Phase III: Natural Gas-Fired Electric Power Generation Infrastructure Analysis
An Analysis of Pipeline Capacity Availability

Prepared for:
The Midcontinent Independent Transmission System Operator

Gregory L. Peters
President, EnVision Energy Solutions
greg_peters1@verizon.net
804.378.0770

Justin Carlson
Rick Notarianni
Jeff Moore
Bentek Energy

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**Disclaimer:** This report was prepared by Gregory L. Peters, President and Principal Consultant of EnVision Energy Solutions, for the benefit of the Midcontinent Independent Transmission System Operator (MISO). This work involves detailed analyses of interstate pipeline daily flow and capacity data; data obtained and compiled by Bentek Energy; and available public information from independent third parties. The appropriate professional diligence has been applied in the preparation of this analysis, using what is believed to be reasonable assumptions. However, since the report also necessarily involves assumptions regarding the future and the accuracy of the data, no warranty is made, expressed or implied.

EnVision Energy Solutions is the prime contractor and Bentek Energy is the subcontractor for this analysis.
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Key Definitions

- **A backhaul transaction** results in the transportation of gas in a direction opposite of the aggregate physical flow of gas in the pipeline. This is typically achieved when the transporting pipeline redelivers gas at a point(s) upstream from the point(s) of receipt. A backhaul condition will exist as long as the aggregate backhaul transactions total less than the aggregate forward haul transactions. A backhaul transaction can result in a delivery by non-delivery or cut back (reduction) of physical flow at a delivery point. Commercially, it is a “paper transport” of natural gas by displacement against the flow on a single pipeline, so that the natural gas is redelivered upstream of its point of receipt.

- **Bi-directionality** is the ability to flow natural gas in both directions in a pipeline through operational management of interconnecting pipelines and management of flows into (receipt points) and out of (delivery points) of a pipeline. Bi-directionality may also be accomplished in conjunction with interconnectivity actions between gas delivery entities, pipelines, or local gas distribution companies (LDCs), or via some type of configuration between pipelines and LDCS.

- **Capacity** is the potential instantaneous output of a generating or storage unit, measured in watts. Energy is the actual amount of electricity generated by a power plant or released by a storage device during a time period, measured in watt-hours. The units are usually expressed in thousands (kilowatts and kilowatt-hours) or millions (megawatts and megawatt-hours). For example, the maximum amount of power a 1,000 megawatt (MW) power plant can generate in a year is 8.76 million megawatt-hours (MWh), calculated as: 1,000 MW x 8,760 hours in a year = 8.76 million MWh.

- **Capacity factor** is a standard measure of how intensively a power plant is utilized. It is the ratio of how much electricity a power plant produces over a period of time, typically a year, compared to how much electricity the plant could have produced if it operated continuously at full output. For example, the maximum possible output of a 1,000 MW power plant in one year is 8.76 million MWh. Assume that for one year the plant actually produced only 7 million MWh. In this case the plant’s capacity factor would be 7.0 million MWh ÷ 8.76 million MWh, or 81%.

- **Curtailment** of gas service is a method to balance a pipeline’s receipts and deliveries or a utility's natural gas requirements with its natural gas supply. Usually there is a hierarchy of customers for the (supply-related) curtailment plan. Customers may be required to partially cut back or totally eliminate their take of gas depending on the severity of the shortfall between gas supply and demand and the customer's position in the hierarchy. Curtailment is also an interstate pipeline term meaning that the pipeline needs to reduce scheduled and flowing gas due to an unexpected event. The order in which to cut the scheduled gas is determined by the pipeline’s tariff.
• **Displacement transactions** permit the lateral movement of gas through a transportation network when the dynamics on the network eliminate the necessity of physical flows from the intended receipt point. The configuration of many pipelines is such that it may not be apparent whether a given movement of gas is forward or backward from the point of receipt. It can be argued that all transportation service is performed by displacement as the physical delivery of the same molecules of gas is impossible.

• **Interconnectivity** is how each pipeline, local gas distribution company (LDC), or some combination of these entities work together operationally to improve delivery reliability, capacity availability and overall flexibility on LDC and interstate pipelines.

• **Interruptible Service** is a low-priority service offered to customers under schedules or contracts that anticipate and permit interruption on short notice, generally in peak-load seasons, by reason of the claim of firm service customers and higher priority users. Capacity is available at any time of the year if the supply is sufficient and the system is not fully utilized by firm shippers.

• **Reticulation** is a pipeline system configuration resembling or forming a net or network. The term 'gas network' collectively identifies in-ground reticulation systems that are used to convey gas within a defined area or district. Supply of this gas may come from a transmission pipeline, a bulk tank or a process plant.

• **Re-Purposing** means changing a pipeline that ships one form of commodity to another, such as changing a gas pipeline to ship liquid products.

• **A System Interconnect** is a connection between two utility or pipeline or LDC and pipeline systems permitting the transfer of gas in either direction.
1 Summary of Assignment

The Phase III: Natural Gas-Fired Electric Power Generation Infrastructure Analysis (Phase III) examines historical and current natural gas pipeline flow patterns on major interstate pipelines in the MISO Midwest footprint. The study also addresses the infrastructure and conditions that impact gas deliverability to existing and forecasted gas-fired power generation in the MISO Midwest footprint, for a 20-year planning horizon. Additionally, supply and demand forecasts are developed for the MISO South Region, and Southeastern US corridor flow patterns are characterized. EnVision Energy Solutions is the prime contractor and Bentek Energy is the subcontractor for this analysis.

Phase III is comprised of three primary analyses:

1. **MISO South Analysis**: A corridor flow assessment provides a quantitative look at historical pipeline flow patterns in the MISO South region. The assessment includes a comprehensive review of the current pipeline infrastructure serving the region including pipelines that provide export capacity to other markets. It examines interstate and intrastate pipeline infrastructure with inflow corridors and outflow corridors in the MISO South Region, and groups individual pipelines into corridors based on the areas they serve.

2. **MISO Midwest Forward Balancing Analysis**: This Analysis involves a comprehensive review of the current and potential pipeline infrastructure serving the MISO Midwest region, including pipelines that provide export capacity to other markets. It examines the future regional supply/demand balance for the MISO Midwest region using Bentek Energy’s database. This defines all fundamental supply and demand components, including storage and pipeline flows, necessary to access and account for the internal dynamics of 11 regions in North America. It also accounts for how external factors from other regions may impact those internal dynamics. The analysis incorporates observations and views related to risks and potential game-changing developments that could have a significant effect on the regional pipeline system as well as inflow/outflow capacity impacting the MISO Midwest region.
The analysis is partly based on Bentek’s forward-looking assessment of the regional dynamics that will impact pipeline flow patterns and capacity in the Midwest market area. In this assessment, Bentek Energy utilizes its “Balancing Model” to identify the interregional interdependencies that will drive dynamics in the future. The Bentek modeling accounts for the regional balances of eight regions in the United States and three additional regions in Canada and Mexico. A regional balance is defined as all fundamental supply and demand components, including storage and pipeline flows, necessary to access and account for the internal dynamics of each region, as well as how external factors from other regions may impact those internal dynamics. The models’ parameters provide not only a national balance to ensure the supply expectations do not exceed demand expectations but also a regional balance that meets the same criteria. For example, the balancing model will help identify how production growth in the Northeast market will impact supply and demand dynamics in the Midwest market and ultimately, flow dynamics between the regions such that each market and their neighboring markets remain in balance.

3. **MISO Midwest Modified Backcast Analysis**: The modified backcast is the third methodology applied in the Phase III Analysis. It provides an update to the Phase I and Phase II Modified Backcast Analyses, completed by Greg Peters of EnVision Energy Solutions. It examines historical pipelines flows for the period of April 1, 2005, to March 31, 2013, and uses MISO-forecasted demand to determine pipeline capacity sufficiency and deficiencies.

Specifically the three primary analyses incorporate into the following Tasks:

1. **Task 1** – provide baseline information over a 20-year (2013-2032) time horizon
   a. Describe projected and known future expansion of natural gas pipelines and pipeline conversions from natural gas to oil.
   b. Calculate maximum total capacity of existing pipeline infrastructure for residential, commercial, industrial and power plant use.
   c. Identify current usage of natural gas by combined cycle (baseload) and combustion turbines (peaking).
2. Task 2 - Identify available capacity on the existing pipeline infrastructure for residential, commercial and power plant use.

3. Task 3 – Provide an overview of how much additional electric generation capacity can be built using existing infrastructure.

4. Task 4 – Provide an overview of how much additional electric generation capacity can be built assuming future pipeline additions as planned by the major pipeline companies.

5. Task 5 – Assess additional pipeline infrastructure and investment costs needed to provide adequate capacity for an electric power plant expansion plan for the next 20 years. The electric expansion plan in terms of timing (year), amount (MW) and type (CC and/or CT) will be provided by MISO.

6. Task 6 - Analyze gas-fired capacity additions that can be supported based on defined locations provided by MISO. The defined areas are associated with coal capacity reductions or retirements that may be driven by the new EPA regulations. MISO will provide estimates of coal capacity reduction or retirements by geographic area.

7. Task 7 – Identify major gas storage locations and capacity and how those locations tie into the interstate gas pipeline infrastructure in the MISO region.
Figure 1-1: MISO Footprint with Overlay of Major Interstate Pipelines (Source: MISO)

Figure 1-2: MISO Midwest Local Resource Zones with Overlay of Major Interstate Pipelines (Source: MISO)
2 Executive Summary

The North American pipeline grid is rapidly changing. Over the past two years, new shale gas supplies across the US have brought about significant infrastructure expansion that has positively impacted pipeline flow patterns and capacity availability throughout North America. Many of the changes occurring in the natural gas industry are presenting positive opportunities for gas-fired electric generators throughout the MISO footprint; however, challenges still exist. It is becoming increasingly obvious that ensuring adequate natural gas infrastructure in the future may require new regulatory, planning and market approaches. The development of such approaches should be through a collaborative process among MISO, its stakeholders, state and federal regulators, and the gas industry.

The following sections present the background, methodology, and findings of the Phase III: Natural Gas-Fired Electric Power Generation Infrastructure Analysis (Phase III), and outline recommendations for next steps.

2.1 Introduction, background and methodology

The Phase III builds upon MISO’s previous gas infrastructure analyses\(^1\) to better understand gas infrastructure development trends and changing pipeline flow patterns, to identify current and potential areas of pipeline congestion, and to assess the ability of natural gas infrastructure throughout the MISO footprint to serve growing demand. The study encompasses a review of current and projected gas supply, current and forecasted fuel needs for gas-fired electric power generation in the MISO footprint, existing and planned natural gas pipelines and storage facilities, and conditions that impact natural gas infrastructure deliverability to current and potential gas-fired power generation for a 20-year planning horizon.

Complementary methodologies—a modified backcast analysis (MBA) and a forward balancing analysis—are applied to the MISO Midwest footprint to capture events that have occurred since the Phase I and II studies, and to address feedback\(^2\) from the natural gas industry on the

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\(^1\) The [Gas and Electric Infrastructure Interdependency Analysis (Phase I) report](#) was published February 22, 2012, and the [Embedded Natural Gas-Fired Electric Power Infrastructure Analysis (Phase II) report](#), on July 6, 2012.

\(^2\) See Appendices 1, 2 and 3 of the [Phase II report](#).
The static nature of these initial analyses. The MBA is anchored by a Daily Insufficiency Analysis, which takes a pipeline-by-pipeline look at daily capacity trends across the Midwest, using as-is natural gas infrastructure. The forward balancing analysis balances gas in-flows and out-flows at the sub-regional, regional and national levels. The forward balancing model is driven by demand projections; it identifies areas of demand growth and subsequent need for new infrastructure but does not prescribe how infrastructure needs are to be met. Together, these methodologies produce a robust picture of capacity availability on pipelines in the MISO Midwest region. A Base Demand Scenario ($3.84/MMBtu base year gas price) and a High Demand Scenario ($2.50/MMBtu base year gas price) are modeled to capture a range of potential fuel needs for gas-fired electric generators. Anticipated generator retirements in compliance with upcoming EPA emissions regulations are modeled at 12,000 MW of coal capacity in 2015, based on MISO’s Quarterly Survey of asset owners.

The MISO South Region enjoys a much more interconnected pipeline system than the Midwest. Accordingly, a corridor flow assessment was selected as the method of analysis, in which pipelines are grouped together into “corridors” to characterize overall flow patterns. The corridor flow assessment also served to build foundational knowledge on gas supply and demand in this new addition to the MISO footprint.

Efforts were made over the course of the study to solicit input from members of the natural gas industry, and preliminary results were shared with MISO stakeholders and natural gas industry representatives. This collaborative effort produced valuable feedback and enhanced context for interpreting study findings.

2.2 Findings

The findings of the Daily Insufficiency Analysis, the forward balancing analysis and the corridor flow assessment together provide a comprehensive look at historical and future pipeline flow patterns and capacity availability in the MISO Midwest and MISO South footprints. The results are presented in the following sections.
2.2.1 MISO Midwest Supply Trends
Historically, the Midwest has served as a waypoint for gas en route to major load centers in the Northeastern U.S. and Eastern Canada, but new and increasing supplies from shale gas basins are changing pipeline flow patterns across the country.

- Continued Northeast production growth will help feed incremental demand growth in the Midwest region and will also “re-invent” the Midwest’s relationship with the cross-continent Rockies Express pipeline (REX) and its impact on gas supplies from the Rockies and Southeastern U.S.
- As Southeastern U.S. gas demand grows, more local supply will stay in the region; inflows to the Midwest from the Southeastern U.S. will become increasingly seasonal.
- Production growth in the Upper Great Plains (Bakken shale) will displace Canadian imports into the Midwest.
- While current processing and gathering constraints in the Bakken basin are limiting factors for moving the supply to markets, infrastructure expansion is underway, with new processing plants slated for completion at the end of 2015 and in 2016.

In combination, these major supply and market corridor developments translate to greater gas supply diversity for the Midwest.

2.2.2 MISO Midwest Demand Trends
Currently, residential and commercial users account for most of the natural gas demand in MISO Midwest. Over the next two decades, power burn and industrial demand are projected to account for a slowly increasing amount of overall demand in the region.

- Power burn represents 9% of average daily demand for 2009-2013 and is projected to account for 14% of daily demand by the 2028-2032 timeframe.
- The growth in power burn demand is led by coal retirements in the region and subsequent gas-fired electric generation demand growth.
- Overall Midwest gas demand will experience a base-load increase with average daily demand projected to grow to 13.4 Bcf/d in 2032 from 11.1 Bcf/d in 2013.
2.2.3 MISO South Supply Trends
The MISO South region has historically been at the heart of U.S. gas production, with unparalleled access to over 90 interstate and intrastate pipeline systems. However, the traditional movement of gas, from south-central production areas to markets in the upper Midwest and the East and West coasts, is in transition, driven by shale gas production growth.

- Production in the southeastern U.S. since 2005 has migrated from off-shore to on-shore at a steady pace (30% of total natural gas production from on-shore in 2005 vs. 69% in 2012) due to the economics of shale gas.
- Local production outlooks are varied with projected growth at the Eagle Ford production area, flat production at Fayetteville and decreasing production from the Haynesville basin; however, local production would respond quickly to a premium price environment which may evolve late in the decade due to demand growth.
- Outflows to the Ohio Valley from the Southeastern U.S. have significantly decreased over the past five years; flows to the East from the MISO South region have also weakened and become more seasonal.
- Flows from Texas and Northeast Louisiana will continue to decline as production growth in the northeast outpaces demand growth in the Southeast.
- While both gas inflows and outflows of the Southeastern U.S. are in decline, net flows into the Southeast have risen over the past few years.

2.2.4 MISO South Demand Trends
Also adding to the changes in market dynamics are the potential impact of LNG export development, re-shoring of gas-use intensive industries and the building momentum of the development of gas feedstock-based industries in the Gulf Coast region. Demand growth is led primarily by LNG exports, gas-to-liquids production, petrochemical, fertilizer and power generation growth. There are also a large number of other industrial projects planned in the region that will also add base-load demand growth in the region.
2.2.5 Natural Gas Market Dynamics
A number of proposed or pending gas infrastructure projects are being developed to accommodate the growth of Appalachian, Southwest, Rockies, Midcontinent and North Mid-Central shale gas and other shale gas developments throughout the US. These projects include additional compression, pipeline reversals, and new mainlines and laterals to move supply from production areas to demand centers in the Southeast and Midwest, as well as to Eastern Canada.

The shale supply paradigm shift is also altering the traditional forward-haul view of capacity availability, as pipelines change their operations to accommodate gas supplies that are coming from all directions. As a result, forward-haul measurements become less relevant as an indicator of the true “net” capacity availability on interstate pipelines. Creative use of backhauls and other operational gas supply displacement are becoming the “new normal” in pipeline operations, making forward capacity evaluations much more difficult without detailed knowledge of proprietary pipeline operational information.

2.2.6 Capacity Availability Outlook for Major Interstate Pipelines in the MISO Footprint
Overall, pipeline capacity availability into the MISO Midwest footprint is positive and continually improving due to shale gas developments, pipeline expansions, transportation contract expirations and the benefits of increased natural gas pipeline reticulation in the Eastern Interconnect.

The forward balancing analysis also indicates that MISO will benefit from these developments and be well-positioned to meet the challenges of increasing capacity requirements for gas-fired electric power generation.

The forward balancing analysis agrees with the overall Modified Backcast Analysis (MBA) conclusion that pipeline capacity availability into the MISO Midwest footprint is generally sufficient and is increasing; however, it also notes a need for infrastructure expansion to accommodate northeastern gas supplies projected to serve future Midwest demand growth.

The MBA provides a “snapshot” of pipeline capacity availability and compares historical pipeline capacity availability to fuel demands of existing and forecasted CTs and CCs in the MISO footprint. Fifteen of the twenty-one interstate pipeline companies in the Midwest have
pipelines serving either existing or MISO-forecasted CCs or combustion turbines CTs. Most of these pipelines currently have or are trending towards sufficient or increasing capacity availability. If all pipelines in the analysis are considered, including those that do not have MISO-identified units, 17 of the 21 interstate pipelines appear to have sufficient capacity and are trending towards increasing capacity (without firm transportation for the MISO-identified units). Overall, the major interstate pipelines in the MISO Midwest footprint are well-positioned to meet the capacity requirements of future power generation; however, the Modified Backcast did identify several constrained areas. These include Northern Natural Gas (NNG) pipeline north of the Ventura Hub (constrained within the Midwest), Northern Border and Alliance Pipeline (constrained into the Midwest). Each of these constrained areas needs to be understood within the broader context of regional and national pipeline dynamics, and each is addressed in the follow sections of this report.

