


Lost but not forgotten: The hidden environmental costs of compensating pipelines for natural gas losses

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Executive Summary

The last decade has seen a dramatic rise in the use of natural gas in electricity generation and other applications. This has been widely heralded as a vital step in the transition to a clean energy economy, with supporters arguing that natural gas can act as a bridge fuel, providing a low-emission alternative to coal while cleaner renewable energy technologies develop. Recently however, concern has been growing about the environmental impacts of natural gas production.

Natural gas is comprised principally of methane, a short-lived but potent greenhouse gas that is released through intentional venting and accidental leaks during the production process. Many of these releases originate from the natural gas transportation system – the network of pipes used to move natural gas from production sites to consumer premises – as gas leaks from damaged pipelines and malfunctioning equipment. This not only wastes a valuable resource but also poses a threat to public safety and the environment.

Unfortunately, current federal and state policies do little to encourage the repair of leaking pipelines. At the federal level, pipeline safety regulations require hazardous leaks to be repaired promptly but impose no repair requirement for other leaks. Just five states – Florida, Kansas, Maine, Missouri, and Texas – have adopted their own safety regulations establishing timeframes for the repair of non-hazardous leaks. In all other states, pipeline operators can and often do leave such leaks unrepaired for months or even years, regardless of their environmental impacts. The classification of a leak as hazardous or non-hazardous is generally based on its proximity to buildings, rather than its size. Therefore, leaks in isolated areas may be classified as non-hazardous and left unrepaired, even if they emit substantial amounts of natural gas.

There is little incentive for pipeline operators to voluntarily repair non-hazardous leaks as the cost of leaked gas can be passed through to ratepayers. In *West Ohio Gas Co. v. Public Utilities Commission,* 249 U.S. 63 (1935), the U.S. Supreme Court held that pipeline rates must include an allowance for gas lost through leakage, condensation, expansion, or contraction. Following this decision, all jurisdictions now allow pipeline operators to recover the cost of lost and unaccounted-for gas, measured as the difference between gas flows into and out of the pipeline system.

Recovery may occur in various ways, depending on the nature of pipeline operations. Historically, pipeline operators offered bundled services, which combined the sale of natural gas with transportation under a single price. In such cases, the pipeline operator will generally recover the cost of lost and unaccounted-for gas through a charge in its rates (i.e., reflecting the cost of gas purchased by the operator to make up for system losses). Alternatively, where gas sales are unbundled, a pipeline operator transporting gas on behalf of other entities (shippers) will typically recover lost gas in kind. That is, the pipeline operator may retain a percentage of the gas volumes tendered for transportation to make up for lost and unaccounted-for gas. That percentage is specified in the operator's tariff. The tariff may permit the operator to sell retained gas and/or purchase additional gas when necessary for operational reasons. Where this occurs, the operator must provide its shippers with a credit for any gas sales and may collect a surcharge from its shippers for any gas purchases.

Since pipeline operators can recover the cost of lost and unaccounted-for gas from customers, they have little incentive to improve system management to reduce gas losses. This White Paper examines the current frameworks for recovery of lost and unaccounted-for gas in each U.S. jurisdiction. It recommends changes to those frameworks to encourage improved management of pipeline leaks, namely:

- **Lost and unaccounted-for gas should be reported based on a standard definition and calculated using a consistent methodology.** With few exceptions, pipeline operators report lost and unaccounted-for gas based on their own definitions, which may vary substantially between and even within jurisdictions. This has led to inconsistent and erroneous reporting, preventing accurate tracking of lost and unaccounted-for gas across jurisdictions. To facilitate this, all jurisdictions should adopt a uniform definition and standard formula for calculating lost and unaccounted-for gas, modeled on that used in Pennsylvania. This process could be led by an industry body, such as the North American Energy Standards Board, which may issue a recommended definition to be used in all jurisdictions.
- **The cost recovery framework should be reformed to incentivize reduction of lost and unaccounted-for gas.** Currently, in most jurisdictions, pipeline operators track changes in the amount of lost gas and periodically update rates to account for those changes. Consequently, ratepayers bear the risk of any increase caused by excessive lost and unaccounted-for gas, and enjoy the benefit of any reduction. Since pipeline operators are unaffected by such changes, they have little incentive to significantly reduce gas losses. This incentive could be strengthened by rewarding operators for any decline, and penalizing operators for any rise, in gas losses. Such an approach is currently used by regulators in New York, whose experience could serve as a guide for other jurisdictions.
- **Pipeline operators' claimed gas losses should be carefully scrutinized.** In allowing cost recovery for lost gas, the U.S. Supreme Court noted that some loss of gas is unavoidable, no matter how carefully the pipeline system is managed. This does not, however, entitle the pipeline operator to recover the cost of gas lost through avoidable

causes. Nevertheless, regulators currently do not distinguish between avoidable and unavoidable gas losses. Many regulators currently lack the information needed for such an analysis as, despite the advent of new measurement technologies, pipeline operators often do not directly measure gas losses due to leaks and other causes. In the future, operators should be required to measure the quantity of gas lost from their systems and report the results of those measurements annually. The report should include a breakdown of gas losses by cause.

- **The federal and state regulations should establish an appropriate cap on cost recovery.** Several states have promulgated caps on allowable cost recovery for lost and unaccounted-for gas. Expanding this approach would create a powerful incentive for operators to reduce gas losses. New caps, designed to encourage pipeline operators to reduce gas losses over time, should be adopted in all jurisdictions.

I. Introduction

Domestic production and use of natural gas has increased significantly over the last decade. Recent prices changes have made natural gas more cost competitive as a fuel in electricity generation, leading to its substitution for coal and petroleum. The U.S. Energy Information Administration (EIA) estimates that, between 2004 and 2014, electricity generation using natural gas increased by approximately fifty-eight percent, while coal based generation declined by nearly twenty percent and petroleum based generation by over seventy percent.[1] This shift has had important public health and environmental benefits, reducing emissions of mercury and other toxic air pollutants.[2] Moreover, it may also lead to a decline in greenhouse gas emissions that contribute to climate change.

Natural gas is often touted as a "clean" fossil fuel, with proponents noting that its combustion emits approximately fifty percent less carbon dioxide and seventy-two percent less nitrogen oxides than coal.[3] However, this is only part of the story. Recent lifecycle analyses suggest that any savings at the point of combustion may be partially or, in some cases, entirely offset by greenhouse gas emissions further up the supply chain.[4]

Methane – the key component of natural gas and a potent greenhouse gas – is released during resource extraction, processing, storage, and transportation.[5] According to the Environmental Protection Agency (EPA), natural gas systems[6] were the second largest source of methane in the U.S. in 2013, accounting for nearly twenty-five percent of national emissions.[7] Over half (fifty five percent) of these emissions occurred during the storage and transportation of natural gas.[8]

The natural gas transportation system comprises a vast network of pipelines, extending approximately 2.5 million miles across the U.S.[9] The system is typically divided into three parts, namely:

- gathering pipelines, which link natural gas production areas with the main transportation system;
- transmission pipelines, which move natural gas from gathering, processing, and storage facilities to local utilities (known as local distribution companies (LDCs)) and large volume consumers (e.g., power plants and factories); and
- distribution pipelines, which deliver natural gas from the city gate (i.e., the point at which natural gas is transferred from a transmission pipeline to the LDC) to residential, commercial, and industrial consumers.[10]

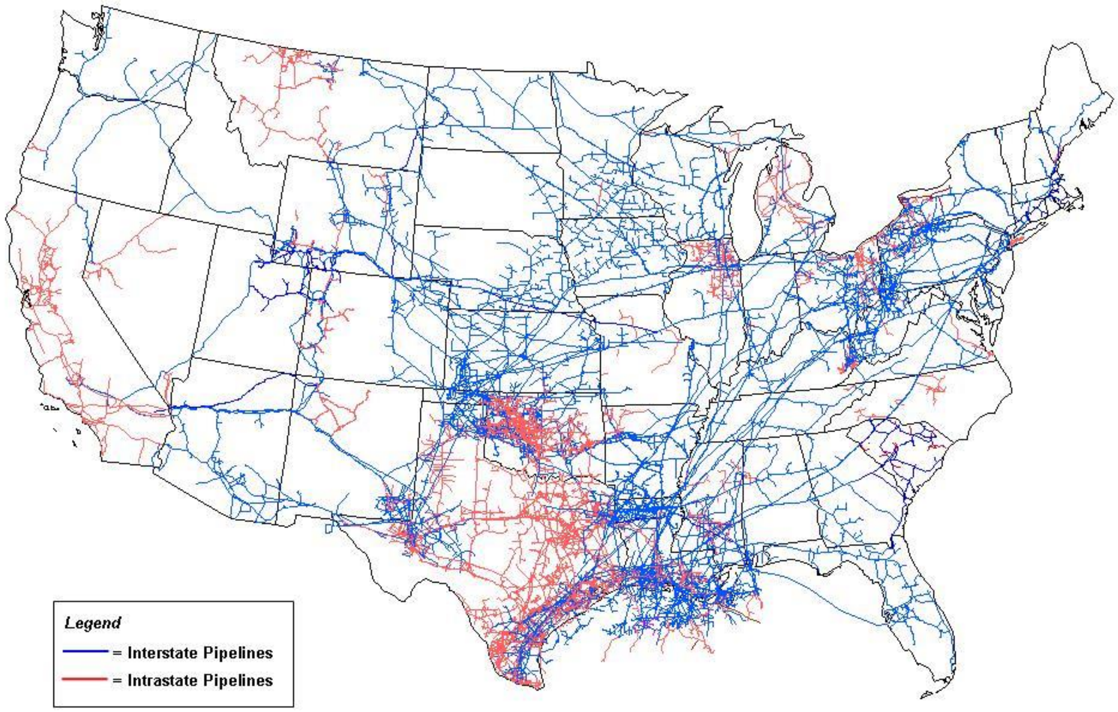

FIGURE 1: U.S. NATURAL GAS PIPELINE NETWORK

SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION (2009). TO SEE A HIGH-RESOLUTION, LARGE-FORMAT VERSION OF THE MAP, VISIT HTTP://WWW.EIA.GOV/PUB/OIL_GAS/NATURAL_GAS/ANALYSIS_PUBLICATIONS/NGPIPELINE/NGPIPELINES_MAP.HTML

Transmission and distribution systems often vent large amounts of natural gas to regulate pipeline flow and pressure.[11] In addition to this intentional venting, natural gas is also released through accidental leaks from corroded pipes and defective valves, pumps, flanges, and other equipment.[12] The EPA estimates that, in 2011 (the latest year for which data is available), over $192 million worth of natural gas was lost through distribution pipeline leaks alone.[13] This is a waste of a valuable resource, as well as a threat to public safety and the environment.

Recent deadly pipeline explosions in San Bruno, California,[14] Allentown, Pennsylvania,[15] and Bergenfield, New Jersey[16] highlight one impact of natural gas leaks. Another less obvious, but equally serious impact of leakage is the emission of greenhouse gases that accelerate climate change. The EPA estimates that, in 2013, natural gas transmission and distribution systems released over 3.5 million metric tons of methane, primarily through accidental leaks.[17] This potent greenhouse gas is thirty-four times more damaging to the climate than carbon dioxide over a 100-year timeframe and has even greater relative impacts over shorter periods.[18] Consequently, reducing methane leaks from natural gas pipelines could help to slow the pace of global climate change. Moreover, it would also have other benefits, conserving a valuable resource and reducing costs to society.

Despite this, existing regulation of pipeline leaks focuses solely on minimizing risks to public safety and is not designed to reduce the total amount of natural gas leaking into the atmosphere. Regulatory authority over the natural gas pipeline system is shared between the federal government and the states. With some exceptions, federal agencies regulate pipelines crossing state boundaries (interstate pipelines), while other (intrastate) pipelines are regulated by state bodies.[19]

Controlling pipeline leaks

At the federal level, the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) regulates pipeline leaks with a view to minimizing public safety risks. To this end, PHMSA regulations require pipeline operators to ensure the prompt repair of leaks posing a hazard to persons or property.[20] The classification of a leak as hazardous is based largely on its proximity to buildings, rather than the amount of gas leaked. Consequently, leaks in isolated areas may be classified as non-hazardous and exempt from the federal regulations, even if they release substantial amounts of natural gas.[21]

A recent study of distribution system leaks, led by researchers at Washington State University, suggests that the bulk of natural gas releases originate from a small number of large leaks.[22] The study, which measured methane emissions from 230 underground pipeline leaks, found that just three large leaks accounted for fifty percent of total measured methane.[23] The largest leak emitted over 34 grams of methane per minute; that is almost 600 times larger than the median emissions rate from all leaks (estimated at 0.06 grams per minute per leak).[24] However, despite their potentially devastating environmental consequences, such large leaks can be classified as non-hazardous provided they are situated away from crowded areas. Under the federal safety regulations, leaks so classified may be left unrepaired indefinitely.

Responsibility for enforcing the federal regulations against intrastate pipeline operators has been delegated to the states, which can impose additional or stricter safety requirements on operators in their respective jurisdictions.[25] Eleven states have also been appointed as agents of the federal government to monitor interstate pipelines in their jurisdictions.[26]

Building on the federal regulations mandating prompt repair of hazardous leaks, fifteen states have adopted rules setting timeframes for other repairs.[27] The rules in each state require immediate repair of leaks currently posing a hazard and specify timeframes ranging from one to fifteen months for repairing leaks likely to become hazardous in the future.[28] Notably however, only five states – Florida, Kansas, Maine, Missouri, and Texas – have mandatory timeframes (varying from three months to five years) for the repair of leaks that are, and will likely remain, non-hazardous.[29] In other states, non-hazardous leaks can generally be left unrepaired indefinitely, despite the fact that they may release more natural gas than hazardous leaks.

Inadequate incentives for prompt leak repair

Pipeline operators currently have little incentive to repair leaks as the cost of leaked gas can be passed through to ratepayers. The rates charged by interstate and intrastate pipeline operators are set by federal and state agencies respectively. The Federal Energy Regulatory Commission (FERC) sets rates for the interstate transport of natural gas, which generally occurs via large transmission pipelines.[30] Rates for intrastate natural gas transportation, occurring via local distribution pipelines, are set by state agencies.[31]

Rate-setting is based on the principle that a pipeline operator is entitled to recover its costs of service including the cost of gas that is lost, either intentionally or accidentally, from the pipeline system. In *West Ohio Gas Co. v. Public Utilities Commission*, 294 U.S. 63 (1935) (*West Ohio Gas*), the U.S. Supreme Court held that pipeline rates must include an allowance for "gas lost as a result of leakage, condensation, expansion or contraction" because "a certain loss through these causes is unavoidable."[32] This gas is often said to be "lost and unaccounted-for" (or simply "unaccounted-for").

In broad terms, lost and unaccounted-for gas refers to the difference between the amount of gas metered into a pipeline system and the amount metered out of that system, expressed as a percentage of system throughput (the lost and unaccounted-for gas percentage).[33] This difference may be due to the factors identified in *West Ohio Gas* – leakage, condensation, expansion, or contraction – as well as other factors such as meter inaccuracy, gas venting, and theft.[34] While some of these factors are outside of pipeline operators' control, many are not.[35] For example, operators can reduce gas theft by preventing consumers tampering with meters.[36] Additionally, operators can also minimize gas leaks by repairing or replacing damaged pipelines.[37]

Pipeline operators have had varying success in controlling lost and unaccounted-for gas. For this and other reasons,[38] gas losses vary widely between operators, ranging from as little as a fraction of one percent to twenty percent or more.[39] Overall, the EIA estimates that approximately 436 billion cubic feet of natural gas was lost and unaccounted-for in 2013.[40] Reducing this figure will require changes in the way pipeline operators recover lost and unaccounted-for gas.

