ORNL/TM-2016/273

U.S. Natural Gas Storage Capacity and Utilization Outlook

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July 19, 2016

OAK RIDGE NATIONAL LABORATORY
MANAGED BY UT-BATTELLE FOR THE US DEPARTMENT OF ENERGY

ORNL/TM-2016/273

Energy and Transportation Science Division.

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Date Published: July 19, 2016

Prepared
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managed by
UT-BATTELLE, LLC
under contract DE-AC05-00OR22725

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INDEX OF ABBREVIATIONS/TERMS

DOE: U.S. Department of Energy

EPSA: DOE Office of Energy Policy and Systems Analysis

ORNL: Oak Ridge National Laboratory

EIA: Energy Information Administration

FERC: Federal Energy Regulatory Commission

SNL: Energy News & Research Company providing data and analytic services on a subscription basis.

ABB Velocity Suite: Energy Research Company providing data and analytic software on a subscription basis.

LDC: Local distribution companies, investor owned utilities, or municipalities offering gas or power services to the public.

Cubic foot (cf), natural gas: The amount of natural gas contained at standard temperature and pressure (60 degrees Fahrenheit and 14.73 pounds standard per square inch) in a cube whose edges are one foot long.

BCF: The abbreviation for billion cubic feet.

BCF/d: The abbreviation for billion cubic feet per day.

TCF: The abbreviation for trillion cubic feet.

British thermal unit (Btu): The quantity of heat required to raise the temperature of 1 pound of liquid water by 1 degree Fahrenheit at the temperature at which water has its greatest density (approximately 39 degrees Fahrenheit). BTUs are a common unit for natural gas.

MMBtu: One million (10^6) British thermal units.

Dth: Ten therms or 1,000,000 Btu.

Megawatt (MW): One million watts of electricity.

Megawatthour (MWh): One thousand kilowatt-hours or 1million watt-hours.

Kilowatthour (kWh): A measure of electricity defined as a unit of work or energy, measured as 1 kilowatt (1,000watts) of power expended for 1 hour. One kwh is equivalent to 3,412 Btu.

Liquefied natural gas (LNG): Natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.

EXECUTIVE SUMMARY

Natural gas storage facilities are an integral part of the U.S. natural gas infrastructure. Most storage facilities function to modulate the naturally occurring seasonality in demand of natural gas – historically providing a demand sink in the summer when natural gas demand is low and a supply source in the winter when demand is high. Storage facilities are also used by pipelines to maintain operational flexibility and system balance. In the late 1990s, a wave of new high-deliverability storage facilities were constructed as a hedging and risk mitigating tool – not only to take advantage of seasonal price differentials but also to act as physical hedge to mitigate high natural gas price volatility[1], experienced during this period.

However, recent growth in U.S. shale gas production has resulted in lower gas prices and reduced price volatility. The increased availability of natural gas supplies reduced the reliance on natural gas storage facilities as a potential supply source in the winter, and recent warm winters also reduced gas storage utilization. Low price levels and low price volatility have, at least temporarily but dramatically, diminished the value of storage facilities as a tool to mitigate price risks. The market price signals that prompted storage development in the late 1990s have largely disappeared. As a result, almost all pending new storage projects and capacity expansions have been delayed or cancelled.

Growth in seasonal peak demand will increase the needs for seasonal storage services. Growth in power sector gas consumption and the need to compensate for variations in renewable generation may heighten the demand for high deliverability storage that can provide flexible natural gas supplies in a short period of time. Key observations and conclusions of the analysis are summarized below.

The U.S. has a large amount of natural gas storage capacity, most of which is owned by pipeline companies and Local Distribution Companies (LDCs)

The U.S. has approximately 5 Tcf of natural gas storage capacity that is capable of delivering up to 118[2] Bcf/d of natural gas supplies. This maximum deliverability exceeds the highest historical average end use natural gas consumption observed in the U.S., in January 2014. Approximately 55% of working gas capacity is owned and operated by pipeline companies, 26% by local distribution companies, investor owned utilities, or municipalities (collectively "LDCs"), and the remaining capacity (18%) is owned by independent storage operators. Correspondingly, 54% of storage deliverability is owned by pipelines, 27% by LDCs, and 27% by independent storage service providers. Pipeline or LDC owned storage facilities are primarily low-deliverability fields while the high deliverability salt domes are primarily owned by independent operators.

[1] Volatility reflects how much prices can move over a certain period of time in percentage terms. For example, 100% annualized volatility indicates that the prices could likely move up or down by 100% in a year. The higher the volatility, the more dramatic price path can be.

[2] This reflects maximum storage deliverability for all U.S. storage facilities, the maximum withdrawal amount at full inventory level. Most storage facilities have "ratchets", which means that withdrawal capabilities decreases with inventory levels.

Due to the exceptional production growth from shale resources and moderate demand growth, storage facilities in some regions are fully utilized only under extreme weather conditions.

The maximum inventory level reached has surpassed 80% for all regions except the Mountain region which has seen a maximum inventory level of 52%. Peak storage deliverability occurred during the winter of 2013-2014 for all regions. The regions with the highest peak storage deliverability utilization are the Mountain and Pacific regions at about 80% during mid December 2013. The East, Midwest, and South Central regions had peak day withdrawals at a more modest level of 46%, 68%, and 46% respectively during the first half of January 2014. Despite cold weather, maximum storage withdrawals in January 2014 were well below maximum deliverability capabilities due to relatively low inventory levels and pipeline constraints.[3]

The persistence of low price levels, decreased demand seasonality, and decreased price volatility has stalled storage expansion.

High price levels, large price differentials between summer and winter, or extreme price volatility provide opportunities for storage capacity owners to profit from the price movements using the flexibility of storage capacity, creating market incentives for sustained storage developments. However, expected seasonal spreads observed in the NYMEX natural gas futures market have been in constant decline in recent years, as a result of robust growth of shale production outpacing growth in gas demand. The steady growth in gas production outpaced any modest increase in seasonal demand; thereby reducing seasonal price spreads. Consequently, storage capacity expansion has virtually stopped in the past couple of years and planned expansion projects mostly delayed or cancelled.

The aggregated market needs for incremental storage capacity in the U.S. are limited under both cases analyzed by ICF.

EPSA provided ICF with two natural gas market projections, based on separate analysis performed in conjunction with the Quadrennial Energy Review. The EPSA Base Case reflects a market environment with readily available economic natural gas and oil resources in the US that increases natural gas demand, mainly from power sector growth in the South Atlantic region and LNG exports out of the Gulf. Expected demand from these sectors could improve the utilization of existing storage capacity in the Gulf coast states, however, no incremental storage development is necessary. As demand from other regions remains flat, the incremental needs for natural gas infrastructure, including storage capacity remain low.

The EPSA Low Oil and Gas Resource (LOGR) case reflects an environment with wide application of energy efficiency measures and renewable generation in the power sector as well as low oil and gas resource levels throughout the continent. The scenario projects very moderate growth in residential and commercial demand which does not increase the peak demand levels or raise demand seasonality. Demand from the power sector is decreasing over time; overall, there is very limited need for incremental natural gas infrastructure in general and storage capacity in particular. However, regional needs may exist

[3] December 2013 was relatively cold in the Northeast that had prompted higher than normal storage withdrawals, reducing storage inventory levels. In January 2014, the wide spread simultaneous cold weather throughout the U.S. East created pipeline capacity constraints that prevented more storage gas supplies from the Gulf Coast regions.

for natural gas infrastructure and/or storage capacity to meet the needs from the power sector. Improved utilization of storage capacity is expected to support renewable generation under the LOGR Case.

In New England, the power sector may face natural gas supply constraints if no incremental infrastructure is specifically built for the power sector.

Under the EPSA Base Case, New England LDCs are able to meet residential and commercial demand in all days through 2035, using a combination of existing pipeline transportation capacity, LNG peak shaving facilities and expected expansions. However, without incremental gas infrastructure, there could potentially be shortfall in capacity available for the power sector by 2025. The EPSA LOGR Case projects similar trends for New England that also require incremental natural gas infrastructure to be developed for the power sector, though the infrastructure gap is shorter in duration and smaller in size.

As New England does not have the geology for underground storage facilities, other approaches are require to meet the need for incremental natural gas supplies.[4] The gap could be met with either LNG peak shaving storage, additional pipeline capacity, or a combination of both. Increased LNG imports could also help address the needs, but this adds complications, such as supply uncertainty and global price exposure. Ultimately, the choice for incremental gas infrastructure into New England, will depend on political, environmental, and regulatory factors, in addition to a cost-benefit comparisons of the different options.

In California, there is limited need for incremental storage capacity in aggregate. Limited constraints could exist based on physical connections to specific load centers. In addition, the significant growth in renewable generation could generate need for more storage capabilities to compensate for the intermittent nature of renewable resources.