Finally, the corridor flow assessment confirms that gas infrastructure in the MISO South Region has sufficient capacity to serve current and projected demand from power burn, as well as demand from other sectors going forward.

2.2.7 Cost Considerations
Estimates for new pipeline infrastructure construction costs (laterals to the gas-fired generators forecasted in the Phase III) range from $870M to $1.1B. This range excludes mainline construction costs, such as looping or compression needed to provide service to the lateral, as well as other costs associated with changes in pipeline operational flows.

2.2.8 Conclusions & Recommendations
The recent, fundamental paradigm shifts in a number of pipelines’ operations and flow patterns due to new shale gas production surrounding the MISO region help to explain the significant distance between Phase II and Phase III study results. These system changes are creating a reticulated pipeline network, enhanced by pipeline and Local Distribution Company (LDC) interconnectivity and cooperation, which are further increasing capacity and gas delivery reliability. Adding to this positive outlook is the initiative of natural gas pipeline and electric power asset owners in the region to increase operational coordination. Historically, they have responded to changing market needs by voluntarily enhancing interconnectivity. Furthermore,
pipeline owners have been responsive to the needs of customers and are developing services to support and provide flexibility to asset owners with a portfolio of generators with firm mainline capacity and storage.

National and regional dialogue in various forums has improved communication between natural gas and electric power industries. This was, in part, encouraged by MISO’s leadership and includes the formation of MISO’s Electric and Natural Gas Coordination Task Force (ENGCTF). The ENGCTF and other similar forums have helped to increase discussion around power generation reliability needs; encouraged pipelines to respond to shale gas producers’ needs for new outlets to the markets; motivated pipelines to re-assess their operations, flow patterns, tariff services and rates to meet demand and supply market needs; and are helping to encourage pipeline owners and local distribution companies (LDCs) to find innovative ways to increase interconnectivity and enhance delivery reliability.

While these are all promising developments for capacity deliverability going forward, as is the historical reliability of natural gas deliveries to gas-fired power generation facilities in the MISO footprint, there are still challenges that remain:

- Pipeline expansions require firm, long-term contractual commitments from customers, as pipeline developers do not build on speculation and do not typically build without significant assurances of fixed cost recovery. Service expansion will be dictated by cost and the market environment in which the power generator is operating. There are minimal financial incentives for asset owners to contract for firm gas transportation contracts for their gas-fired electric generation assets.

- As reliable operation of the electric transmission system increasingly depends upon the operation of gas transportation and delivery systems, so does the need to consider gas system contingencies in electric system planning. The differences between planning processes, regulatory constructs and physical system operations of the two industries complicate this question.

- Some areas of natural gas infrastructure in the Midwest will remain constrained without infrastructure expansion. This includes segments of several pipelines routing through the southern Minnesota/northern Iowa region. Integration of gas system contingencies...
into electric system modeling will require a much more granular understanding of gas infrastructure constraints, such as this sub-regional constraint in the MISO Midwest footprint.

- Electric transmission system planning requires knowledge of forward generation resource planning. While MISO is currently working with the appropriate state regulatory bodies to increase transparency around future generation resources, ensuring reliable operation of the transmission system going forward will also require a better understanding of future gas demand from not only the power sector but also from residential, commercial and industrial users in the footprint.

This report offers the following recommendations to begin to address these issues:

- MISO needs to work with gas pipeline companies in constrained areas to better characterize and quantify gas infrastructure limitations, and their impacts on gas-fired electric generators, both existing and future units.

- The increase in gas deliverability to the MISO footprint places power generators in a position to act on the opportunities that have developed to restructure gas supply and transportation portfolios. Now is the time for power generators to work with pipelines as the pipelines undergo evaluation and changes with consideration to new flow configurations that impact their operations.

- The natural gas production community has been a major force in enhancing the reliability of natural gas deliveries to end-users and to the electric power industry by financing pipeline projects (system expansion financed by producers is commonly described as “supply-push”). Solutions to remaining reliability concerns may include increased financial commitments from power generators and other end users to support infrastructure development that complements supply-push projects and improves the overall reliability of deliveries as the natural gas grid reconfigures.

- MISO stakeholders, regulators, and pipeline developers need to continue to find collaborative ways to financially support infrastructure needed to deliver gas from producer-sponsored pipelines to gas-fired generators to meet the implications of the pending EPA regulations.
An Action Plan is needed on a state-by-state basis to address the issues identified in this Report. Actions should be taken to analyze total gas and electric demand, at both the MISO market footprint and at the state level. MISO and MISO stakeholders should support State regulatory bodies in developing a better understanding of all future energy demands, in both the electric and natural gas industries, and take action to develop a “Total Energy Solution”. Natural gas supply and flow developments, combined with compliance deadlines for Environmental Protection (EPA) regulations, demand immediate action as total energy landscape changes accelerate.

Regulators should continue to address contractual and cost recovery assurances as well as incentives for end users to commit to financial support of additional gas pipeline infrastructure in the interest of reliability and to enable increased use of natural gas. This could include reducing cost recovery and prudence ambiguities that exist at the state and federal level.

3 Introduction

The primary objective of this analysis is to examine natural gas pipeline dynamics in the MISO Midwest and MISO South regions and the changes in capacity availability and flows of natural gas on the interstate pipeline systems between 2013 and 2032. This analysis addresses the infrastructure (such as supply, demand, pipeline capacity, changes in pipeline flows and operations, and storage) and the conditions that impact deliverability to current and forecasted gas-fired power generation.

Natural gas pipeline flow corridors have historically moved natural gas into the MISO region from the west and south and out of the MISO region to the east (Figure 3-1). This is prior to recent Appalachian and other shale gas basin developments.
The MISO Midwest and the MISO South regions are corridor crossroads in the U.S. natural gas market. An extensive network of more than 21 pipelines in MISO Midwest and more than 90 interstate and intrastate pipelines in the MISO South region transport gas from nearly all major supply basins in North America to and around these regions. By 2032, it is predicted that interregional flows will increase due to growing unconventional production in the Midcontinent and the Appalachian basin (Figure 3-2). As a result, the pipeline corridors entering the Midcontinent will continue to experience high utilization while the development of the Marcellus and Utica will displace supplies coming into the Northeast and will likely reverse pipeline flows. These volume shifts are supply-push (producer-sponsored projects) increases, but opportunities for a demand pull into the Midwest and Southeast are emerging as end users evaluate the changing gas flow dynamics. The prolific nature of supply growth has resulted in a demand pull across all sectors of the market including industrial re-shoring, power generation, liquefied natural gas (LNG) exports and pipeline exports to Canada and Mexico.
Traditional South to North (Gulf and Southeast gas) and North to South (Canadian gas) gas flow was first altered by the Rockies Express Pipeline (REX) and continues to change on a national scale, driven by shale gas developments. Increased Marcellus shale production, for example, combined with additional pipeline construction in the Northeast, has unprecedented flow implications for the entire North American gas market. As production from the Marcellus shale increases, it impacts supply and demand shifts that affect other production regions. Combined with shale gas developments nationwide, pipeline infrastructure projects have created a major paradigm shift in supply sourcing in North America, which in turn alters traditional gas pipeline flow patterns. **Figure 3-3**: Market responsive infrastructure additions (is an overview of the market response pipeline projects many of which are due to new supply developments.
Figure 3-3: Market responsive infrastructure additions (Source: FERC)
4 Market Analysis

4.1 Major Changes in Pipelines Operations due to Shale Gas Developments

Major changes in pipelines operations have occurred due to shale gas developments, particularly since 2011 (Figure 4-1). As a result, the national pipeline structure has changed radically since the Phase II report with new displacement, backhaul and bi-directionality options due to growing pipeline reticulation.

The Midwest and the MISO region has become a crossroads in the North American natural gas market. An extensive network of 21 interstate pipelines transport natural gas from nearly all major supply basins in North America to and around the MISO region. Shifting supply and demand fundamentals outside and inside the Midwest market will increasingly position the region as a destination rather than a waypoint for gas en route to other markets.

The increase in new shale gas supply in the Midwest has had an impact even on straight-line pipelines like Great Lakes, which historically has transported Canadian supply to markets in the Midwest and back to eastern Canada. The Great Lakes pipeline now finds itself a year-round bi-directional pipeline and the impact of the new supply to a reticulated pipeline has been just as
significant. In theory, a pipeline that is sourced from either end has double the capacity. For example, natural gas nominated from NGPL Harper Station 109 to move north on Northern Border can be used by Northern Border for deliveries to the south. Gas nominated from Canada to move south on Northern Border can be used by Northern Border for deliveries to the north. This displacement scenario assumes that contractually firm gas and transportation is nominated at either end every day.

While it cannot be assured that a shipper’s pricing will always allow this to be the case, pipeline displacement operations and bi-directionality are increasingly common in today’s pipeline market. In MISO South, NGPL has constructed bi-directional facilities in its TexOK segment located in East Texas to physically be capable of moving natural gas north or south along the Gulf Coast corridor. Installation of looped lines and additional compression can transform a one-way pipe into a fully bi-directional pipeline, able to physically move gas in both directions.

A reticulated pipeline, like ANR, can access most of the major supply basins and physically flow gas in different directions. ANR, for example, often has pockets of available capacity to sell its customers but not always in the correct location to reach the desired market at the right price. However, the new shale gas supplies and the resulting changes in historical flows have opened new routes of available capacity at attractive prices. Traditional pipeline constraint points are changing or being eliminated by currently nominated routes. Long-haul transactions that supply gas from the Gulf of Mexico and West Texas are being replaced with shorter-haul transactions into the Midwest. For example, excess supply in the Midwest is reaching customers via ANR’s southern markets. Injection and withdrawal activity related to storage transactions has also changed with new shale plays, seasonal pricing and locational basis differences.

Reticulated pipelines can offer more capacity options due to the many supply–to-market route alternatives. For example, the ANR system consists of two major mainline pipelines routing from the southern US to market-area facilities between northern Michigan and Wisconsin. ANR’s northern Michigan pipeline facilities connect to approximately 250 Bcf of gas storage, which ANR owns and operates. Gas displacement, backhauls, long-hauls, short-hauls and storage activity across these ANR facilities are changing as a result of new gas supplies in the market area and how that supply is routed to get to market.
As predicted in the Phase I and II Studies, these pipeline dynamics are now altering traditional south-to-north and Canada-to-U.S. pipeline flows. The extent has become clearer through the empirical analyses of the Phase III Study. It could be suggested that had the Marcellus not been developed, the Midwest would be competing with the Northeast region for the same supply with the likely need for additional pipeline construction from the supply regions.

The pipeline corridors with the most significant flow changes include: the Rockies Express corridor from Wyoming to the U.S. Northeast and the Mid-continent; the Appalachian Basin to the Northeast and also to the west and South; the East Texas / Northern Louisiana corridor to the Midwest Central and Northeast; Western Canada to the Midwest and Chicago corridor; and along the Gulf Coast into Florida. All these volume shifts are supply-push increases (with the exception of Florida, which is driven by demand).

The supply push is a direct result of the abundance of U.S. and Canadian natural gas in North America. In fact, gas supply has continually challenged the extent of the demand markets’ ability to absorb it since 2008. Prices that were expected to be high and volatile are now expected to be moderate and relatively stable. Shale gas development has turned the economics of drilling for gas on its head. Shale gas production is making a significant contribution to the U.S. supply portfolio and will continue to grow for an extended period of time, potentially doubling over the next 20 years. The increase in North American supply has lowered gas prices and compressed basis spreads. Due to thinner margins, many marketers are exiting the business or scaling back significantly. In certain regions, marketers have turned back interstate pipeline capacity, freeing up capacity and storage for other customers. The interconnectivity that has existed for some time in the pipeline network will be more utilized in the future due to greater amounts of supply located closer to markets.

As described by the Federal Energy Regulatory Commission (FERC) in the 2012 State of the Markets Report⁴, declines in pipeline utilization and changing customer needs pose financial risks to long-haul pipelines. More than 10 Bcf/d of long-term capacity contracts on U.S. natural gas pipelines expired in 2012. The instances of customers re-contracting were generally for shorter durations and smaller volumes.

The erosion of regional price differences over the past few years has reduced the value of many long-haul pipeline routes. Pipelines that move natural gas into the Northeast from the Gulf Coast and the Rocky Mountains eastward experienced the greatest declines in utilization in 2012. The new natural gas flow patterns raised the possibility that some pipelines may be unable to find buyers for long-term capacity. Further, long-haul natural gas pipelines saw some increases in financial risk, as customers with firm contracts considered whether to renew expiring transportation contracts. Customers who did not renew their contracts opted to access shale gas from cheaper local supplies, as opposed to gas supplies previously delivered from the Gulf Coast and South Central U.S.

As a result of declining utilization, some pipeline companies are converting or considering converting natural gas pipelines to transport crude oil or natural gas liquids. Several pipeline systems, including Texas Gas, Tennessee, TransCanada and Trunkline, are considering partial conversions to oil or NGL transport. With this conversion, a portion of the system would remain active for natural gas while another operating line will be converted to crude oil transport in the case of TransCanada and Trunkline, and natural gas liquid (NGL) transport in the case of Texas Gas and Tennessee. The impact on available natural gas pipeline capacity should be minimal. Any reduced capacity caused will be filled due to competition, further reticulation and follow FERC regulations. For FERC to allow this, the sponsors of potential conversions must prove that such actions will not be harmful to the public good and that contractual remedies be settled.

The interaction changing pipeline flow patterns between the Southeast and Midcontinent, also allows a pipeline such a Trunkline to convert oil south of its REX interconnection because shippers can take new supply from REX, and potentially others, to serve markets in Michigan.

Other examples of these major shifts include the following, as cited by the FERC in the 2012 State of the Markets Report:

- The ANR pipeline experienced a shift in natural gas supply from the offshore Gulf of Mexico to the Marcellus Shale in the Northeast. Some segments on ANR’s southeast mainline began to transport natural gas from north to south, reversing the traditional flow direction between Louisiana and Michigan. Utilization of the southeast portion of ANR’s mainline was down 20 percent in 2012 from 2011, and down almost 50 percent
from 2009. To compensate for the decline, ANR’s use of its southwest mainline, which transports natural gas from the Anadarko Basin, increased to 84 percent in 2012 from 54 percent in 2009.

- Trunkline, which traditionally sourced its natural gas supplies from East Texas, shifted its source to northern Louisiana in 2012. Natural gas receipts from northern Louisiana have increased 15 percent since 2010. Overall utilization on Trunkline in the South Texas zone declined to zero in 2012, while flows in the North Texas portion of the pipeline are 5 percent lower than in 2011.

- TGP experienced a decline in natural gas receipts from the Gulf Coast and a significant increase in natural gas receipts from the Marcellus Shale. Flows on TGP south of the Kentucky/Ohio border declined 49 percent in 2012 compared to 2011, while flows from Marcellus-producing areas in Pennsylvania grew 25 percent.

- Texas Eastern Transmission Co. (TETCO) experienced a decline of 60 percent from South Texas and west Louisiana supply zones on its southern leg and 52 percent on the northern leg.

- Long-haul natural gas pipelines saw some increases in financial risk as customers with firm contracts considered the renewal of expiring transportation contracts. Customers who did not renew their contracts faced opportunities for accessing shale gas from cheaper local supplies, as opposed to gas supplies previously delivered from the Gulf Coast and the South Central U.S.

Pipelines are re-examining flow patterns with some reversing flows or moving towards becoming bidirectional. Historically, almost all of the pipelines serving the MISO region flow southeast to northeast and several of those pipelines are also converting to bi-directional capability and expanding displacement services that will benefit power generators. Activity through REX is low; this $2 billion pipeline was built based on old assumptions that changed radically before it even went into service. As a result, REX exists as a 1.8 Bcf/d header (or bottle) that traverses the heart of the Midwest region and is positioned to go beyond current displacement services to bi-directional optionality. The degree of flexibility and optionality that
REX may eventually add to the region has not yet been fully assessed but it will likely enhance REX’s position as a supply header.

Overall, many of the pipelines are improving flow and capacity options for power generators by improving displacement abilities on other interconnecting pipeline systems, resulting in high operational liquidity in the MISO region. This impacts and potentially expands optionality on pipelines.

Production increases in the Bakken, Marcellus and other shale plays has incentivized producers to sponsor projects out of the new supply regions and improve connectivity with the Midwest region (Figure 4-2: Impact of Marcellus production growth on regional flows for 2012-2025 (Source: ICF) ). Producer-push projects are an important part of enhancing the natural gas grid, which in turn enhances electric power reliability throughout North America. The rapidly emerging Appalachian production area, including the Utica Shale play, has created new opportunities to increase supply diversity for growing domestic natural gas markets. The Utica Shale holds impressive quantities of natural gas, oil and NGLs.

Figure 4-2: Impact of Marcellus production growth on regional flows for 2012-2025 (Source: ICF5)

5 Presented by Rich Hoffman, Executive Director, The INGAA Foundation Inc. (“The Outlook for Pipeline Construction, presented at the National Association of Pipe Coating Applications”), April 25, 2013.
To deliver the increasing shale gas supplies, a number of gas pipeline projects are in development, planned or are underway (Figure 4-3). New pipeline infrastructure projects are concentrated in the expanding shale-rich oil, NGLs and natural gas production areas throughout the U.S. and Canada. This layer of infrastructure provides access primarily to local markets and interconnections through the interstate natural gas pipeline network.

![Natural gas pipeline projects](image)

**Figure 4-3: Natural gas pipeline projects by year (Source: EIA)**

In June, 2013, Spectra Energy asked FERC to begin pre-filing review of two unrelated projects that aim to deliver gas supply from the Marcellus and Utica basins to markets in the northeast US, midcontinent and Gulf Coast. Spectra’s projects involve expansion of capacity on the Algonquin Gas Transmission and Texas Eastern Transmission (TETCO) interstate systems. TETCO, which extends from Texas to New York, now absorbs so much gas from Marcellus producers in Appalachia that the direction of flow on one of its mainlines in Ohio has reversed to a predominantly westbound pattern. The following project descriptions are from the pipelines’ publically available information from press releases and regulatory filings.