Pipeline operators that offer bundled services – that combine natural gas sales with transportation – set rates so as to recover the cost of all gas purchases including those made to replace lost gas. Where services have been unbundled, such that a pipeline operator merely transports gas on behalf of other entities (shippers), the operator may require its shippers to contribute a percentage of the gas volumes tendered for transportation to make up for lost gas. That percentage is set out in the pipeline operator's tariff. The tariff may establish a procedure by which the operator can adjust the percentage over time. Generally, as part of the adjustment, the pipeline operator compares the volume of gas retained against the volume actually lost. Where too little gas has been retained, the pipeline operator may impose a surcharge on shippers. Conversely, if too much gas has been retained, shippers will receive a refund. This undermines incentives for pipeline operators to improve system management to reduce gas losses as the benefits of any such reduction are enjoyed by shippers. Likewise, shippers also bear the cost of any increase in gas losses.

Recognizing this, and seeking to promote improved management of the pipeline system, policy makers in New York, Pennsylvania, Texas, and other jurisdictions have recently updated the rules governing recovery of lost and unaccounted-for gas. Based on those states' experiences, this White Paper recommends improvements to all cost recovery frameworks that will encourage pipeline operators to reduce the amount of lost and unaccounted-for gas.

II. Defining lost and unaccounted-for gas

While lost and unaccounted-for gas has been an accepted cost of service since the 1930s, more than eighty years on, there remains no standard definition for the term. In most jurisdictions, pipeline operators report lost and unaccounted-for gas based on their own definitions, which reflect individual company experience. Consequently, definitions vary significantly between and even within jurisdictions, making comparisons difficult. This impedes monitoring by regulators and others, who are frequently unable to assess the reasonableness of claimed gas losses. Additionally, it also obscures the financial burden lost gas imposes on ratepayers, as well as the environmental and other impacts it has on society as a whole.

Inconsistent definitions

The terminology used to describe pipeline gas losses in each jurisdiction is set out in Appendix A to this White Paper. As can be seen there, various monikers are applied to lost gas, with regulators in some jurisdictions using the phrase "lost and unaccounted-for gas," while others use simply "unaccounted-for gas" and others refer to "system or line losses." There is even less consistency in the definition of these terms.

In most jurisdictions, pipeline operators report gas losses based on their own definitions, with little or no input from regulators. Just four jurisdictions – Ohio, Pennsylvania, Texas, and West Virginia – have regulations defining lost gas. While the term may be defined in regulator decisions in other jurisdictions, these tend to be general in nature, allowing pipeline operators significant latitude to compute gas losses as they see fit. Notably, the decisions often do not specify the formula to be used in computing lost gas and/or identify the appropriate timing or scope of that calculation. This leads to considerable variation in terms of:

- **Methodology**: Pipeline operators may use differing methodologies to calculate gas losses.[41] The calculation is generally similar, reflecting the difference between gas flows into and out of the pipeline system, but may be based on system inflows minus outflows or outflows minus inflows.[42] Calculated losses may be adjusted for gas pressure and temperature changes, company gas use, gas purging for construction, gas venting during maintenance, and other factors. There is no industry-wide standard dictating what and/or how adjustments should be made.[43]

- **Reporting period**: Some pipeline operators report system losses semi-annually, while others report only annually. Moreover, even if the frequency of reporting is the same, there may be differences in timing. For example, annual reports may be prepared for each calendar year, for the fiscal year, or on some other basis.[44]

- **Covered facilities**: The scope of reports also varies, with pipeline operators having the option of reporting combined gas losses from all facilities or preparing separate loss reports for pipeline and other infrastructure.[45] Reported losses from pipeline infrastructure may or may not be further subdivided into transmission and distribution system losses.[46]

These differences have led to significant variation in the reporting of gas losses by pipeline operators.[47]

Consequences of using inconsistent definitions

The lack of a uniform definition for lost gas is thought to have contributed to errors in reporting by pipeline operators.[48] Many operators commonly report negative gas losses[49] indicating that gas deliveries from the pipeline system exceeded gas receipts into it; a result which is physically impossible in a closed system.[50] Recognizing this, a 2013 study by the Pennsylvania Public Utilities Commission (PPUC) found that "[c]alculation error, inaccuracies or timing differences are the most probable explanation" for negative losses.[51] The study also highlighted other problems in the reporting of lost and unaccounted-for gas.

The PPUC study noted that the rates charged by pipeline operators in Pennsylvania include an allowance for unaccounted-for gas; a metric which, until recently, was not defined in legislation.[52] In the absence of a legislative definition, pipeline operators reported unaccounted-for gas based on industry- or company-specific practices.[53] The PPUC reviewed the practices of eight large gas utilities and found that there is no standard methodology for computing unaccounted-for gas.[54] On the contrary, each utility had its own distinct methodology, with significant variation in the formula used for, and the timing and scope of, the computation.[55] The methodologies used by pipeline operators often vary between reports – even within the same year – producing inconsistent estimates of unaccounted-for gas. PPUC data indicates that, out of nine gas utilities surveyed, only two estimated consistent unaccounted-for gas levels (i.e., varying by less than one percent) across three reports in 2010.[56] Estimates from the remaining six operators varied by more than one percent between reports, with two operators' reports varying by three percent or more.[57]

These reporting inconsistencies make it difficult for regulators and others to track pipeline operators' gas losses over time and to benchmark losses against those of other operators. Without such analysis, it may be difficult for regulators to verify whether claimed gas losses are justified and/or accurately measure the financial and other impacts of lost gas.

A regulator may investigate the gas losses claimed by a pipeline operator on its own motion or upon receiving a complaint. Regulators in some jurisdictions seek to identify excessive gas losses requiring investigation by comparing the pipeline's loss rate against that of other similar pipelines, to the industry average, and/or with historical norms.[58] However, recognizing the variation in calculating lost gas, many regulators currently only investigate large deviations from industry and/or historical trends.[59] Yet, it is actually small deviations that are most likely to require investigation by regulators. Whereas major pipeline losses can indicate the presence of a hazardous leak requiring study under federal safety regulations, there may be little reason for pipeline operators to examine smaller (likely non-hazardous) gas losses. It is therefore vital that such losses be investigated by regulators and/or others. In the absence of investigation, the cost of lost gas is simply passed through to ratepayers, undermining incentives for pipeline operators to minimize gas losses.

Ensuring accurate and consistent reporting

Seeking to address these problems, in June 1979, West Virginia became the first state to adopt regulations defining lost and unaccounted-for gas. The regulations, issued by the Public Service Commission of West Virginia (PSCWV) define "unaccounted-for gas" as "the difference between total gas supply, net of measured company use and measured free gas, and total gas sales."[60]

Similar definitions have also been adopted in Ohio,[61] Pennsylvania,[62] and Texas.[63] Notably, the definitions in Ohio and Pennsylvania are more comprehensive than those in other states, providing additional guidance on the calculation of lost and unaccounted-for gas. For example, regulations issued by the Public Utilities Commission of Ohio (PUCO) in May 1988 require unaccounted-for gas to be calculated on an annual basis for the twelve months ended August thirty-first each year, or such other date" as is shown to be more appropriate.[64]

Pennsylvania recently went one step further, prescribing the formula to be used in calculating lost and unaccounted-for gas. In August 2013, the PPUC issued regulations defining "unaccounted-for gas" as "the difference between the total gas available from all sources and the total gas accounted for as sales, net interchange and company use,"[65] calculated as follows:

> Unaccounted-for gas = gas received *less* gas delivered *less* adjustments[66]
>
> Where:
>
> > "Gas received" means the volume of gas supplied to the facility;[67]
> >
> > "Gas delivered" means the volume of gas provided by the facility;[68] and

> "Adjustments" means gas used by the operator for safe and reliable service, provided that such use is individually identified by category and supported by metered data, sound engineering practice, or other quantifiable results.[69]

PPUC regulations require utilities to calculate unaccounted-for gas by system type (i.e., distribution, transmission, storage, and production) wherever possible.[70] Unaccounted-for gas from the distribution system must be calculated annually for the twelve months ending August 31.[71] The calculation must be based on actual gas volumes[72] or, if such volumes are unavailable, using supported, transparent, and consistent estimations.[73]

This uniform definition addresses many of the inconsistencies in current reporting, prescribing the formula to be used in calculating unaccounted-for gas and specifying the appropriate timing and scope of that calculation. Use of this standardized approach will ensure consistent reporting by pipeline operators and thereby facilitate improved regulator monitoring of claimed gas losses.

Recommendation

Regulators in all jurisdictions should require pipeline operators to report lost and unaccounted-for gas based on a uniform definition prescribed by law. In adopting a legal definition of lost and unaccounted-for gas, regulators could look for guidance to the rules in Pennsylvania. Consistent with the approach there, the definition should require use of a standard formula for calculating lost and unaccounted-for gas and identify the appropriate timing and scope of that calculation. A recommended definition and formula to be used in each jurisdiction could be developed by the North American Energy Standards Board or another industry body.

III. Recovering the cost of lost and unaccounted-for gas

Lost and unaccounted-for gas is an accepted cost of service, recoverable through pipeline rates. The regulatory framework vis-à-vis cost recovery has a direct bearing on the amount of gas lost from the pipeline system, with some frameworks providing an incentive for operators to reduce gas losses, while others disincentivize such reductions. Unfortunately, most jurisdictions have adopted cost recovery frameworks of the latter type.

Existing cost recovery frameworks

Pipeline operators may recover the cost of lost and unaccounted-for gas in various ways, depending on the nature of their operations. Historically, regulated gas utilities provided bundled services, wherein the sale of natural gas was combined with transportation under a single price. Recently however, some jurisdictions have moved to deregulate the natural gas industry and, as part of this process, required the unbundling of natural gas services. With unbundling, pipeline operators are required to separate their sales and transportation services, such that customers can purchase those services from different suppliers. FERC has required all interstate pipeline operators to unbundle gas sales and transportation services.[74] Additionally, unbundling has also been required for intrastate pipelines in over twenty states.[75]

Generally, where natural gas sales are bundled with transportation, the pipeline operator will recover the cost of lost gas in dollars, through an additional charge levied on ratepayers. This frequently occurs through a purchased gas adjustment (PGA) (also known as a gas cost adjustment).[76] Broadly, the PGA is a charge added to pipeline rates to reflect the cost of actual gas purchases, including those made to replace gas lost during transportation on the pipeline system.

Where sales have been unbundled, such that pipeline operators merely transport gas on behalf of other entities (shippers), operators generally recover lost and unaccounted-for gas from shippers in kind. A pipeline operator may require its shippers to contribute a percentage of the gas volumes tendered for transport to make up for system losses. That percentage is set out in the pipeline operator's tariff. The tariff may provide for the pipeline operator to sell the retained gas and/or purchase additional gas when necessary to maintain system operations. In such cases, the operator must credit shippers for the revenues generated from gas sales and may impose a surcharge on shippers to recover the cost of gas purchases.

Three key approaches are used to determine the volume of lost gas that can be recovered – either in dollars or in kind – by pipeline operators. These are:

1. **Cost tracking for lost and unaccounted-for gas**: In most jurisdictions, pipeline operators track changes in the amount of lost and unaccounted-for gas. Any changes are flowed through to ratepayers via a periodic adjustment, without the pipeline operator having to file a new rate case. As part of its periodic adjustment, the pipeline operator forecasts gas losses for the next period (generally based on historic levels) and reconciles any past under- or over-recoveries compared to actual losses. Typically, in this reconciliation, the operator is "made whole" and can recover actual gas losses in excess of those forecast but must provide refunds if actual losses are below forecasts. However, regulators in some jurisdictions require the sharing of under- and over-recoveries between operators and their ratepayers.

   Example jurisdictions: Federal, Alaska, Colorado, Florida, Oregon, Wyoming

2. **Fixing lost and unaccounted-for gas in a general rate case**: In some jurisdictions, recoverable gas losses are set in general rate proceedings. Losses set in this way cannot be tracked and updated, but instead remain fixed until the next rate proceeding. Prior to this time, the pipeline operator incurs the cost of any under-recoveries and enjoys the benefit of any over-recoveries if actual gas losses are higher or lower than specified in its filed rates.

   Example jurisdictions: Federal, Indiana, Michigan, New York, South Carolina

3. **Maximum allowable rate of lost and unaccounted-for gas**: Five jurisdictions have legislation capping the amount of lost gas that can be recovered in pipeline rates.[77] In another seven jurisdictions, caps have been established in rate proceedings or other administrative decisions.[78] Gas losses exceeding the cap are generally presumed to be unreasonable and disallowed, unless the pipeline operator furnishes evidence to the contrary. Other losses, falling within the cap, are generally recovered through a tracking mechanism which enables the pipeline operator to update gas losses periodically without filing a new rate case.

   Example jurisdictions: Connecticut, Kansas, Idaho, Ohio, Pennsylvania, Texas, West Virginia

Further information on the cost recovery frameworks in each jurisdiction is provided in Appendix A to this White Paper.

Differing incentives for cost reduction

The cost recovery framework determines how the financial impact of any change in the amount of lost and unaccounted-for gas is shared between pipeline operators and their customers.

TABLE 1: IMPACT OF CHANGE IN GAS LOSSES UNDER THE THREE MAJOR COST RECOVERY FRAMEWORKS

Framework for Cost Recovery	Consequences of Increasing Gas Losses	Consequences of Reducing Gas Losses
Cost tracking for lost and unaccounted-for gas	The cost of additional gas losses, in excess of those forecast in the tracker, is passed on to ratepayers through periodic reconciliations.	The value of any reduction in gas losses, compared to those forecast in the tracker, is returned to ratepayers through periodic reconciliations.
Fixing lost and unaccounted-for gas in a general rate case	The cost of additional gas losses, in excess of those forecast in filed rates, is borne by the pipeline operator until the filing of its next rate case. Through its filed rates, the operator may recover the cost of higher gas losses in the future, but cannot recoup any past under-recoveries.	The value of any reduction in gas losses, compared to those forecasts in filed rates, is retained by the pipeline operator until the filing of its next rate case. In its filed rates, the operator must reduce the amount collected for future gas losses, but need not refund past over-recoveries.
Maximum allowable rate of lost and unaccounted-for gas	Where total gas losses exceed the specified maximum, the cost of additional losses is borne by the pipeline operator, unless an exception is granted. Where total gas losses are below the specified maximum, additional costs are passed on to ratepayers.	Where total gas losses exceed the specified maximum, the value of any reduction in gas losses is retained by the pipeline operator. Where total gas losses are below the specified maximum, reduced costs are returned to ratepayers.