Under the EPSA Base Case Projections, demand for gas from the power sector increases moderately over time and the hourly requirements from the power sector approach the limit of the storage availability without Aliso Canyon, meaning the potential exists for power market disruptions.

Under the EPSA LOGR Case projections, natural gas demand in California is declining, on an annual average basis, from an average of 6.5 Bcf/d in 2016 to 5.8 Bcf/d in 2035. The demand for natural gas from the power sector, is expected to decline at more than 3% per year to nearly 50% of 2016 demand levels by 2035. During the same period, annual generation from renewable resources is expected to grow from 80 billion Kwh a year in 2016 to 200 billion Kwh a year by 2035.

Under this projection outlook, there is no need for incremental natural gas infrastructure in aggregate. Even the decommissioning of the Aliso Canyon storage facility would have very limited impacts on supply sufficiency to the region as a whole. However, the Aliso Canyon storage facility is critical in providing natural gas fuels to several large gas fired generators in the Los Angeles area. The reduced service level

[4] It is also possible that the need for incremental gas supplies into New England could be reduced through measures such as increased energy efficiency, demand response, and fuel switching; however, a comprehensive assessment of all energy options is beyond the scope of this study, which focuses on the future need for gas storage.

from Aliso Canyon could make fuel supply disruptions to these generators more likely and impact grid security for a short period of time.

Under the EPSA LOGR and Base Cases, utilization of existing high-deliverability storage facilities in the Gulf Coast could improve due to LNG exports and growing needs from the power sector

Under the EPSA Base Case Projections, gas demand for power generation grows at over 4% a year in the South Atlantic region, which will increase the daily demand from 6.5 Bcf/d to 7.5 Bcf/d by 2035. Given several already planned pipeline expansions, gas infrastructure is sufficient to meet the increase in needs for natural gas supplies. However, the needs for intra-day flexibility and the intermittent and instantaneous demand from the power sector in these regions could improve the utilization of the upstream storage facilities in the Gulf coast. Expected LNG exports in the region could also lead to improved utilization of the storage facilities in the Gulf Coast as LNG suppliers need to support potential supply disruptions.

Under the LOGR Case, renewable generation growth could increase needs for natural gas infrastructure in SERC and FRCC if electric storage or other technology to firm up the intermittent nature of renewable generation is not widely deployed in the next twenty years. The dramatic increase in renewable generation will require fast dispatch gas generators to act as a compensating measure, among others, when the power is not available. However, neither region has the geology to develop natural gas storage facilities. Construction of additional pipeline capacity to near-by Gulf Coast region, where sufficient storage facilities exist, could help alleviate this problem by increasing both regions' access to flexible, high deliverability facilities.

U.S. NATURAL GAS STORAGE OVERVIEW

INTRODUCTION

ICF was engaged by the Oak Ridge National Laboratory (ORNL) in support of the U.S. Department of Energy's Energy Policy and Systems Analysis Office (EPSA) to study the U.S. natural gas storage market, as part of a larger study which also includes sections on the Natural Gas Outlook and Vulnerability, Ethane Market Outlook, and Liquefied Natural Gas.

EPSA sought to answer a few key questions regarding the role of natural storage in the future; as natural gas demand and supply conditions evolve in the U.S., will there be sufficient U.S. storage capacity in the future to meet the market's needs? What role will storage play? To help answer these questions, ICF reviewed recent storage utilization and valuation trends across the U.S. using public and proprietary databases, and identified future market needs for storage capacity with its modeling and forecasting tool – the Gas Market Model (GMM) – using a range of market assumptions provided by EPSA.

Major conclusions have been presented in the Executive summary, supporting evidence is presented in the following sections of the report.

US STORAGE FIELD CHARACTERISTICS

All storage fields in the US report their total working gas capacity, total field capacity, and maximum daily deliverability. ICF compiled these statistics using EIA's data sets. Working gas capacity refers to the amount of gas available for injections and withdrawals. Total field capacity refers to working gas capacity plus base gas which is gas that is necessary to have in storage at all times in order to maintain operational standards. Daily deliverability is the maximum amount of gas that any given storage facility can dispatch in a single day. As of the end of 2014, there were more than over 400 storage facilities in the U.S. with nearly 4.8 Tcf of working gas capacity and capable of delivering more than 118 Bcf/d of supplies. They consist of 333 depleted fields, 46 aquifers and 39 salt dome facilities, as shown in Table 1.

Table 1: US Lower 48 Storage Characteristics

	Number of Fields by Type	Working Gas Capacity (Bcf)	% of Total Working Gas Capacity	Total Field Capacity (Bcf)	% of Total Field Capacity	Maximum Daily Deliverability (Bcf/d)	% of Total Maximum Daily Deliver-ability [5]
Aquifer	46	452	9%	1445	16%	9.7	8%
Depleted Field	333	3845	80%	7086	77%	75.5	64%
Salt Dome	39	489	10%	703	8%	33.1	28%
Total	**418**	**4786**	**100%**	**9233**	**100%**	**118.3**	**100%**

Source: EIA, ABB Velocity Suite, ICF

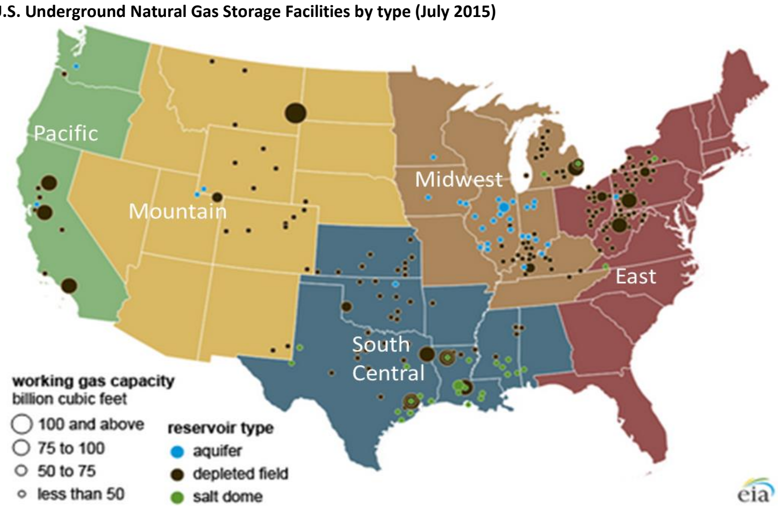
[5] Maximum deliverability is the operationally maximum storage withdrawal capabilities when the storage facility is nearly full. Depleted fields tend to have more pronounced "ratchets" than salt dome storage facilities, the negative correlation of the storage withdrawal capability with the inventory level.

As shown in Figure 1, depleted fields are depleted natural gas or oil reservoirs, scattered throughout most U.S. regions with storage facilities. They typically require a long injection season with moderate withdrawals during winter months. Even though depleted fields represent 80% of total working gas capacity, they only account for 64% of total maximum daily deliverability capabilities.

Aquifer storage facilities are converted natural aquifers with water-bearing sedimentary rock formation overlaid with an impermeable cap rock. Aquifer storage typically requires larger base gas reserves and allow for less flexibility in injecting and withdrawing. Aquifers make up 9% of working gas capacity and 8% of maximum daily deliverability in the U.S. The Midwest has the most aquifer storage.

Salt dome storage facilities are naturally formed salt caverns shaped into a dome structure through leaching and dissolving the salt. Most salt dome storage facilities are located in the Gulf Coast states (South Central storage region) while a few exist in the Midwest and East regions. Salt dome storage requires very little base gas, and provides high deliverability rates relative to working gas capacity. In the U.S., salt dome facilities account for 10% of working gas capacity and 28% of maximum daily deliverability.

Figure 1: U.S. Underground Natural Gas Storage Facilities by type (July 2015)



Source: EIA

STORAGE OWNERSHIP AND FIRM SHIPPERS

As shown in Table 2, 55% of U.S. natural gas storage working gas capacity is owned and operated by interstate and intrastate pipeline companies, 26% by local distribution companies, investor owned utilities or municipalities (collectively "LDCs"), and the remaining capacity is owned by independent storage operators.

Correspondingly, 46% of deliverability is owned by pipelines, 27% by LDCs and 27% by independent storage service providers. Independently owned storage facilities typically have higher deliverability than pipeline or Utility owned storage facilities.

