rule addresses several integrity management topics, including:

- Revision of integrity management repair criteria for pipeline segments in HCAs to address cracking defects, non-immediate corrosion metal loss anomalies and other defects;
- Codifying functional requirements related to the nature and application of risk models consistent with current industry standard;
- Codifying requirements for collecting, validating, and integrating pipeline data models consistent with current industry standards;
- Strengthening requirements for applying knowledge gained through the integrity management program models consistent with current industry standards;

- Strengthening requirements on the selection and use of direct assessment methods models by incorporating recently issued industry standards by reference;
- Adding requirements for monitoring gas quality and mitigating internal corrosion, and adding requirements for external corrosion management programs including above ground surveys, close interval surveys, and electrical interference surveys; and
- Codifying requirements for management of change consistent with current industry standards.

With respect to non-integrity management requirements, the proposed Mega Rule would impose:

- A new ‘‘moderate consequence area’’ definition;
- Requirements for monitoring gas quality and mitigating internal corrosion;
- Requirements for external corrosion management programs including above ground surveys, close interval surveys, and electrical interference surveys;
- Requirements for management of change, including invoking the requirements of ASME/ ANSI B31.8S, Section 11;
- Repair criteria for pipeline segments located in areas not in an HCA; and
- Requirements for verification of maximum allowable operating pressure (MAOP) and for verification of pipeline material for certain onshore steel gas transmission pipelines including establishing and documenting MAOP if the pipeline MAOP was established in accordance with §192.619(c) or the pipeline meets other criteria indicating a need for establishing MAOP.

The proposed Mega Rule also proposes requirements for additional topics that have arisen since issuance of the ANPRM including:

- Requiring inspections by onshore pipeline operators of areas affected by an extreme weather event such as a hurricane or flood, landslide, an earthquake, a natural disaster or other similar event;
- Allowing extension of the 7-year reassessment interval upon written notice;
- Requiring operators to report each instance when the MAOP exceeds the margin (build-up) allowed for operation of pressure limiting or control devices;

- Adding requirements to ensure consideration of seismicity of the area in identifying and evaluating all potential threats;
- Adding regulations to require safety features on launchers and receivers for in-line inspection, scraper, and sphere facilities; and
- Incorporating consensus standards into the regulations for assessing the physical condition of in-service pipelines using inline inspection, internal corrosion direct assessment and stress corrosion cracking direct assessment.

The new administration has delayed the publication of the Mega Rule regulation. The industry anticipates the regulation will be published by the end of 2017 or early 2018. There is speculation by industry experts that non-statutory parts may be modified, but no official statement to this effect has been provided by PHMSA.

Plastic Pipe Rule

PHMSA published this regulation as a NPRM on May 21, 2015, with an anticipated final rule publication in 2017. PHMSA is proposing to amend the natural and other gas pipeline safety regulations to address regulatory requirements involving plastic piping systems used in gas services. These proposed amendments are intended to correct errors, address inconsistencies and respond to petitions for rulemaking. The requirements in several subject matter areas are affected, including incorporation of tracking and traceability provisions; design factor for polyethylene (PE) pipe; more stringent mechanical fitting requirements; updated and additional regulations for risers; expanded use of Polyamide-11 (PA-11) thermoplastic pipe; incorporation of newer Polyamide-12 (PA-12) thermoplastic pipe; and incorporation of updated and additional standards for fittings.

Valve Installation and Minimum Rupture Detection Standards Rule

PHMSA plans to publish this rule as an NPRM in May 2017. This rule is expected to cover rupture detection and response time metrics including the integration of automatic shutoff valves and remote control valves on transmission pipelines with an objective to improve overall incident response.

Miscellaneous Rule

PHMSA published this regulation as a final rule on March 11, 2015, with an effective date of October 1, 2015. One component of this rulemaking includes the performance of post-construction inspections and qualification of plastic pipe joiners. Post-construction inspection could have a significant impact on the Company. PHMSA is currently in the process of developing guidance for the interpretation and implementation on the requirements associated with post-construction inspection. The effective date for the rules requirements for post construction inspection has been extended indefinitely by PHMSA. The Company anticipates publication of further guidance in the future.