Where cost tracking is used, ratepayers bear the risk of any increase, and enjoy the benefit of any reduction, in lost and unaccounted-for gas. This leaves pipeline operators unaffected by such changes, giving them little incentive to improve system management to reduce gas losses.[79]

New York is one of the few states that has sought to address this problem by changing the way pipeline operators recover the cost of lost and unaccounted-for gas. The New York Public Service Commission (NYPSC) allows recovery of lost and unaccounted-for gas through a factor of adjustment which is applied to gas sales to calculate the gas purchase costs recoverable in rates.[80] Pipeline operators historically tracked and updated the factor of adjustment annually.[81]

However, in 1990, the NYPSC issued new rules providing for the establishment of a fixed factor of adjustment in each pipeline operator's rate case.[82] In the rate case, the NYPSC determines a maximum rate of loss from the pipeline system – based on historic gas losses – which is used to calculate the fixed factor of adjustment.[83]

As the name suggests, the fixed factor of adjustment remains constant for the duration of the regulatory period, until a new factor is established in the pipeline operator's next rate case.[84] There is no mechanism for reconciling the operator's actual gas losses with the historic losses reflected in its fixed factor of adjustment. This creates an incentive for the operator to reduce the amount of lost gas since, if losses are below historic levels, the operator may retain the difference.[85] Conversely, if losses exceed historic levels, the difference must be absorbed by the operator.[86] Thus, as the NYPSC has observed, "[w]ith the advent of the fixed factor of adjustment, [pipeline operators] realized a gain from every reduction in [losses] through either a reduced penalty, when the actual factor of adjustment exceeds the fixed factor adjustment, or an increased benefit, when the actual factor of adjustment was less than the fixed factor of adjustment."[87]

The NYPSC approach – whereby pipeline operators recover lost gas at a fixed level and may keep any excess if gas losses are below that level – is analogous to benchmarking in electric utility ratemaking. Broadly, that approach permits electric utilities to retain earnings above a set threshold, giving them an incentive to improve performance. Similarly, allowing pipeline operators to retain excess gas is likely to encourage improved management of the pipeline system to reduce losses. This has been the experience in New York. Indeed, the NYPSC has noted that statewide fixed factors of adjustment have declined in recent years, with the factors for seven large distribution pipelines averaging just 1.0183 in 2013 compared to 1.0348 in 1997.[88]

Other studies also suggest that fixing recovery for lost and unaccounted-for gas in a general rate proceeding may lead to reduced gas losses. A recent study compared the gas losses of thirty-two interstate transmission pipelines – twenty-two of which recovered lost gas under a tracker and ten of which recovered lost gas at a fixed rate – over the ten years from 1997 to 2006.[89] The comparison showed that pipeline operators using fixed recovery reported lower average gas losses in eight of the ten years.[90] Moreover, those pipeline operators also reduced gas losses at a faster rate.[91] Whereas those operators were able to reduce gas losses by eighty-six percent over the ten year period, pipeline operators using cost tracking reduced losses by just fifty nine percent.[92] These findings suggest that, compared to cost tracking, fixed recovery may be a more effective in controlling lost and unaccounted-for gas.

Recommendation

Policy makers should consider whether the applicable cost recovery frameworks provide incentives for pipeline operators to reduce lost and unaccounted-for gas. Policy makers are encouraged to consider whether the framework currently in place in New York or another similar framework incentivizing the reduction of gas losses would be effective in their states.

IV. Verifying lost and unaccounted-for gas

As noted above, currently, pipeline operators recover the cost of lost and unaccounted-for gas (either in dollars or in kind) from their customers. To ensure that customers are not unfairly burdened by such costs and provide incentives for their reduction by operators, recovery should be limited to the cost of *unavoidable* gas losses only.

The avoidable versus unavoidable dichotomy

In *West Ohio,* the U.S. Supreme Court upheld the right of pipeline operators to recover the cost of "gas lost as a result of leakage, condensation, expansion or contraction," reasoning that "a certain loss through these causes is unavoidable no matter how carefully business is conducted."[93] While this remains true today, the fact that some losses are unavoidable does not entitle a pipeline operator to recover the cost of gas lost through preventable causes. Indeed, the U.S. Supreme Court has held that "a public utility will not be permitted to include negligent or wasteful losses among its operating charges."[94]

In setting pipeline rates, regulators must balance the interests of consumers against those of pipeline operators. From consumers' perspective, including the cost of lost and unaccounted-for gas in pipeline rates may seem unfair, as it forces them to pay for gas that is not received.[95] However, from the operator's perspective, lost and unaccounted-for gas is a cost of service (i.e., since pipeline losses necessitate additional gas purchases) that needs to be recovered in rates.[96] Seeking to balance these competing interests, regulators typically include only prudently incurred costs in pipeline rates.[97] In determining whether costs associated with lost and unaccounted-for gas meet this standard, regulators should consider the feasibility of reducing pipeline losses.[98] Where reductions are economically feasible, gas losses can be said to be "avoidable" and the costs thereof should be excluded from rates.[99]

While separating avoidable and unavoidable gas losses is not without difficulties, it is far from impossible.[100] One commonly identified cause of lost gas is leakage, which can frequently be avoided by repairing or replacing pipeline infrastructure. Pipeline operators can, and often do, institute monitoring programs to locate leaks and assess their suitability for repair. Technologies enabling the identification and measurement of leaks are developing rapidly, with many now commercially available. For example, acoustic devices can be used to detect the noise generated by leaking gas, sampling instruments can measure radiation or hydrocarbon vapors in the air, and electronic tools can detect volume and pressure changes on the pipeline.[101]

Failure to investigate the cause of gas losses

Notwithstanding the above, in permitting cost recovery for lost and unaccounted-for gas, regulators typically do not distinguish between avoidable and unavoidable gas losses. Since pipeline operators can recover for all lost and unaccounted-for gas, they have little reason to investigate its cause, much less take remedial action.

A recent study of cost recovery frameworks in forty-one states by the National Regulatory Research Institute (NRRI) found that pipeline operators and other gas utilities generally do not break down lost and unaccounted-for gas by source, at least in quantitative form.[102] This makes it difficult for regulators to ascertain whether gas losses are due to avoidable or unavoidable causes. Perhaps for this reason, regulator investigation of pipeline losses tends to be cursory at best. Research by the NRRI indicates that regulators in many states do not closely scrutinize the gas losses claimed by pipeline operators.[103] Moreover, in the few states where close scrutiny does occur, regulators tend only to act when claimed gas losses markedly exceed industry or historical averages, enabling cost recovery for small losses with minimal oversight.[104]

As an illustration of current regulatory practice, the case studies below discuss regulator monitoring of lost and unaccounted-for gas at the federal level and in the states of New York and Texas. These jurisdictions were selected to demonstrate the regulation of all classes of natural gas pipelines (i.e., interstate and intrastate transmission and distribution systems). Moreover, they also provide examples of the three key frameworks for recovery of lost and unaccounted-for gas used nationally.[105] For each jurisdiction, regulatory decisions concerning the gas losses claimed by one pipeline operator during the last five years have been assessed to determine the extent of regulator investigation into the cause of those losses. Due to the limited nature of the review, care should be taken in drawing generalizations from the findings.

CASE STUDY 1: FERC REVIEW OF LOST AND UNACCOUNTED-FOR GAS RECOVERED THROUGH COST TRACKING

As noted above, at the federal level, FERC regulates interstate natural gas pipelines. FERC rules permit the in kind recovery of gas used or lost during routine pipeline operations, between the point of receipt onto the pipeline system and the point of delivery off the system. To this end, the pipeline operator may retain a percentage of the gas tendered for transport to compensate for fuel use and lost gas. This percentage, known as the fuel reimbursement percentage, is specified in the pipeline operator's tariff.[106] The tariff also sets out whether and how the pipeline operator can update the fuel reimbursement percentage.

Pipeline operators typically update their fuel reimbursement percentages annually.[107] FERC has indicated that all annual filings "will be carefully reviewed" to ensure that claimed gas losses are appropriate.[108] Notably however, FERC often does not inquire into the source of claimed losses, reasoning that lost gas "is by definition a cost item that cannot be fully explained."[109] For example, in reviewing the last five annual fillings of Algonquin Gas Transmission, LLC, FERC did not require a breakdown of gas losses by source.[110] Rather, FERC was satisfied with general data showing overall forecasts of pipeline gas throughput, gas required for fuel use, and rates of gas loss based on historic levels.[111] Significantly, FERC did not investigate the drivers of historic loss rates.

FERC has likely used the same approach when reviewing gas losses from other pipeline systems. As a matter of practice, FERC requires pipeline operators to file rates, which become effective unless a complaint is made and a hearing is held. Thus, unless an operator's claimed gas losses are disputed by shippers and/or other interested parties, they are unlikely to be closely scrutinized by FERC.

CASE STUDY 2: NYPSC REVIEW OF LOST AND UNACCOUNTED-FOR GAS SET IN FILED RATES

Unlike most other states, New York offers pipeline operators an incentive to reduce lost and unaccounted-for gas. The NYPSC sets, in each pipeline operator's rate case, an allowed rate of lost and unaccounted-for gas (the allowed LAUG factor) based on historic rates of loss from the pipeline system.[112] The allowed LAUG factor is used to establish a fixed factor of adjustment, which is applied to the operator's gas sales to determine the amount of gas purchases recoverable through rates.[113]

The NYPSC exercises great care over the calculation of each pipeline operator's allowed LAUG factor and its associated fixed factor of adjustment. As an illustration, in past rate filings by Central Hudson Gas and Electric Corp (Central Hudson), the NYSPC carefully reviewed the methodology used to set the fixed factor of adjustment.[114] This review included evaluating the historic data relied upon to ensure that it provided an appropriate basis for projecting future gas losses.[115] It did not, however, extend to investigating the causes of historic gas losses. Given this, it is perhaps unsurprising that the NYPSC did not require Central Hudson to provide a quantitative breakdown of gas losses by cause. In fact, Central Hudson did not even describe the causes of lost gas in qualitative form.

CASE STUDY 3: TEXAS RRC REVIEW OF LOST AND UNACCOUNTED-FOR GAS SUBJECT TO A FIXED CAP

The Texas Railroad Commission (RRC) sets rates for intrastate pipelines in areas outside of municipalities. Within municipalities, pipeline rates are set by local government and appealable to the RRC.

RRC regulations cap the amount of lost gas that can be recovered in pipeline rates at five percent of system input for distribution pipelines and three percent for transmission pipelines.[116] Gas losses exceeding the cap can only be recovered if the pipeline operator demonstrates special facts and circumstances justifying recovery.[117] Notably however, operators are not required to justify recovery of other gas losses, falling within the cap. Thus, for example, West Texas Gas, Inc. (WTG) was recently permitted to recover gas lost from its distribution system without establishing that the gas losses were unavoidable.[118] WTG reported total gas losses from its system in the previous four years, but did not provide a quantitative breakdown of lost gas by cause.[119] It did not even discuss the causes of lost gas in qualitative terms and provided only a brief summary of steps taken to reduce gas losses.[120]

Findings from case studies

The examples discussed above suggest that regulators do not closely monitor pipeline operator's claimed rates of lost and unaccounted-for gas. Notably, the regulators in each example did not investigate the source of claimed gas losses to verify that they were unavoidable. On the contrary, the regulators uniformly permitted cost recovery for all lost gas, regardless of source. Disallowing recovery for avoidable gas losses would shift the financial burden thereof from ratepayers to pipeline operators, encouraging them to reduce the amount of lost gas.

Currently, many regulators lack the information needed to distinguish between avoidable and unavoidable gas losses. Despite the advent of new measurement technologies, pipeline operators typically do not measure the actual volume of gas lost from their systems, but rather estimate losses based on historical averages. Such estimates are generally accepted by regulators who have, to date, been loath to require direct measurement of gas losses. By way of example, as part of the EPA's Greenhouse Gas Reporting Program, certain pipeline operators must report carbon dioxide, methane, and nitrous oxide emissions resulting from system leaks and other sources.[121] Notably however, in reporting emissions due to leakage from pipelines, operators are not required directly measure the size of leaks.[122] Rather, operators may rely on estimates, calculated based on average emission rates developed in the 1990s.[123]

A 1996 study by the Gas Research Institute (GRI) and EPA developed emissions factors (EFs) for various components in the natural gas industry.[124] Those EFs are multiplied by an activity factor (AF), reflecting the population of each component type, to estimate overall emissions of methane.[125] Those estimates may not, however, accurately reflect the volume of methane emitted. As noted above, a recent study led by researchers at Washington State University found that "a few leaks account for a large fraction of the total" emissions.[126] Where the distribution is skewed in this way, average emission rates are unlikely to accurately reflect the volume of methane emitted from any one leak.[127] This highlights the need for direct measurement of leaks by pipeline operators.

Additionally, there is also a need for operators to investigate the cause of pipeline leaks. Currently, when reporting gas losses, pipeline operators often do not breakdown lost gas by cause. Rather, as illustrated in the above examples, operators generally report a single figure for all lost gas, making it difficult for regulators to identify unjustified losses. Seeking to address this problem, the New Hampshire Public Utilities Commission has required pipeline operators to separately report gas losses due to leaks and billing errors.[128] Similar reporting requirements have also been proposed in Massachusetts.[129]

Recommendation

Regulators should examine the cause of pipeline gas losses. For this purpose, regulators may direct pipeline operators to measure the amount of gas lost due to leaks and other causes. Operators should be required to report the results of these measurements annually and include, as part of the annual report, a breakdown of gas losses by cause. Using this information, regulators can identify and limit recovery for gas lost through avoidable causes.

V. Capping recovery for lost and unaccounted-for gas

Limiting the amount of lost gas that can be recovered in pipeline rates would shift the financial burden of excess gas losses (i.e., above the specified limit) from ratepayers to the pipeline operator. This is likely to create a powerful incentive for operators to minimize losses by, for example, repairing or replacing leaking pipes. Nevertheless, despite the significant environmental and other benefits of controlling pipeline leaks, there are currently few limits on recovery. Indeed, just five states have legislation capping the amount of lost and unaccounted-for gas for which pipeline operators can recover. Many of the caps are excessive, allowing pipeline operators to recover for all lost gas and thereby undermining incentives for the control of pipeline leaks.

Existing caps on recovery

Legislation capping the recovery of lost and unaccounted-for gas by all pipeline operators has been enacted in Connecticut, Ohio, Pennsylvania, Texas, and West Virginia. The legislation in each state is similar, defining a maximum allowable rate of loss from the pipeline system (expressed as a percentage of system input) and preventing recovery for losses exceeding that rate unless special circumstances exist. The caps in most states apply to both transmission and distribution pipelines.[130] In Texas and West Virginia, different caps apply depending on the nature of the pipeline[131] and the size of the operator,[132] respectively.

TABLE 2: STATEWIDE CAPS ON COST RECOVERY FOR LOST AND UNACCOUNTED-FOR GAS

Jurisdiction	Application of cap	Maximum amount of lost gas	Treatment of excess gas losses
Connecticut	All pipelines	3 percent	Subject to investigation by the regulator, who must establish a cost mechanism incentivizing loss reduction.[133]
Ohio	All pipelines	5 percent	Subject to adjustment by the regulator unless the operator shows that its losses are reasonable.[134]
Pennsylvania	Distribution pipelines	5 percent, declining by 0.5 percent per year for 5 years (i.e., to 3 percent in year 5)	Excluded from rates unless the pipeline operator shows that its losses are warranted.[135]
Texas	Transmission pipelines	3 percent	Excluded from rates unless special facts and circumstances justify recovery of excess losses.[136]
	Distribution pipelines	5 percent	

Jurisdiction	Application of cap	Maximum amount of lost gas	Treatment of excess gas losses
West Virginia	Large utilities (i.e., with annual sales exceeding 2 billion cubic feet)	8 percent	Excluded from rates.[137]
	Small utilities (i.e., with annual sales less than 2 billion cubic feet)	10 percent	

Recovery of lost and unaccounted-for gas was only recently capped in Connecticut in 2014 and Pennsylvania in 2013. It is therefore not yet possible to assess the impact of those state's caps. There is, however, some evidence that caps may have been effective in promoting improved management of the pipeline system in other states. One example is West Virginia, where a cap on recovery has been in place since 1979. In the intervening years, unaccounted-for gas has declined significantly, more than halving over the last twenty years alone.[138] While it is difficult to tie this decline to any specific policy, the cap on recovery of lost and unaccounted-for gas has likely been a contributing factor.