Table 2 - Storage Capacity by Owner Type

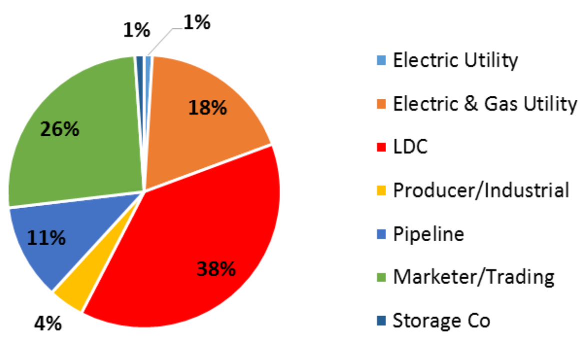
	Working Gas Capacity (Bcf)	% of Total	Maximum Deliverability (Bcf/d)	% of Total
Pipeline	2649	55%	54	46%
LDC	1259	26%	32	27%
Independent	877	18%	32	27%
Grand Total	**4786**	**100%**	**118**	**100%**

Source: EIA, ICF

The storage facilities owned by utilities are used by themselves to meet their customers' needs. On the other hand, the majority of storage facilities owned and operated by pipeline and independent service providers are contracted by third-party shippers.

ICF identified the composition of these third-party shippers using the Index of Customers data released by all interstate pipelines and certain independent storage operators every quarter. The Index of Customers data covers nearly 80% of total US storage capacity owned and operated by pipelines and independent storage operators. According to the most recent index of customers data from fourth quarter 2015, among the 2270 Bcf of storage capacity, 38% of the capacity is contracted by natural Gas LDCs, 18% by power & gas utilities and 26% by marketers &/or traders.

Figure 2: Contracted Storage Capacity by Shipper Industry



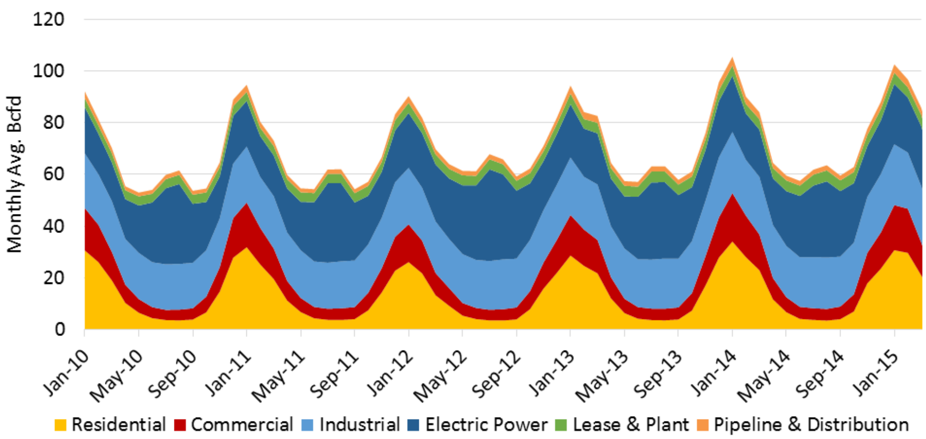
Source: ABB Velocity Suite, ICF

STORAGE CAPACITY UTILIZATION

DEMAND SEASONALITY

As discussed earlier, a large amount of storage capacity is either owned or firmly contracted by natural gas and electric utilities to offset the naturally occurring seasonal pattern of U.S. natural gas demand. As shown in Figure 3, the peak monthly average demand in the U.S. exceeds 100 Bcf/d while the lowest months are less than 60 Bcf/d. The seasonal demand difference requires natural gas storage as a key supply source in winter time since natural gas production is steady on a monthly basis. The seasonality of natural gas demand depends on weather, when winter is cold, the seasonal demand pattern is peakier when more gas is needed during the winter months, which were the cases for the winters of 2013-2014 and 2014-2015. The weather normalized natural gas demand seasonality remains relatively stable over time.

Figure 3: Monthly U.S. Demand

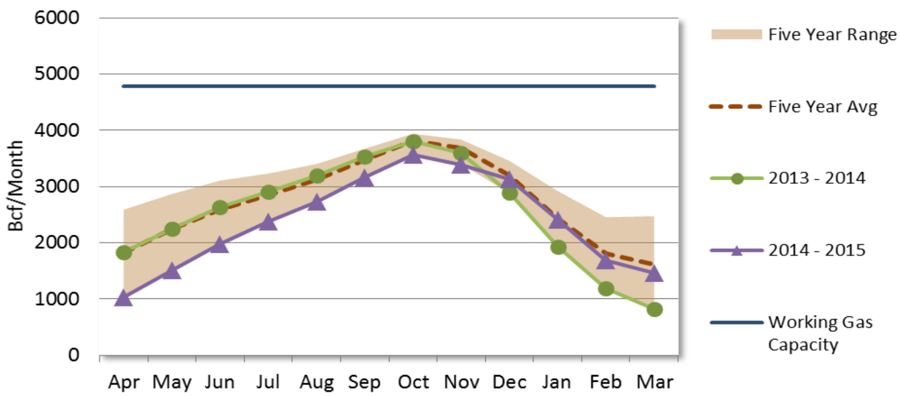


Source: EIA

Natural gas is injected into storage facilities in the summer time when seasonal demand is relatively low and withdrawn in winter time as an incremental supply source. Therefore, the utilization of storage capacity follows a distinct seasonal pattern, with gas inventory in the storage built up from April through October, and withdrawn down to the lowest level in March.

Figure 4 shows that for the past five years, storage inventory level range was fairly narrow from September to November, while much wider in other months depending on market and weather conditions. This shows that the U.S. has enough flexibility in storage operation to achieve an appropriate storage inventory ready for the upcoming winter. For example, persistent colder than normal weather starting in November, during the 2013 – 2014 winter, drained storage inventory to unprecedented levels in December. The shortage of gas supplies during cold snaps in January through March caused dramatic price spikes in many parts of the country. Despite the historic depletion, storage inventory was built back to the normal range for the 2014-2015 winter.

Figure 4: US Storage Inventory



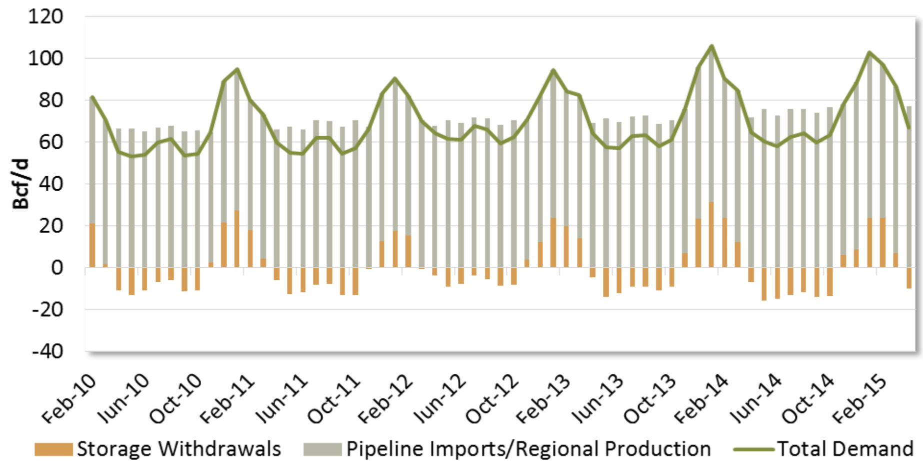
Source: EIA

US DEMAND AND SUPPLY BALANCE

From a total supply and demand balance perspective, the role of storage in meeting U.S. natural gas demand has not changed very significantly despite a major production uptick over the past five years. The usage pattern reflects the fact that most storage capacity is contracted for long-term capacity and owned by local distribution companies, whose usage for the facility depends upon their seasonal needs for natural gas. The percentage of winter demand met by storage supplies ranges between 20% to 26%, fluctuating with winter weather conditions as seen in

Figure 5. As will be discussed later, higher production dampens the value and utilization of high deliverability salt dome facilities.