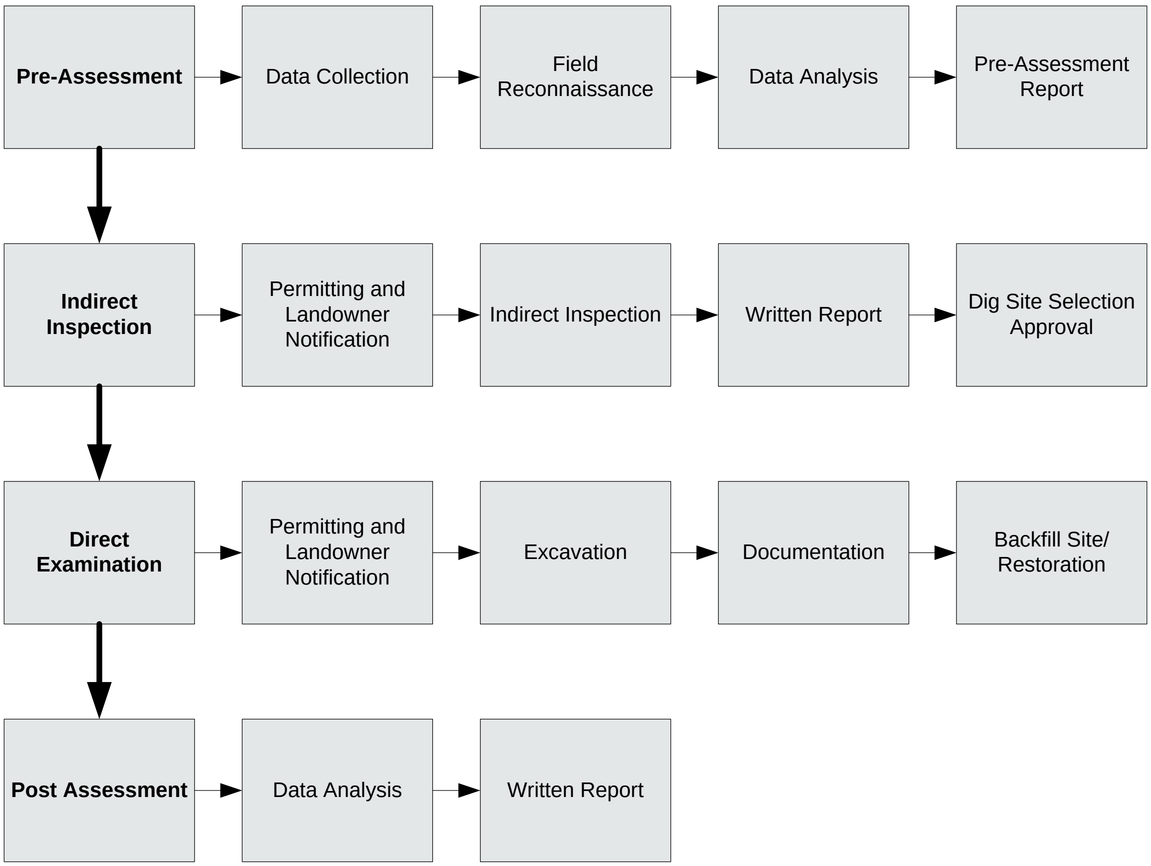

Figure 4.10: ECDA Process Overview

Table 4.3: Transmission Integrity Management Costs

$ Thousands

Activity	2017	2018	2019
Transmission Integrity Management			
ECDA			
Pre-Assessment			
2017 (FL4,11,26-non uprate portion,34, 85,103) (20 HCA miles @ 2 K/mile)	40		
2018 (FL6, 12, 13, 22, 24, 33, 46, 51, 53) (17.5 HCA miles @ 2 K/mile)		35	
2019 (FL18, 21, 47) (23.5 HCA miles @ 2 K/mile)			47
Indirect Inspections			
2017 (FL4,11,26-non uprate portion,34, 85,103) (20 HCA miles @ 30 K/mile)	500		
2018 (FL6, 12, 13, 22, 24, 33, 46, 51, 53) (17.5 HCA miles @ 30 K/mile)		525	
2019 (FL18, 21, 47) (23.5 HCA miles @ 30 K/mile)			705
Direct Examinations			
2016 (FL10,14,26,35,41,42,48, 88) (10 excavations @ 35 K ea.)	175		
2016 (FL10,14,26,35,41,42,48,88) (Pipetel 1 sites, 1 casings @ 175 K /site)	175		
2016 (FL021, 62) (4 excavations @ 35/mile)			
2017 (FL4,11,26-non uprate portion,34, 85,103) (10 excavations @ 35 K ea.)	175	175	
2017 (FL4,11,26-non uprate portion, 34, 85, 103) (Pipetel 2 sites, 2 casings @ 175 k/site)		350	
2018(FL6, 12, 13, 22, 24, 33, 46, 51, 53) (12 Excavations @ 35 K ea)		210	210
2018 (FL6, 12, 13, 22, 24, 33, 46, 51, 53 (Pipetel 4 sites, 4 casings @ 175 K/site)			700
2019 (FL18, 21, 47) (8 excavations @ 35 K ea.)			140
Post Assessment			
2017 (FL4,11,26-non uprate portion,34, 85,103) (20 HCA miles @ 1.5 K/mile)	30		
2018 (FL6, 12, 13, 22, 24, 33, 46, 51, 53)(17.5 HCA miles @ 1.5 K/mile)		26.25	
2019 (FL18, 21, 47) (23.5 HCA miles @ 1.5 K/mile)			35
Inline Inspection			
2016 Excavations/ Validations Digs/ Remediation (10 excavations @ 35 K ea)	140		
2017 (FL068)	350		