In states with a cap, pipeline operators must absorb the cost of any excess gas losses (i.e., above the cap). Therefore, in order to maintain their profit margins, operators must reduce the amount of lost gas below the specified cap and avoid future increases in gas losses above that cap. As the PSCWV has observed, a cap gives pipeline operators "an incentive to improve their operation and maintenance [since operators], not their customers, must suffer the consequences of failing to [control lost and] unaccounted for gas."[139]

Selecting the appropriate cap

To ensure the minimization of gas losses, a cap should be set equal to the amount of gas lost through unavoidable causes. This amount is likely to decline over time as new processes and technologies enable the control of formerly unavoidable gas losses. Notwithstanding this, state authorities typically cap recovery for lost and unaccounted-for gas at a fixed rate, which often exceeds the reasonably achievable minimum.

As shown in Table 2, the existing caps vary substantially between jurisdictions. The highest cap is in West Virginia, where small utilities may recover up to ten percent of pipeline input as lost gas.[140] A marginally lower cap, of eight percent of pipeline input, applies to the gas losses of large utilities in West Virginia.[141]

When West Virginia first capped recovery in 1979, pipeline gas losses frequently exceeded ten percent. In that environment, the caps are likely to have provided a strong incentive for pipeline operators to reduce gas losses. Today, however, the caps may do little to encourage further reduction of gas losses. Most pipelines in West Virginia now operate with gas losses below the caps. The state's three largest utilities, accounting for over ninety percent of gas deliveries, reported percentages of gas lost and used in pipeline operations ranging from four to seven percent in 2012 (the latest year for which data is available).[142] Therefore, even with the cap, the utilities can recover for all lost gas and face no pressure to minimize gas losses. On the contrary, the gas losses reported by two of the three utilities actually increased between 2011 and 2012.[143]

Like most other states, West Virginia has a fixed cap on recovery for lost and unaccounted-for gas. These fixed caps are rarely updated, even where new developments in pipeline management could enable further reduction of gas losses. In West Virginia for example, the cap applying to small utilities has not changed since 1981, while the cap for large utilities has remained unchanged since 1979. Similarly, the caps in Texas have not been updated since their initial adoption in 2002. In the intervening years, many utilities have substantially reduced their gas losses. The experience of other states suggests that further reductions are possible, with West Virginia and Texas having the third and fourth highest loss rates of all states respectively.[144]

Recommendation

Regulators should consider capping the amount of lost and unaccounted-for gas that can be recovered in pipeline rates. Any cap should be sufficiently low to encourage pipeline operators to reduce gas losses and, to this end, may be expressed to decline over time. Where the cap is fixed, it should be regularly updated to account for improvements in pipeline management enabling the reduction of gas losses.

VI. Conclusion

The substitution of natural gas for coal and oil in electricity generation has contributed to improved air quality, reducing emissions of mercury and other toxic air pollutants. Moreover, it can also reduce greenhouse gas emissions, helping to mitigate climate. Unfortunately however, these reductions are frequently offset by greenhouse gas emissions during natural gas production. Realizing the full benefits of this so-called "clean fossil fuel" will therefore require changes in the production process.

Action is urgently needed to prevent natural gas – which is comprised principally of methane – leaking from the pipeline system. There is, however, currently little incentive for pipeline operators to repair system leaks as the cost of leaked gas can be passed through to ratepayers.

Pipeline rates in all jurisdictions include an allowance for lost and unaccounted-for gas, reflecting the difference between gas flows into and out of the pipeline system. This difference may be attributable to various causes, including system leaks and measurement errors. While some loss of gas through these and/or other causes is unavoidable, pipeline operators should act to reduce losses wherever possible. Encouraging such action will require changes in the way pipeline operators recover the cost of lost and unaccounted-for gas as follows:

- **Lost and unaccounted-for gas should be reported based on a standard definition.** Use of a standardized approach will ensure consistent and accurate reporting, facilitating enhanced monitoring by regulators.

- **The cost recovery framework should incentivize reduction of lost and unaccounted-for gas.** To this end, the framework should reward pipeline operators for any decline, and penalize operators for any rise, in gas losses.

- **Pipeline operators' claimed gas losses should be closely scrutinized.** To facilitate such scrutiny, each pipeline operator should be required to directly measure gas lost through leaks and other causes. The results of these measurements should be reported annually and the report should identify the cause of all gas losses.

- **There should be a cap on cost recovery.** Any such cap should be set so as to encourage pipeline operators to reduce gas losses over time.

Appendix 1: Treatment of lost and unaccounted-for gas by jurisdiction

The table below outlines the cost recovery framework vis-à-vis lost and unaccounted-for gas in each U.S. jurisdiction.

Jurisdiction	Regulator	Terminology	Definition	Rules for recovery
Federal	Federal Energy Regulatory Commission	Lost and unaccounted-for gas or L&U gas	No legislative definition. Defined in administrative decisions as the difference between receipts onto, and deliveries off, the pipeline system.[145]	L&U gas may be recovered from shippers in kind. The L&U gas percentage may be fixed in a general rate proceeding or adjusted periodically between rate filings. Where periodic adjustments are made, the pipeline operator must have a true-up mechanism to reconcile past under- and over-recoveries compared to actual gas losses.[146]
Alabama	Alabama Public Service Commission	Unaccounted-for gas	No legislative definition. Defined in administrative decisions as the difference between gas purchases and gas sales over a twelve month period.[147]	For transportation services, unaccounted-for gas is generally recovered from shippers in kind. For commodity sales, unaccounted-for gas is generally recovered through the purchased gas adjustment (PGA).[148] No data is available on the calculation of the unaccounted-for gas percentage.
Alaska	Regulatory Commission of Alaska	Lost and unaccounted-for gas or LAUF gas	No legislative definition.	For transportation services, LAUF gas is generally recovered from shippers in kind. For commodity sales, LAUF gas is generally recovered through the PGA. The LAUF gas percentage may be tracked and updated periodically, without the filing of a new rate case.[149]
Arizona	Arizona Corporation Commission (ACC)	Lost and unaccounted-for gas	No legislative definition.	For transportation services, lost and unaccounted-for gas may be recovered from shippers in kind or in dollars. For gas sales customers, lost and unaccounted-for gas is generally recovered through the PGA. The lost and unaccounted-for gas percentage may be tracked

Jurisdiction	Regulator	Terminology	Definition	Rules for recovery
				and updated periodically, without the filing of a new rate case. The ACC has previously imposed operator-specific caps on recovery for lost and unaccounted-for gas.[150]
Arkansas	Arkansas Public Service Commission	Lost and unaccounted for gas or LUFG	No legislative definition. Defined in case law as "the difference between the total volume of gas purchased from all sources and the volume delivered and billed to customers."[151]	For transportation services, LUFG may be recovered from shippers in kind or in dollars. For commodity sales, LUFG is generally recovered through the PGA. The LUFG percentage may be tracked and updated periodically, without the filing of a new rate case.[152]
California	California Public Utilities Commission	Lost and unaccounted-for gas or LUAF gas	No legislative definition. Defined in administrative decisions as the difference between gas purchases and sales.[153]	For transportation services, LUAF gas is generally recovered from shippers in kind. For commodity sales, LUAF gas is generally recovered from consumers through the PGA. The LUAF gas percentage may be tracked and updated periodically, without the filing of a new rate case.[154]
Colorado	Colorado Public Utilities Commission	System losses	No legislative definition.	For transportation services, system losses are recovered from shippers in kind. For commodity sales, system losses are recovered through the PGA. The loss percentage may be tracked and updated periodically, without the filing of a new rate case.[155]
Connecticut	Public Utilities Regulatory Authority (PURA)	Lost and unaccounted-for gas	No legislative definition. Defined in administrative decisions as the difference between the sum of all inputs into the pipeline system and the sum of all outputs from that system.[156]	For transportation services, lost and unaccounted-for gas is generally recovered from shippers in kind. For commodity sales, lost and unaccounted-for gas is generally recovered through the PGA. The lost and unaccounted-for gas percentage may be tracked and updated periodically, without the filing of a new rate case.

Jurisdiction	Regulator	Terminology	Definition	Rules for recovery
				There is a 3 percent cap on lost and unaccounted-for gas. If the amount of lost and unaccounted-for gas exceeds the cap, PURA must commence an investigation. As part of the investigation, PURA must establish a cost recovery mechanism providing an incentive for the operator to reduce lost and unaccounted-for gas, replace aging infrastructure, and comply with any other requirements considered relevant by PURA.[157]
Delaware	Delaware Public Service Commission	Unaccounted-for gas or UFG	No legislative definition. Defined in administrative decisions as the "difference between the total amount of gas delivered by [a pipeline operator] through its meters and the amount of gas delivered to customers through their meters."[158]	For transportation services, UFG is generally recovered from shippers in kind. For commodity sales, UFG is generally recovered through the PGA. The UFG percentage may be tracked and updated periodically, without the filing of a new rate case. A pipeline operator's filed rates may include an incentive mechanism establishing a target UFG percentage. If the operator's actual UFG percentage in any year varies from the target, it may be subject to a penalty or reward in that year. Alternatively, any variation may be taken into account in the operator's next general rate case.[159]
District of Columbia	Public Service Commission of the District of Columbia	Unaccounted-for gas	No legislative definition.	For transportation services, unaccounted-for gas is generally recovered from shippers in kind. For commodity sales, unaccounted-for gas is generally recovered through the PGA. The unaccounted-for gas percentage may be tracked and updated periodically, without the filing of a new rate case.[160]
Florida	Florida Public Service Commission	Lost and unaccounted-for gas or LAUF gas	No legislative definition.	For transportation services, LAUF gas is generally recovered from shippers in kind. For commodity sales, LAUF is generally recovered through the PGA. The LAUF percentage may be tracked and updated

Jurisdiction	Regulator	Terminology	Definition	Rules for recovery
				periodically, without the filing of a new rate case.[161]
Georgia	Georgia Public Service Commission (GPSC)	Lost and unaccounted-for gas	No legislative definition. Formerly defined in legislation as "the difference between the city gas volumes and the measured volumes."[162]	For transportation services, lost and unaccounted-for gas is generally recovered from shippers in kind. For commodity sales, lost and unaccounted-for gas is generally recovered through the PGA. The lost and unaccounted-for gas percentage may be fixed in the pipeline operator's rate case or tracked and updated periodically (without the filing of a new rate case). The GPSC is authorized by legislation to cap lost and unaccounted-for gas.[163]
Hawaii	Hawaii Public Utilities Commission	Unaccounted-for gas	No legislative definition.	Data not available.
Idaho	Idaho Public Utilities Commission	Lost and unaccounted-for gas or LAUF gas	No legislative definition. Defined in administrative decisions as "the difference between the amount of natural gas delivered to the…distribution system at the city gate and amount of natural gas ultimately recorded at the customers' meters."[164]	LAUF gas may be recovered in base rates and/or through the PGA. The LAUF gas percentage may be tracked and updated periodically, without the filing of a new rate case. In response to abnormal increases in LAUF gas, the IPUC has previously imposed temporary, operator-specific caps on recovery thereof.[165]
Illinois	Illinois Commerce Commission	Unaccounted for gas or GLU	No legislative definition. Defined in administrative decisions as "the difference between the amount of gas sent out and that which has been sold."[166]	For transportation services, LAUF gas is generally recovered from shippers in kind. For commodity sales, LAUF gas is generally recovered through the PGA. The LAUF gas percentage may be tracked and updated periodically, without the filing of a new rate case.[167]

Jurisdiction	Regulator	Terminology	Definition	Rules for recovery
Indiana	Indiana Utility Regulatory Commission	Unaccounted-for gas or UFG	No legislative definition. Defined in administrative decisions as "the difference between gas purchased and gas sold" by the pipeline operator.[168]	For transportation services, UFG is generally recovered from shippers in kind. For commodity sales, UFG is generally recovered through the PGA. The UFG percentage may be fixed in a general rate proceeding. Alternatively, the UFG percentage may be tracked and updated periodically, without the filing of a new rate case. Where cost tracking is used, a maximum UFG percentage may be established in the general rate proceeding.[169]
Iowa	Iowa Utilities Board	Lost and unaccounted-for gas or LAUF gas	No legislative definition. Legislation requires LAUF gas to be calculated as the difference between gas sales and purchase volumes.[170]	For transportation services, LAUF gas is generally recovered from shippers in kind. For commodity sales, LAUF gas is generally recovered through the PGA. The LAUF gas percentage may be tracked and updated periodically, without the filing of a new rate case.[171]
Kansas	Kansas Corporation Commission (KCC)	Lost and unaccounted-for gas	No legislative definition.	For transportation services, lost and unaccounted-for gas is generally recovered from shippers in kind. For commodity sales, lost and unaccounted-for gas is generally recovered through the PGA. The lost and unaccounted-for gas percentage may be tracked and updated periodically, without the filing of a new rate case. The KCC has previously imposed a 4 percent cap on lost and unaccounted-for gas. Lost and unaccounted-for gas in excess of the cap cannot be recovered.[172]
Kentucky	Kentucky Public Service Commission (KPSC)	Lost and unaccounted-for gas or L&U gas	No legislative definition.	For transportation services, L&U gas is generally recovered from shippers in kind. For commodity sales, L&U gas is generally recovered through the PGA. The L&U gas percentage may be tracked and updated

Jurisdiction	Regulator	Terminology	Definition	Rules for recovery
				periodically, without the filing of a new rate case. The KPSC has previously imposed a 5 percent cap on L&U gas. L&U gas in excess of the cap cannot be recovered unless the KPSC finds that recovery should be permitted in the particular circumstances of the case.[173]
Louisiana	Louisiana Public Service Commission (LPSC)	Lost and unaccounted-for gas or LAFG	No legislative definition. Defined in administrative decisions as the difference between gas received by the pipeline and gas delivered to customers due to metering inaccuracies, leakage, and/or theft.[174]	For transportation service, LAFG is generally recovered from shippers in kind. For commodity sales, LAFG is generally recovered through the PGA. The LUFG percentage may be tracked and updated periodically, without the filing of a new rate case. The LPSC has previously imposed caps on recovery of LAFG in general rate proceedings.[175]
Maine	Maine Public Utilities Commission	Lost and unaccounted-for gas	No legislative definition.	For transportation services, lost and unaccounted-for gas is generally recovered from shippers in kind. For commodity sales, the cost of lost and unaccounted-for gas is generally recovered through the PGA. The lost and unaccounted-for gas percentage may be tracked and updated periodically, without the filing of a new rate case.[176]
Maryland	Maryland Public Service Commission	Unaccounted-for gas	No legislative definition. Defined in administrative decisions as "the difference between the quantity of gas received by a [pipeline operator] and the quantity of gas it delivers."[177]	For transportation services, lost and unaccounted-for gas is generally recovered from shippers in kind. For commodity sales, the cost of unaccounted-for gas is generally recovered through the PGA. The unaccounted-for gas percentage may be fixed in the pipeline operator's filed rates or tracked and updated periodically (without the filing of a new rate case). A pipeline operator that reports unaccounted for gas exceeding five percent in any year must provide a detailed