Figure 5: Historical Monthly U.S. Demand and Supply Balance



Source: EIA

REGIONAL STORAGE INVENTORY

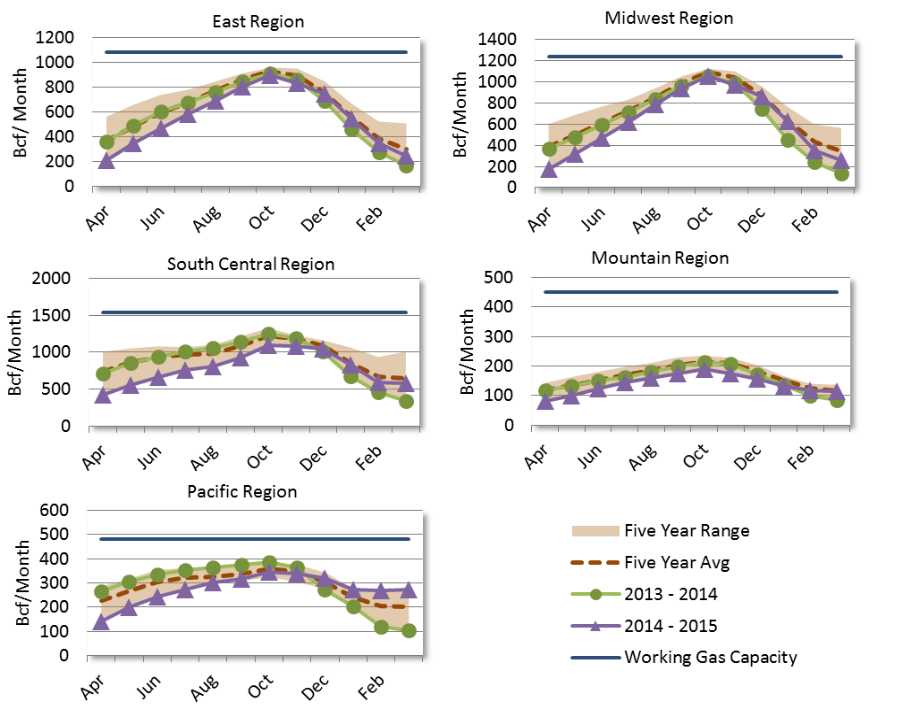
The Energy Information Administration reports natural gas storage data for five regions in the U.S.; the East, Midwest, Mountain, South Central, and Pacific. Storage inventory by region for the last 5 years on record are depicted in

Figure 6 and summarized in Table 3. The East and Midwest regions' storage inventory levels are fairly consistent with maximum inventory utilization nearing 90%. The approximate peak storage deliverability utilization is estimated at 46% and 68% for the East and Midwest regions respectively during the 2013-2014 winter.

Historically, the Mountain region has the least utilized storage inventory with a max inventory utilization of 52%, however the Mountain region's approximate peak storage deliverability utilization was 82% in December 2013. The Pacific region is comparably well utilized with a maximum inventory utilization of 80%, and an approximate peak storage deliverability utilization of 79%. The South Central region has a fairly wide range of inventory utilization with maximum of 86%, and a peak storage deliverability utilization of 46%.

Figure 6: Storage Inventory by Region

U.S. Natural Gas Storage Capacity and Utilization Outlook



Source: EIA, ICF

Table 3 – Historical Storage Utilization (2010 – 2015)

	Working Gas Capacity (Bcf)	Max Daily Deliver-ability (Bcfd)	Max Inventory Level (Bcf)	Max Inventory Utilization	Approximate Peak storage deliverability day [6]	Approximate Peak Storage Deliverability Day Utilization [7]
East	1080	24.5	960	89%	11.2	46%
Midwest	1233	28.4	1123	91%	19.3	68%
Mountain	450	3.7	235	52%	3.0	82%
Pacific	483	10.5	386	80%	8.3	79%
South Central	1541	51.1	1327	86%	23.7	46%
Total US Lower 48	4786	118.3	3939	82%	56.6	48%

Source: EIA, ABB Velocity Suite, ICF

[6] ICF first identified the highest withdrawal week for the period using EIA weekly withdrawal data. ICF then analyzed pipeline and storage operator publicly available data to identify the peak day withdrawal during the peak withdrawal week.
[7] ICF then used the peak withdrawal quantity and applied it to the regions maximum daily deliverability capacity to obtain a peak day withdrawal utilization.

East

The East region has nearly all of its storage facilities located in the Appalachian Basin production region, which primarily spans Pennsylvania, New York, Ohio, and West Virginia. Nearly all of the region's storage capacity and deliverability is comprised of depleted reservoirs. Several major markets in the East lack easy access to this storage, including: New England, the Southeast, and Florida. Winter demand peak could become higher with cold weather in the region because of both residential and commercial demand, as well as demand for gas from the electric sector could increase as a response to cold weather conditions. This phenomenon was observed for the past two colder than normal winters.

The region's storage capacity has been heavily utilized in the past five years. There is no under-utilized storage capacity that could offer additional flexibility. All the East region prices exhibit relatively pronounced seasonality, but only limited storage expansion opportunities exist. Recent working gas capacity additions have mostly been concentrated in the Marcellus production regions in Pennsylvania, West Virginia and Ohio. Natural gas infrastructure, including storage capacity, might become constrained during the winter season, resulting in price spikes and extreme price volatility. Additional pipeline infrastructure to important market centers might be needed for the market to take advantage of supplies from production or storage. As the region's reliance on natural gas fired power generators grows to replace retired facilities using coal or oil, the location of these facilities will need to be optimized to consider their proximity to production, storage facilities, or population centers.

Midwest

There is sufficient natural gas storage capacity in Midwest to meet the region's seasonal demand needs under a wide range of weather conditions. The extreme cold weather in the 2013-2014 winter represents a 1 in 66 year occurrence, with less than 2% probability. The region's access to a wide range of supply sources provide a diversified hedging portfolio for filling up the regions storage facilities. The seasonal withdrawal and injection patterns are expected to continue as LDCs in the region continue to use storage as an important supply source to meet winter customer needs, even with incremental pipeline capacity from the Marcellus/Utica production region.

South Central

There is sufficient natural gas storage capacity in South Central to meet the region's modest demand seasonality as well as the higher winter gas requirements from the exports markets. The salt dome storage facilities in the region are currently underutilized. The primary entities using the salt dome storage are marketers and gas trading companies, and recent low natural gas prices and low price volatility has squeezed the potential profit margin from trading these assets. The quick turn, flexible salt dome storage capacity could become important service providers for load flowing to power plants that require intra-day quick start up or ramp down due to electric load profile and backing up renewable generation, as well as LNG facilities that could facilitate globally trading opportunities.

Mountain

Storage capacity is underutilized in the Mountain region. On an average year natural gas inventory volumes do not exceed 50% of existing working gas capacity. Sufficient production and pipeline capacity exist to meet seasonality of regional demand. Rocky mountain gas has been driven out of the Midwest and East markets by the production growth from the Marcellus/Utica shale. The Pacific Northwest market lacks strong demand growth for natural gas or strong seasonality for winter peak needs

If power generation will be the growth engine of future demand, the physical capabilities of regional storage facilities need to be enhanced to help power plants with intra-day load following services or support quick start gas generation as back up for renewable resources.

Pacific

Storage capacity is sufficient to meet the market needs in the Pacific region. Maximum storage fill in the past five years only reached less than 80% of existing working gas capacity. Maximum withdrawals only reached approximately 60% of the maximum deliverability. The shrinking differential between summer and winter demand peaks indicates a dual-peak seasonal pattern of demand in the region. As a result, storage operation may not strictly follow a seasonal pattern. Frequent summer withdrawals and winter injections are required.

August, and to a lesser extent, July are becoming peak demand months that require net storage withdrawals to meet power demand needs. Storage owned by SoCal gas is more actively used than storage operated by PG&E as Northern California has more supply flexibility from pipeline imports and independent storage facilities. Independently operated storage facilities provide more flexibility and respond more quickly to daily demand fluctuations. Daily storage operations of these facilities have increasingly become non-seasonal in nature. Storage facilities may become crucial following the intra-day electric load fluctuations during the peak summer months of July and August.

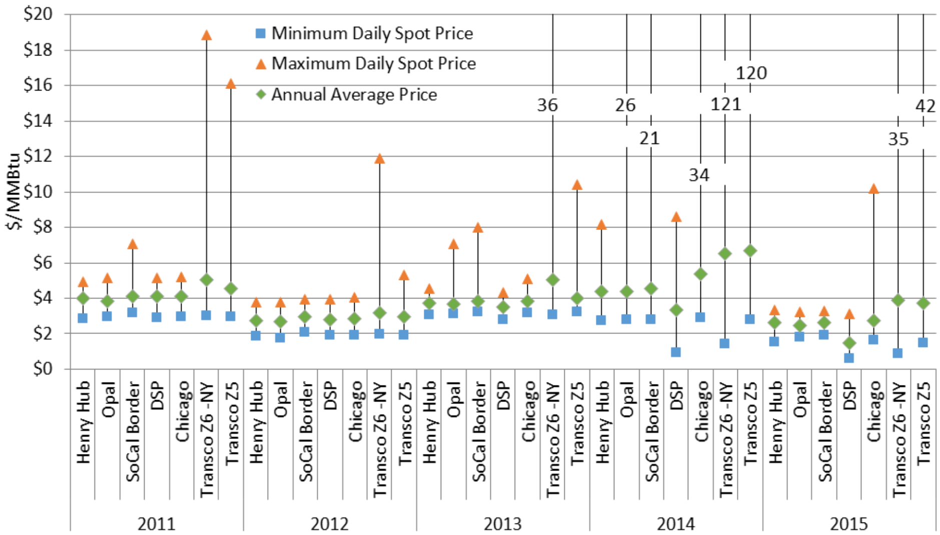
Regional Prices

The representative gas prices over the past five years in each storage region are shown in Figure 7. The East region is represented by three different price points, representing Northeast production, and Northeast and Southeast markets. The South Central, Mountain, and Pacific markets (represented by Henry Hub, Opal, and SoCal Border respectively) remain fairly stable throughout the period, with Opal and SoCal border peaking above $20/MMBtu in February of 2014. These regions all have underutilized storage capacities and this is reflected in their price history.