Table 4.3: Transmission Integrity Management Costs

$ Thousands

Activity	2017	2018	2019
2017 (FL071)	350		
2017 Excavations/ Validations Digs/ Remediation (14 excavations @ 35 K ea)	245	245	
2018 (FL104)		350	
2018 (FL081)		350	
2018 Excavations/ Validations Digs/ Remediation (6 excavations @ 35 K ea)		105	105
2019 (FL019)			350
2019 (FL004)			350
2019 Excavations/ Validations Digs/ Remediation (6 excavations @ 35 K ea)			105
Direct Examination – Spans and Vaults			
2017 - Spans Reassessment (3 @ 10 K/ span)	30		
2017 - Vaults (5 @ 15 K/ vault)	75		
2018 - Spans Reassessment (1 @ 10 K/ span)		10	
2018 - Vaults (10 @ 15 K/ vault)		150	
2019 - Spans Reassessment (4 @ 10 K/ span)			40
2019 - Vaults (9 @ 15 K/ vault)			135
Pressure Test Assessment			
2017 - 2 pipeline segments @ 100K/segment	200		
2018 - 2 pipeline segments @ 100K/segment		200	
2019 - 2 pipeline segments @ 100K/segment			200
Excavation Standby			
6 employees (2,080 hrs x 6 x $70/hr)	873.6	873.6	873.6
Additional Leak Survey			
120 hrs @ $70/hr	8.4	8.4	8.4
Additional Cathodic Protection Survey			
System Integrity Support - Cathodic Protection (2,080 hrs x 2 $70/hr)	291.2	291.2	291.2
Administration			
Project Coordination (4 employees (2080 hrs x 4 x $80.00/hr))	582.4	582.4	582.4

Table 4.3: Transmission Integrity Management Costs

$ Thousands

Activity	2017	2018	2019
Data Integration Specialists (2 employees (2080 hrs x 2 x $70/hr))	291.2	291.2	291.2
Construction Records Tech (2080 x $70)	145.6	145.6	146.6
Lead Engineer (2080 hrs x $70/hr)	145.6	145.6	145.6
Senior Engineer M2 (2080 hrs x $70/hr)	145.6	145.6	145.6
Engineer - Integrity Engineering (2080 hrs x $70.00/hr)	145.6	145.6	145.6
IM Engineer - Engineer Tech (1 employee (2080 hrs @ $ 70/hr))	145.6	145.6	145.6
Damage Prevention Tech (2080 hrs x $70/hr)	145.6	145.6	145.6
IM Engineer-Intern (1 employee (1,040 hrs @ $30/hr))	31.2	31.2	31.2
New Position - Integrity Engineer M3 (2080 hrs x $70/hr)	72.8	145.6	145.6
New IM Position - Technical Writer (2080 hrs x $50/hr)	52	104	104
New Position - Data Integration Specialists (2080 hrs x $70/hr)		145	145
Training (for IM and Engineering personnel)	25	30	35
Consultant - 3rd Party Review		30	
NOTE: all labor costs associated with both DIMP and TIMP are captured in the TIMP costs.			
Transmission Integrity Management Total	$5,586	$6,137	$6,504

Table 4.4 : Distribution Integrity Management Costs

$ Thousands

Activity	2017	2018	2019
Distribution Integrity Management			
NOTE: *The costs estimated here are based on additional and accelerated actions initiated based on the threats identified. The costs also reflect the administration costs associations with this new regulation.*			
Additional and Accelerated Actions			
Stray Current Surveys	350	350	350
Additional Leak Survey	300	300	300
Region specific accelerated actions	150	150	150
Mapping improvements	200	200	200
Damage Prevention	650	750	750
ILI - FL106	500		
FL106 Digs (6 @ 35 K ea.)		210	
ILI - FL062	300		
FL062 Digs (1 @ 35 K ea)		35	
Pipetel - FL106	300		
ILI - Discretionary		500	
Discretionary Digs (3 @ 35 K ea)			105
ILI - Discretionary			500
Administration			
Consultant - 3rd Party Plan Review		30	
Distribution Integrity Management Total	$2,750	$2,525	$2,355