Jurisdiction	Regulator	Terminology	Definition	Rules for recovery
				explanation regarding the level of its unaccounted-for gas.[178]
Massachusetts	Massachusetts Department of Public Utilities	Lost and unaccounted-for gas	No legislative definition. Defined in administrative decisions as "the difference between gas metered at the company's city gate stations and gas metered at a company's customers" premises.[179]	For transportation services, lost and unaccounted-for gas is generally recovered from shippers in kind. For commodity sales, lost and unaccounted-for gas is generally recovered through the PGA. The lost and unaccounted-for gas percentage may be tracked and updated periodically, without the filing of a new rate case.[180]
Michigan	Michigan Public Service Commission	Lost and unaccounted-for gas	No legislative definition.	For transportation services, lost and unaccounted-for gas is generally recovered from shippers in kind. For commodity sales, lost and unaccounted-for gas is generally recovered in base rates. The L&U gas percentage is fixed in a general rate proceeding.[181]
Minnesota	Minnesota Public Utilities Commission	Lost and unaccounted-for gas or LUF gas	No legislative definition. Defined in administrative decisions as "the difference between gas purchased and gas sold."[182]	For transportation services, LUF gas is generally recovered from shippers in kind. For commodity sales, LUF gas is generally recovered through the PGA. The LUF gas percentage may be tracked and updated periodically, without the filing of a new rate case.[183]
Mississippi	Mississippi Public Service Commission	Lost and unaccounted-for gas	No legislative definition.	For transportation services, lost and unaccounted-for gas is generally recovered from shippers in kind. For commodity sales, lost and unaccounted-for gas is generally recovered through the PGA. The lost and unaccounted-for gas percentage may be tracked and updated periodically, without the filing of a new rate case.[184]

Jurisdiction	Regulator	Terminology	Definition	Rules for recovery
Missouri	Missouri Public Service Commission	Lost and unaccounted-for gas or L&U gas	No legislative definition. Defined in administrative decisions as the difference between the amount of gas purchased and sold by a pipeline operator. This is calculated by subtracting sales volumes from purchase volumes.[185]	For transportation services, L&U gas is generally recovered from shippers in kind. The L&U gas percentage may be negotiated between the pipeline operator and its shippers. For commodity sales, L&U gas is generally recovered through the PGA. The L&U gas percentage may be tracked and updated periodically, without the filing of a new rate case.[186]
Montana	Montana Public Service Commission	Unaccounted-for gas or UAF gas	No legislative definition.	For transportation services, UAF gas is generally recovered from shippers in kind. For commodity sales, UAF gas is generally recovered through the PGA. The UAF gas percentage may be tracked and updated periodically, without the filing of a new rate case.[187]
Nebraska	Nebraska Public Service Commission	Lost and unaccounted-for gas	No legislative definition.	For transportation services, lost and unaccounted-for gas may be recovered from shippers in kind or in dollars. For commodity sales, lost and unaccounted-for gas generally recovered through the PGA. The lost and unaccounted-for gas percentage may be tracked and updated periodically, without the filing of a new rate case.[188]
Nevada	Public Utilities Commission of Nevada	Unaccounted-for gas	No legislative definition.	For transportation services, lost and unaccounted-for gas may be recovered from shippers in kind or in dollars. For commodity sales, lost and unaccounted-for gas is generally recovered through the PGA. The unaccounted-for gas percentage may be tracked and updated periodically, without the filing of a new rate case.[189]
New	New Hampshire	Unaccounted-for gas	No legislative definition.	For transportation services, the cost of lost and unaccounted-

Jurisdiction	Regulator	Terminology	Definition	Rules for recovery
Hampshire	Public Utilities Commission (NHPUC)		Defined in administrative decisions as "the difference between the amount of gas billed to customers and the amount of gas sent out of. . . [a] facility, excluding the amount of company gas use."[190]	for gas is generally recovered through a charge levied on shippers. For commodity sales, unaccounted-for gas is generally recovered through the PGA. The unaccounted-for gas percentage may be tracked and updated periodically, without the filing of a new rate case. The NHPUC has previously imposed operator-specific caps on recovery of unaccounted-for gas through the PGA.[191]
New Jersey	New Jersey Board of Public Utilities	Lost and unaccounted-for gas or LAUF gas	No legislative definition.	For transportation services, LAUF gas is generally recovered from shippers in kind. For commodity sales, LAUF gas is generally recovered through the PGA. The LAUF gas percentage may be fixed in the pipeline operator's filed rates.[192]
New Mexico	New Mexico Public Regulation Commission	Lost and unaccounted-for gas or UFG	No legislative definition. Defined in administrative decisions as representing physical losses and "differences in accuracy between purchase and sales meters as well as the time lag between purchase and sales billing."[193]	For transportation service, UFG may be recovered from shippers in kind or in dollars. For commodity sales, UFG is generally recovered through the PGA. The UFG percentage may be fixed in a general rate proceeding.[194]
New York	New York State Public Service Commission	Lost and unaccounted-for gas or LAUF gas	No legislative definition. Defined in administrative decisions as the difference "between the amount of gas metered into the [pipeline] system and the amount of gas metered out of" that	LAUF gas is generally recovered through the PGA. In the PGA, the cost of gas reflects the actual volume of gas sold, plus a fixed factor of adjustment reflecting lost and unaccounted-for gas (with certain other adjustments)). The fixed factor of adjustment is determined in the operator's rate case (based on historic gas losses). It remains unchanged

Jurisdiction	Regulator	Terminology	Definition	Rules for recovery
			system.[195]	until a new factor is fixed in the new rate case. There is no mechanism for reconciling actual gas losses with those forecast in the rate proceeding.[196]
North Carolina	North Carolina Utilities Commission	Lost and unaccounted-for gas or LAUF gas	No legislative definition.	For transportation services, LAUF gas is generally recovered from shippers in kind. For commodity sales, LAUF gas is recovered partly in base rates and partly through the PGA. Each pipeline operator's LAUF gas percentage is fixed in its general rate proceeding.[197]
North Dakota	North Dakota Public Service Commission	Lost and unaccounted-for gas	No legislative definition	For transportation services, lost and unaccounted-for is generally recovered from shippers in dollars. For commodity sales, lost and unaccounted-for gas is recovered partly in base rates partly through the PGA.[198]
Ohio	Public Utilities Commission of Ohio	Unaccounted-for gas	Unaccounted-for gas is "the difference between the measured volume of total gas supply, which includes gas purchased, gas produced by the company, and gas received by the company on behalf of specific customers for redelivery; and the measured volume of gas disposition, which includes gas billed or redelivered to customers and gas for company use." It is calculated on an annual basis for the twelve months ended August 31, or such other date as may be shown	For transportation services, unaccounted-for gas is generally recovered from shippers in kind. For commodity services, unaccounted-for gas is generally recovered through the PGA. The unaccounted-for gas percentage may be tracked and updated periodically, without the filing of a new rate case. There is a 5 percent cap on unaccounted-for gas. Unaccounted-for gas exceeding the cap is presumed to be unreasonable and disallowed, unless the pipeline operator proves otherwise.[200]

Jurisdiction	Regulator	Terminology	Definition	Rules for recovery
			to be more appropriate.[199]	
Oklahoma	Oklahoma Corporation Commission (OCC)	Lost, used and unaccounted-for gas or LUFG	No legislative definition.	For transportation services, LUFG may be recovered from shippers in kind or in dollars. For commodity sales, LUFG is generally recovered through the PGA. The LUFG percentage may be tracked and updated periodically, without the filing of a new rate case. All pipeline operators have included in their tariffs provisions capping recovery for LUFG. Where a pipeline operator's LUFG percentage exceeds the cap, a review is undertaken by the OCC, which must determine whether the operator should be permitted to recover the excess LUFG.[201]
Oregon	Oregon Public Utility Commission	Lost and unaccounted for gas	No legislative definition.	Lost and unaccounted-for gas is generally recovered through the PGA. The lost and unaccounted-for gas percentage is tracked and updated periodically. Where a pipeline operator over-recovers compared to its actual lost and unaccounted-for gas, it must share the excess earnings with ratepayers.[202]
Pennsylvania	Pennsylvania Public Utility Commission (PPUC)	Unaccounted-for gas or UFG	UFG is "the difference between the total gas available from all sources and the total gas accounted for as sales, net interchange and company use." It is equal to gas received less gas delivered less adjustments, where: • "gas received" means gas supplied to the facility;	For transportation services, UFG is generally recovered from shippers in kind. For commodity sales, UFG is generally recovered through the PGA. The UFG percentage is tracked and updated periodically. There is a cap on UFG. The cap declines over time according to the following schedule: • 5.0 percent in 2014/15; • 4.5 percent in 2015/16;

Jurisdiction	Regulator	Terminology	Definition	Rules for recovery
			• "gas delivered" means gas provided by the facility; and • "adjustments" reflect gas used by the operator for safe and reliable service. Adjustments must be consistent between filings, individually identified by category, and supported by metered data, sound engineering practice or other quantifiable results. Where possible, UFG must be calculated by system type (distribution, transmission, storage and production).[203]	• 4.0 percent in 2016/17; • 3.5 percent in 2017/18; • 3.0 percent in 2018/19 and thereafter. UFG exceeding the applicable annual cap may be disallowed.[204]
Rhode Island	Rhode Island Public Utilities Commission	Unaccounted-for gas	No legislative definition. Defined in administrative decisions as the "differential between the amount of gas sent out and the amount of gas actually sold."[205]	For transportation services, unaccounted-for gas is generally recovered from shippers in kind. For commodity sales, unaccounted-for gas is generally recovered through the PGA. The unaccounted-for gas percentage may be tracked and updated periodically, without the filing of a new rate case.[206]
South Carolina	Public Service Commission of South Carolina	Lost and unaccounted-for gas or LAUF gas	No legislative definition.	For transportation services, LAUF gas is generally recovered from shippers in kind. For commodity services, the cost of LAUF gas is generally recovered through the PGA. The LAUF percentage may be fixed in a general rate proceeding.[207]
South Dakota	South Dakota Public Utilities	Lost and	No legislative definition.	For transportation service, lost and unaccounted-for gas may

Jurisdiction	Regulator	Terminology	Definition	Rules for recovery
	Commission	unaccounted-for gas		be recovered from shippers in kind or in dollars. For commodity sales, lost and unaccounted-for gas is generally recovered through the PGA. The lost and unaccounted for gas percentage may be tracked and updated periodically, without the filing of a new rate case.[208]
Tennessee	Tennessee Regulatory Authority	Lost and unaccounted-for gas	No legislative definition.	For transportation services, lost and unaccounted-for gas is generally recovered from shippers in kind. For commodity sales, lost and unaccounted-for gas is generally recovered through the PGA. The lost and unaccounted-for gas percentage may be tracked and updated periodically, without the filing of a new rate case.[209]
Texas	Railroad Commission of Texas	Lost and unaccounted-for gas	Lost and unaccounted for gas is "the difference between the amount of gas metered into a distribution or transmission system and the amount metered out."[210]	For commodity sales, lost and unaccounted for gas is generally recovered through the PGA. The lost and unaccounted-for gas percentage may be tracked and updated periodically, without the filing of a new rate case. There is a cap on lost and unaccounted-for gas as follows: • Cap on distribution system losses = 5 percent of the gas metered into the system; and • Cap on transmission system losses = 3 percent of the gas metered into the system. Losses exceeding the applicable cap cannot be recovered unless permitted by the Railroad Commission "based on special facts and circumstances, including, where appropriate, the cost of effecting a reduction of the actual amount of lost gas, as may be demonstrated in a given ratemaking proceedings."[211]
Utah	Utah Public	Lost and	No legislative definition.	For transportation services, lost and unaccounted-for gas is

Jurisdiction	Regulator	Terminology	Definition	Rules for recovery
	Service Commission	unaccounted for gas		generally recovered from shippers in kind. For commodity sales, lost and unaccounted-for gas is generally recovered through the PGA. Pipeline operators must report annually on the amount of lost and unaccounted-for gas and efforts to reduce that amount.[212]
Vermont	Vermont Public Service Board	Unaccounted-for gas	No legislative definition.	Unaccounted-for gas is generally recovered through the PGA. A pipeline operator must keep its unaccounted-for gas to a minimum. The operator must file an annual statement detailing the amount of unaccounted-for gas on its system. If that amount exceeds the national average, the operator must develop a plan for reducing that amount.[213]
Virginia	Virginia State Corporation Commission	Unaccounted-for gas	No legislative definition. Defined in administrative decisions as "the difference between the amount of all gas recorded "as received" and the amount recovered "as delivered" to all customers."[214]	For transportation services, lost and unaccounted-for gas is generally recovered from shippers in kind.[215] For commodity sales, unaccounted-for gas is generally recovered through the PGA. The unaccounted-for gas percentage may be fixed in the pipeline operator's filed rates or tracked and updated periodically (without the filing of a new rate case).[216]
Washington	Washington Utilities and Transportation Commission	Lost and unaccounted-for gas	No legislative definition. Defined in administrative decisions as "the difference in the number of therms [of gas] purchased and the number of therms sold."[217]	For transportation services, lost and unaccounted-for gas is generally recovered from shippers in kind. For commodity sales, unaccounted-for gas is generally recovered through the PGA. The lost and unaccounted-for gas percentage may be tracked and updated periodically, without the filing of a new rate case.[218]
West Virginia	Public Service Commission of West Virginia	Unaccounted-for gas	Unaccounted-for gas is "the difference between total gas supply, net of measured company use and measured	The cost of unaccounted-for gas is generally recovered through the PGA. The unaccounted-for gas percentage may be tracked and

Jurisdiction	Regulator	Terminology	Definition	Rules for recovery
			free gas, and total gas sales."[219]	updated periodically, without the filing of a new rate case. There is a cap on unaccounted-for gas as follows: • Cap for large utilities (i.e., with annual sales exceeding 2 billion cubic feet) = 8 percent; and • Cap for small utilities (i.e., with annual sales equal to or less than 2 billion cubic feet) = 10 percent. Unaccounted for gas in excess of the applicable cap cannot be recovered.[220]
Wisconsin	Public Service Commission of Wisconsin	Lost and unaccounted-for gas	No legislative definition.	For transportation services, lost and unaccounted-for gas is generally recovered from shippers in dollars. For commodity sales, the cost of lost and unaccounted-for gas may be recovered in base rates and/or through the PGA. The lost and unaccounted-for gas percentage is fixed in a general rate proceeding.[221]
Wyoming	Wyoming Public Service Commission	Fuel, lost and unaccounted-for gas or FL&U gas	No legislative definition.	For transportation services, FL&U gas is generally recovered from shippers in kind. For commodity sales, FL&U gas is generally recovered through the PGA. The FL&U gas percentage is tracked and updated periodically, without the filing of a new rate case.[222]

— *Endnotes* —

[1] U.S. EIA, MARCH 2015 MONTHLY ENERGY REVIEW, 105 (2015), *available at* http://www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf (indicating that, in 2004, 1,978,301 million kilowatt hours of electricity was generated using coal, 121,145 million kilowatt hours of electricity was generating using petroleum, and 710,100 million kilowatt hours of electricity was generated using natural gas. In 2014, 1,585,697 kilowatt hours of electricity was generated using coal, 30,489 million kilowatt hours of electricity was generated using petroleum, and 1,121,928 million kilowatt hours of electricity was generated using natural gas).

[2] U.S. EPA, *Coal*, CLEAN ENERGY, http://www.epa.gov/cleanenergy/energy-and-you/affect/coal.html (last updated Sep. 25, 2013) (indicating that, "[w]hen coal is burned, carbon dioxide, sulfur dioxide, nitrogen oxides, and mercury compounds are released"); U.S. EPA, *Natural Gas*, CLEAN ENERGY, http://www.epa.gov/cleanenergy/energy-and-you/affect/natural-gas.html (last updated Sep. 25, 2013) (finding that "[e]missions of sulfur dioxide and mercury compounds from burning natural gas are negligible").