- According to Argus\(^6\), Spectra asked FERC to start the pre-filing review process for its Algonquin Incremental Market expansion project, which will enable shippers to move 433,000 Mcf/d from the Ramapo, New York, interconnect with Millennium pipeline for

delivery in Massachusetts. Spectra said it may adjust the scope of that project if it entices power plants in New England to sign for new capacity made available by the expansion.

- Besides the Algonquin expansion into New England, Spectra’s TETCO business unit has several proposed projects to move supply out of the Northeast to the West and South. TETCO’s Nexus project proposes to move up to 1.0 Bcf/d from Ohio to an interconnection with Vector Pipeline in Michigan and then into Dawn Hub in Canada. This would also potentially leave more consumption-ready supply in the Midcontinent. The Nexus Project is also expected to come online in November 2016, according to Spectra’s website.

- TETCO also proposed two other north-to-south projects: the Ohio Pipeline Energy Network (OPEN) project and the Renaissance project, which is also known as the Gulf Coast Access project. Both leverage TETCO’s existing infrastructure to connect growing supply in the Northeast to Demand Markets in the South. The OPEN project is designed to provide pipeline transportation capacity to deliver new, incremental production from the emerging Utica Shale and Marcellus Shale plays to growing and diverse markets in the Midwest, Southeast and Gulf Coast. The OPEN would link Gulf Coast demand markets with Northeast producers by providing up to 550 MMcf/d of firm capacity and has a targeted project completion date of November 2015.

- The TETCO Renaissance provides transport on a similar route as the OPEN project but is targeted more toward demand markets originating in Georgia, northeast Alabama and Tennessee. This would benefit MISO South stakeholders. The project would provide end users the opportunity to source up to 1.0 Bcf/d of supply near Kosciusko, Miss., from the Marcellus, the Gulf Coast or Midcontinent. The Renaissance project is expected to begin service in the second Quarter of 2017.

- Natural gas volumes on Tennessee Gas Pipeline (TGP) are moving south of Ohio with more regularity due to more Utica shale the long-haul interstate system and an increase in Marcellus shale production. The emergence of Marcellus and Utica shale gas production in Appalachia has created an additional source of supply for TGP’s upper-
midcontinent segment. TGP also has exported gas into Ontario, Canada, since November 2012. Spot gas prices in Appalachia are significantly lower than at TGP's Gulf Coast segment, according to Argus data. While TGP already accommodates backhaul service, the company recently announced an open season for the Southwest Louisiana Supply Project to move up to 1.0 Bcf/d from the receipt meters in the Northeast to interconnections in Louisiana.

- In April 2013, Columbia Gas Transmission announced plans to lease about 520 MMcf/d of natural gas transportation capacity from sister pipeline Columbia Gulf Transmission in preparation for an eventual reversal to a north-to-south pattern. Columbia Gulf has offered some more immediate backhaul services totaling around 150 MDth/d through 2014 to accommodate near-term growth in the Northeast. It has placed portions of its West Side Expansion project into service, which will provide 440 MDth/d of supply takeaway from West Virginia on the Columbia Gas System to an interconnect with Columbia Gulf. From there Columbia Gulf has enabled its mainline system for up to 550 MDth/d of bi-directional flow south to Rayne, La.

- In June 2013, according to Argus, Williams Partners signed long-term agreements with seven shippers for its Transcontinental Gas Pipe Line (Transco) Leidy Southeast expansion project, designed to move Marcellus shale gas volumes from Pennsylvania to the southeast along Transco's mainline. Additional interest from shippers in the summer of 2013 allowed Transco to increase the size of the project to 507 MMcf/d. The project allows shippers to receive gas volumes at receipts points along Transco's Leidy Line, which extends from the Leidy storage hub in central Pennsylvania to Transco's mainline in New Jersey. Shippers can move those volumes to Transco’s Zone 4 pooling points in Alabama, against the traditional flow of gas on Transco’s mainline.

- In September 2013, Dominion Resources announced a planned expansion of the Dominion Transmission interstate natural gas transportation system that will enable delivery of 300 MDth/d from Utica and Marcellus shale gas producers in Appalachia to markets in the midcontinent. The $90M project, dubbed Western Access, will connect a

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7 “TGP swings to southbound gas flow in Ohio”, 06 Sep 2013, Argus Media.
third-party gas processing complex in eastern Ohio to other interstate natural gas pipelines in that state for gas transportation further west. The project could be on line in late 2014.

- In other developments, ANR has proposed the Lebanon Lateral Project to complement projects by Dominion and Texas Eastern, moving up to 630 MMcf/d from interconnects in Lebanon, Ohio, to markets currently served by ANR. The Northeast is forecasted to send up to 2.0 Bcf/d to the Midwest by the turn of the decade. This forecast is based on these developments, the balance of the Northeast, demand growth in the Midwest and decreased incentive to produce natural gas in the Rockies.

- WBI Energy has proposed the Dakota Pipeline that will add approximately 400 miles of pipeline with approximately 400 MMcf per day of capacity, expandable to more than 500 MMcf per day. If this project is completed it will add a tremendous amount of additional capacity and flow diversity to the MISO region. It is proposed to interconnect with Northern Border, Alliance Pipeline and end with an interconnection to Viking Gas Transmission. This proposed pipeline would be a boon to power generators in the MISO region, not only due to the capacity and reticulated flow benefits, but it would also increase supply opportunities with access to greater storage and Bakken, Rockies and Canadian production.

- Other important expansions to balance supply and demand include storage expansions. For example, NGPL has over 281 Bcf of working gas capacity in the Chicago Hub and continues to evaluate storage expansions given firm shipper commitments for its Gulf Coast Storage Optimization Project CP11-547 and working gas increases at Cooks Mills, central Illinois in CP13-97 and Herscher Mt. Simon, Kankakee, IL in CP13-476. The storage deliverability from these expansions are in addition to the existing 1.7 Bcf/day with dedicated pipeline capacity beyond the long haul Amarillo mainline of 1.677 Bcf/day and Gulf Coast mainline of 1.574 Bcf/d.

The continual expansion of the pipeline grid to deliver new shale supplies impacts the value of capacity as reflected by the locational basis differentials. The locational basis differential measures the difference in the price of natural gas between two geographic locations.
Locational basis differentials are impacted by available capacity, demand and storage serving a market area. Falling locational basis differentials, particularly in the electric Eastern Interconnect, indicate increased availability of transportation capacity. The exception is certain peaking situations, such as New England markets during extreme cold temperature conditions. Locational basis differentials continue to be in flux as pipelines continue to reticulate and impact Market and Demand Centers. This affects the MISO region positively from a cost perspective as it enhances lower-cost transportation capacity options, particularly as the Chicago region continues to develop into a vibrant sourcing and market center for the MISO region.

![Map of North America with gas prices](image)

**Figure 4-4: Average spot gas prices in 2012 in $/MMBtu (Source: FERC Division of Energy Market Oversight*)**

In 2013, Appalachian locational basis differentials turned consistently negative to Henry Hub prices. As shown in Figure 4-4, there has been an average decrease of about 30% in hub prices relative to the Henry Hub from 2011 to 2012. Furthermore, there has not been a single major basis congestion price response in Chicago over the last 10 years, which is an indicator of the Midwest pipeline network’s flexibility and robustness. Chicago is already an active and vibrant trading and supply sourcing hub with excess supply. Due to increasing interconnectivity and reticulation of LDCs and pipelines, as well as Appalachian supply headed to the Midwest,

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additional supply and pricing options will continue to benefit gas consumers in the Chicago market. **Figure 4-5** provides a national overview of the outlook for locational basis differentials.

**Figure 4-5: Basis outlook (Source: Bentek Energy, presented at 2013 WBI Energy customer meeting)**

Overall, the Midwest market will have greater flexibility due to the changing dynamics of US gas production and developing pipeline reconfiguration. The Midwest used to have three routes in (Midcontinent, Rockies, and Canada), no local supply and two routes out (Northeast and East Canada). Now it will have four routes in (including the Northeast), one route out (East Canada), a growing local supply (Bakken) and backhaul and displacement from the Marcellus shale/Appalachian Basin.

Historically, almost all of the pipelines serving the MISO region flowed southeast to northeast. Many of those pipelines are converting to bi-directional flow and expanding displacement services that will benefit power generators. These developments will enhance the benefits of regional storage assets and will complement many of the new service offerings by the pipelines and marketers. The Midwest also has numerous aquifers, reservoirs and a few salt caverns to balance the changing flow dynamics, with more than 1,000 Bcf of working storage in the MISO footprint.

The reliability of natural gas deliveries to natural gas-fired power generation facilities in the MISO market is positive for capacity availability. However, certain parts of pipelines have
capacity constraints and will require infrastructure upgrades to accommodate increased demands from power generation and industrial end-users.

The natural gas production community has been the major force in enhancing the reliability of natural gas deliveries to end-users as well as to the electric power industry through the financing of supply-push pipeline growth. Pipelines and producers alike are targeting potential sources of demand. To further enhance pipeline infrastructure development, regulators could re-visit matters of contractual cost recovery assurances, incentives and rate designs to encourage demand-pull responsibility. These factors should be considered to support domestic demand-pull market needs.

4.2 Pipeline Reticulation and Flow Change Examples

Current market events are beginning to reflect the recent shifts in the gas distribution market and account for different ways in which pipelines will be able to provide firm transportation, storage and line pack services. These market events and pipeline reconfigurations will reduce landowner and environmental impacts of new gas lateral construction as well as reduce the cost and lead time for mainline facility construction compared to requirements of only two years ago.

Future available capacity on each pipeline is determined on a case-by-case basis. The future capacity profile will be altered by changing shipper requirements and the flexibility to alternatively source economically-delivered gas supplies. This is seen in the increased reticulation and interconnectivity experienced in the market during the past two years. For example, the Chicago-area peak day gas market is approximately 10 Bcf/d. This market has eight LDCs, many of which have storage fields and pipeline-supplied services that add value and deliverability through interconnectivity between themselves and the supply. Supply is provided by eight interstate pipeline companies that make up more than 20 Bcf/day of throughput capacity to this market area.

MISO teams have met with nearly all the pipeline companies identified in the Phase I and II Analyses. Through these meetings, MISO learned that the Chicago-area market has a potential 10 Bcf/d of surplus deliverability in light of the increased interconnectivity. Additionally, market locational basis differentials and pipeline rate discounting reflect pricing signals that make
Chicago a supply hub. Consequently, this area could already have the key features MISO needs for future gas-fired deliverability, including a tremendous amount of existing infrastructure to move gas in multiple directions. For example, NGPL has the capability, through its extensive market area pipeline network, to physically move supply from the Amarillo system to its Gulf Coast System. Likewise, supply from the Gulf Coast System can be physically backhauled onto the Amarillo system providing reliable and diverse supply sourcing. ANR has similar capabilities. NGPL, ANR and others may also provide backhauls via displacement, using no capacity. Other systems in the MISO region have and are developing similar flexibilities, such as REX, NNG, Great Lakes, WBI Energy, Viking and others.

Two hypothetical examples below show how power generators can be served from this capacity flexibility. The case studies use two hypothetically situated facilities: one in Des Moines, Iowa, which is about 325 miles southwest from Chicago and one in Pinckneyville, Ill., which is about 65 miles southeast of St. Louis.

These two cases provide a real-world look at how potential power generation can be provided affordable gas supplies with minimal incremental infrastructure by both backhaul and forward haul combined with the cooperative pipeline interconnectivity.

**Case 1: Service Options to Des Moines, Iowa**

The pipeline transportation service options to a CC and a CT power generation facility near Des Moines, Iowa, would require about 130,600 Dth/d and could receive reliable gas supply deliveries through a combination of forward-haul and backhaul options from NNG, NGPL and NB (Northern Border).

- A forward-haul supply with gas sourced from NNG in Mills Co., Iowa, at NGPL’s compressor station 107 in eastern Iowa reduces available forward-haul capacity by only a fraction of the posted capacity on NGPL’s website due to the distances involved (for example, on a particular day, only 80 percent is used to serve the CT and CC requirements).

- A backhaul supply sourcing from Northern Border (Harper, Iowa) at Compressor Station 109 or the Chicago/Joliet Hub CS 113 would capture receipts from interstate pipelines such as Alliance, ANR and Midwestern, and would not utilize any forward haul capacity.
• Forward and backhaul paths to capture NGPL’s eastern Iowa storage provide added reliability, balancing and intra-day flexibility.

Case 2: Service Options to Pinckneyville, Ill.

The pipeline transportation service options to a power generation facility near Pinckneyville, Ill., would require about 46,000 Dth/d. In this Case, a combination of forward-haul and backhaul could reliability deliver natural gas while enhancing supply and storage options, including:

• A NGPL backhaul that sources supply from the Chicago/Joliet Hub or REX would result in no loss of forward-haul capacity for others on the NGPL system;

• A forward haul with supply sourcing from prolific shale plays such as the Eagle Ford (Texas), Woodford (Okla.), Barnett (Texas), Haynesville (E. Texas and Louisiana) and Fayetteville (Ark.) on any number of pipelines, including NGPL to minimize transportation costs;

• Forward and backhaul paths in this region capture NGPL’s Gulf Coast line Gas Storage Fields for added reliability, balancing and intra-day flexibility.
5 Methodology

Phase III of the study includes inputs from the expansion into MISO South, which occurred in 2013 and after the completion of the Phase II analysis. Because of the MISO South addition the Phase III analysis was a more robust and rigorous analysis of the current and projected capabilities of the interstate natural gas pipeline systems into these market areas, consistent with the MISO’s mission of safe, reliable and best-value management of the power grid. The Phase III builds upon the Phase I and II Modified Backcast Analyses with an updated backcast and a forecast of the Midcontinent Region, along with a MISO South gas pipeline corridor assessment.

As part of the Phase III analysis, MISO staff performed an updated resource forecast to capture current natural gas market prices using NG Planning LLC’s Electric Generation Expansion Analysis System (EGEAS). Capacity factors for the embedded and forecasted gas CTs and CCs were calculated based on simulation outputs for the 20-year (2013-2032) study period.

The Phase III employs two forms of economic analysis—a modified backcast and a forecast—and applies three methodologies, including:

- An import/export corridor assessment of the MISO South region (MISO South Analysis)
- A forward balancing analysis of the MISO Midwest region (MISO Midwest Analysis)
- An update to the Phase II Analysis (MISO Midwest Modified Backcast Analysis).

The methodology of Phase III attempts to account for forward, backward and current market and regulatory issues.

5.1 Backcasting and Forecasting Perspectives

Both backcasting and forecasting for the Phase III study started with a common base: the outputs of MISO’s regional resource forecast using NG Planning’s Electric Generation Expansion Analysis System (EGEAS) software.

Forecasting and backcasting are accepted economic methodologies that generally start from the same base assumptions and historical trends. Backcasting identifies an end-goal through a collaborative process and reverse-forecasts to the present period; forecasting is based on the
analysis of historical trends and current conditions. The goal of the modified backcast analysis (MBA) is to determine capacity availability based on historical flow trend analysis, market-event trends and regulatory trends in the aggregate to make a reasoned conclusion on capacity availability through a collaborative, iterative process with all parties. An important benefit of backcasting is the wide reach of the collaborative process to accomplish the Phase III goal of electric reliability based on natural gas delivery infrastructures.

### 5.2 MISO Models and Methodologies

The EGEAS optimization software, an NG Planning product, was used to forecast gas Dth/day requirements for the years 2013 through 2032. The EGEAS model uses MISO generation and production cost data to dispatch the MISO system to meet current and projected energy demand. In addition to energy requirements, EGEAS forecasts capacity requirements needed to maintain a Planning Reserve Margin\(^{10}\) by timing and type. The forecasted capacity requirement is the basis for the MBA.

For the Phase I and II gas infrastructure analyses, the modeling foundation was MISO’s EGEAS model built for the EPA Impact Analysis\(^ {11}\) completed in October 2011, which included 12.6 GW of coal retirements in 2015 and retrofits projected for compliance with four EPA regulations under consideration at that time, including the Mercury and Air Toxics Standard (MATS), the Cross-State Air Pollution Rule (CSAPR), the Coal Combustion Residuals (CCR) and Cooling Water Intake Structures (Section 316(b) of the Clean Water Act). Resource forecasts for the Phase III analysis were developed using the MISO Transmission Expansion Plan (MTEP) EGEAS model for 2012. This model is similar to that used for the EPA Impact Analysis, but with updates based on events that have taken place in the time since, such as generator retirements or new plants going into service. Additionally, the 2013 (base year) gas price modeled for the Phase III analysis was updated for the Base Demand scenario to $3.84/MMBtu, Henry Hub price. The Phase III High Demand case models the same gas price as the Phase II analysis, of $2.50/MMBtu, at the Henry Hub (Table 5-1).

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10 MISO’s Planning Reserve Margin (PRM) is rooted in the 1-in-10 electric industry reliability standard. This is generally interpreted as an acceptable level of service interruption of 1 event every 10 years. The PRM aims to ensure that load can reliably be served on a forward-looking basis, and it functions as a key modeling input for MISO’s resource forecasting process.

<table>
<thead>
<tr>
<th>Study</th>
<th>Base Year Gas Price ($/MMBtu)</th>
<th>Base Demand Scenario</th>
<th>High Demand Scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td>Phase I</td>
<td>4.50</td>
<td>2.50</td>
<td></td>
</tr>
<tr>
<td>Phase II</td>
<td>4.50</td>
<td>2.50</td>
<td></td>
</tr>
<tr>
<td>Phase III</td>
<td>3.84</td>
<td>2.50</td>
<td></td>
</tr>
</tbody>
</table>

Table 5-1: Base and High Demand Scenarios Base Year Gas Price Assumptions for Phase I, II and III

Figure 5-1: Phase III nominal gas price escalation with MISO MTEP13 gas price assumptions for comparison (Source: MISO)

Annual energy requirements in MWh for all MISO gas units were calculated in the EGEAS model runs. Each individual unit is matched to its gas pipeline and then all MISO units on the pipeline are aggregated to get an average annual energy requirement for each pipeline. The annual energy requirements in MWh are finally converted into dekatherms per day for use in the gas infrastructure analysis (Figure 5-2).
Two natural gas demand scenarios for existing or “embedded” units and incremental units were analyzed in the Phase III study. A comparison of capacity factors for embedded and forecasted CCs and CTs for the Phase I, II and III studies is presented in Table 5-2. The capacity factors for the Phase III Analysis were used to determine fuel requirements for the MBA portion of the analysis.