In contrast the Northeast and Southeast market prices (represented by Transco Z6-NY and Transco Z5 respectively) consistently spike during winter months, and peaked in January 2014 above $120/MMBtu, surpassing $30/MMBtu on several days during that winter. The production area of the East, represented by Dominion South Point remained stable throughout the period, including peak winter demand seasons – even during the 2013-2014 winter when it rose to only $8.63/MMBtu.

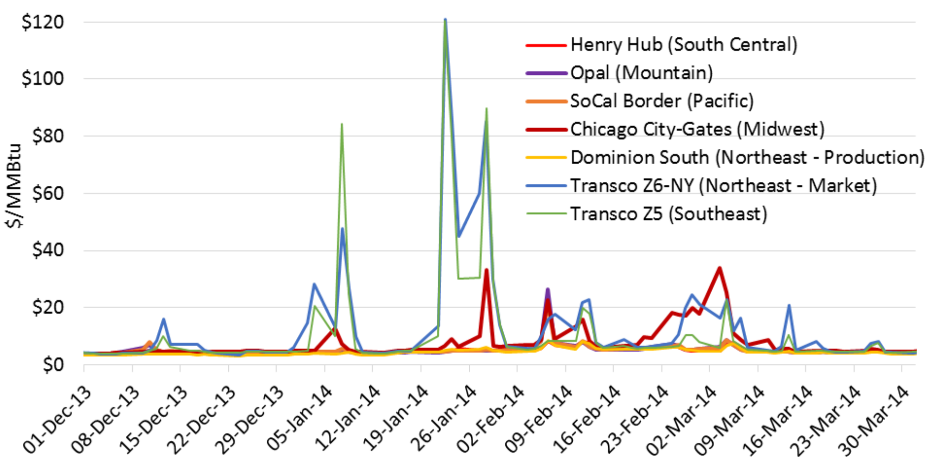
The Midwest region's representative price point (Chicago City-Gates) shows a more modest trend, with exceptional peaks during winter months but not nearly as high as Eastern markets. The Midwest has ample storage capacity that is largely underutilized and therefore it stands to reason that its markets were less constrained than that of the East during the 2013-2014 winter.

Figure 7: Representative Regional Prices - Historical



Source: SNL

Figure 8: Representative Daily Regional Prices – Winter 2013-2014



Source: SNL

Table 4: Representative Regional Prices – Peak Day Price & Date – Winter 2013 - 2014

	Henry Hub (South Central)	Opal (Mountain)	SoCal Border (Pacific)	Chicago City -Gates (Midwest)	Dominion South (Northeast - Production)	Transco Z6-NY (Northeast - Market)	Transco Z5 (Southeast)
Peak Price	$ 8.15	$ 26.36	$ 21.22	$ 34.00	$ 8.63	$ 120.75	$ 120.25
Peak Day	11-Feb-14	6-Feb-14	6-Feb-14	3-Mar-14	6-Feb-14	22-Jan-14	22-Jan-14

Source: SNL

VALUE OF STORAGE AND STORAGE CAPACITY ADDITIONS

DEFINITION OF STORAGE VALUE

The value of storage has been closely related to the way storage facilities are owned and operated over time.

Regulated Valuation

Prior to 1994, interstate pipelines owned natural gas transportation and storage facilities as well as the natural gas that utilizes the infrastructure. Storage capacity and utilization were controlled entirely by these companies.

With the implementation of FERC Order 636[8], interstate pipelines were required to operate their storage facilities on an open-access basis, which turned the pipeline companies into the storage facilities' owner &/or operator, forcing them to offer their storage capacity in the open market. Shippers who pay for the firm use of the storage capacity control the actual utilization of these storage facilities.

As is the case with interstate pipeline capacity, the firm contract rate for storage capacity is determined by the Cost of Service approach. The cost of providing storage services is based on the capital cost of storage facilities, depreciation, regulated rate of return on investment, regulated debt/equity structure, A&G costs and O&M costs.

Market Based Valuation

In 2006, FERC Chairman Joseph T. Kelliher observed that "since 1988, natural gas demand in the United States has risen 24 percent. Over the same period, gas storage capacity has increased only 1.4 percent. While construction of storage capacity has lagged behind the demand for natural gas, we have seen record levels of price volatility. This suggests that current storage capacity is inadequate. Further, this year, what storage capacity exists may be full far earlier than in any previous year. According to some analysts, that raises the prospect that some domestic gas production may be shut-in."

As a response, FERC enacted the following rule in 2006 that provides two approaches for developers of natural gas storage facilities to seek authority to charge market-based rates. For a storage facility that

[8] http://www.eia.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/ferc636.html

charges market based rates, the value of the facility is correspondingly estimated based on market and price drivers with the underlying assumption that the storage capacity allows the capacity owners to arbitrage gas price differentials over time. A market based valuation of storage facility consists of two key components:

- Intrinsic Value. Seasonal price spreads which the storage capacity owner can lock-in today in the forward markets by optimizing storage withdrawals and injections. If the storage capacity is located closer to the Henry Hub pricing point, the intrinsic value can be locked in using NYMEX prices. If the storage capacity is located at other regional markets, NYMEX prices and forward basis are both required.
- Extrinsic Value. Incremental value that the owner can realize by re-optimizing storage withdrawals and injections according to spot and forward price movements.

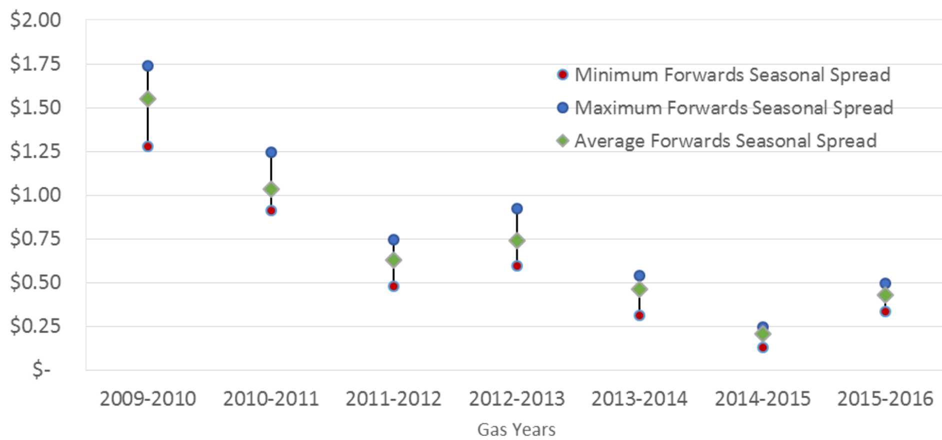
DRIVERS OF STORAGE VALUE

For regulated storage facilities, the value of the facility and the rate the shippers of capacity are determined by the set of regulatory parameters: rate of return allowed on the asset, depreciation and O&M/A&G costs. None of these drivers is likely greatly influenced by market developments.

For storage facilities with market based rates, however, the value of the facilities is closely related to market developments. Besides the physical characteristics of the storage capacity, the key value drivers for intrinsic value is the seasonal spreads, defined as the differentials between summer and winter gas prices. The bigger the seasonal spreads, the higher the intrinsic value for storage as owners of storage capacity can withdraw and sell gas at a much higher price than the cost of gas they inject into the storage.

The extrinsic value of storage is primarily influenced by natural gas price volatility and correlations. Higher price volatility and low correlation between spot and forward curves provide more opportunity for the capacity owner to trade the injection and withdrawal capabilities of the storage capacity and realize higher profit. For example, if the spot market price is prone to spikes, the storage owner can withdraw gas from the storage and buy the same gas back and inject when gas prices return to normal levels. Figure 9 describes the seasonal spreads change over the past seven gas years; ICF calculated the range of seasonal spreads as the average peak winter months (December, January, and March) forward prices minus average injection month (April, May, June, September, and October) forward prices for the next gas year (April – Oct) during the three months prior to the start of the next gas year. For example, January 2015 through March 2015 for the 2015 to 2016 gas year.