[3] U.S. EPA, *Natural Gas*, CLEAN ENERGY, http://www.epa.gov/cleanenergy/energy-and-you/affect/natural-gas.html (last updated Sep. 25, 2013) (estimating that natural gas-fired power plants emit 1,135 pounds of carbon dioxide, 0.1 pounds of sulfur dioxide, and 1.7 pounds of nitrogen oxides per megawatt hour of electricity generated); U.S. EPA, *Coal*, CLEAN ENERGY, http://www.epa.gov/cleanenergy/energy-and-you/affect/coal.html (last updated Sep. 25, 2013) (estimating that coal-fired power plants emit 2,249 pounds of carbon dioxide, 13 pounds of sulfur dioxide, and 6 pounds of nitrogen oxides per megawatt hour of electricity generated).

[4] See, for example, Robert W. Howarth et al., *Methane and the Greenhouse-Gas Footprint of Natural Gas from Shale Formations*, 106 CLIM. CHANGE 679 (2011) (finding that lifecycle greenhouse gas emissions from shale gas are 100% higher than coal over a twenty year timeframe); Mohan Jiang et al., *Life Cycle Greenhouse Gas Emissions of Marcellus Shale Gas,* 6 ENVIRON. RES. LETT. 034014 (2011) (estimating that, on a lifecycle basis, greenhouse gas emissions from electricity generation using shale gas are twenty to fifty percent higher than those from electricity generation using coal); Andrew Burnham et al., *Life Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal and Petroleum,* ENVIRON. SCI. TECHNOL. 619 (2011) (finding that lifecycle greenhouse gas emissions from compressed natural gas vehicles are comparable to gasoline vehicles over a 100 year time horizon, but twenty to thirty percent higher over a twenty year time horizon). However, compare Nathan Hultman et al., *The Greenhouse Impact of Unconventional Gas for Electricity Generation,* 6 ENVIRON. RES. LETT. 044048 (2011) (estimating that lifecycle greenhouse gas emissions from electricity generation using shale gas are fifty-six percent those of coal-fired generation); Ian J. Laurenzi & Gilbert R. Jersey, *Life Cycle Greenhouse Gas Emissions and Freshwater Consumption of Marcellus Shale Gas,* 49 Environ. Sci. Technol. 4896 (2013) (finding that, on a lifecycle basis, the carbon footprint of Marcellus shale gas is fifty three percent lower than coal).

— Endnotes Continued —

5 Shana Cleveland, CONSERVATION LAW FOUNDATION, INTO THIN AIR: HOW LEAKING NATURAL GAS INFRASTRUCTURE IS HARMING OUR ENVIRONMENT AND WASTING A VALUABLE RESOURCE 7 (2012), *available at* http://www.clf.org/static/natural-gas-leaks/WhitePaper_Final_lowres.pdf. The Environmental Defense fund has commissioned a series of studies investigating methane emissions across the natural gas supply chain. The work is divided into five modules, assessing emissions during natural gas production, gathering and processing, long distance transmission and storage, local distribution, and transportation. See Environmental Defense Fund, *What Will it Take to get Sustained Benefits from Natural Gas?* CLIMATE AND ENERGY, http://www.edf.org/energy/methaneleakage (last visited Apr. 14, 2015).

6 The EPA defines "natural gas systems" as comprising the gas wells, processing facilities, and transmission and distribution pipelines used to produce, transport, store, and distribute natural gas. See U.S. EPA, INVENTORY OF GREENHOUSE GAS EMISSIONS AND SINKS: 1990 – 2013 3-68 (2015), *available at* http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.

7 *Id.* at ES-5 – ES-7 (indicating that national methane emissions in 2013 totaled 636.3 million metric tons of carbon dioxide equivalent, of which 157.4 million metric tons was emitted by natural gas systems). It should be noted that recent studies suggest that the EPA's greenhouse gas inventory may overstate methane emissions from natural gas production. See, for example, Brian K. Lamb et al., *Direct Measurements Shown Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States*, ENVIRON. SCI. AND TECHNOL., B (2015) (estimating that methane emissions from natural gas distribution systems are thirty-six to seventy percent lower than those reported in the EPA's 2011 greenhouse gas inventory).

8 *Id.* at 3-70 (indicating that, in 2013, total methane emissions from natural gas systems were 6,295 kilotons, of which 2,176 kilotons originated from the transmission and storage sector and 1,333 originated from the distribution sector).

9 Pipeline and Hazardous Materials Safety Administration, *Pipeline Miles and Facilities*, https://hip.phmsa.dot.gov/analytics SOAP/saw.dll?Portalpages (last visited Mar. 31, 2015) (indicating that, in 2014, there were 2,157,318 miles of distribution pipelines, 301,213 miles of transmission pipelines, and 17,319 miles of gathering pipelines).

10 Pipeline and Hazardous Materials Safety Administration, *Gathering Line*, PIPELINE GLOSSARY, http://primis.phmsa.dot.gov/comm/glossary/#GatheringLine (last visited Mar. 26, 2015); Pipeline and Hazardous Materials Safety Administration, *Transmission Line*, PIPELINE GLOSSARY, http://primis.phmsa.dot.gov/comm/glossary/#TransmissionLine (last visited Mar. 26, 2015); Pipeline and Hazardous Materials Safety Administration, *Distribution Line*, PIPELINE GLOSSARY, http://primis.phmsa.dot.gov/comm/glossary/#DistributionLine (last visited Mar. 26, 2015).

11 RAMÓN A. ALVAREZ & ELIZABETH PARANHOS, AIR POLLUTION ISSUES ASSOCIATED WITH NATURAL GAS AND OIL OPERATIONS 1 (2012), *available at* http://www.edf.org/sites/default/files/AWMA-EM-airPollutionFromOilAndGas.pdf.

12 *Id.*

— *Endnotes Continued* —

[13] U.S. EPA Office of Inspector General, Improvements Needed in EPA Efforts to Address Methane Emissions from Natural Gas Distribution Pipelines: Report No. 14-P-0324 10 (2014), *available at* http://www.epa.gov/oig/reports/2014/20140725-14-P-0324.pdf

[14] National Transportation Safety Board, *Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire*, Accident Investigations, http://www.ntsb.gov/investigations/Pages/2010_sanbruno_ca.aspx (last visited Mar. 26, 2015).

[15] National Transportation Safety Board, *UGI Utilities, Inc., Natural Gas Distribution Pipeline Explosion and Fire*, Accident Investigations, http://www.ntsb.gov/investigations/AccidentReports/Pages/PAR9601.aspx (last visited Mar. 26, 2015).

[16] National Transportation Safety Board, *Natural Gas Service Line Break and Subsequent Explosion and Fire*, Accident Investigations, http://www.ntsb.gov/investigations/AccidentReports/Pages/PAB0701.aspx (last visited Mar. 26, 2015).

[17] U.S. EPA, *supra* note 6, at 3-68.

[18] Gunnar Myhre et al., *Anthropogenic and Natural Radiative Forcing*, *in* Climate Change 2013: The Physical Science Basis. Working Group I Contribution to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change 659, 714 (Thomas F. Stocker et al. eds., 2013) (indicating that methane has a global warming potential twenty-eight times that of carbon dioxide over a 100-year time horizon and eighty-four times that of carbon dioxide over a twenty-year time horizon).

[19] The regulation of natural gas pipelines differs depending on whether those pipelines are used in interstate commerce (see U.S. Const. art. 1, § 8). Broadly, pipelines crossing state boundaries (interstate pipelines) are regulated at the federal level, while pipelines located within the boundaries of a single state (interstate pipelines) are regulated by that state. In general, federally regulated interstate pipelines tend to be transmission line used to move natural gas from gathering and processing facilities to distribution centers. Most interstate pipelines regulated at the state level are distribution lines used by LDCs to deliver natural gas to end-consumers.

[20] 49 C.F.R. § 192.703(c) (2015).

[21] Lamb et al., supra note 5, at B (noting that "[b]ecause leaks are classified on the basis of safety (i.e., proximity to buildings) and not magnitude, class 1 [i.e., hazardous] leaks are not necessarily larger than" other non-hazardous leaks).

[22] *Id.*

[23] *Id.* at c.

[24] *Id.*

— *Endnotes Continued* —

[25] Natural Gas Pipeline Safety Act, 49 U.S.C. §§ 60105, 60106. See also NATIONAL ASSOCIATION OF PIPELINE SAFETY REPRESENTATIVES, COMPENDIUM OF STATE PIPELINE SAFETY REQUIREMENTS AND INITIATIVES PROVIDING INCREASED PUBLIC SAFETY LEVELS COMPARED TO CODE OF FEDERAL REGULATIONS 9 (2nd Ed., 2013), *available at* http://www.naruc.org/resources.cfm?p=397. The author notes that, in Alaska and Hawaii, the PHMSA is responsible for enforcing the federal safety regulations against both interstate and intrastate pipeline operators.

[26] The eleven states are Arizona, California, Connecticut, Iowa, Michigan, Minnesota, New York, Ohio, Virginia, Washington, and West Virginia. See NATIONAL ASSOCIATION OF PIPELINE SAFETY REPRESENTATIVES*, supra* note 25, at 10.

[27] The states with more stringent leak repair standards are Arizona, Arkansas, Florida, Georgia, Kansas, Maine, Massachusetts, Missouri, New Hampshire, New York, Ohio, South Carolina, Tennessee, Texas, and Washington. It should be noted that an additional three states – Delaware, Indiana, and Michigan – have adopted rules requiring leaks to be repaired within the period determined by the relevant pipeline operator. See *Id.* at 38, 45 – 46, 87, 94, 117, 125, 135, 176, 199, 220, 229, 246, 266, 272, 280 – 281, 310. See also 2014 Mass. Adv. Legis. Serv. 149 (LexisNexis).

[28] *Id.*

[29] *Id.* See also CLEVELAND, *supra* note 5, Appendix A. It should be noted that, in addition to the five states listed, Arizona has mandatory timeframes for the repair of certain leaks (e.g., underground leaks from intrastate gas transmission pipelines). See Ariz. Admin. Code § 14-5-202(R) (2015).

[30] Natural Gas Act, section 1(b) (15 U.S.C. § 717(b)) authorizes FERC to regulate the transportation and sale for resale of natural gas in interstate commerce and the natural gas companies engaged therein. However, the section exempts the local distribution of natural gas and the facilities used for that distribution from FERC regulation. In addition, Natural Gas Act, section 1(c) (15 U.S.C. § 717(c)) also exempts from FERC regulation those companies that receive natural gas at or within the borders of a state, where the gas is consumed entirely within that state and the company is regulated by a state commission.

[31] Rates for intrastate pipelines are set by state regulators. The regulator for each state is shown in Appendix A to this White Paper.

[32] West Ohio Gas Co. v. Public Utilities Commission, 294 U.S. 63, 67 (1935). It should be noted that the U.S. Supreme Court handed down its decision in West Ohio Gas Co. v. Public Utilities Commission in 1935. In the intervening years, gas markets have changed significantly. Indeed, gas markets in many jurisdictions have been deregulated, with gas sales being unbundled from transportation services. With unbundling, customers can choose their natural gas supplier. However, the transmission and distribution of natural gas is not open to choice and the price for those services continues to be set in

— *Endnotes Continued* —

state and federally approved tariffs. The principles espoused in West Ohio Gas remain relevant to the setting of rates for the transmission and distribution of gas.

33 Gas may be used by the pipeline operator as a fuel for compressors, line heaters, and power generation and in other applications. See KEN COSTELLO, NATIONAL REGULATORY RESEARCH INSTITUTE, LOST AND UNACCOUNTED-FOR GAS: PRACTICES OF STATE UTILITY COMMISSIONS, REPORT NO. 13-06 4, 17 (2013), *available at* http://www.nrri.org/web/guest/research-papers?p_auth=XO6cbxid&p_p_auth=s86EYrOn&p_p_id=20&p_p_lifecycle=1&p_p_state=exclusive&p_p_mode=view&_20_struts_action=%2Fdocument_library%2Fget_file&_20_groupId=317330&_20_folderId=0&_20_name=7626. See also U.S. EIA, NATURAL GAS ANNUAL, 194 (2013), *available at* http://www.eia.gov/naturalgas/annual/pdf/nga13.pdf (defining "unaccounted-for gas" as "the difference between the sum of the components of natural gas supply and the sum of components of natural gas disposition"). Appendix A to this White Paper provides further information on the definition of lost and unaccounted for gas in each jurisdiction.

34 CLEVELAND, *supra* note 5, at 16.

35 COSTELLO, *supra* note 33, at 4, 17.

36 *Id.*

37 *Id.*

38 The amount of gas lost from the pipeline system differs depending on the characteristics of that system, including the piping materials used, the age of the piping, and the type of meters and regulators. *Id.* at 16, 43-44.

39 U.S. PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION, 2013 GAS DISTRIBUTION ANNUAL DATA, *available at* http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Pipeline2data/annual_gas_distribution_2013.zip.

40 U.S. ENERGY INFORMATION ADMINISTRATION, *supra* note 33, at 194.

41 EDWARD J. MARKEY, AMERICA PAYS FOR GAS LEAKS: NATURAL GAS PIPELINE LEAKS COST CONSUMERS BILLIONS, 9 (2013), *available at* http://www.markey.senate.gov/documents/markey_lost_gas_report.pdf (noting that pipeline operators "do not use a consistent methodology to calculate unaccounted for gas").

42 DUANE A. HARRIS, DETERMINING LOST AND UNACCOUNTED FOR GAS, 1 (2012), *available at* http://flowcal.com/wp-content/uploads/2012/02/Determining-Lost-and-Unaccounted-For-Gas-Loss.pdf (stating that "[t]here is no a recognized industry standard that dictates whether to use Inlet minus Outlet or Outlet minus Inlet to determine the" amount of lost and unaccounted-for gas).

— Endnotes Continued —

43 MARKEY, *supra* note 41, at 9 (indicating that each pipeline operator "decides which adjustments to make and less sophisticated operators may not make basic adjustments, such as adjusting volumes based on standard temperature pressure").

44 PENNSYLVANIA PUBLIC UTILITY COMMISSION, UNACCOUNTED-FOR-GAS IN THE COMMONWEALTH OF PENNSYLVANIA: JOINT REPORT BY THE BUREAU OF INVESTIGATION AND ENFORCEMENT AND THE BUREAU OF AUDITS 6 (2012), *available at* http://www.puc.state.pa.us/transport/gassafe/pdf/UFG_Report_Feb2012.pdf.

45 *Id.* at 6-7.

46 *Id.* See also NEW YORK DEPARTMENT OF PUBLIC SERVICE, STAFF WHITE PAPER ON LOST AND UNACCOUNTED FOR (LAUF) GAS 10 (2013), *available at* file:///C:/Users/rmw2632/Downloads/%7B0413ECDD-C194-46DE-8B04-AFDB3FBBE404%7D.pdf (indicating that each pipeline operator in New York "has a distinct approach for determining [lost and unaccounted-for gas] LAUF. Within their distinct approaches, each [operator] makes various adjustments to the total send out and total disposition to arrive at the send out and disposition used in their LAUF calculation").

47 MARKEY, *supra* note 41, at 9.

48 *Id.* See also PENNSYLVANIA PUBLIC UTILITY COMMISSION, *supra* note 44, at 9.

49 MARKEY, *supra* note 41, at 9. See also U.S. EIA, *supra* note 33(finding that, in 2013, overall gas losses were negative in Florida, Georgia, Hawaii, Maine, Nevada, Oklahoma, Washington, and Wyoming).