The High Demand Case provides significant insight into how units are dispatched and what the generation fleet in the MISO footprint would look like in a future with sustained low gas prices.
Under the High Demand Scenario, gas units displace coal units for base load energy needs, as well as capacity needs.

While the price chosen for the High Demand Scenario is characteristic of an exceptional market period, it is important to understand the context of this absolute value within the model. Fuel price largely drives unit dispatch in EGEAS, and the High Demand price represents a delta between the marginal cost of generation burning gas versus other fuels.

Basis differentials are modeled in both the High Demand Case and Base Demand Case, though differentials in flux due to future reticulation are not captured. The basis differentials are based on historical data and are held constant throughout the study period in EGEAS. The differentials are calculated and researched by Ventyx, the vendor of the majority of the data used in EGEAS.

The locations of the incremental units for both Base Demand and the High Demand Scenario used in the Backcast analyses are presented on the MISO Zonal Maps in Figure 5-3 and Figure 5-4.

Figure 5-3: MISO Local Resource Zone map with forecasted Base Demand CCs and CTs (Source: MISO)
Figure 5-4: MISO Local Resource Zone map with forecasted High Demand CCs and CTs (Source: MISO)

5.3 Bentek Balancing Forecast and Assessment Methodologies

The MISO Midwest forward-looking analysis uses Bentek Energy’s regional Balancing Model to report the daily dynamics of eight US regions, two Canadian regions and Mexico. This historical balance, back to 2005, is then utilized as a base to forecast how regional dynamics will transpire. These reports, and the data that supports them, are not only used by FERC and EIA but are also analyzed by numerous pipelines, utilities, producers, marketers, end users and other participants in the gas industry.

Bentek’s approach to the forecasting process starts with numerous foundational factors that are built upward into other components through an iterative process using regression analyses (Figure 5-5).

CellCAST is Bentek’s proprietary forecast modeling system. By breaking down the geographic areas into regions, the forecast model estimates the initial condition for each fundamental component. These initial conditions serve as input to the general equilibrium market balancing model. Through a series of iterative adjustments of supply and demand, the results are a balanced market to zero with consideration of storage requirements and pipeline transportation dynamics.
A regional balance is defined as all fundamental supply and demand components, including storage and pipeline flows, necessary to access and account for the internal dynamics of each region as well as how external factors from other regions may impact those internal dynamics. For example, if the Marcellus adds 8 Bcf/d of supply to the Northeast Region in the next five years and demand in the region only grows by 3 Bcf/d, 5 Bcf/d of supply will either need to be displaced out of pipelines currently flowing into the region and/or physically transported from the region.

The Midwest and South forecasts make use of cell (region) model methodology (Figure 5-6). This is used in each stage of the balanced forecast methodology for production (supply), demand, corridor flow analysis and storage analysis, starting with a small region and building up to a national balancing level. Flows are tracked into and out of a defined region, along with demand and production within the region. The difference is called net storage. Not only do the individual cells in question have to balance, but the cells surrounding the region do as well, because the whole country must balance. The cell definitions line up well with the MISO region, with the exception of Nebraska, which is included in Bentek’s Midwest Analyses.
Bentek collects and monitors natural-gas pipeline nominations as posted on individual pipeline electronic bulletin boards (EBBs). Bentek has assigned geographic and usage descriptions, such as state, province, county, production region, and customer type and connected party to more than 30,000 pipeline points. The descriptions assigned to these pipeline data points provide the ability to monitor and forecast US production, US imports, US LNG sendout, demand from multiple sectors and storage injection and withdrawal activity. It also allows for the assessment of capacity and utilization of pipelines at various locations across the entire US grid. This information, along with Bentek’s proprietary supply and demand forecast models, enables the assessment of each region, and account for how all regions in the US interplay with each other. Figure 5-7 shows the geographical “Cell Regions” used in the Analysis.
Bentek’s data sources and Balancing Modeling systems used actual and projected data from Bentek for projected interstate pipeline flow modifications. These change dynamics are due to new and projected shale gas developments, changes in demand and conversions of gas pipeline to “oil and NGL”. This Analysis also included new gas pipeline projects, as well as other potential from bi-directional gas.

The output of the Balancing Model is a forward-looking assessment of the fundamentals within the Midwest, which is designed to assist MISO in evaluating and planning. The outputs from the Balancing Model are given in Table 5-3.

<table>
<thead>
<tr>
<th>Balancing Model Output</th>
<th>Components</th>
</tr>
</thead>
<tbody>
<tr>
<td>Supply</td>
<td>Onshore production, offshore production, LNG</td>
</tr>
<tr>
<td>Demand</td>
<td>Industrial, residential/commercial, power, LNG</td>
</tr>
<tr>
<td>Corridor Flows</td>
<td>Expected inflows, expected outflows</td>
</tr>
<tr>
<td>Storage</td>
<td>Inventories, injections, withdrawals</td>
</tr>
</tbody>
</table>

Table 5-3: Bentek Balancing Model Outputs
Bentek then incorporated MISO inputs to determine impacts on its regional forecasts. This outlook covers a 10-year seasonal forecast and a 20-year annual average forecast through 2032. The three scenarios modeled include:

**Scenario 1: Steady State – Base Demand Growth Case**
- Provide a future assessment of the adequacy of current infrastructure into the MISO footprint given Bentek’s base case demand and supply outlook within the region;
- Used a control scenario.

Assumptions:
- Does not account for supply and demand changes outside the region;
- Does not consider the location of supply sources available to meet the demand growth;
- Does not consider the location of available pipelines, which have capacity to bring gas into the region;
- Utilizes Bentek’s base case price forecast.

**Scenario 2: Steady State – High Demand Growth Case**
- Provide a future assessment of the adequacy of current infrastructure into the MISO footprint given a high case (low gas price) power demand within the region.
- This scenario will bookend any potential lost opportunity in a high power demand growth case. This scenario isolates the impact a stronger power market could have on the region.

Assumptions:
- Assumes a High Demand Case; Inflation of 1.7 percent;
- Assumes an adequate supply at this price to meet all potential demand growth;
- Assumes Bentek base case supply, industrial demand, and residential/commercial forecast within the MISO region;
- Does not consider the location of supply sources available to meet the demand growth;
Does not consider the location of available pipelines which have capacity to bring gas into the region.

**Scenario 3: Future State – Shifting Regional Dynamics**

- Provides Bentek’s future assessment of how the base case supply and demand estimates in the MISO region figure into an overall shifting market dynamic.

**Assumptions:**

- Accounts for how Bentek foresees changing market dynamics outside the MISO footprint impacting current, planned and necessary pipeline infrastructure that supplies the MISO footprint;
- Assumes Bentek base forecast of supply and demand in other regional markets including Canada and Mexico;
- Does not assume infrastructure constraints (pipeline or processing) beyond three years;
- Assumes infrastructure will constrain supply growth prior to three years;
- Utilizes Bentek’s base case price forecast.

These assumptions are controls, with the Midwest as the driver and the supply markets as the responder. If the Midwest has greater demand, the producing basins will respond to meet that need within the confines of the available capacity. If there is available capacity into the Midwest, the basins supplying those pipelines will respond to fill it given the higher Midwest demand.

In Scenario 3 there was an adjustment to the basin growth case and discussion of whether the pipeline capacity available is sufficient or will even be used given our expectation of how the dynamics will change.

Bentek’s nominal gas price curve through 2032 ranges from $3.84/Dth to $9.66/Dth at the Henry Hub is shown in Table 5-4. In real terms, this translates into a curve that approximates $5.00/Dth as inflation dictates the growth curve.
<table>
<thead>
<tr>
<th>Study Year</th>
<th>Nominal Henry Hub Gas Price ($/MMBtu)</th>
<th>Real Henry Hub Gas Price ($/MMBtu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>3.84</td>
<td>3.84</td>
</tr>
<tr>
<td>2014</td>
<td>4.38</td>
<td>4.23</td>
</tr>
<tr>
<td>2015</td>
<td>4.80</td>
<td>4.48</td>
</tr>
<tr>
<td>2016</td>
<td>5.12</td>
<td>4.62</td>
</tr>
<tr>
<td>2017</td>
<td>5.57</td>
<td>4.85</td>
</tr>
<tr>
<td>2018</td>
<td>5.86</td>
<td>4.93</td>
</tr>
<tr>
<td>2019</td>
<td>6.33</td>
<td>5.15</td>
</tr>
<tr>
<td>2020</td>
<td>6.63</td>
<td>5.21</td>
</tr>
<tr>
<td>2021</td>
<td>6.87</td>
<td>5.22</td>
</tr>
<tr>
<td>2022</td>
<td>6.87</td>
<td>5.04</td>
</tr>
<tr>
<td>2023</td>
<td>7.07</td>
<td>5.01</td>
</tr>
<tr>
<td>2024</td>
<td>7.29</td>
<td>4.99</td>
</tr>
<tr>
<td>2025</td>
<td>7.52</td>
<td>4.98</td>
</tr>
<tr>
<td>2026</td>
<td>7.82</td>
<td>5.00</td>
</tr>
<tr>
<td>2027</td>
<td>8.11</td>
<td>5.01</td>
</tr>
<tr>
<td>2028</td>
<td>8.40</td>
<td>5.02</td>
</tr>
<tr>
<td>2029</td>
<td>8.69</td>
<td>5.01</td>
</tr>
<tr>
<td>2030</td>
<td>9.01</td>
<td>5.02</td>
</tr>
<tr>
<td>2031</td>
<td>9.31</td>
<td>5.01</td>
</tr>
<tr>
<td>2032</td>
<td>9.66</td>
<td>5.03</td>
</tr>
</tbody>
</table>

Table 5-4: Real and nominal Henry Hub gas price assumptions

### 5.3.1 Production Forecast Methodology

The starting point for gas production projections is based on a detailed analysis of individual basins and regional gas plays (prolific production area) and current drilling activities. Sixty-six unique reporting areas with more than 250 individual “type” curves are developed for each class of well. Well-class criteria includes oil, gas and coal bed methane production and by vertical or horizontal orientation. The areas are analyzed starting with the well-level production criteria using well class and orientation grouped into well groups. Each well group is fitted with a “type” curve in order to predict future production trends in the area of new and existing production wells (Figure 5-8). Each well is then assigned to a specific production profile going forward and all wells are then aggregated to the area level. Each area is then aggregated to a basin in order to assess and perform a projection or forecast of regional and national gas
production. The overall production forecast methodology is summarized in Figure 5-9. The plays with the highest financial returns attract the most drilling activity as shown in Figure 5-10.

Figure 5-8: Basin Forecasting: Future well additions (Source: Bentek Energy)

Figure 5-9: Production forecast methodology (Source: Bentek Energy)
5.3.2 Demand Forecast Methodology
The Demand Forecast Methodology, like the Production Forecast Methodology, starts with basic demand variables and builds on these variables using the cell methodology that develops into a regional and then national balancing model for forecast purposes.

The starting point for the Demand Forecast is an analysis of historical data as the best indicator of future performance. In this regard, there is a similarity in starting points for forecasting and backcasting used in this analysis and is described in more detail in the following sections.

Three main drivers of natural gas demand are weather and temperature; fuel market share or fuel switching driven by short-term market dynamics; and long-term fuel price competition, particularly between natural gas for power generation and to a lesser extent other industrial fuel demands including fuel oils.

Analyzing the demand components by cell region, a 10-year population of weighted normal temperatures is structured for each cell region. Future demand growth and decline is predicted through detailed research and analysis of capacity additions and retirements or demand destruction by cell region. Also, substitute or alternate fuel price spreads are analyzed and
incorporated into the forecast as they influence fuel switching potential into the future. Regression analysis of the various inputs is used to determine the initial Demand Forecast as shown below in Figure 5-11.

![Diagram showing the Demand Forecasts – Starting Point process](image)

**Figure 5-11: Demand forecasts – starting point (Source: Bentek Energy)**

As shown in Figure 5-12, regulatory action, existing infrastructure, announced LNG projects and global LNG demand are all considerations in forecasting the impact of LNG on US natural gas demand.
5.4 *EnVision Modified Backcast Analysis (MBA)*

The Phase III MBA uses the same methodology as Phase I and II to simulate the impact on pipeline capacity of embedded generation and incremental generation requirements. MISO, through the use of its models, provided the inputs to determine individual unit fuel burns that were applied to historical pipeline flow data. This determines adequacy of natural gas infrastructure to serve projected demand on a pipeline-by-pipeline basis.

Pipeline capacity is affected by a number of operational capabilities and factors that were addressed extensively in Phase I and II. These include shale gas developments impacting pipeline flow patterns, infrastructure build-out, backhaul opportunities, pipeline utilization and utilization rates, integration of market-area storage capacity, market-area capacity versus mainline capacity, secondary capacity markets, asset management arrangements and other contracting options, and discretionary pipeline operations and flexibilities. The MBA analysis applies actual data and experiences over an extended time period in order to compare pipeline capacity, evaluate the impact of capacity trends, understand pipeline supply and determine demand dynamics. The MBA was performed to:
• Provide continuity with Phase I and II studies
• Establish baseline data to provide insight into changes in pipeline flow patterns
• Identify seasonal pipeline throughput trends to determine impacts of shifts in macroeconomic variables such as supply location, demands, etc.
• Provide perspective on the relative strengths of one pipeline to another based on competition, new entrants and sourcing shifts
• Reveal how similarly-situated pipelines’ throughput changes due to such factors as changing capacity from competing pipelines
• Indicate current and potential future pipeline congestion given a static infrastructure (i.e. not enough firm commitments to expand infrastructure)
• Accommodate a pipeline-by-pipeline approach, which is geared toward mainline pipelines vs. networked pipelines (both exist within the MISO footprint)

The Phase III MBA determines the number of days that pipeline capacity would have been insufficient, based on the potentially higher capacity factors for the MISO gas fleet, without year-round firm transportation arrangements for the simultaneous maximum gas capacity requirements of the existing or embedded CTs and CCs. The analysis provides a static “snapshot” and serves as a screening study of mainline or trunk line pipeline capacity based on actual flow information at measurement locations into the various pipelines’ market areas within the MISO Midwest footprint.

The MBA used MISO’s gas delivery requirements for the period 2013-2032 for existing and forecasted units under a 12,000 MW coal retirement scenario. Power burn was converted to Dekatherm gas requirements and applied to historic pipeline flows and compared to the respective pipeline’s daily maximum flow design capabilities. This application was the method used to determine the days in which capacity would have been insufficient to deliver natural gas requirements for each pipeline for each day in the period April 1, 2005 through March 31, 2013. The daily nomination data from each respective pipeline’s electronic bulletin board and historical maximum flowing capacity data was compiled by Bentek Energy. If the existing or “embedded” CTs and CCs maximum gas requirement quantities, in both the Base Demand
Scenario and the High Demand Scenario, exceeded the respective pipeline’s daily maximum flow design capabilities, that day was deemed to be a day of “insufficient capacity”.

Capacity Factors for both the Base Demand and the High Demand Scenario were determined through the MISO models. Based on the assumptions set forth in the Phase II Study, the same MWh to Dth conversion factors were used to calculate the natural gas requirements for the embedded and incremental CCs and CTs in the Phase III analysis. Tables showing LDC-to-pipeline allocations, as well as Base Demand and High Demand Scenario CC and CT gas requirements by pipeline are provided in the Phase III report Appendix.

The base modeling assumptions include:

- MISO MTEP12 business-as-usual (BAU) assumptions (see “MTEP12 Assumptions Doc” at https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlanning.aspx)
- 20-year study period
- 12 GW coal capacity retirements in 2015
- Generator siting methodology commonly used by MISO (see slides 51 to 83)
- Gas price assumptions for Base Demand and High Demand Scenarios
- Static natural gas infrastructure

Both scenarios assume adequate gas supply to meet all potential demand growth. Additionally, both consider the location of supply sources available to meet demand growth as well as the location of pipelines with available capacity to bring gas into the region. Assumptions specific to the Base Demand Scenario include a 1.43% Compound Annual Growth Rate (CAGR) and 2.5% inflation rate; corresponding assumptions for the High Demand Scenario include a 1.7% CAGR and 1.7% inflation rate.

Exceptions exist when comparing a grid system to a forward-haul trunkline system, which was recognized in the Phase I and II analyses. Grid-like pipelines are uniquely different in operations from a long-line, forward-haul pipeline system. The indications of capacity constraints into
these grid-like systems, such as ANR and NGPL, are potentially misleading and do not fully reflect actual operations behind the measurement point in their market areas. Also in this regard, there are exceptions that have developed since the Phase II Analysis in which, even on certain forward-haul systems, the impacts of displacement and feeds from pipelines beyond the chosen measurement points may not be fully accounted for except as indicated in the analyses’ trending of the decreasing number of days in which capacity would have been unavailable.
6 Phase III Analysis

The Phase III analysis is a major step in clarifying the changes that have occurred, particularly in the past two years. Phase III indicates that shale gas developments surrounding the MISO Midwest region will have beneficial capacity impacts to power generators. Shale gas developments are leading to increased backhaul and short haul capacity to power plant locations; available capacity due to contract turn-backs; displacement services and impacts of on the flow patterns into and on the pipelines. Shale gas developments have brought about pipeline flow and operational changes that are increasing capacity and transportation options as part of the larger re-assessment of pipeline flow optimization.

6.1 National Assessment

Bentek produced a macroeconomic US forecast in conjunction with the MISO South and MISO Midwest Forward Assessments. Bentek’s US forecast points to a supply-driven US market that is in a long position compared to US demand, hence the growth of a robust LNG export market coming into play by 2016, (Figure 6-1 through Figure 6-4).

![Figure 6-1: Historical and forecasted U.S. natural gas supply/demand balance (Source: Bentek Energy)](image)

While demand is not forecasted to keep pace with a balanced domestic supply market, hence the growth of the LNG export market, demand will nonetheless be primarily driven by electric power generation. This will overshadow increases of consumption in the industrial, commercial and residential markets. MISO anticipates that residential demand will concentrate in markets that encourage a switchover from oil to gas heating, such as New England. Regulatory and
governmental encouragement of demand-side management and conservation efforts in this market and elsewhere in the US will dampen gas usage growth.