Table 4.5: HCA Miles Assessed/ Anomalies Repaired

YEAR	HCA Miles Assessed	Anomalies Repaired
2012	26.470	28
2013	50.367	27
2014	54.555	20
2015	11.040	2
2016	37.226	4
NOTE: Approximately 17 miles of HCA were assessed in 2014 that were originally planned to be completed in 2015. Due to favorable circumstances for completing the direct examinations these assessments were completed early.		

Environmental Review

The Company is committed to compliance with environmental laws and regulations. Some of the regulations with which the Company must comply include the National Environmental Policy Act, the Endangered Species Act, the Clean Air Act, the Clean Water Act, the Toxic Substance Control Act, the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), the Emergency Planning and Community Right to Know Act, the Oil Pollution Act and the National Historic Preservation Act, as well as similar state and local laws that can be more strict than their federal counterparts.

Agencies issuing permits and enforcing these regulations frequently place restrictions on the Company's activities. Requirements are becoming more stringent over time and are affecting the location and construction of the Company's infrastructure. When projects impact the environment, regulatory agencies require permit applications, agency review and public comment periods prior to permit approval. Permit conditions can be rigorous and costly, requiring compliance activities long after project completion. Monitoring may be required for the life of the installation.

For example, the U.S. Fish and Wildlife Service may designate critical habitat areas to protect certain threatened and endangered species. A critical habitat designation for a protected species, such as the desert tortoise, can result in restrictions to federal and state land use. Such restrictions can delay or prohibit access to or use of subject land. Because the Company infrastructure crosses many miles of federal and state lands that include the critical habitat of protected plant and animal species, there can be a material impact on the location of pipeline facilities and construction schedules.

The Clean Water Act and similar state laws regulate discharges of storm water, hydrostatic test water, wastewater, and other pollutants to surface water bodies such as lakes, rivers, wetlands, and streams. Failure to obtain permits for such discharges or accidental releases could result in civil and criminal penalties, orders to cease such discharges, corrective actions, and other costs and damages.

Pre-existing conditions complicating project construction include situations where the Company's pipelines, both new and existing, cross contaminated sites owned by third parties. In many cases, these sites have not been reported to regulatory agencies by the prior owner, and in some cases the boundaries of the sites are unknown, resulting in unforeseen construction interruptions as the Company consults with the regulators on proper remedial activities. Where they have been reported, the sites, usually regulated by the CERCLA or comparable state regulations, require corrective actions as construction activities proceed.

The Company must determine soil disposition prior to construction (when presence of the contamination is known), properly train employees, equip employees with protective equipment, and invoke proper disposal and decontamination procedures, all of which result in escalated project costs. Accidental spills and releases requiring cleanup may also occur in the ordinary course of business, requiring remediation. The Company may incur substantial costs to take corrective actions in any of these cases. Failure to comply with these laws and regulations can result in fines as well as significant costs for remedial activities or injunctions.

New and revised environmental policy is affecting the industry and the Company specifically, and will result in additional costs to conduct business. For example, federal and state courts and administrative agencies are addressing claims and demands related to climate change under various laws pertaining to the environment, energy use, and development.

In 2010, the EPA adopted Greenhouse Gas (GHG) Reporting Regulations requiring the measurement and reporting of carbon dioxide equivalent (CO_2e) emissions emitted from combustion at large facilities (emitting more than 25,000 metric tons/year of CO_2e). Although the Company does not have any single facilities that exceed that threshold, local distribution companies are required to account for the GHG emissions of their customers (residential, commercial and industrial customers using less than 460 MMcf per year of natural gas) annually.

In 2011, the EPA expanded reporting under this regulation to include measurement and reporting of GHG emissions attributed to fugitive methane emissions, requiring on-going measurement and monitoring of methane emissions at the Company's regulator and gate-stations. In 2016, the Company reported a total of 6.4 million metric tons of CO_2e emissions in Utah and 232,282 metric tons of CO_2e emissions in Wyoming. The Company also reported approximately 105,050 metric tons attributed to fugitive methane sources in Utah and zero fugitive methane emissions in Wyoming. Figure 4.11 shows the Company's CO_2 emission rate per million BTU (greenhouse gas intensity) over the last five years.