50 MARKEY, *supra* note 41, at 9.

51 PENNSYLVANIA PUBLIC UTILITY COMMISSION, *supra* note 44, at 9. See also Establishing a Uniform Definition and Metric for Unaccounted-for-Gas, 42 Pa.B. 6637 (2012).

52 Regulations defining the term "unaccounted-for gas" were adopted in Pennsylvania in August 2013. *Id.*

53 *Id.* See also PENNSYLVANIA PUBLIC UTILITY COMMISSION, *supra* note 44, at 4.

54 PENNSYLVANIA PUBLIC UTILITY COMMISSION, *supra* note 44, at 5-7.

55 *Id.*

56 *Id.* at 8.

57 Id.

— *Endnotes Continued* —

[58] As noted above, the amount of gas lost from a pipeline system may differ depending on the unique characteristics of that These differences should be taken into account when comparing gas losses from different pipelines. See COSTELLO, *supra* note 35, at 16, 43-44.

[59] *Id.* at 19.

[60] 10 W. VA. CODE R. § 150-2-13.2.c(2)(A) (2015).

[61] OHIO ADMIN. CODE 4901:1-14-01(CC) (2015) (defining "unaccounted-for gas" to mean "the difference between the measured volume of total gas supply…and the measured volume of gas disposition…calculated on an annual basis for the twelve months ended August thirty-first each year, or such other date as the company may show to be more appropriate").

[62] 52 PA CODE § 59.111(a) (2014) (defining "unaccounted-for gas" to mean "the difference between the total gas available from all sources and the total gas accounted for as sales, net interchange and company use.")

[63] 16 TEX. ADMIN. CODE § 7.115(21) (2015) (defining "lost and unaccounted-for gas" to mean "the difference between the amount of gas metered into a distribution or transmission system and the amount metered out").

[64] OHIO ADMIN. CODE 4901:1-14-01(CC) (2015).

[65] 52 PA CODE § 59.111(a) (2015).

[66] *Id.* § 59.111(b)(1).

[67] *Id.* § 59.111(a).

[68] *Id.*

[69] *Id.* §§ 59.111(a), 59.111(b)(5).

[70] *Id.* § 59.111(b)(3).

[71] *Id.* § 59.111(c)(2).

[72] *Id.* § 59.111(b)(4).

[73] *Id.*

[74] Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 24 of the Commission's Regulations and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, 59 FERC ¶

— *Endnotes Continued* —

61,030 (1992), *order denying reh'g and clarifying* 60 FERC ¶ 61,102 (1992), *order denying reh'g and clarifying* 61 FERC ¶ 61,787 (1992), *order on remand* 78 FERC ¶ 61,186 (1997).

[75] U.S. EIA, Natural Gas Annual 2013, 73 (2014), available at http://www.eia.gov/naturalgas/annual/pdf/nga13.pdf (indicating that, as of 2013, California, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Montana, Nebraska, New Jersey, New Mexico, New York, Ohio, Pennsylvania, Rhode Island, Virginia, Wisconsin, and Wyoming allowed residential customers and other small volume users to choose their natural gas supplier).

[76] COSTELLO, *supra* note 35, at 20-21.

[77] The five jurisdictions are Connecticut, Ohio, Pennsylvania, Texas, and West Virginia. See Appendix 1 for further information.

[78] The seven jurisdictions are Arizona, Georgia, Idaho, Kansas, Kentucky, Louisiana, and New Hampshire. In Oklahoma, pipeline operators have voluntarily included caps in their tariffs.

[79] Fuel Retention Practices of Natural Gas Companies: Notice of Inquiry, 120 FERC ¶ 61,255 (2007), *terminated* 125 FERC ¶ 61,213 (2008) (noting that with "a tracker and a true-up mechanism, the pipeline simply passes through its fuel costs to its customers, and, therefore, there may in fact be little incentive for the pipeline to try to reduce those costs"); American Gas Association, Before the Federal Energy Regulatory Commission: Fuel Retention Practices of Natural Gas Companies: Docket No. RM07-20-000: Comments of the American Gas Association 7 (FERC, Nov. 30, 2007), *available at* file:///C:/Users/rmw2632/Downloads/20071130-5066(18325426).pdf (stating that "existing fuel trackers with true-up mechanisms do not provide sufficient incentives to reduce fuel consumption or to make investments to improve fuel efficiency"); Kinder Morgan, Before the Federal Energy Regulatory Commission: Fuel Retention Practices of Natural Gas Companies: Docket No. RM07-20-000: Comments by the Kinder Morgan Interstate Pipelines on Notice of Inquiry 18 (FERC, Nov. 30, 2007), *available at* file:///C:/Users/rmw2632/Downloads/20071130-5106(18325776).pdf (indicating that "[w]ith a tracker, the pipeline's incentive to incur significant operating expenses…to reduce gas lost is reduced").

[80] N.Y. COMP. CODES R. & REGS. tit. 16, § 720-6.5(g) (2015). See also Central Hudson Gas & Electric Corp. for Gas Service, 31 NY PSC 1823 (July 1, 1991).

[81] Central Hudson Gas & Electric Corp. for Gas Service, 31 NY PSC 1823 (July 1, 1991).

[82] *Id.*

[83] Gas losses are calculated as the difference between system send-out and system dispositions of gas. The result is divided by total gas send-out on the pipeline system to produce an allowed loss rate (known as the allowed LAUF factor) which is

— *Endnotes Continued* —

used to calculate the fixed factor of adjustment. Mathematically, the fixed factor of adjustment is equal to (1 / (1 – LAUF factor)). See NEW YORK DEPARTMENT OF PUBLIC SERVICE, *supra* note 46, at 10.

[84] N.Y. Comp. Codes R. & Regs. tit. 16, § 720-6.5(e).

[85] NEW YORK DEPARTMENT OF PUBLIC SERVICE, *supra* note 83, at 6.

[86] *Id.*

[87] *Id.*

[88] Id.

[89] Kinder Morgan Interstate Pipelines, Before the Federal Energy Regulatory Commission: Fuel Retention Practices of Natural Gas Companies: Docket No. RM07-20-000: Comments by the Kinder Morgan Interstate Pipelines on Notice of Inquiry, Appendix C (FERC, Nov. 30, 2007), *available at* file:///C:/Users/rmw2632/Downloads/20071130-5106(18325776).pdf.

[90] *Id.*

[91] *Id.*

[92] *Id.* (finding that the average losses reported by pipeline operators recovering lost and unaccounted-for gas at a fixed rate fell from 0.51 percent in 1997 to 0.07 percent in 2006, while the average losses reported by pipeline operators recovering lost and unaccounted-for gas through a tracking mechanism fell from 0.41 percent in 1997 to 0.17 percent in 2006).

[93] West Ohio Gas Co. v. Public Utilities Commission, 294 U.S. 63, 67 (1935).

[94] *Id.* at 68.

[95] COSTELLO, *supra* note 33, at 2.

[96] *Id.*

[97] *Id.* at iv.

[98] *Id.* at 2.

[99] Regulators could determine whether action to reduce pipeline gas losses is economically feasible by, for example, undertaking a cost-benefit analysis. For a discussion of this issue see COSTELLO, *supra* note 28, at 2.

— *Endnotes Continued* —

100 *Id.* at v.

101 BIPARTISAN POLICY CENTER, NATURAL GAS INFRASTRUCTURE AND METHANE EMISSIONS 8 (2014), *available at* http://bipartisanpolicy.org/wp-content/uploads/sites/default/files/BPC%20Energy%20Natural%20Gas%20 Infrastructure%20Methane%20Emissions.pdf

102 *Id.* at 22.

103 *Id.* at 17-19.

104 *Id.*

105 See *supra* Chapter III.

106 Fuel Retention Practices of Natural Gas Companies, 120 FERC ¶ 61,255 (2007), *terminated*, 125 FERC ¶ 61,213 (2008).

107 Fuel Retention Practices of Natural Gas Companies, 120 FERC ¶ 61,255 (2007), *terminated* 125 FERC ¶ 61,213 (2008). See also ANR Pipeline Co., 108 FERC ¶ 61,050 (2004), *order on reh'g and compliance filing*, 110 FRC ¶ 61,069 (2005), order on *reh'g and compliance filing*, 111 FERC ¶ 61,290 (2005).

108 Texas E. Transmission Corp., 64 FERC ¶ 61,305.

109 *Id.*

110 Algonquin Gas Transmission, LLC, 133 FERC ¶ 61,181 (2010); Algonquin Gas Transmission, LLC, 137 FERC ¶ 61,169 (2011); Algonquin Gas Transmission, LLC, 141 FERC ¶ 61,160 (2012); Algonquin Gas Transmission, LLC, 144 FERC ¶ 61,038 (2013); Algonquin Gas Transmission, LLC, 145 FERC ¶ 61,175 (2013); Algonquin Gas Transmission, LLC, 149 FERC ¶ 61,167 (2014).

111 Id.

112 NEW YORK DEPARTMENT OF PUBLIC SERVICE, *supra* note 46, at 10.

113 N.Y. COMP. CODES R & REGS. tit. 16, § 720-6.5(g)(1) (2015). See also NEW YORK DEPARTMENT OF PUBLIC SERVICE, *supra* note 46, at 5.

114 Central Hudson Gas & Electric Corp. for Gas Service, Case 09-G-0589 (N.Y. Pub. Serv. Comm'n, Jun. 18, 2010).

115 *Id.*

— Endnotes Continued —

[116] 16 TEX. ADMIN CODE § 7.5525(b)(1) (2015).

[117] *Id.* § 7.5525(b) – (c).

[118] West Texas Gas, Inc., Statement of Intent of West Texas Gas, Inc. to Increase Gas Distribution Rates in the Unincorporated Areas of Texas: GUD No. 10235 (RRC, 2013).

[119] *Id.*

[120] *Id.*

[121] 40 C.F.R. § 98.232(e), (i).

[122] It should, however, be noted that pipeline operators are required to directly measure methane emissions from metering and regulating facilities.

[123] 40 C.F.R. § 98.233(q). See also U.S. ENVIRONMENTAL PROTECTION AGENCY, GREENHOUSE GAS EMISSIONS REPORTING FROM THE PETROLEUM AND NATURAL GAS INDUSTRY: BACKGROUND TECHNICAL SUPPORT DOCUMENT, 7 & 47 (2009), *available at* http://www.epa.gov/ghgreporting/documents/pdf/2010/Subpart-W_TSD.pdf.

[124] The EFs were calculated using published data on methane leakage rates from 1992. See LISA M. CAMPBELL ET AL., METHANE EMISSIONS FROM THE NATURAL GAS INDUSTRY, VOLUME 9: UNDERGROUND PIPELINES, 36 – 40 (1996), *available at* http://www.epa.gov/gasstar/documents/emissions_report/9_underground.pdf.

[125] *Id.* at 36. See also U.S. ENVIRONMENTAL PROTECTION AGENCY, *supra* note 123, at 117 – 118.

[126] Lamb et al., *supra* note 18, at c.

[127] Jonathan Peress, Environmental Defense Fund, *Study Shows Utilities and Regulators Making Progress on Methane Leaks, But a Major Emissions Problem Remains*, ENERGY EXCHANGE (Mar. 31, 2015), http://blogs.edf.org/energyexchange/2015/03/31/study-shows-utilities-and-regulators-making-progress-on-methane-leaks-but-a-major-emissions-problem-remains/.

[128] New Hampshire Gas Corp., DG 99-046, Order No. 23,293 (N.H. Pub. Util. Comm'n, Aug. 30, 1999).

[129] H.B. 3765, 188th Gen. Court (Ma. 2013).

[130] The caps in Ohio and Pennsylvania apply to the distribution system only. With respect to the cap in Ohio, see OHIO ADMIN. CODE 4905.03(E), 4901:1-14-01, 4901:1-14-08 (2015). With respect to the cap in Pennsylvania, see 57 PA. CODE § 59.111(c) (2014) (2015).

[131] 16 TEX. ADMIN CODE § 7.5525(b) (2015).

— Endnotes Continued —

[132] 10 W. VA. CODE R. § 150-2-13.2.c(2)(B)(2) (2015).

[133] Conn. Gen. Stat. § 16-34a (2015).

[134] OHIO ADMIN. CODE § 4901:1-14-08(F)(3) (2015). See also OHIO ADMIN. CODE § 4901:1-14-01(2015); OHIO REV. CODE ANN. § 4905.03(E) (LexisNexis 2015).

[135] 52 PA. CODE § 59.111(c) (2015).

[136] 16 TEX. ADMIN CODE § 7.5525(b)-(c) (2015).

[137] 10 W. VA. CODE R. § 150-2-13.2.c(2)(B) (2015).

[138] U.S. EIA, NATURAL GAS ANNUAL 1994 VOLUME 1, 232 (1994), *available at* http://www.eia.gov/naturalgas/annual/archive/1994/0131941.pdf (finding that 7,790 million cubic feet of natural gas was unaccounted-for in West Virginia in 1994); U.S. EIA, *supra* note 33, at 194 (finding that 2,856 million cubic feet of natural gas was unaccounted-for in West Virginia in 2013).

[139] General Order No. 183.4, (W. Va. Public Service Commission, 1979).

[140] 10 W. VA. CODE R. § 150-2-13.2.c(2)(B)(2) (2015).

[141] Id.

[142] PUBLIC SERVICE COMMISSION OF WEST VIRGINIA, SUPPLY-DEMAND FORECAST FOR GAS UTILITIES 2012-2021, 9 (2012), *available at* http://www.psc.state.wv.us/Special_Reports/Gas_Supply_Demand_2012.pdf.

[143] *Id.* (indicating that, in 2012, gas lost and used in pipeline operations was equal to 4.0 percent of pipeline throughput for Mountaineer Gas, 7.2 percent of pipeline throughput for Dominion Hope, and 4.7 percent of pipeline throughput for Equitable Gas); PUBLIC SERVICE COMMISSION OF WEST VIRGINIA, SUPPLY-DEMAND FORECAST FOR GAS UTILITIES 2011-2020, 7 (2011), *available at* http://www.psc.state.wv.us/Special_Reports/Gas_Supply_Demand_2011.pdf (estimating that, in 2011, gas lost and used in pipeline operations was equal to 5.31 percent of throughput for Mountaineer Gas, 6.27 percent of pipeline throughput for Dominion Hope, and 3.41 percent of pipeline throughput for Equitable Gas).

[144] U.S. EIA, *supra* note 33, at 194 (estimating that, in 2013, 198 billion cubic feet of natural gas was lost and a further 238 billion cubic feet of natural gas was unaccounted-for in the pipeline system in West Virginia (representing 5.1 percent of total natural gas consumption) and 91 billion cubic feet of natural gas was lost and a further 76 billion cubic feet of natural gas was unaccounted-for in the pipeline system in Texas (representing 4.2 percent of total natural gas consumption)).

— *Endnotes Continued* —

145 See, for example, Washington Gas Light Co., 145 FERC ¶ 61,0921 (2013).

146 ANR Pipeline Co., 108 FERC ¶ 61,050 (2004), *order on reh'g and compliance filing*, 110 FERC ¶ 61,069 (2005), *order on reh'g and compliance filing*, 111 FERC ¶ 61,290 (2005). See also, 18 C.F.R. 154.403 (2015).

147 Alabama Gas Corp., 25 P.U.R.3d 257 (Ala. Pub. Serv. Comm'n, Sep. 23, 1958).

148 See, for example, ATLANTA GAS LIGHT COMPANY, TARIFF (2014), *available at* https://www.atlantagaslight.com/rates-tariff.