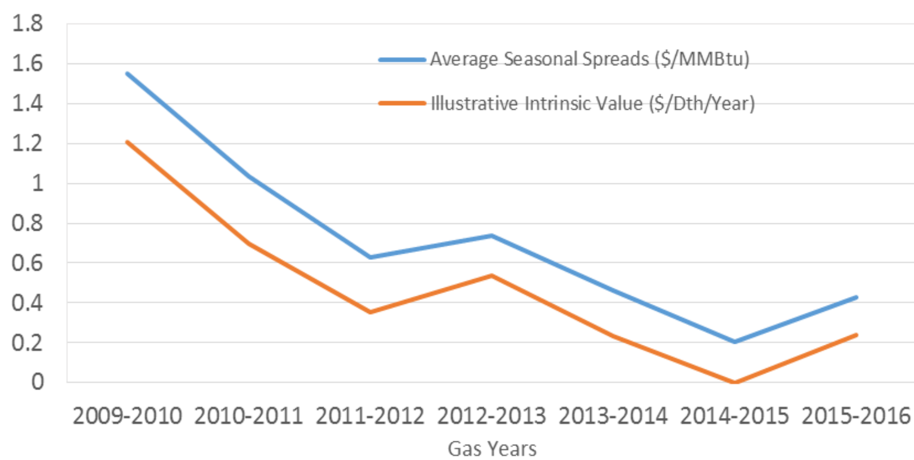
Figure 9: Range of Seasonal Spreads



Source: SNL

As a result, the intrinsic value of storage declined significantly over recent years, as shown in Figure 10.

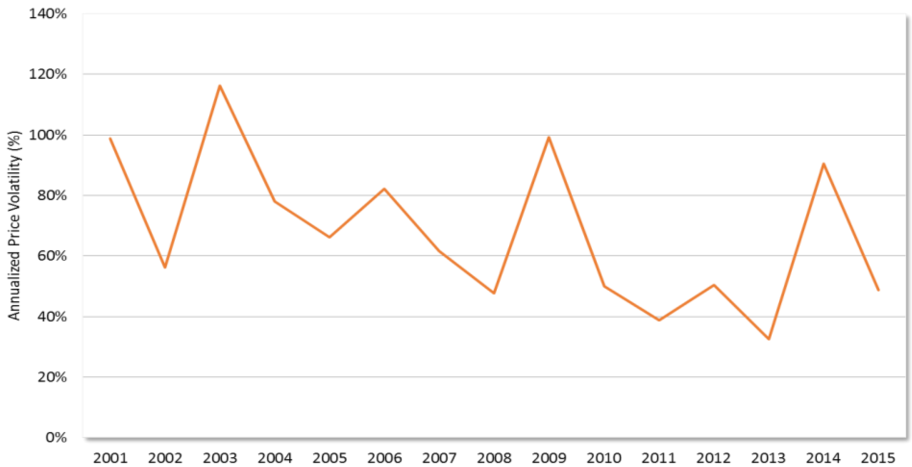
Figure 10: Average Seasonal Spreads vs. Illustrative Storage Intrinsic Value



Source: ICF

In addition, natural gas price volatility also experienced a similar trend, as shown in Figure 11. Average gas price volatility at Henry Hub for the past three years, is approximately 60% of the average levels reached in the 2001-2005 time period. Accordingly, the extrinsic value of storage capacity will be approximately 60% or less of the 2001-2005 value. Natural gas price volatility reflects a complex set of market drivers, such as weather, market demand and supply balance, trading behavior, general expectation of supply availability, etc. A tight demand and supply balanced market is conducive to higher volatility levels since demand increases might trigger strong competition in a tight market environment and can drive the price up significantly over a short period of time. On the other hand, if the market has surplus supply, any demand increase will be met readily with minimum impact on price levels.

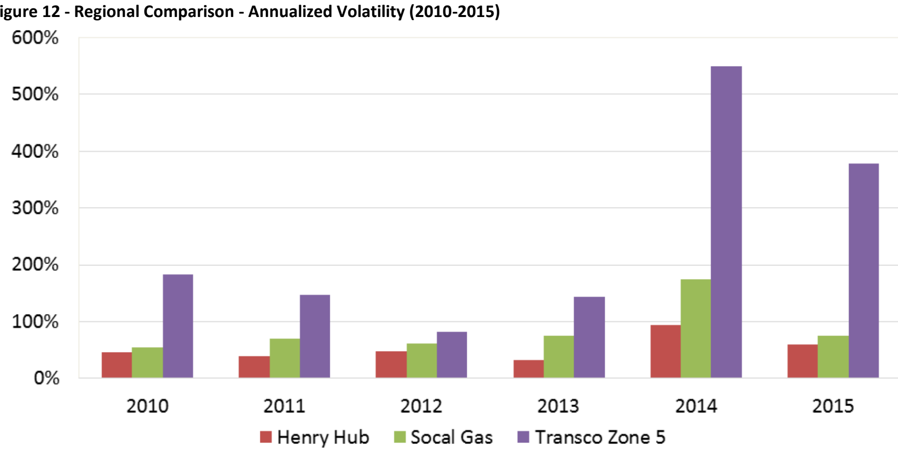
Figure 11: Annualized Henry Hub Gas Price Volatility



Source: ICF

As shown in Figure 12, gas price volatility at the SoCal Border, a gas pricing point for Southern California, experienced a similar trend as Henry Hub. But volatility levels at Transco Zone 5, representative pricing point for Virginia, spiked up to extremely high levels during the past two years due mainly to the extreme cold winter during both years. This shows that the value for storage capacity serving markets with high demand sensitivity to weather still holds steady.

Figure 12 - Regional Comparison - Annualized Volatility (2010-2015)

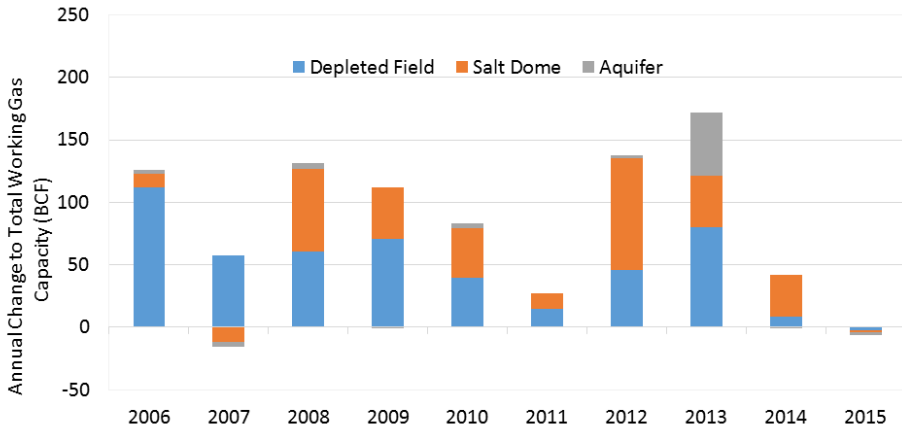


Source: SNL, ICF

Storage Capacity Expansion Figure 13 shows U.S. storage working gas capacity[9] change over time. Following the FERC rule change of 2006 granting new storage developers the ability to charge market based rates, there was marked growth in Storage capacity additions. From 2006 to 2013 approximately 830 Bcf of storage capacity was added in the U.S. Much of this growth was due to an increase in high-deliverability salt cavern storage, which was supported by the need for more flexibility as the gas market expanded.

Since 2013 there have been no new storage facilities added. Instead, capacity additions have stemmed from existing field expansions. The process slowed down significantly in 2014 and there was a net decrease in capacity in 2015 due to field abandonment or derating. According to FERC records, applications for new projects or announced expansion plans have all but disappeared in the last couple of years. This is consistent with the market value of storage drastically declining, as discussed above. There will be limited market incentives to develop incremental storage capacity under the current environment in most regions.

Figure 13: U.S. Working Gas Storage Capacity Additions



Source: EIA

Table 5: U.S. Working Gas Storage Capacity Additions (Net Change vs. Prior Year)

[9] This chart reflects change of total working gas capacity and not pad gas capacity.

U.S. Natural Gas Storage Capacity and Utilization Outlook

	Depleted Field	Salt Dome	Aquifer
2006	112	11	3
2007	58	-12	-4
2008	61	66	5
2009	71	41	-1
2010	39	40	4
2011	15	12	0
2012	46	90	2
2013	80	42	50
2014	9	33	-1
2015	-2	-1	-2

Source: EIA

U.S. NATURAL GAS MARKET OUTLOOK

ICF was asked to assess the needs and potential roles for U.S. storage capacity under two projected future market scenarios: EPSA Base Case and EPSA HOGR Case. Under both cases, the projected demand through 2035 in each sector – residential, commercial, industrial and power, for each census region is directly provided by EPSA.