Figure 6-2: Historical and forecasted U.S. natural gas demand by sector (Source: Bentek Energy)

As production of shale gas accelerates, the US will be poised to become natural gas independent by 2017 (Figure 6-3). Canadian supply will move to LNG export and domestic markets but there will be continuing export to limited US markets. Canadian imports to the US will be primarily impacted by the increased supply portfolio diversity into the Midwest and East coast US markets.
Bentek’s forecast points to a supply-driven US market that has excess supply for domestic requirements. Hence the growth of a robust LNG export market by 2016 (Figure 6-3).

Figure 6-3: U.S. natural gas import and export trends (Source: Bentek Energy)

Figure 6-4: Forecasted natural gas regional flow patterns (Source: Bentek Energy)
6.2 MISO Midwest Region

The Northeast region will become the Midwest region’s fourth supply area when it begins exporting to the Midwest. The current supply regions are the Rockies/Midcontinent, the Southeast and Canada. However, the gas sources will change dramatically as Northeast Production growth pushes gas into the Midwest region to meet incremental demand load. Meanwhile, production from the Bakken will displace Canadian supplies into the region. Northeast production has a huge impact on this effect as it pushes gas back into the Midcontinent, changing the look of the MISO region, the gas flow and transportation options.

The Midwest is not a dead-end for gas flow; it can move through to other market areas. Historic flows out of the region are to East Canada, with its significant storage capacity and markets, and into the Northeast. However, flows from Canada will decrease as production growth in the Bakken is expected to approach 1.8 Bcf/d by 2020. Bakken’s growth will primarily affect Northern Border, WBI Energy and the Alliance pipelines. Current constraints in the Bakken region are due primarily to processing and gathering, but pipeline capacity is constrained under current growth scenarios. Once infrastructure comes online, estimates indicate that the Bakken supply will force a reduction of imported Canadian supply. Bakken’s growth will primarily affect Alliance pipelines, Northern Border and WBI Energy. In May 2013, WBI Energy announced plans to build the Dakota Pipeline, which will move Bakken gas from far western North Dakota to western Minnesota where it would connect with Viking Gas Transmission Company’s pipeline, and through interconnecting pipelines could serve Minnesota, Wisconsin and Midwest U.S. markets. The Dakota Pipeline is slated for completion in late 2016. Proposed projects, such as WBI Energy’s Dakota Pipeline, illustrate the market response to shale gas movement into the Midwest. These types of projects not only have the potential to substantially increase capacity into the Midwest, but they also offer alternatives for gas deliveries where constraints may develop.

Gas from the Midcontinent region will largely remain flat from historic levels due to pipeline constraints downstream. Both Southwestern legs of NGPL and ANR are constrained during peak

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day conditions in the study period and when pipeline transportation is priced to meet market demands for increased load factors, at measurement points into the Midwest region. NNG is constrained downstream due to the amount of gas it receives from Northern Border at the Ventura Hub to serve its market area. However, the NNG’s market area north of the Ventura Hub is capacity constrained for significant power generation and other demand growth and would require significant infrastructure build-out to meet these needs. PEPL and REX really carry the incremental capacity into the MISO market, but even on PEPL, interruptible transportation service space is limited. However, it will be a capacity beneficiary of REX’s role as a header system and westward flowing Appalachian-based gas supplies on other pipelines.

Pipelines moving gas from the Southeast have additional capacity. Flows will likely increase from this region in the short term but have limited growth potential based on demand constraints within the Southeast region. Long-term flows will likely decrease as large demands such as LNG in the Southeast come online and reduce flows northward and retain relatively more gas in the Southeast region.

Meanwhile, the Midwest will play a key market role for absorbing Marcellus and Utica gas as total Northeast production is expected to grow from its current 11 Bcf/d to more than 20 Bcf/d by 2020. In the short term, this displacement leaves supply available for end users in the Midcontinent and contributes to some of the decreased utilization of other pipes entering the MISO region. In the future a reversal will come from new infrastructure and the directional conversion of existing infrastructure. This dynamic will allow even greater flexibility in the MISO region.

Demand in the MISO region is still mostly residential and commercial (Figure 6-5), though baseload growth over the next few decades will come from power burn and industrial use. Average daily demand is projected to increase from 11.1 Bcf/d in 2013 to 13.4 Bcf/d in 2032. The growth in demand for power burn is led by coal retirements in the region, which Bentek is tracking at 3.7 GW (announced retirements), with many more likely to be announced once MATS regulations take effect.
The other growth aspect is 5.0 GW of new gas plants announced in the region. Power burn represents 9 percent of average daily demand in the time period of 2009-2013 and grows to 14 percent of daily demand by the 2028-2032 timeframe as pictured in Figure 6-6, below.
6.2.1 Impact of Bakken Shale Gas

The growth of gas production in the Bakken is significant; however, it is important to keep it in context of the market. Current production of just under 1 Bcf/d can supply approximately 10 percent of daily demand in the region. Figure 6-7 is an overview of this forecasted growth.

Oil production growth is the main driver of gas production growth in the Bakken region. High internal rates of return (IRRs) for oil producers will bring continued growth to the region. Decline curves for historic wells in the area show associated gas yields a stronger gas/oil ratio as a well ages. Currently, gas gathering and processing systems are a limiting factor for moving gas out of the Bakken. However, more than 500 MMcf/d in new processing plants have been announced for the region by 2019, including build-out in late 2015 and 2016. This will increase existing processing capacity (920 MMcf/d) by over 50 percent. Production in the region will grow to approximately 2.5 Bcf/d by 2032, which should supply approximately 18 percent of daily demand. Even with production growing faster than demand, the MISO region is still a net-importer.

Figure 6-7: Bakken production growth (Source: Bentek Energy)
6.2.2 Impact of Appalachian Shale Gas
The Northeastern US will count on long-haul pipelines from the Southeast for backflow transportation to other regions, including the Midwest. This will first push back flows from the Southeast and eventually push back flows into the Midwest as pipelines no longer have a need to import gas from other regions. As Northeast gas production begins to overtake demand, Bentek forecasts a growth increase of more than 10 Bcf/d by 2032 from current levels.

The growth of shale gas production in the Appalachian Basin Figure 6-8 has already caused a decrease in Southwestern, Gulf Coast and Canadian supplies into the Northeast. This trend will continue in the Northeast with the addition of 10 Bcf/d of production from current levels.

Over time, the MISO region will benefit from continued Appalachian supply growth as producers seek incremental markets in the Midwest. Initially, gas pipeline flows going from the Midwest to Northeast will decline through 2015. By mid-2015, the pipeline flows will reverse and the Midwest, including MISO, will receive substantial gas supplies from the Appalachian basin. Figure 6-9 and Figure 6-10 show these forecasted developments below. Appalachian supply growth is also impacting the traditional west-to-east flow of a major cross-continent pipeline, the Rockies Express (“REX”). REX has offered physical backhaul from the Utica and
Marcellus basins to pipeline interconnections in the Midcontinent, including ANR, NGPL, Trunkline, PEPL, Midwestern and a number of others in Ohio. This would allow REX to bring supply from both the Rockies and Marcellus to fill available capacity on those pipes or displace current volumes from other regions. Currently REX is offering up to 1.8 Bcf/d of service, with anticipated availability in the fourth quarter of 2016.

Figure 6-9: Decreasing inflows to Northeast (Source: Bentek Energy)

Figure 6-10: Forecasted flow reversals benefit Midwest (Source: Bentek Energy)
REX has interconnects with several pipes in the Midcontinent region. A reversal of the REX along with additional infrastructure build-out, such as the Nexus pipeline and ANR’s proposed Lebanon Lateral, complement a proposal by Dominion and Texas Eastern which will add capacity to access the Midwest from Northeast production.

![Figure 6-11: REX interconnection with Appalachian pipeline supplies (Source: Bentek Energy)](image)

### 6.2.3 Impact of Rockies Gas Supplies on MISO Region

REX is the key inflow of Rockies gas supplies into the MISO region. REX has interconnects with several pipes in the Midcontinent region. A reversal of the pipeline along with additional infrastructure such as the Nexus pipeline as shown in Figure 6-11 will add capacity to access the Midwest from Northeast production.

REX has been delivering more and more gas to the Midcontinent as Northeast Production grows. Additionally, a higher percentage of inflows are staying in the MISO region (Figure 6-12). In other words, less gas that is flowing into the Midwest region is leaving the Midwest region. This dynamic is expected to continue as further pushback from Northeast production eventually leads REX to flow volumes back into the Midcontinent region from the Northeast.
As shown below in Figure 6-13, inflows from the Rockies have decreased slightly from 2008-2009 levels; however, net Rockies gas in the Midwest is projected to increase, with pushback from the Northeast keeping more Rockies imports in the Midwest.
6.2.4 Impact of Anadarko Traditional and Shale Gas Supplies

Anadarko Production will continue its growth. Production in the Midcontinent is expected to grow almost 4 Bcf/d as shown in Figure 6-14. However, much of this production growth will not be accessible to Midwest users unless new infrastructure comes online. It could, however, push out other supply areas (Rockies, Canada) if the economics are attractive.

![Anadarko Production continues its growth](image)

**Figure 6-14: Forecasted Anadarko production growth (Source: Bentek Energy)**

Gas from the Midcontinent region will largely remain flat from historic levels due to pipeline constraints downstream without supply-push projects. Both Southwestern legs of NGPL and ANR are forward-haul constrained during peak-days, when pipeline transportation is priced to meet market demands for increased load factors, at the measurement points into the Midwest region. PEPL and REX largely carry the incremental capacity into the market, but even on PEPL, space is limited. However, as explained in this Analysis, PEPL and REX pipelines’ market areas are seeing increased capacity options north of these locations as a result of shale gas developments. Increased MISO Midwest region grid reticulation and voluntary industry interconnectivity activities are helping to relieve these southern constraints (Figure 6-15 and Figure 6-16).

NNG is constrained downstream north of Ventura due to the amount of gas it receives from Northern Border and due to physical pipeline capacity to serve its market area to the north and
northeast on its “branch” systems. NNG appears to have sufficient capacity into the Midcontinent region. However, if downstream receipts from Northern Border are overlaid on the inflows, it becomes more obvious that the pipe is very highly utilized and constrained on the NNG “branch-systems” in the market region north of Ventura, Iowa.

Figure 6-15: Southwest pipeline constraints, NNG and NB (Source: Bentek Energy)

Figure 6-16: Southwest pipeline constraints, ANR, NGPL and PEPL (Source: Bentek Energy)
The reduction in flows on NNG compared to its capacity limit appear to indicate sufficient capacity to bring gas in from this region. However, the production growth will continue to expand and pipelines flowing gas from the Southwest into the Midwest, like NNG and PEPL, will actually have limited capacity. Production growth in the Midcontinent producing region leads to additional flows into the Midwest as shown in Figure 6-17. However, growth is limited due to capacity restraints on pipelines bringing gas from that region.

Also, a seasonal average throughput above 5 Bcf/d suggests pipeline capacity constraints during the season, especially on peak demand days. Using the winter of 2010-2011 as an example, pipeline flows averaged 5.2 Bcf/d for the entire season. However, even with average daily capacity of 6.6 Bcf/d, pipeline utilization from the region averaged above 90% for 32 days, which equates to 21% of the total season. This indicates that there could be concerns about peaking capacity availability if load growth occurs without pipeline capacity expansions.

![Figure 6-17: Midcontinent production (Source: Bentek Energy)](image)

6.2.5 Impact of Canadian Traditional and Shale Gas Supplies
New supply and demand sources in the US will reduce inflows from Western Canada to the Midwest as shown below in Figure 6-18. Traditionally, natural gas is produced in Alberta and British Columbia and is transported on Canadian pipelines to be exported into the US. However,
these flows are forecasted to decline, as market trends clearly demonstrate. Inflows from Canada are declining for two reasons. The first is production growth in the Bakken, which sits directly in the path of the Canadian pipelines coming into the US. Transportation rates from the Bakken are cheaper because there is less distance to travel and no stacked transportation rates between Canadian and US pipes. The second reason for decreased flows is increased demand in Western Canada. This is due largely to the introduction of LNG exports facilities starting in 2017. Bentek expects incremental demand growth in Canada to reach 3.7 Bcf/d above current levels of 10.5 Bcf/d.

![Figure 6-18: Western Canadian supplies to Midwest (Source: Bentek Energy)](image)

Imports from Canada are already seeing a decline into the MISO region. The largest decreases are on Great Lakes Gas Transmission, which had contract non-renewals two separate times and even reversed flows to net export into western Canada during the winter of 2012-13. Bakken growth will lead to a pushback in Canadian flows on Northern Border. Alliance has not been impacted and has actually been experiencing increased NGL-laden (“wet-gas”) supplies from Canada and can expect additional wet gas with the September 2013 start-up of the Tioga lateral in North Dakota. The Tioga Lateral Pipeline runs from an existing gas processing facility near Tioga, North Dakota, and ties in to the existing Alliance mainline near Sherwood, North Dakota. Alliance will be less impacted because it is a wet-gas pipeline that transports NGL-laden
supplies southward to processing facilities near Chicago and may also be attractive to domestic producers. However, Alliance will continue to experience capacity constraints at least in the near-term. In anticipation of potential contract non-renewals, Alliance is offering capacity on its system for natural gas transportation services effective December 1, 2015.

The majority of inflows lost from Canada have come from Great Lakes as shown in Figure 6-19. Contract renewals have declined and were not renewed in 2010 and then again in 2011. Since a significant amount of Great Lakes’ flows get exported back into East Canada, the decrease was also due to push-back in production growth in the Northeast, as East Canada had less of a need to export to the Northeast, leaving more gas coming into the region to supply local demand. During the winter of 2012-2013, Great Lakes reversed flow direction and net exported to western Canada.

Local Midwest and total US production will pushback Canadian inflows and the 2.0 Bcf/d of growth in the Bakken will displace most Canadian gas hitting Northern Border. This can be seen in Figure 6-20 and Figure 6-21. This will be a positive capacity-enhancement for Bakken supply options.
6.2.6 Impact of Southeast and Gulf Gas Supplies

While pipeline flows from the Southeast have been stable, two things will cause changes in both the near-term and long-term. The first is the limited amount of future growth potential for pipeline flow to the Midwest in the near-term. Generally speaking, outflows to the Midwest and Northeast have been weakening for various reasons but primarily due to alternatives in the
various shale gas regions (Figure 6-22).

With Trunkline’s potential to convert to a crude line and reduce capacity by over 300 MMcf/d, and Texas Gas’ abandonment project from the Southeast, there will be limited non-contracted space available on some pipelines in which there is capacity constrained downstream. However, these pipelines will likely have sufficient capacity in the MISO region to serve future generation and other demands through interconnections with REX and other Northeast expansion projects.

Figure 6-22: Outflows from Southeast (Source: Bentek Energy)
The second factor impacting outflows to the Midcontinent and Northeast is demand in the Southeast, which is forecast to gain over 10 Bcf/d by the end of 2032 ([Figure 6-23](#)). This will cause outflows from Southeast to Northern markets to decrease. Demand growth will be led primarily by LNG exports; however, there are a large number of industrial projects planned in the region that will also add base-load demand growth in the region.

Flows are expected to become much more seasonal corresponding with high-demand periods in the Midcontinent. Demand peaking requirements in the winter periods will remain even though overall base load decreases.

### 6.2.7 Summary of Inflows to MISO Midwest Region

Northeast production growth will supplement incremental demand growth in the Midwest and will also “re-invent” the Midwest’s relationship with REX and its impacts on Rockies gas supplies and Southeast gas supplies. Local production growth in the Bakken will displace Canadian imports, while inflows from the Southeast will become increasingly seasonal as demand in the region grows, requiring it to retain more local gas. The interconnectivity of the pipelines in the region will become important as how gas moves into and through the region will change due to the addition of new supply regions ([Figure 6-24](#)).
6.3 MISO South Region

One of the Phase III objectives was to produce a pipeline-by-pipeline, data-intensive overview of the MISO South region. A point-by-point data analysis was used to aggregate pipeline flow data into “flow corridors” and to determine patterns of the natural gas market in Louisiana, Arkansas, Mississippi and parts of Texas.

The MISO South region has historically been at the heart of the gas production world in the US with unparalleled access to over 90 interstate and intrastate pipeline systems crossing its footprint. Additionally, MISO South region gas supplies have been highly reliant on Gulf offshore gas production as show below in Figure 6-25.
Production since 2005 has migrated from offshore to onshore at a steady and substantial pace. Onshore production growth has become a significant supply source as a percentage of overall regional gas supplies. By 2012, the percentages above had basically switched, with 69% of Southeast production onshore and 29%, offshore.
The Southeastern market dynamics are changing the structure of the traditional gas flow on the interstate pipeline systems that were largely built in the 1950s and 1960s. The traditional flow pattern has been to move natural gas from the south-central U.S. to demand markets in the upper Midwest and the East and West coasts.

In the period after Hurricane Katrina and coincident with the development of shale gas basins in the Rockies, Midcontinent and Appalachia, the south-central U.S. is no longer the dominant supplier of natural gas. Texas, Louisiana and Gulf gas production have all seen a steady decline as a percentage of total U.S. production and overall shale gas production. Moreover, localized shale gas developments around the U.S. are having not only gas price impacts, but also impacts on the value of storage and the need for further storage development. The combination of these factors is helping to accelerate changes in locational basis differentials to the Henry Hub.

Southeast inflows to the Midwest will likely continue to decline in the short-to-medium term. Large local production areas like the Haynesville remain unattractive to producers until prices increase relative to today. This will be offset by the steadily declining need for outflows from the Southeast, due to production growth in the Northeast.

Texas production growth is coming largely from Eagle Ford, with some growth in production from the Permian basin as well. Shale gas production from the Fayetteville will likely remain flat in the near term until natural gas prices increase. Haynesville production will likely continue to decline as current and forward curve economics make it difficult to attract producers when returns in liquids-rich shale gas locations are more economically attractive, particularly in the case of the Eagle Ford shale production in South Texas as shown in Figure 6-27.
Flows from Texas and Northeast Louisiana into MISO-South will continue to decline, but outflows from the MISO-South area will remain strong due to power demand needs in Florida, Georgia and the Carolinas. In combination with the decline of flows to the Northeast, pipeline utilization has decreased in the MISO-South area. As a result, forecasted basis spreads are unlikely to increase much beyond variable costs between supply regions west of MISO-South. As shown in Figure 6-28, the outflow declines to the Northeast and Midwest will become increasingly independent on Southeast supply as a baseload supply.
Flows out of the Southeast to the Midcontinent will continue to be pressured by Northeast production growth, especially during the summer. While this will continue to put pressure on southeast supply in the short term, production can, and is likely to respond quickly to a premium price environment that may evolve late in the decade due to regional demand growth from LNG export terminals, industrial demand and increasing power generation needs. This would mute the potential for long-term price strength, as producers can bring incremental volumes to the market fairly quickly due to previous experience in dry-gas basins. The impact is that high prices are likely to be short-lived rather than a phase shift.