149 See, for example, Beluga Pipe Line Co., 2013 Alas. PUC LEXIS 10 (Alaska Regulatory Comm'n, Jan. 4, 2013).

150 See, for example, Southern Union Gas Co., 1991 Ariz. Sec. LEXIS 205 (Ariz. Corp. Comm'n, May 24, 1991); Southwest Gas Corp., 1991 Ariz. Sec. LEXIS 86 (Ariz. Corp. Comm'n, Sep. 5, 1991).

151 Consumer Utils. Rate Advocacy Div. v. PSC, 86 Ark. App. 254 (2004).

152 See, for example, Arkansas Oklahoma Gas Corp., 246 P.U.R.4th 228 (Ark. Pub. Serv. Comm'n, Dec. 1, 2005); SourceGas Arkansas Inc., 2014 Ark. PUC LEXIS 242 (Ark. Pub. Serv. Comm'n, Jul. 7, 2014).

153 Pacific Gas & Electric Co., 23 CPUC 84 (Cal. Pub. Util. Comm'n, Dec. 22, 1986).

154 Pacific Gas & Electric Co., 179 P.U.R.4th 485 (Cal. Pub. Util. Comm'n, Aug. 1, 1997); Pacific Gas & Electric Co., 2001 Cal. PUC LEXIS 1279 (Cal. Pub. Util. Comm'n, Dec. 18, 2003).

155 4 Colo. Code Regs. §§ 4601(e), (g), (h), (m), 4602, 4603, 4604(c) (2015). See also, for example, COLORADO NATURAL GAS, INC., SCHEDULE OF RATES FOR NATURAL GAS SERVICE AVAILABLE IN THE ENTIRE TERRITORY SERVED BY COLORADO NATURAL GAS, INC. (2013), *available at* http://www.coloradonaturalgas.com.

156 See, for example, THE SOUTHERN CONNECTICUT GAS COMPANY, GAS TARIFF OF THE SOUTHERN CONNECTICUT GAS COMPANY AS FILED WITH PUBLIC UTILITIES REGULATORY AUTHORITY (2012), *available at* http://www.dpuc.state.ct.us/dpucinfo.nsf/$FormGasRelatedItemsView?OpenForm.

157 Conn. Gen. Stat. § 16-34a (2015).

158 Chesapeake Utilities Corp., 1990 Del. PSC LEXIS 3 (Del. Pub. Serv. Comm'n, Jan. 17, 1990).

159 See, for example Delmarva Power & Light Co., 1992 Del. PSC LEXIS 12 (Del. Pub. Serv. Comm'n, Jun. 2, 1992); Chesapeake Utilities Corp., 1993 Del. PSC LEXIS 7 (Del. Pub. Serv. Comm'n, Jun. 15, 1993); Chesapeake Utilities Corp.,

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1996 Del. PSC LEXIS 82 (Del. Pub. Serv. Comm'n, Apr. 30, 1996); Chesapeake Utilities Corp., 2004 Del. PSC LEXIS 108 (Del. Pub. Serv. Comm'n, Aug. 10, 2004).

[160] See, for example, District of Columbia Natural Gas, 12 DC PSC 494 (D.C. Pub. Serv. Comm'n, Aug. 27, 1991).

[161] Peoples Gas System, Inc, 1988 Fla. PUC LEXIS 1941 (Fla. Pub. Serv. Comm'n, Dec. 27, 1988); Indiantown Gas Co., 2007 Fla. PUC LEXIS 322 (Fla. Pub. Serv. Comm'n, Jun. 26, 2007).

[162] GA. COMP. R. & REGS. 515-3-3-.02(s), (t) (2015).

[163] GA. CODE ANN. § 46-4-158.1(a)(1) (2015); GA. COMP. R. & REGS. 515-7-7-.05(b) (2015). See also SCANA Energy Marketing, Inc., 2002 Ga. PUC LEXIS 11 (Ga. Pub. Util. Comm'n, Jan. 10, 2002); Atlanta Gas Light Co., 2011 Ga. PUC LEXIS 67 (Ga. Pub. Util. Comm'n, Mar. 15, 2015).

[164] Intermountain Gas Co., 2014 Ida. PUC LEXIS 121 (Ida. Pub. Util. Comm'n, Sep. 26, 2014).

[165] See, for example, Intermountain Gas Co., 2007 Ida. PUC LEXIS 184 (Ida. Pub. Util. Comm'n, Sep. 26, 2007); Intermountain Gas Co., 2008 Ida. PUC LEXIS 145 (Ida. Pub. Util. Comm'n, Sep. 30, 2008).

[166] Peoples Gas Light & Coke Co. (Ill. Commerce Comm'n, Mar. 28, 2006).

[167] 83 Ill. Adm. Code 525, 1995 Ill. PUC LEXIS 579 (Ill. Commerce Comm'n, Aug. 23, 1995).

[168] Indiana Gas Co., Inc., 86 P.U.R.4th 241 (Ind. Pub. Util. Regulatory Comm'n, Sep. 18, 1987).

[169] Gas Cost Tracking Procedures, 1986 Ind. PUC LEXIS 339 (Ind. Pub. Util. Regulatory Comm'n, May 14, 1986); Indiana Gas Co., Inc., 2008 Ind. PUC LEXIS 104 (Ind. Pub. Util. Regulatory Comm'n, Feb. 13, 2008).

[170] IOWA ADMIN. CODE r. 199-19.10(476)(1)(b) (2015).

[171] *Id.* r. 199-19.10(1); 199-19-13(476)(2)(a). See also Revisions to Purchased Gas Adjustment & Reserve Margin Rules, 2004 Iowa PUC LEXIS 239 (Iowa Util. Bd., May 21, 2004).

[172] Peoples Natural Gas Co., 1999 Kan. PUC LEXIS 1113 (Kan. Corp. Comm'n, Jun. 17, 1999).

[173] See, for example, Kentucky Frontier Gas Co., LLC, 2012 Ky. PUC LEXIS 94 (Ky. Pub. Serv. Comm'n, Feb. 3, 2012).

[174] Weighted Average Cost of Gas Filings, 193 P.U.R.4th 218 (La. Pub. Serv. Comm'n, Mar. 24, 1999).

[175] *Id.*

[176] Northern Utilities, Inc., 2001 Me. PUC LEXIS 315 (Me. Pub. Util. Comm'n, Apr. 24, 2001).

— *Endnotes Continued* —

[177] Line Losses of Electric Utilities & Unaccounted for Gas of Gas Utilities, 70 Md. P.S.C. 153 (Md. Pub. Serv. Comm'n, May 18, 1979).

[178] *Id.* See also Purchased Gas Adjustment Costs, 71 Md. P.S.C. 358 (Md. Pub. Serv. Comm'n, Sep. 15, 1980).

[179] Boston Gas Co., 2012 Mass. PUC LEXIS 17 (Mass. PUC, May 7, 2012).

[180] See, for example, BAY STATE GAS COMPANY, TARIFFS, RATE SCHEDULES AND AGREEMENTS (2012), *available at* https://www.columbiagasma.com/docs/default-document-library/cma-tariffs-%28effective-11-1-13%29.pdf; NEW ENGLAND GAS COMPANY, DISTRIBUTION SERVICE TERMS AND CONDITIONS (2011), *available at* http://www.libertyutilities.com/ma/saving/gas_rates.php.

[181] Consumers Power Co., 108 P.U.R.4th 301 (Mich. Pub. Serv. Comm'n, Dec. 7, 1989).

[182] Minnegasco, Inc., 143 P.U.R.4th 416 (Minn. Pub. Util. Comm'n, May 3, 1993). See also 2011-12 Annual Automatic Adjustment Reports & Annual Purchased Gas Adjustment True-up Filings, 2013 Minn. PUC LEXIS 243 (Minn. Pub. Util. Comm'n, Nov. 14, 2013).

[183] Minnegasco, Inc., 143 P.U.R.4th 416 (Minn. Pub. Util. Comm'n, May 3, 1993).

[184] Centerpoint Energy Resources Corp., 2013 Miss. PUC LEXIS 148 (Miss. Pub. Util. Comm'n, Sep. 25, 2013).

[185] Kansas Power & Light Co., 30 Mo. P.S.C. (N.S.) 76 (Mo. Pub. Serv. Comm'n, Dec. 29, 1989).

[186] *Id.*

[187] See, for example, Montana Power Co,, 1994 Mont. PUC LEXIS 12 (Mont. Pub. Serv. Comm'n, Dec. 21, 1994).

[188] See, for example, NORTHWESTERN CORPORATION, NATURAL GAS RATE SCHEDULE FOR NORTHWESTERN CORPORATION D/B/A NORTHWESTERN ENERGY, *available at* http://www.psc.nebraska.gov/natgas/natgas_filings.html#.

[189] Sierra Pacific Power Co., 2013 Nev. PUC LEXIS 281 (Nev. Pub. Serv. Comm'n, Dec. 18, 2013).

[190] See, for example, New Hampshire Gas Corp., 90 NH PUC 184 (N.H. Pub. Util. Comm'n, Apr 29, 2005).

[191] EnergyNorth Natural Gas, Inc, 79 NH PUC 202 (N.H. Pub. Util. Comm'n, Apr 6, 1994); Keene Gas Corp., 80 NH PUC 225 (N.H. Pub. Util. Comm'n, Apr. 25, 1995); New Hampshire Gas Corp., 90 NH PUC 184 (N.H. Pub. Util. Comm'n, Apr 29, 2005).

[192] See, for example, Elizabethtown Gas Co., (N.J. Bd. of Pub. Utils., May 13, 1997); New Jersey Natural Gas Co., 188 P.UR.4th 369 (N.J. Bd. of Pub. Utils., Sep. 14, 1998).

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193 Standard Purchased Gas Adjustment, 40 P.U.R.4th 619 (N.M. Pub. Serv. Comm'n, Dec. 10, 1980).

194 N.M. CODE R. § 17.10.640.12(A)(4) (2015); Standard Purchased Gas Adjustment, 40 P.U.R.4th 619 (N.M. Pub. Serv. Comm'n, Dec. 10, 1980). See also, PNM Gas Services, 179 P.U.R.4th 406 (N.M. Pub. Serv. Comm'n, Aug. 18, 1997); PNM Gas Services, 2004 P.U.R.4th 433 (N.M. Pub. Serv. Comm'n, Oct. 24, 2000).

195 See, for example, NEW YORK STATE DEPARTMENT OF PUBLIC SERVICE, *supra* note 83, at 5.

196 N.Y. COMP. CODES R & REGS. tit. 16 § 720-6.5(e), (g) (2015).

197 See, for example, Piedmont Natural Gas Co., Inc., 269 P.U.R.4th 320 (N.C. Utils. Comm'n, Oct. 24, 2008); Piedmont Natural Gas Company, Inc., 2013 N.C. PUC LEXIS 2122 (N.C. Utils. Comm'n, Dec. 17, 2013).

198 See, for example, GREAT PLANS NATURAL GAS CO. STATE OF NORTH DAKOTA GAS RATE SCHEDULE (2014), *available at* http://www.gpng.com/rates-and-services/rates.

199 OHIO ADMIN. CODE 4901:1-14-01(CC) (2015).

200 *Id.* 4901:1-14-04, 4901:1-14-08(F)(3), 4901:1-14-05(A) (2015). See also Vectren Energy Delivery of Ohio, Inc., 2014 Ohio PUC LEXIS 48 (Ohio Pub. Utils. Comm'n, Mar. 12, 2014).

201 Fort Cobb Fuel Authority, LLC, 2010 Okla. PUC LEXIS 69 (Okla. Corp. Comm'n, Apr. 2, 2010).

202 For example, the Oregon Public Utilities Commission has approved a mechanism for the sharing of cost savings associated with reductions in lost and unaccounted-for gas between pipeline operators and their ratepayers. Under the sharing mechanism, the pipeline operator is entitled to retain sixty-seven percent of any cost savings, but must return thirty-three percent to ratepayers. See Recovery of Purchased Gas Costs by Oregon's Regulated Gas Distribution Utilities, Order No. 99-272 (Or. Pub. Util. Comm'n, Apr. 19, 1999).

203 52 PA. CODE § 59.111(a), (b) (2015).

204 *Id.* § 59.111(c); 66 Pa. Code § 1307(f)(3), (5) (2015).

205 Providence Gas Co., 102 P.U.R.4th 348 (R.I. Pub. Utils. Comm'n, May 4, 1989).

206 See, for example, Valley Gas Co., Docket No. 2473 (R.I. Pub. Utils. Comm'n, May 13, 1997).

207 See, for example, South Carolina Electric & Gas Co., 2010 S.C. PUC LEXIS 352 (S.C. Pub. Serv. Comm'n, Oct. 14, 2010).

— *Endnotes Continued* —

[208] See, for example, MidAmerican Energy Company, Response to SDPUC Staff Questions (2010), *available at* https://puc.sd.gov/commission/dockets/rulemaking/2010/rm10-001/063010midamer.pdf.

[209] See, for example, Atmos Energy Corp., 2008 Tenn. PUC LEXIS 25 (Tenn. Regulatory Util. Comm'n, Apr. 10, 2008).

[210] 16 Tex. Admin. Code § 7.115(21) (2015).

[211] 16 Tex. Admin. Code § 7.5525(c) (2015). See also Texas Gas Service Co., Gas Utilities Docket No. 10069 (Tex. R.R. Comm'n, Jun. 27, 2011).

[212] Questar Gas Co., 2009 Utah PUC LEXIS 82 (Utah Pub. Serv. Comm'n, Mar. 31, 2009).

[213] 30-000-047 Vt. Code R. § 6.161 (2015). See also Vermont Gas Systems, Inc., Docket Nos. 7803 and 7843 (Vt. Pub. Serv. Bd., Aug. 21, 2012).

[214] Commonwealth Gas Services, Inc., Case No. PUE86031 (Va. State Corp. Comm'n, Aug. 6, 1987).

[215] Charlottesville, Va., Code § 31-61(g) (2014); Richmond, Va., Code §§ 106-203(g)(2), 106-204(g)(3) (2014).

[216] See, for example, Columbia Gas of Virginia, Inc., 255 P.U.R.4th 1 (Va. State Corp. Comm'n, Dec. 28, 2006); Atmos Energy Corp., 2009 Va. PUC LEXIS 1148 (Va. State Corp. Comm'n, Nov. 23, 2009).

[217] Washington Natural Gas, Cause No. UG-77-47 (Wash. Utils. & Transp. Comm'n, Nov. 22, 1977).

[218] See, for example, Cascade Natural Gas Corp., 254 P.U.R.4th 194 (Wash. Utils. & Transp. Comm'n, Jan. 12, 2007).

[219] 10 W. Va. Code R. § 150-2-14.2.c(2)(A) (2015).

[220] 10 W. Va. Code R. § 150-2-14.2 (2015).

[221] Wisconsin Electric Power Co., 192 P.U.R.4th 480 (Wis. Pub. Serv. Comm'n Mar. 25, 1999); Wiscconsin Pub. Serv. Corp., 2000 Wisc. PUC LEXIS 48 (Wis. Pub. Serv. Comm'n Dec. 22, 2000); Wisconsin Electric Power Co., 2006 Wisc. PUC LEXIS 73 (Wis. Pub. Serv. Comm'n, Jan. 25, 2006).

[222] See, for example, KN Energy, Inc., 1999 Wyo. PUC LEXIS 127 (Wyo. Pub. Serv. Comm'n, Mar. 16, 1999); Northern Gas Company, 2000 Wyo. PUC LEXIS 157 (Wyo. Pub. Serv. Comm'n Oct. 19, 2000).

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