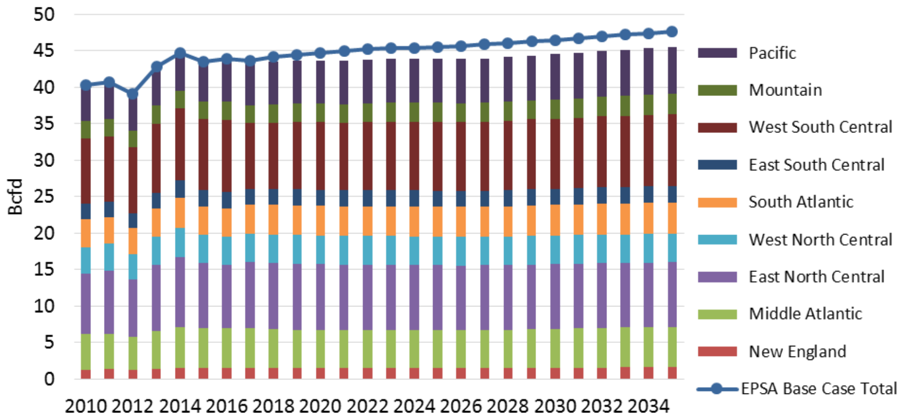
The EPSA Base Case reflects a market outlook with very limited demand growth from the residential and commercial sectors. Industrial sector demand grows very modestly while demand from the power sector declines significantly due to sustained renewable penetration. Overall, total gas demand in the U.S. declines from an annual average of 68 Bcf/d in 2016 to 63 Bcf/d in 2035.

The EPSA HOGR Case reflects a comparably more optimistic outlook for U.S. gas demand. Under the EPSA HOGR case, total U. S. natural gas demand increases from 70 Bcf/d in 2016 to 83 Bcf/d in 2035. However, the majority of the demand growth comes from power sector demand in the South Atlantic and Midwest (East & West North Central) regions. Other regional demand remains flat through the projection period.

RESIDENTIAL, COMMERCIAL AND INDUSTRIAL DEMAND

The eastern storage region represented here by New England, Mid-Atlantic, and South Atlantic see very low demand growth in the RCI sectors under the EPSA base case and slight growth in the EPSA Base case. RCI sector growth is highest in the Pacific with about 1% growth under both scenarios. RCI demand does not eclipse 1% in any of the remaining regions and is flat to declining in the Midwest (East & North Central).

Figure 14: Natural Gas Demand by Census Region- RCI – EPSA LOGR Case & Base Case



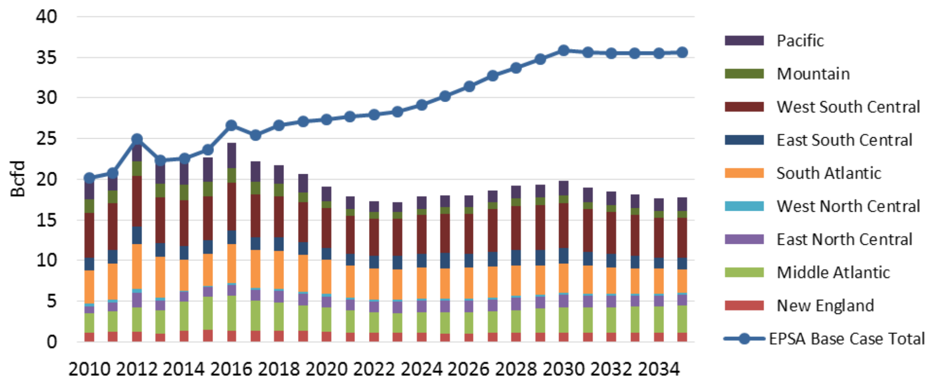
		New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
2015-2035 CAGR	LOGR	0.3%	0.0%	0.0%	0.1%	0.5%	0.0%	0.0%	0.6%	1.1%
	Base	0.6%	0.2%	-0.1%	0.2%	0.9%	0.4%	0.6%	0.9%	1.0%

Source: ICF

DEMAND FOR GAS FROM THE POWER SECTOR

Demand for natural gas from the power sector varies widely between the two cases, as renewable penetration is the driving difference between the LOGR case and the Base case. The EPSA LOGR case forecasts a decline in consumption from the power sector in all regions except the Midwest (East & North Central). The EPSA Base case also forecasts very moderate to flat demand in the Pacific, Mountain, South Central and Northeastern (New England & Mid-Atlantic) markets. The South Atlantic and Midwest markets are forecast to grow between 3% and 6% per year throughout the projection.

Figure 15: Natural Gas Demand by Census Region- Power – EPSA LOGR Case & Base Case

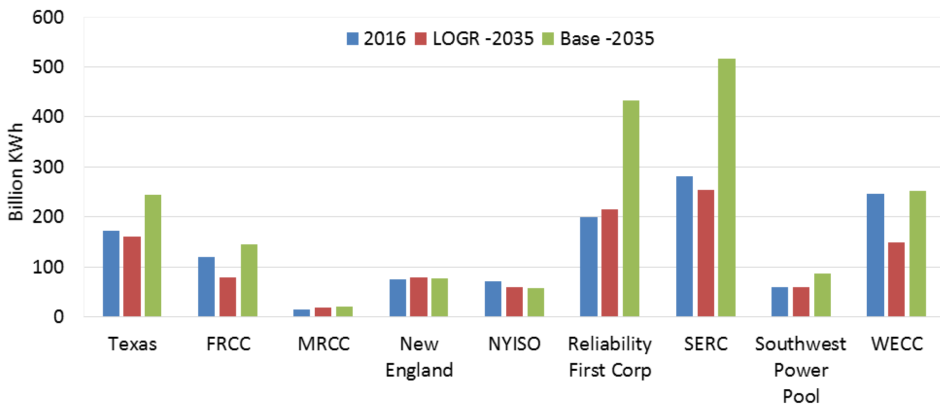


		New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
2015-2035 CAGR	LOGR	-1.2%	-1.0%	0.5%	2.8%	-1.7%	-0.6%	-0.5%	-3.4%	-3.1%
	Base	0.1%	-0.3%	3.4%	5.7%	4.8%	1.4%	2.3%	0.4%	0.4%

Source: ICF

Figure 16 presents the demand for natural gas from power generation in terms of power sector consumption by major power supply districts. Reliability First Corp and SERC show the greatest growth in the HOGR case as they consist of South Atlantic and Midwest Markets predominately.

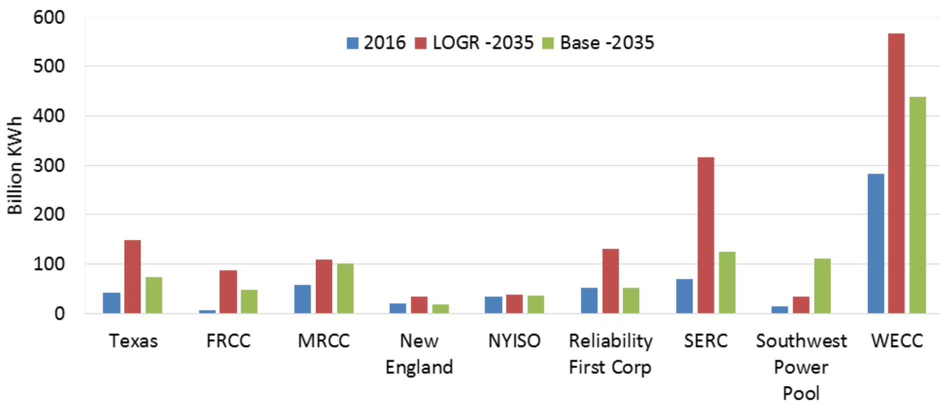
Figure 16: Power Generation from Natural Gas – EPSA Base Case & LOGR Case (Billion KWh Annually)



Source: ICF

Figure 17 presents the demand for renewables from power generation in terms of power sector consumption by major power supply districts. Most districts show a steep decline in the HOGR case as renewables are assumed to have lower market penetration in the HOGR case, leaving natural gas to fill in the void.

Figure 17: Power Generation from Renewables– EPSA Base Case & LOGR Case (Billion KWh Annually)



Source: ICF

MARKET NEEDS FOR NATURAL GAS STORAGE CAPACITY

ICF assessed the market needs for storage capacity across the U.S. under the EPSA Base Case and EPSA HOGR Case scenarios. To identify incremental needs for capacity, ICF focused on the following regional developments that could prompt needs for additional storage capacity or storage services:

- Growth in the highly seasonal gas demand from the residential and commercial sector. If the residential and commercial sector demand grows significantly, seasonal demand differentials will widen between winter and summer, resulting in need for seasonal supply sources, such as storage.
- Growth in power sector demand with limited pipeline capacity to handle intra-day flexibility. Natural gas pipelines are designed to transport and deliver gas on a steady flow rate basis, with every hour flowing 1/24 of the daily quantity. The power demand for gas, however, typically follows intra-day electric load fluctuations, and may need gas supplies for a few peak hours only and no gas needs for off-peak hours. Pipeline line pack[10] could provide some flexibility to accommodate this requirement, but storage is a reliable source that could provide almost instantaneous gas supplies.