Flows from Carthage into Louisiana are unlikely to strengthen as producing areas are flat to declining in the future, but this will be offset by reduced need to send supply to the Ohio Valley and the Atlantic Seaboard. Essentially, if gas prices spike and stay high for a long period, Haynesville production will return, weakening the upward trend of the “potential” price escalation.

Also adding to the changes in market dynamics are the potential impacts of LNG export development, the re-shoring of US industry and the building momentum of the development of gas feedstock-based industries in the Gulf Coast region. Demand growth is led primarily by LNG
exports, gas-to-liquids production, petrochemical, fertilizer and power generation growth. There are also a large number of other industrial projects planned in the region that will add base-load demand growth.

Southeast demand, shown in Figure 6-29, looks to grow substantially by the end of the decade, adding 4 Bcf/d of LNG demand, 0.5 Bcf/d of incremental power demand, and nearly 0.8 Bcf/d of industrial demand. By the end of 2032, Southeast demand is forecast to increase by over 10 Bcf/d, largely driven by continued increases in the LNG export markets. The shifting dynamic will help contrast decreasing north-to-south pipeline flow patterns while also stimulating growth in local supply basins.

![Southeast Demand Growing and Poised to Rapidly Accelerate](image)

**Figure 6-29: Forecasted growth Southeast demand markets (Source: Bentek Energy)**

One consequence of the supply and demand market changes is clearly shown in Figure 6-30 in the 2011-2013 period. This shows that the balance of inflows to the Southeast appear to increase to meet growing Southeast area market demands and decreased downstream demand in other regions. The traditional northward production flow patterns are changing to a situation where more production as a percentage of flows is staying in the Southeast.
Demand outside the MISO South region is increasing, but not at a pace fast enough in the Northeast to absorb excess Appalachian-based supply. Though intraregional flows from the MISO South area east to Georgia, Florida and the Carolinas should remain strong, they will remain strong only so long as those regions continue to grow their electric demand profiles with conversions to natural gas fired electric power generation.

On a pipeline-specific basis, long-term supply and demand dynamics may create additional supply and capacity opportunities for pipelines that are underutilized leaving the region—Transco, TETCO, Columbia Gulf, and Kinder Morgan’s Elba Express Pipeline. These pipelines are proposing backhaul projects and conversions to support new products (NGLs and crude oil), which all reflect the increasing imbalance and support the growing need to move Appalachian shale gas supplies westward and southward to new markets.

A number of announced or pending projects are being developed to accommodate the growth of Appalachian-based shale gas such as those shown in Figure 6-31.
On the other side of the MISO South Region, flows from Texas and Northeast Louisiana will continue to decline as production growth in the northeast continues to outpace demand growth in the Southeast. Long-term supply and demand dynamics may create additional supply opportunities as demand growth in the region begins to pick up. Underutilized pipelines leaving the region may see higher use for transportation of supply from other regions to meet growing local demand. Additionally, local production can, and is likely to respond quickly to a premium price environment that may evolve late in the decade due to demand growth. Increased local supply is expected to develop only if gas prices increase. This dynamic may exacerbate the continuum of locational basis fluctuations when demand and supply cycles become out of sync with production cycles. As a result, more supply will be drawn into the MISO South region to supplement localized production until gas prices strengthen making local dry gas supply more economically attractive.

To summarize, the traditional flow trends of south-to-north are in several cases reversing due to the Northeast market’s inability to absorb southeast production. Also pipeline reconfigurations and expansions from the Appalachian westward and southward contribute to less dependency on southwest gas supplies. Simultaneously, gas supplies from Canada that would have historically been delivered to the Northeast U.S. are finding their way into the
Midwest. The Midwest market is the only U.S. market with recent year-over-year demand increases for Canadian gas supplies. However, going forward, those inbound supplies will also be challenged. Industrial demand and power generation are the largest growing components of Southeast demand and will likely continue to be until LNG appears late in the decade. Although power burn growth in Southeast has been substantial, most power-burn growth has and is projected to occur outside of MISO South. The pipeline infrastructure within MISO South is adequate to continue to foster growth in the medium-term, but demand growth could cause constraints.

Southeast production is declining, but growing demand is attracting supply that would have originally been shipped into the region. Declining outflows will be offset by physical backhaul projects and displacement from Northeast production. Additionally, the gas price environment continues to decrease flows from Texas and dry gas plays, while flows out of MISO South remain strong as demand pulls supply to Florida, Georgia and the Carolinas.

6.4 Modified Backcast Analysis (MBA)

Over the past two years, new shale gas supplies across the US have brought about significant infrastructure expansion that has positively impacted pipeline flow patterns and capacity availability throughout North America. It is becoming increasingly clear that the traditional ways of viewing capacity availability from a forward-haul perspective has been significantly altered by the revolutionary impact of the new shale supply paradigm shift.

The forward-haul based MBA has become less relevant as an indicator of the true “net” capacity availability on the interstate pipelines. Over the past two years and due primarily to new shale gas supply sources, the creative uses of backhauls and other operational gas supply displacement operations are becoming the “new normal” in pipeline operations making forward capacity evaluations much more difficult without detailed knowledge of proprietary pipeline operational information. For this reason, the Phase III Report analyzes capacity from two perspectives: the Modified Backcast Analysis (MBA) and the forecast assessment.
Overall, pipeline capacity into the MISO Midwest is positive and continually improving due to shale gas developments and accommodating pipeline expansions, contract expirations and the benefits of increased pipeline reticulation underway in the Eastern Interconnect. The forward balancing analysis indicates that the MISO Midwest will benefit from these developments and be well-positioned to meet the challenges of capacity requirements for gas-fired electric power generation. The forward balancing analysis agrees with the overall MBA conclusion that there is a developing trend toward sufficient and increased pipeline capacity into the MISO Midwest footprint; however, it also notes that there is the need for infrastructure expansion to accommodate northeastern gas supplies projected to serve future Midwest demand growth.

The MBA results should be viewed as a “snapshot” of capacity trends that are showing enhanced mainline capacity on the majority of the MISO-region pipelines. It is an application of real-life data and experiences over an extended period to evaluate the impacts of the pipelines’ capacity trends and determine insights into pipelines’ supply and demand dynamics. Each pipeline’s CT and CC capacity requirements were analyzed from a combined daily requirements perspective. This is a high-level “screening” analysis of MISO-region pipelines’ mainline capacity based on publically-available data at major interconnections into each pipeline’s market area and is intended to serve as an indicator of capacity availability into the pipelines’ market areas.\(^\text{13}\)

In the Phase I and II studies, pipeline nomination flow data from April 2005 through October 2011 was analyzed. The Phase III MBA results are based on actual nomination data from April 2005 through March 2013. The additional data points have improved the trending analysis to include the impacts of shale gas supplies which have positively impacted pipeline flow patterns and capacity availability.

There are 21 interstate pipeline companies in the MISO Midwest region as shown in Table 6-1.

\(^{13}\) This Analysis is not intended to be a detailed market-area engineering analysis using sophisticated flow modeling. Transient flow analysis is not performed and detailed market area pipeline segment’s operational interdependencies are not examined. Analysis accounting for detailed pipe sizes and pressures at the power plant delivery point level would require access to the pipelines’ proprietary data and information.
<table>
<thead>
<tr>
<th>Pipeline Name</th>
<th>Principal Supply Source(s)</th>
<th>System Configuration</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Alliance Pipeline&lt;sup&gt;1&lt;/sup&gt;</td>
<td>Canada</td>
<td>Trunk</td>
</tr>
<tr>
<td>2. ANR Pipeline</td>
<td>Louisiana, Kansas, Texas</td>
<td>Trunk/Grid</td>
</tr>
<tr>
<td>3. Bison Pipeline LLC</td>
<td>Wyoming, Montana, North Dakota</td>
<td>Trunk</td>
</tr>
<tr>
<td>4. Mississippi River Trans.</td>
<td>Arkansas, Oklahoma</td>
<td>Trunk</td>
</tr>
<tr>
<td>5. Crossroads Pipeline</td>
<td>Interstate System (feeder)</td>
<td>Trunk</td>
</tr>
<tr>
<td>6. Great Lakes Gas Trans. Ltd&lt;sup&gt;1&lt;/sup&gt;</td>
<td>Canada/Canada export</td>
<td>Trunk</td>
</tr>
<tr>
<td>7. Guardian Pipeline</td>
<td>Interstate System (feeder)</td>
<td>Trunk</td>
</tr>
<tr>
<td>8. KO Gas Trans. Co.&lt;sup&gt;14&lt;/sup&gt;</td>
<td>Interstate System (feeder)</td>
<td>Trunk</td>
</tr>
<tr>
<td>9. Midwestern Gas Trans.</td>
<td>Interstate System (feeder)</td>
<td>Trunk</td>
</tr>
<tr>
<td>10. Northern Border Pipeline&lt;sup&gt;1&lt;/sup&gt;</td>
<td>Canada, ND and Bison PL</td>
<td>Trunk</td>
</tr>
<tr>
<td>11. Natural Gas PL Co. of America</td>
<td>Kansas, Oklahoma, Louisiana, Texas</td>
<td>Trunk/Grid</td>
</tr>
<tr>
<td>12. Northern Natural Gas</td>
<td>Kansas, Oklahoma, Texas</td>
<td>Trunk/Grid</td>
</tr>
<tr>
<td>13. Panhandle Eastern PL&lt;sup&gt;1&lt;/sup&gt;</td>
<td>Kansas, Oklahoma, Texas</td>
<td>Trunk</td>
</tr>
<tr>
<td>14. Texas Eastern Transmission</td>
<td>Louisiana, Texas</td>
<td>Trunk</td>
</tr>
<tr>
<td>15. Texas Gas Transmission</td>
<td>Louisiana, Texas</td>
<td>Trunk</td>
</tr>
<tr>
<td>16. Trunkline Gas</td>
<td>Louisiana, Texas</td>
<td>Trunk</td>
</tr>
<tr>
<td>17. Viking Gas Transmission&lt;sup&gt;1&lt;/sup&gt;</td>
<td>Canada</td>
<td>Trunk</td>
</tr>
<tr>
<td>18. Vector Pipeline&lt;sup&gt;1&lt;/sup&gt;</td>
<td>Interstate/export Canada System</td>
<td>Trunk</td>
</tr>
<tr>
<td>19. Rockies Express Pipeline</td>
<td>Wyoming, Colorado</td>
<td>Trunk</td>
</tr>
<tr>
<td>20. Southern Star Central PL&lt;sup&gt;15&lt;/sup&gt;</td>
<td>MI, NE, KS OK, TX</td>
<td>Trunk/Grid</td>
</tr>
<tr>
<td>21. WBI Energy&lt;sup&gt;1&lt;/sup&gt;</td>
<td>ND, WY, MT, Canada</td>
<td>Trunk/Grid</td>
</tr>
</tbody>
</table>

Trunk - systems are large-diameter long-distance trunklines that generally tie supply areas to natural gas market areas.

Grid - systems are usually a network of many interconnections and delivery points that operate in and serve major natural gas market areas.

<sup>1</sup>Also operates natural gas import/export facilities located at the Canada border.

<sup>2</sup>Function as intrastate or LDC with cross-state links.

**Note:** Bolded pipelines have “MISO-identified” facilities or units.

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Table 6-1: MISO Region Interstate Natural Gas Pipelines

Of the 21 interstate companies, 15 interstate companies have MISO-identified CCs or CTs, embedded and/or incremental which were analyzed using the MBA methodology. As in the Phase I and II Studies, Phase III applied MISO’ s projected gas delivery requirements but for the

<sup>14</sup>KO Gas Trans Co. (KY-OH) is a 90 mile interstate pipeline between KY and OH and **should not** be considered as a major pipeline. KO is fully subscribed. KO Gas Transmission by default of location is included in this analysis. Likewise, Southern Star it is included because of its proximity to the MISO region.

<sup>15</sup>Ibid.
period 2012 – 2032 for existing units and the incremental, gas-fired requirements under a 12,000 MW coal-to-gas retirement scenario. Forecasted energy production (MWh) for CCs and CTs, both embedded and incremental, was converted to Dth gas requirements and added to historic actual flows and compared to the respective pipeline’s daily maximum flow design capabilities. If the sum was greater than a pipeline’s daily maximum flow design capabilities on any given day it was assumed that there would have been insufficient capacity to deliver natural gas requirements for that pipeline.

The following pipelines and local (gas) distribution companies (“LDCs”) were analyzed:

**Pipelines/LDCs MISO identified as serving embedded Combustion Cycle (CCs) Facilities:**

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Supply Sources</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. ANR Pipeline</td>
<td>Gulf/Southwest</td>
</tr>
<tr>
<td>2. Consumers Energy (LDC)</td>
<td>Upstream Pipelines</td>
</tr>
<tr>
<td>3. Guardian Pipeline</td>
<td>Upstream Pipelines</td>
</tr>
<tr>
<td>4. Michigan Consolidated Gas (LDC)</td>
<td>Upstream Pipelines</td>
</tr>
<tr>
<td>5. Midwestern Gas Transmission</td>
<td>Upstream Pipelines</td>
</tr>
<tr>
<td>6. NGPL East</td>
<td>Gulf Coast</td>
</tr>
<tr>
<td>7. NGPL West</td>
<td>TX/OK/KS</td>
</tr>
<tr>
<td>8. Northern Indiana Public Service (LDC)</td>
<td>Upstream Pipelines</td>
</tr>
<tr>
<td>9. Northern Natural Gas</td>
<td>W. Texas/TX Panhandle</td>
</tr>
<tr>
<td>10. Panhandle Eastern Pipe Line</td>
<td>TX/OK/KS</td>
</tr>
</tbody>
</table>

**Pipelines/LDCs MISO identified as serving embedded Combustion Turbine (CTs) Facilities:**

<table>
<thead>
<tr>
<th>Pipelines</th>
<th>Supply Sources</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. ANR Pipeline</td>
<td>SE-Central system</td>
</tr>
<tr>
<td>2. ANR Pipeline</td>
<td>North Illinois - Wisconsin</td>
</tr>
<tr>
<td>3. ANR Pipeline</td>
<td>North Illinois - Michigan</td>
</tr>
<tr>
<td>4. Consumers Energy (LDC)</td>
<td>Upstream Pipelines</td>
</tr>
<tr>
<td>5. Great Lakes Gas Transmission</td>
<td>Canadian Border</td>
</tr>
<tr>
<td>6. Guardian Pipeline</td>
<td>Upstream Pipelines</td>
</tr>
<tr>
<td>7. Michigan Consolidated Gas</td>
<td>Upstream Pipelines</td>
</tr>
<tr>
<td>8. CenterPoint Mississippi River Transmission</td>
<td>TX/OK/LA/AR</td>
</tr>
<tr>
<td>9. NGPL Amarillo System</td>
<td>TX/OK/KS</td>
</tr>
<tr>
<td>10. NGPL Southeast System</td>
<td>Gulf Coast</td>
</tr>
<tr>
<td>11. Northern Indiana Public Service (LDC)</td>
<td>Upstream Pipelines</td>
</tr>
<tr>
<td>12. Northern Natural Gas</td>
<td>TX/OK/KS</td>
</tr>
<tr>
<td>13. Panhandle Eastern Pipe Line</td>
<td>TX/OK/KS</td>
</tr>
<tr>
<td>14. Rockies Express Pipeline</td>
<td>Rockies</td>
</tr>
<tr>
<td>15. Texas Gas Transmission</td>
<td>Gulf Coast/MS/AR/NE TX</td>
</tr>
</tbody>
</table>
16. Trunkline Gas  
17. Viking Gas Transmission  
18. WBI Energy Transmission  

The LDCs’ gas quantities were allocated to their upstream pipelines based on a percentage of their Firm Transportation Maximum Daily Quantities (”MDQ”). These allocations are given in the Appendix. Also in the Appendix are Tables showing existing CCs and CTs per pipeline or LDC, and calculated daily gas requirements per pipeline for existing and forecasted units, for the Base and High Demand Scenarios.

The Appendix also includes specific pipeline Tables showing the number of days, by season, for the period April 1, 2005, through March 31, 2013, in which the embedded and incremental gas-fired power generation requirement would have exceeded the historical pipeline flow capacity, without firm transportation.

The CCs’ and CTs’ gas requirements on ANR were allocated to ANR’s three (3) distinct pipeline segments and on NGPL into two (2) distinct segments because of the geographical and operational differentiation of these pipeline segments. Therefore, a daily flow analysis was done for each of the eighteen (18) pipelines/pipeline segments below.