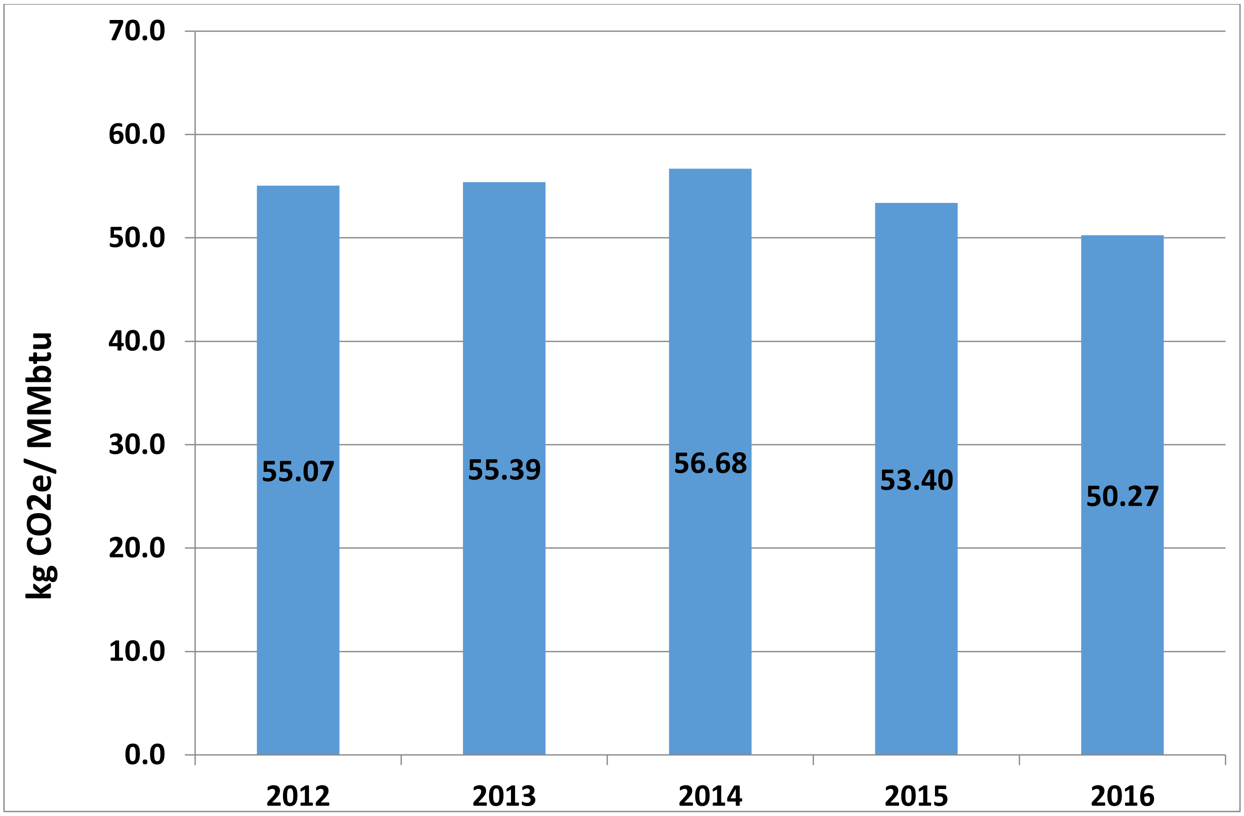

Figure 4.11 – Greenhouse Gas Intensity

In March 2016, the Company became a Founding Partner with the EPA in the Natural Gas STAR Methane Challenge Program, committing to voluntary practices that will reduce methane emissions.

The Company expects that greater awareness regarding the benefits of natural gas for high-efficiency residential, commercial, transportation, industrial, and electricity generation purposes will result in the advancement of these applications and increased utilization of natural gas-fueled equipment. Greater utilization of natural gas should result in significantly lower U.S. greenhouse gas emissions in comparison with more carbon intensive fuels. For a more detailed discussion about full fuel-cycle efficiency, refer to the Customer and Gas Demand Forecast section.

Conservation efforts will also continue to have a positive environmental impact. For example, the Company estimates annual savings of more than 5 MMDth of natural gas from 2007 to 2016. The savings represents the equivalent of about 265,000 metric tons of CO_2e or 56,000 passenger vehicle equivalents (calculated using EPA's GHG equivalence calculator). Lifetime savings attributable to the ThermWise® program totals more than 2.4 million tons of CO_2e or the equivalent of about 507,000 passenger vehicles.