<table>
<thead>
<tr>
<th>Pipelines/Pipeline Segments</th>
<th>Mainline Measurement Locations</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Alliance</td>
<td>Canadian Border</td>
</tr>
<tr>
<td>2. ANR Pipeline N: IL – WI</td>
<td>IL/WI Border</td>
</tr>
<tr>
<td>3. ANR Pipeline SE Central</td>
<td>Kentucky Border</td>
</tr>
<tr>
<td>4. ANR Pipeline N: IL – MI</td>
<td>IL/MI Border</td>
</tr>
<tr>
<td>5. CenterPoint - Mississippi River Transmission</td>
<td>IL/MO Border</td>
</tr>
<tr>
<td>6. Great Lakes Gas Transmission</td>
<td>Canadian Border (Emerson)</td>
</tr>
<tr>
<td>7. Guardian</td>
<td>IL/WI Border</td>
</tr>
<tr>
<td>8. Midwestern</td>
<td>KY Border</td>
</tr>
<tr>
<td>9. Natural Gas Pipeline Co. of America - Gulf Coast</td>
<td>Harper Iowa</td>
</tr>
<tr>
<td>10. Natural Gas Pipeline Co. of America – Amarillo</td>
<td>IA/NE Border</td>
</tr>
<tr>
<td>11. Northern Border Pipeline</td>
<td>Canadian Border (Morgan)</td>
</tr>
<tr>
<td>12. Northern Natural Gas</td>
<td>NE/IA Border</td>
</tr>
<tr>
<td>13. Panhandle Eastern Pipe Line</td>
<td>Iowa/MO Border</td>
</tr>
<tr>
<td>14. Rockies Express Pipeline</td>
<td>MO/IL Border</td>
</tr>
<tr>
<td>15. Texas Gas Transmission</td>
<td>IN/KY Lateral Border</td>
</tr>
<tr>
<td>16. Trunkline Gas</td>
<td>IL/KY Border</td>
</tr>
<tr>
<td>17. Viking Gas Transmission</td>
<td>Canadian Border (Emerson)</td>
</tr>
<tr>
<td>18. WBI Energy Transmission</td>
<td>MT/ND Border</td>
</tr>
</tbody>
</table>
The majority of the pipelines analyzed have sufficient capacity and are trending towards increased capacity. From a forward-haul perspective, three of the major interstate pipelines appear to have area-specific capacity deficiencies at certain times based on the locations of the projected units. In both the High Demand Scenario and the Base Demand Scenario, for the forecast horizon, 15 of 18 of the pipeline “segments” or 12 of 21 interstate pipeline companies that have MISO-identified units appear to have sufficient capacity at measurement points into their market area if they operate at expected capacity factors. The 5 additional pipelines not included (no MISO-identified units) have sufficient or excess capacity for incremental power generation. Therefore 17 of 21 interstate pipelines have sufficient capacity into the MISO market area.

Of the 18 pipelines or pipeline segments, Alliance, Northern Border and Northern Natural north of Ventura in the branch systems appear to have incremental capacity deficiencies at this time based on the locations of the projected units. NNG has sufficient capacity into the market area but within the market area, the pipeline sections north of the Ventura are capacity constrained for significant power generation and would require infrastructure build-out to meet the needs of the forecasted units identified in that location. Canadian-based Northern Border and Alliance are the most volumetrically constrained pipes into the region. Alliance is a “wet-gas” pipeline, heavily-laden with NGLs and could be considered as “gas quality” constrained from a power generator’s perspective. Northern Border and Alliance however, appear to be well-positioned to benefit from changes in the overall pipeline flow changes that are occurring in the MISO region. These changes could materially enhance backhaul and other displacement options. There may be additional caveats regarding their interconnectivity with other regional pipelines that must be further researched with these specific pipelines. A more detailed overview of these 3 pipelines and outline of actions underway that could positively change the capacity outlook are provided in the section titled “Trending Deceasing Capacity Pipelines”.

Seven (7) additional pipelines\(^\text{16}\) (5 interstate and 2 intrastate) were analyzed in the Phase I and II studies but were not addressed in detail here because CTs and/or CCs were not sited on them. These 7 additional pipelines were analyzed in the MBA and it was concluded that they have available capacity for additional electric generation demand. These pipelines appear to be

\(^{16}\text{Bison, Crossroads, Horizon, KM Illinois, Southern Star, TETCO and Vector.}\)
well-positioned to meet future power burn demand as explained below.

- **Bison (interstate)** has an average of about 100,000 Dth/d available capacity and is well-positioned to support power generation with area pipeline interconnectivity.

- **Crossroads (interstate)** has sufficient capacity and on average, Crossroads has up to 150,000 Dth/d of extra capacity in the winter and over 300,000 Dth/d extra capacity in the summer period.

- **Horizon (intrastate)** has sufficient capacity and it can benefit power generators with backhaul and other displacement options.

- **KM Illinois (intrastate)** has over 150,000 Dth/d extra capacity and because of its south and north interconnections, it can provide displacement options.

- **Southern Star (interstate)**, on average, has over 150,000 Dth/d of extra capacity and on most days, has considerable capacity available to serve additional units and to support deliveries into the MISO region.

- **TETCO (interstate)** was analyzed in the Phase I and II Studies and TETCO has experienced a positive and dramatic change in capacity availability due to Appalachian shale gas developments. TETCO is changing various operations to move gas bilaterally, and creative displacement and backhaul opportunities are developing to provide significant capacity into the MISO region.

- **Vector (interstate)** also has sufficient capacity for additional units and power generators can benefit from backhaul and displacement options.

If the pipelines that did not have MISO-identified units are included, 17 of the 21 interstate pipelines appear to have sufficient capacity and are positively trending towards increased capacity availability. The major interstate pipelines are well-positioned to meet the capacity requirements of future power generation.

The MBA concludes that as a primary result of changing interstate flow patterns and increased grid reticulation, the major interstate pipelines in the Midwest appear to have sufficient capacity into their market area to handle the needs of existing and forecasted combustion turbines (CTs) and combined cycle units (CCs), if these units operate at expected capacity factors, and are positively trending towards having additional capacity. The Phase III projects a continuation of increasing access to capacity on the majority of major interstate pipelines in the MISO Midwest footprint.
6.4.1 Sufficient and/or Increasing Capacity Pipelines

The following pipelines have been analyzed using the MBA methodology and have been trending since 2005 toward sufficient capacity. This trend became more pronounced starting with the development of shale gas in 2008 and accelerated significantly starting in 2011-2012, opening up new capacity options through infrastructure construction and pipeline operational changes to move shale gas to markets. The implication of increasing capacity trending is that there will be sufficient capacity to serve projected power generation requirements. This is based on today’s outlook for continued shale gas developments.

In each of the graphs below it is important to note that the scale of the y-axis is different for each pipeline and the number of Insufficient Days may be immaterial for some due to routine maintenance. Also, the winter of 2010 – 2011 was one of the coldest in over 25 years. This may skew the overall data trend of increasing capacity, particularly in certain geographical areas, and especially on Texas Gas, Trunkline, WBI Energy and Alliance. Also, as explained later in the Report, Alliance is a unique “wet system” and does not necessarily fit circumstantially with the other “dry” pipelines. It should also be noted that significant market flow changes have greatly reduced REX flows in the past two years and the trend does not reflect future flow changes on REX.

Figure 6-32: ANR SE-Central Base Demand Case
Figure 6-33: ANR SE-Central High Demand Case

Figure 6-34: ANR N IL-WI Base Demand Case

Figure 6-35: ANR N IL-WI High Demand Case
Figure 6-36: ANR N IL-MI Base Demand Case

Figure 6-37: ANR N IL-MI High Demand Case

Figure 6-38: CenterPoint MRT Base Demand Case
The CenterPoint-MRT trend is statistically insignificant as the days of insufficiency in the summer periods appear to be maintenance-related.

Figure 6-39: CenterPoint MRT High Demand Case

Figure 6-40: GLGT Base Demand Case

Figure 6-41: GLGT High Demand Case
Figure 6.42: Guardian Base Demand Case

Figure 6.43: Guardian High Demand Case

Figure 6.44: Midwestern Base Demand Case
Figure 6-45: Midwestern High Demand Case

Figure 6-46: NGPL Amarillo Base Demand Case

Figure 6-47: NGPL Amarillo High Demand Case
Figure 6-48: NGPL SE Base Demand Case

Figure 6-49: NGPL SE High Demand Case

Figure 6-50: NNG Base Demand Case
Figure 6-54: REX Base Demand Case

Figure 6-55: REX High Demand Case

Figure 6-56: Texas Gas Base Demand Case
Figure 6-57: Texas Gas High Demand Case

Figure 6-58: Trunkline Base Demand Case

Figure 6-59: Trunkline High Demand Case
Figure 6-60: Viking Base Demand Case

Figure 6-61: Viking High Demand Case

Figure 6-62: WBI Energy Base Demand Case
6.4.2 Trending Deceasing Capacity Pipelines

There are no major “choke” points for gas deliveries to the MISO Midwest forecasted power generator locations except for NNG north of Ventura, Iowa, and on Northern Border (limited displacement options are available) and Alliance in the near-term. This is the area, roughly within the oval shape on below on Figure 6-64.
Alliance Pipeline is currently re-contracting its system and transitioning from a single-service, single-toll, pipeline system to one offering customers a suite of transportation services and contract tenures to the Chicago market. Alliance is offering capacity on its system for natural gas transportation services effective December 1, 2015. Alliance is a “wet gas” system that transports high Btu natural gas that has high concentrations of natural gas liquids or “NGLs”. In order to provide a fuel specification typically required for a large natural gas-fired combustion turbine, Alliance would have to incorporate extraction and liquids reinjection back onto the pipeline. This presents a type of “gas quality” constraint for power generation without the installation of costly gas processing off any lateral before its end point in Joliet, Illinois.

At this time, it appears that Alliance is at or near capacity based on current contract requirements.

Northern Natural indicated in discussions that allocations are possible for facilities through Farmington into the Scott County, MN area. The customers’ nominated volumes are typically only partially allocated. During a nomination allocation, other receipt points may be available which would allow the customer to continue to operate. According to NNG, they currently have mainline capacity available in both of the areas identified by MISO for the two facilities in Phase III. Additional mainline capacity may be required to serve the entirety of the facility requirements for each plant. With acceptable contracts Northern is willing to expand its system to meet the customer requirements.

Northern Natural Gas Company (Northern) is holding a binding open season for firm transportation service to delivery points between Northern’s interconnect with Northern Border Pipeline Company near Welcome, Minnesota, and Northern’s Paullina, Iowa, compressor station located in Northern’s Market Area. This open season is for service commencing on or after November 1, 2014. Construction is required on Northern’s system to provide the service. Expected facility modifications include a new interconnect with Northern Border Pipeline Company near Windom, Minnesota, and newly constructed pipeline connecting Northern’s system to the proposed interconnect. It is unclear at this point how much of this potential capacity will support the incremental capacity requirements and findings of the MBA.
Northern Border is completely-filled from a forward-haul perspective on an almost year-round basis, according to the Company. In theory, if a pipeline can be sourced from either end it has double the capacity. Gas nominated from a southerly pipeline interconnection with Northern Border to move north on Northern Border can be used by Northern Border for deliveries to the south. Gas nominated from Canada to move south on Northern Border can be used by Northern Border for deliveries to the north. No gas actually physically flows northerly but can achieve a northerly off-take under this type of displacement scenario and assumes contractual firm gas and transportation is nominated at either end every day. While analysis of the Northern Border system indicates little to no available capacity from supply sources located on the western end of its system, it should be noted that Northern Border and its customers have been successfully selling capacity using supply from in and around Chicago to transport gas on a backhaul basis to power plants further upstream on its system. On the Northern Border system this backhaul is physically accomplished by displacing gas flows on the pipeline as there is no need to physically switch the flow direction of the gas. This type of displacement transaction is a direct result of the new shale plays and their impacts on nominated flows on interstate pipelines. Displacement transactions like these generally require no facility expansions and can be provided on a daily basis. When Northern Border is operating at full capacity moving gas from west to east, that physical operation actually increases the reliability for these types of backhaul nominations. Northern Border interconnects that are designed to physically flow gas in one direction can have nominations going in the opposite direction as long as the net of all nominations do not exceed the physical capabilities of the meter itself. These opportunities are well understood by the major players in the gas industry and will need to be better understood and utilized by the electric players. A backcast analysis of pipeline capacity may not expose these types of opportunities and how to effectively utilize a pipeline’s capabilities.
Figure 6-65: Alliance Base Demand Case

Figure 6-66: Alliance High Demand Case

Figure 6-67: Northern Border Base Demand Case (2 CC units)
6.5 Comparison of EnVision Analysis to Bentek Analysis

Similarities between the EnVision and Bentek Analyses include:

- Both analyses confirm the trending towards increased capacity availability in the MISO region.
- Both analyses confirm that changing supply basin dependencies are impacting the flow changes and hence trends toward increased capacity.
- Both analyses agree that there are no major “choke” points for gas deliveries to the MISO Midwest forecasted power generator locations except for NNG north of Ventura, Iowa, and limited capacity options for new firm contracts on Northern Border and Alliance in the near-term through 2015.
- Both analyses confirm that pipeline operations are having a material impact on the flow changes and projected increased capacity and transportation options.
- Both analyses confirm that the MISO region is becoming less dependent on traditional Southwest and Gulf Coast supplies.
- Both analyses confirm that MISO’s regional supply and capacity options have undergone a paradigm shift due to the trends from Anadarko, Appalachian, Bakken and other shale basins since 2008 but have accelerated significantly since 2011 – 2012. In particular, this has caused the acceleration of increased pipeline capacity options over the past two
years and relieved previous concerns about pipeline capacity constraints from the Gulf and Southwest.

- Both Analyses agree that the MISO is well-positioned to capture the benefits of increasing supply options and related pipeline flow changes that have enhanced transportation and capacity options and opportunities.

- Lastly there were no significant differences in the Bentek and EnVision conclusions.

### 6.6 Natural Gas Storage Serving the MISO Region

Storage is another form of pipeline capacity. However, storage deliverability in the MISO footprint could face an infrastructure constraint because of the geology in the region. Natural gas-fired power generation relies on high-deliverability storage. In the MISO Midwest region, storage is limited to aquifer and depleted oil/gas reservoirs that have seasonal injection and withdrawal cycles versus salt cavern storage which has high-deliverability cycling which is available in the MISO South area. Pipelines can have some level of flexibility on injection and withdrawals within a season, but generally, the seasonal schedules must abide by fairly strict physical injection and withdrawal requirements and by tariff conditions. Another alternative may be additional above-ground LNG facilities.

The Midwest has numerous aquifers and reservoirs and a few salt caverns to balance the changing flow dynamics. With more than 1,000 Bcf of working gas storage, the MISO footprint has about 25% of total US working gas capacity of approximately 4 TCF or 4,000 Bcf. (Table 6-2). Working gas capacity is the actual amount of gas that customers inject and withdraw from storage for their needs.
<table>
<thead>
<tr>
<th>Company</th>
<th>Capacity (Bcf)</th>
<th>Capacity %</th>
<th>Working Gas (Bcf)</th>
<th>Working Gas %</th>
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</thead>
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<td>15.88</td>
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<td>54.12</td>
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<td>Blue Water GS</td>
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<td>25.70</td>
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<td>CenterPoint MRT</td>
<td>138.97</td>
<td>6.99</td>
<td>71.40</td>
<td>7.14</td>
</tr>
<tr>
<td>NGPL</td>
<td>616.66</td>
<td>31.00</td>
<td>281.00</td>
<td>28.09</td>
</tr>
<tr>
<td>NNG</td>
<td>216.55</td>
<td>10.89</td>
<td>88.92</td>
<td>8.89</td>
</tr>
<tr>
<td>Southwest GSC</td>
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<td>22.17</td>
<td>2.22</td>
</tr>
<tr>
<td>Texas Gas</td>
<td>179.87</td>
<td>9.04</td>
<td>80.60</td>
<td>8.06</td>
</tr>
<tr>
<td>WBIP</td>
<td>353.35</td>
<td>17.77</td>
<td>193.35</td>
<td>19.33</td>
</tr>
<tr>
<td>Wabash (MGC)</td>
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<td>TBD</td>
<td>14.00</td>
<td>1.40</td>
</tr>
<tr>
<td>TOTAL</td>
<td>1,988.98</td>
<td>100</td>
<td>1,000.4</td>
<td>100</td>
</tr>
</tbody>
</table>

Table 6-2: MISO Midwest Region underground gas storage facilities

Storage facilities are generally owned by the pipeline to which they are attached, however, this is not always the case because independent storage companies can develop their own facilities on a respective pipeline. Pipelines are required to allow transportation in and out of a storage facility under the FERC regulations governing open-access, non-discriminatory transportation.

As shown in history, weather can and does have a huge effect on inventory levels. From a forecasting perspective, the main take-away is that inventory levels remain in line with general historic levels and there will be a slight “tightening” in inventory levels when comparing the difference from peak-to-trough as local supply is able to meet more demand as shown in Figure 6-69. This is the case until LNG comes online in 2017-2019, where the additional demand will decrease total U.S. inventory levels for a few years until additional production increases and helps fill inventory again.
In the MISO South Region, the net storage activity is being reduced due to the lower need for storage gas demand on peak days in the northeast. Local supply can make up for the gap between local storage and daily demand. Nonetheless, inventory levels should remain in line with general historic levels. As shown below in Figure 6-70, there appears to be a slight “tightening” in inventory levels in recent years when comparing the differences from peak-to-trough as local supply is able to meet more demand. This should continue to be the case until LNG comes online in 2017-2019, when the forecasted additional demand will decrease total U.S. inventory levels until additional production maximizes inventory.

Figure 6-69: Midcontinent seasonal, historical gas storage inventory levels and forecast (Source: Bentek Energy)
6.6.1 New Storage in MISO Area Since 2000
Since March 2011, there has not been any new underground natural gas storage added within the MISO Midwest area except with Wabash under development on Midwestern. However since 2000, there have been eleven (11) FERC-certificated projects in the MISO region adding 92.35 Bcf (9.2%) of working gas capacity out of a total working gas capacity of 996.39 Bcf, as shown in Figure 6-71.
Figure 6-71: New gas storage since 2000 (Source: FERC Office of Energy Projects)

1. ANR Pipeline Company (Storage Realignment Project) in Lapeer Cty., MI (Map # 14), 4.1 Bcf Working Gas Capacity, CP04-79, Order date: 8/9/2004
5. Northern Natural Gas Company Redfield Expansion in Dallas Cty., IA, (map # 42), 2 Bcf Working Gas Capacity CP06-461, Order Date: 7/1/2007
6. Northern Natural Gas Company (Redfield Proposal) in Dallas Cty., IA (map # 53), 8 Bcf Working Gas Capacity, CP07-108, Order Date: 3/12/2008
7. Natural Gas Pipeline Company of America (2009 Storage Expansion Project) in Kankakee Cty., IL, (map # 60), 10 Bcf Working Gas Capacity, CP08-32, Order Date: 8/11/2008
8. Tallgrass Interstate Gas Transmission LLC (Huntsman 2009 Expansion Project) Cheyenne Cty., NE (map # 76), 1.2 Bcf Working Gas Capacity, CP09-109, Order Date: 9/30/2009
9. Texas Gas Transmission, LLC in multiple counties in KY, IN (map # 88), 4.1 Bcf Working Gas Capacity, CP10-255, Order Date: 9/16/2010
10. Natural Gas Pipeline of America LLC, Louisa Cty., IA (map # 92), 0.5 Bcf Working Gas Capacity, CP10-452, Order Date:10/21/2010

17 Items 1-11 sourced from FERC Office of Energy Projects,
Storage development has decreased significantly in the last few years with low gas prices and regional pipeline reticulation. It appears that there will be minimal if any new storage development until summer/winter price spreads increase to be competitive with storage rates.

To meet unexpected power generation peaking needs, there is the need for natural high deliverability gas storage development for power generators. However, cost-competitiveness is an issue for power generators when pricing in these types of physical delivery services.

Some the pipelines have indicated that they are considering storage development, but, because of the highly competitive nature of these projects compared to financial hedging and low gas costs and potential new pipeline services from competing pipelines, there is a reluctance to divulge any plans. The only other controllable alternative for a power generator is above-ground liquefaction and re-gasification LNG facilities.

Alternatively, depending on both the operational characteristics of the storage assets of the pipelines, LDCs and wholesale markets, there are a number of gas storage options and services available to the electric power industry. These options include hourly balancing services, temporary loaning and parking services and longer term options that can be accommodated through the use of 30-day cycled salt dome storage and traditional seasonal (summer/winter) injection and withdrawal cycles using underground depleted reservoirs and aquifers. Depending on the asset characteristics, a wide range of services can be available, including pipelines’ use of “line pack” to accommodate temporary storage-like services, which may vary considerably from asset owner to asset owner. Linked to storage options is transportation which is required to move the gas from storage. The pipelines have a wide array of offerings that are available and are allowed by the FERC to offer unique customized, stand-alone services at the request of power generators.

Firm Storage Service provides shippers with the ability to have a pipeline inject, store and withdraw quantities of natural gas on a firm basis. Transportation of storage quantities must be performed under a separate transportation service rate schedule. Transportation service will be provided on a no-notice basis from storage only when such transportation occurs under the
storage transportation services. Storage service transportation provides shippers with firm transportation of natural gas from storage to the shipper's primary delivery points and is provided on a no-notice basis when used in conjunction with firm storage service withdrawals.

Additionally pipelines generally offer many other variations or storage services such as interruptible storage service when sufficient capacity becomes available in a pipeline’s storage fields. This availability will be posted via the pipeline’s electronic bulletin board, (EBB). Service is usually awarded to shippers through a bidding procedure. The shipper must separately arrange for transportation to and from storage.

Parking and Lending Services (PAL) provide the shippers with the ability to hold or receive quantities of natural gas at any point listed on the pipeline’s Master List of Interconnects (MLI) on an interruptible basis. Transportation to and from PAL points is usually arranged under a separate transportation rate schedule.

As another alternative, capacity release options, more flexible operation of the physical facilities and innovative pipeline rate design and service offerings are available and can be developed further to serve more power generation with temporary, load following and intermediary (wind) following services. Pipeline and storage operators need to continually innovate and exploit their flexibility to meet the needs of CTs and CCs with combinations of services or new services that can fulfill the traditional storage roles. Many of the pipelines already offer an array of creative balancing services, variations of firm storage services, and various combinations of no-notice services that combine firm transportation and storage, as well as flexibility for taking gas non-ratably.

While further development of physical gas storage faces financial challenges due to relatively low natural gas prices and financial futures, options and derivatives alternatives, existing storage dynamics are also impacted by increasing pipeline operational flexibility and interconnectivity. Additional “storage-like” service opportunities for power generators are being developed by pipelines in their operational evaluations of how their flow patterns are being impacted by new shale gas supply sources.

Most LDCs will retain their storage. There are minimal amounts of storage available at this time and much of the pipeline infrastructure for firm transportation is used during the summer to
inject natural gas into storage. In some cases, since spare seasonal pipeline capacity may not be available on some pipelines, incremental pipeline infrastructure will be needed to serve an increasing summer power generation market.

Power generators will have to be continually creative in their use of pipeline capacity release opportunities, parking, lending services and other pipeline services as well as operations communication and coordination with the pipelines’ Control Operators to meet summer and winter requirements.

Marketers can play a key role in providing gas delivery capacity to MISO region electric power customers. While LDCs and electric companies hold a majority of capacity on the pipelines, marketers are able to assign long-term capacity to their customers who may be companies that require capacity for future electric power generation projects.

6.7 **Pipeline Infrastructure and Investment Costs**

The impact of future changes in supply development on the flow patterns of pipelines may well allow pipelines to serve incremental power generation load in some instances with no or minimal investment in infrastructure. Generally FERC policy states that existing shippers should not subsidize expansions for new facilities. If new facilities exceed the current rates charged, then the new facilities are charged incremental rates to cover the costs of expansion. The shippers utilizing these new facilities are all charged the incremental rates. An exception to this general rule would be if the pipeline can justify benefits to all shippers as a result of the expansion. This exception to the rule is extremely rare, leaving power generators with four (4) options to obtain firm capacity:

1. Released capacity from existing shipper;
2. Bundled capacity with supply from marketer or asset manager;
3. Contract directly with pipeline or obtain a customized tariff service; or,
4. Pay to build capacity.

Infrastructure investment costs projections for the MISO-identified units in the Phase III scenarios are based on the actual cost calculations by each respective pipeline for the units (CTs and/or CCs) assigned to their pipelines, as provided in detail from the MISO Survey responses.
These costs do not include additional mainline expansion costs that may be required in all instances.

In determining the cost of a pipeline lateral to a facility, pipeline companies select the appropriate equipment for a particular service based on both technical (e.g., flow, pressure ratio, utilization, efficiency) and commercial considerations (e.g., delivered cost, contractual underpinning, etc.).

Also, each pipeline system is the unique result of its age, geographic location, original design, subsequent modifications, and shifting supply/demand patterns. As a result, technologies that may improve efficiency or may be cost effective on one pipeline system may not be feasible or economic on another pipeline system. A “one-size-fits-all” approach to transportation efficiency targets or technology prescriptions, such as mandatory efficiency targets or forced adoption of specific technologies, therefore is not practical. The Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations and requirements may also impact future line repairreplacement costs.

The weight given to these criteria varies from pipeline to pipeline and from application to application. What may improve system efficiency or be cost-effective on one pipeline system may not be cost-effective or practical on another system. Therefore, there is no one-size-fits-all efficiency prescription that will yield desired efficiency improvements on all pipeline systems.

Natural gas pipeline companies’ interstate pipeline projects are based on shippers’ willingness to sign long-term contracts for natural gas transportation, not on the assumption that there will be a future market for natural gas transportation. The shippers’ commitment is needed to raise capital for a project to demonstrate a long-term revenue stream. Also, the Federal Energy Regulatory Commission (“FERC”) is legally required to rule as to the need for a pipeline before it can issue a certificate authorizing the construction and operation of a proposed project. It is easy to see that pipelines are not going to make the capital investments necessary simply by a forecast or a projection of future demand for the capacity. EnVision’s pipeline survey revealed a range of potential costs, shown in Table 6-3, for construction of the laterals required to interconnect the Phase III MISO-forecasted CCs and CTs to a mainline. The total pipeline lateral cost estimates span from $870 million to $1.08 billion.
These costs do not include all the mainline costs associated with moving the natural gas at the required pressures to the power generation facilities. These costs could be substantial, based on data and research done in the Phase I and II Studies and also due to the increasing competition as described below in “Development Cost Uncertainty”. Mainline capacity costs of this nature are speculative due to many remaining uncertainties around how the national pipeline grid, particularly in the electric Eastern Interconnect, will unfold as it undergoes further pipeline reticulation.

It should be noted that natural gas interconnection costs for new gas-fired generating plants will depend on many factors, including the obvious such as the size of the plant and its location relative to existing gas transmission lines, pressure requirements, metering, etc. It is also difficult to give a generalized estimation for pipeline construction cost because it is very dependent on the location, such as urban or rural, environmental topographical factors and other factors and concerns.

Those building pipelines in shale regions can expect higher costs. Pipeline owners are seeing higher construction costs in the shale regions of Marcellus, Eagle Ford, Haynesville, Barnett, Woodford, Fayetteville, and Horn River. After analyzing costs of 120 pipelines from the past decade, some, like Ziff Energy Group’s results show the average estimated shale gas pipeline

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<td>Pipeline 11</td>
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<td>$30.00</td>
</tr>
<tr>
<td>Pipeline 12</td>
<td>$43.00</td>
<td>$43.00</td>
</tr>
<tr>
<td>Total</td>
<td>$869.60</td>
<td>$1,082.23</td>
</tr>
</tbody>
</table>

Table 6-3: Total estimated lateral construction cost ranges
rose in 2011 to almost $200,000/inch-mile, three times higher than 2004. However, the pipelines examined in this Study have indicated cost ranges from $80,000/inch-mile to $175,000/inch-mile.

It has even been noted by general industry observers such as Ziff that the Marcellus shale gas region (Pennsylvania) is the most expensive with an average cost of under $300,000/inch-mile. These large-diameter (24-36 inches) projects are typically 120 miles in length and cost $500 million. The Ziff report attributed rising construction costs to a 30% rise in steel costs in 2013 to along with new industry regulations and practices to reduce right-of-way and minimize environmental effects.

6.7.1 Development Cost Uncertainty
As is discussed in the Phase I and II Studies, the cost of developing new infrastructure projects is extremely volatile as there is always the issue of cost over-run. Cost over-runs can occur due to many reasons such as: market demand-urgency factors, project opposition, fewer equipment and pipe suppliers and regional factors (proximity to cities and other infrastructure) are more frequently issues on new projects.

The current map of North American production regions is evolving more rapidly than pipelines can be built. This is important, because production without "takeaway" pipelines leaves gas and oil stranded, with little or no value. In many shale basins, prices and production being are pressured by a lack of pipeline capacity.

That will lead the industry into another new phase of investment. The first phase of the shale production era saw significant amounts of capital poured into exploration and production companies with shale gas assets. That action is still in play but giving way to a second phase of pipeline development which is being tested by low natural gas prices. Today, natural gas is being “flared” in the Bakken and other shale basins for lack of gas infrastructure, as producers shift their interest to shale-oil production. Regardless of the economy, shale gas, NGL and oil resources will continue to develop. That development is changing the industry's map of flow patterns dramatically. The result implies a period of demand for new and expanded pipeline routes and capacity.

From the supply side, gathering systems feed into mainline systems. On the demand side, end-user requirements call for additional capacity to meet their needs. In between is the balance of pipeline safety, operational reliability and infrastructure financing and cost recovery issues and concerns.

Beyond the next few years, it is difficult to identify specific pipeline projects, but general predictions for new capacity can be made. Most of the capacity will be used to access new supply areas and the expansions will correspond with the increased flows as have been identified earlier in this Analysis. Also, demand-driven infrastructure requires increased regulatory cost recovery clarity.

In addition to regulatory cost recovery uncertainty there are other construction costs and time-cost issues to consider such as the potential for construction delays due to a sudden ramp-up of power generation interconnection requests as the EPA’s April 2015 HAPS MACT deadline requirements swiftly approach. Power generators will find themselves in a competitive bidding war with industrial and LNG developers for the skilled labor and materials (steel, pipes, valves, compressors, meters, etc.) that are needed to build industrial interconnections with the pipelines and build LNG export facilities over the next few years. Not only is this a significant cost issue, but also a major skilled labor and materials availability issue and/or hurdle the industry is facing now.

Producers of new natural gas supplies are helping to drive these pipeline investments by committing to the firm pipeline capacity needed to ensure the deliverability of these new supplies to markets. However, gas distribution companies (LDCs), marketers and power companies are in ever-increasing competition for limited pipeline and storage capacity when there are no expansion projects on the horizon.

While gas demand in the residential, commercial and industrial sectors largely has been flat in recent years, natural gas consumption for power generation has continued to grow as natural gas has become a fuel of choice for power generation. Keeping pace with these changes, midstream infrastructure investments have been substantial, but more is needed to serve the next wave of demand, driven in large part by more stringent power generation environmental regulations and offshore energy-intensive industries returning to onshore or Greenfield
projects. There will be increased contracting tension for pipeline capacity between traditional LDCs, electric power generators, energy-intensive industries and LNG developers.

There is a gap between the timing when the market indicates it is ready to commit to new infrastructure projects and how long it takes supply and infrastructure to respond. If infrastructure utilization approaches 100%, the value of infrastructure capacity increases in the market. The problem is exacerbated through infrastructure cost increases and delivered gas price increases though this usually cannot result in an immediate increase in capacity.

6.7.2 Capital Cost Recovery Uncertainty
Major infrastructure projects today are often sponsored by producers who are reluctant to commit (i.e., cost of warranty) for longer than 10-15 year terms. Since regulated recovery of capital is usually for longer terms, pipeline and storage infrastructure developers are uncertain of recovering new capital investments. An approach to incentivize pipelines and power generators, in particular, is needed to move forward with greater certainty about regulatory cost recovery.

Most current infrastructure was sponsored and constructed during a highly regulated environment when the market supported development with long term purchase, sales and transportation contracts. Since then, LDCs have retreated to “short-term” contracting (1 to 3 years, and maybe as long as 5 years depending on the regulator) versus the 15 to 20 year contracts that built our nation’s “demand-pull” infrastructure 40 to 50 years ago. Short-term perspectives, cost recovery uncertainty, and the right of first refusal (ROFR) provisions of firm transportation contracts are also a source of concern. ROFR provisions, for example, encourage continuous “contract rollover” by firm contract shippers. Under ROFR, the current customer must match the rate (up to the maximum rate) that another customer is willing to pay in order to retain the capacity. Existing customers have the security of knowing that the ROFR provisions will allow them to keep that capacity and match any offer up to the maximum rate, ad infinitum while potential customers have no planning certainty with regard to potential capacity availability and at best, only a short time to react should capacity become available. Pipelines are handicapped in their ability to market the capacity since a customer can retain the capacity even though others in the market are willing to pay more or contract for greater quantities over
a longer term.
The major driver for the Phase I, II and III gas infrastructure studies was the need to better understand the ability of natural gas infrastructure to serve growing demand for gas from power burn, in the context of an evolving gas industry. The tremendous development in the various shale formations at the delivery end of many major pipelines, coupled with producers’ substantial investment in delivery infrastructure to move new production out of the shale plays enable power generators to buy from many competitive sellers and have the security of a new and increasingly reliable, reticulated natural gas pipeline system. This has alleviated many concerns about the ability of natural gas infrastructure to reliably serve growing electric power industry demand. Producers have made significant investments in long-term, firm delivery arrangements on numerous pipelines, resulting in the construction and enhancement of the existing pipeline infrastructure network.

Overall, pipeline capacity availability and the reliability of natural gas deliveries to natural gas-fired power generation facilities in the MISO market footprint are positive. The EnVision analysis and the Bentek forward assessment conclude that:

- There is a clear trend of decreasing sub-regional constraints and increasing pipeline interconnectivity in the Eastern Interconnect that benefit MISO stakeholders.
- Shifting supply and demand fundamentals outside and inside the Midwest will increasingly position the region as a destination rather than a waypoint for gas en route to other markets.
- Increased retention of supply passing through the region, greater diversity of supply options and growth in Bakken production will provide end users with opportunities to reassess transportation and asset portfolios and on desired levels of reliability.
- Strong supply basins in the Northeastern US will continue to impact pipeline flow patterns and increasingly help serve Midwest demand; however, infrastructure expansion is still needed to move gas into the region and to address area-specific capacity constraints.
- End users in the MISO South Region will continue to have access to numerous supply sources due to an exceptionally well-connected pipeline network.
The MBA concludes that 15 of the 18 major interstate pipeline segments that have power generation sited in the MISO Midwest appear to have sufficient capacity availability into their market area to handle the needs of existing and forecasted combustion turbines (CTs) and combined cycle units (CCs), if these units operate at expected capacity factors. If the pipelines that did not have MISO-identified units are included, 17 of the 21 interstate pipelines appear to have sufficient capacity and are trending towards increased capacity availability. The major interstate pipelines are well-positioned to meet the capacity requirements of future power generation.

While the gas delivery system is becoming more robust, the potential for a 3-7 GW resource shortfall in MISO Midwest in 2016/2017 still exists, as uncertainty surrounding commitments to build capacity persists.

7.1 Action Plan
Opportunity exists for electric utilities and other end users to capitalize on current resource and infrastructure investment. Generators, MISO stakeholders, regulators, and pipeline developers need to act now in a collaborative effort to find ways to financially support cost recovery of additional infrastructure that may be needed to deliver gas during the transitional period when EPA regulations are taking effect.

The opportunities for pipeline capacity options are rapidly developing for power generators. However, these developing opportunities from shale gas supplies and pipeline reconfigurations require urgent, critical decision-making to meet the upcoming 2015 EPA requirements and the subsequent transitional years. Decisions must be made while pipelines are formulating plans now to consider how their systems may be operationally re-configured to meet the challenge of increased shale gas supplies and power generation needs. Simultaneously, the availability of pipeline firm contracts is changing due to large number of renewals prior to 2015. Additionally, there must be consideration for the lead-time required for pipeline construction to meet the need of power generators by 2015/2016 and the potential for construction delays due to the anticipated increase in power generation interconnection requests. Lastly, decision-makers must recognize the competing needs for pipeline construction as industrials and other
reshoring industries ramp-up. This will affect the availability of skilled labor and materials and will most likely increase costs for those that postpone decision-making.

The electric power industry must determine its own level of redundancy and reliability requirements and the means to recover costs associated with the value of reliability under its economic models.

Collaboration among members of the gas industry, the electric industry, and regulators have progressed significantly over the past two years as stakeholders work to refine pragmatic capacity solutions to meet future pipeline capacity requirements for gas-fired power generation; however, more needs to be done. Specifically, MISO should support state regulatory bodies in developing an action plan or “Total Energy Solution” that considers aggregate energy demands for both the electric and natural gas industries, and which addresses total resource needs going forward. This action plan should stress planning around natural gas resources in conjunction with electric resource planning, particularly as it impacts gas-fired power generation. Furthermore, it should quantify gas consumption across all sectors, in the context of larger resource adequacy considerations. This effort will require an ongoing commitment amongst all the stakeholders and a higher level of participation than previously seen on a state, regional and national level. The development of state-specific action plans is beyond the scope of this study but such plans need to address the entire gas requirements of each state and the MISO footprint as a whole.

Note: The Appendix is a Separate Document.