[10] Pipeline line pack are the volumes accumulated in the pipeline during non-peak demand hours that can be drawn down during the peak demand hour. The pipelines are designed to hold line pack to meet firm customers' needs. However, for some power customers who only utilize the pipeline on an interruptible basis, pipelines may not be able to provide the hourly flexibility required using their line pack.

- The variable nature of renewable generation. Wind and Solar generation is variable in nature. If the renewable resource is not available to dispatch during peak hours, another fast dispatch resource, typically a gas-fired power plant will be called upon to maintain grid integrity.
- Supply optimization or disruption safeguards for LNG export volumes. Shippers at LNG export terminals may require storage capacity to optimize their gas supplies, purchasing gas when prices are lower and injecting into storage and shipping supplies when prices are high. In addition, natural gas supply could be used to house the gas supplies when liquefaction operation is disrupted.

U.S.

Considering the U.S. as an aggregate, under the EPSA LOGR Case projection, U.S. demand for natural gas decreases over time. The needs for additional infrastructure, including storage facilities, decreases. As described previously, recent history shows that the U.S. has significant storage capability and is capable of restoring storage inventory quickly back to normal levels even after an extreme draw down during the 2013-2014 Polar Vortex winter. With declining demand projected in the EPSA LOGR Case, there is no market signal to add storage capacity in regions where capacity could be expanded. Market incentives for storage investment, such as seasonal spreads, or price volatility are not expected to recover from the current depressed levels. However, as we will discuss in detail below, several regions present unique challenges.

Under the EPSA Base Case, the growth of U.S. total gas demand increases moderately. However, the growth is concentrated in South Atlantic. As demand in other regions remains flat, no aggregate needs for incremental capacity is identified.

New England

New England is located at the end of the natural gas supply infrastructure, and has traditionally relyed on supplies from Eastern Canada, the Gulf Coast, LNG imports, and peak shaving facilities. For example, in 2005, approximately 20% of New England's gas needs are met with LNG imports, 30% from Western Canada, 15% from Eastern Canada, and 30% from Gulf Coast/Midcontinent. Marcellus supplied less than 5% of New England's demand.

Commented [JS(1]: "Since November 2010, LNG has supplied about 25% of New England's daily natural gas demand and, on a peak day, LNG in the winter has sometimes accounted for 60% of New England's total natural gas supply needs." EIA "Short-Term Energy Outlook Supplement: Constraints in New England likely to affect regional energy prices this winter."

The recent production boom in the Marcellus/Utica basin coupled with declining production from Eastern Canada, has caused notable pipeline capacity into the region from the west in winter season.

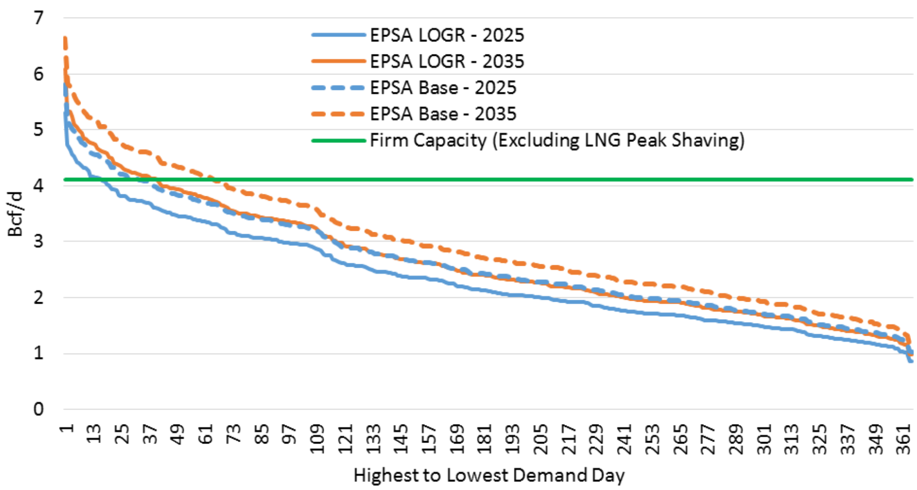
The current natural gas market in New England is more volatile than most other regions in the U.S. because the LDCs own the majority of firm natural gas transportation capacity and peak shaving facilities, while the power sector typically relies upon "interruptible" (non-firm) transportation capacity or spot gas for fuel supplies. During cold winter days, when residential and commercial demand is high, LDCs need to utilize their capacity to meet customer demand. As a result, non-firm capacity and spot gas becomes scarce, and natural gas prices spike. New England's whole sale market power price is determined by the bids from the marginal generators, which are more than likely gas generators. During days when gas prices spike, the marginal generator's costs could be extremely high, leading to high power prices across the grid.

Therefore, infrastructure constraints in New England have negative ramifications beyond the natural gas market. It is critical to assess how New England market demand grows in the future and identify feasible gas infrastructure solutions to fix the problem.

ICF constructed load duration curves for years 2025 and 2035 under the EPSA LOGR Case and EPSA Base Case. The load duration curve arranges the daily demand from the highest to the lowest demand days based on normal weather patterns. Firm natural gas supply sources are dispatched to meet the daily demand. If daily demand exceeds firm supply sources, supply "gaps" are identified, which means some demand may not be met and price spikes could be expected.

Figure 18: New England Load Duration Curves – 2025 and 2035

Commented [JS(2]: Including all LNG terminal send out capacity? Or is that included in the "LNG Peak Shaving." (Everett, Canaport, Neptune and Northeast Gateway).



Source: ICF

Under both cases, New England needs incremental natural gas infrastructure to meet potential demand growth for the power sector during the highest demand days of the year. LDCs are able to meet residential and commercial demand in all days through 2035, using a combination of firm pipeline transportation capacity and LNG peak shaving facilities. If no dedicated infrastructure or firm gas supply contracts are designed for the power sector, especially after 2030, the sector may not have the fuel supplies it needs to dispatch some generators in winter days, which could result in electric price spikes. The extent and consequences of this lack of supply is beyond the scope of this study.

Under the EPSA LOGR Case, assuming LDCs will utilize their peak shaving facilities for 10-days in the winter, ICF observes a potential 10-day gap in available capacity for the power sector in 2025, with the maximum daily gap of 260 MMcf/d and average gap of 120 MMcf/d. By 2035, the number of days that the power sector may not have sufficient capacity for fuel increases to 32, with a maximum daily gap of 770 MMcf/d and average gap of 355 MMcf/d. Under the EPSA Base Case, the 2025 gap starts at 30 days and increases to more than 45 days by 2035.

Under the EPSA LOGR Case, ICF expects the needs for four peak-shaving facilities, at 1.1 Bcf each; each facility can deliver 60 MMcf/d of natural gas for 18 days and will cost $120 million to construct. Total capital costs for the proposed facilities are $480 million. A natural gas pipeline with 600 MMcf/d of incremental capacity could also be a solution.

Other options, such as oil back-up or LNG imports could be potential economic solutions. However, each has its own disadvantages - specifically, adverse environmental impacts for oil back-up, and global market and price dependency for LNG imports.

Under the EPSA Base Case, since the duration of potential gaps exceeds 30 days, ICF expects a long-term solution, such as a natural gas pipeline would be more appropriate.

Commented [JS(3]: This is at least not coupled to the price impacts of that all pipelines into NE are subject to (namely, price adders from going through PJM, NY or Canada).

Commented [JS(4]: Do these exist? How much pipe was built because of this? In the model?

California

Currently sufficient supply sources, including natural gas pipelines and storage facilities, meet demand needs from all sectors while the regional prices have remained relatively stable compared to other markets.

According to the EPSA projection, natural gas demand in California is declining, on an annual average basis, from an average of 6.5 Bcf/d in 2016 to 5.8 Bcf/d in 2035. The demand for natural gas from the power sector, is expected to decline at more than 3% a year to nearly 50% of 2016 demand levels by 2035. Therefore, on an annual average basis, California will not need any incremental natural gas infrastructure.

However, the recent incident at Aliso Canyon has called into question the long-term stability of the facility. In the short-term, because of the critical nature of the facility's connection to nearby natural gas fired power plants, emergency measures need to be put into place to manage the reduced deliverability from the facility.[11]

Under the EPSA LOGR Case, considering the power sector needs to take the daily gas requirements on a condensed hourly basis, on a 12 to 16 hour period, rather than the normal 24-hour period that the gas infrastructure is designed for, the natural gas deliverability surplus is below 200 MMcf/hour without Aliso Canyon. In addition, both EPSA cases assume that California will increasingly rely upon renewable resources to meet its electric load requirement. Annual generation from renewable resources is expected to grow from 80 billion Kwh a year in 2016 to 200 billion Kwh a year by 2035.

However, all renewable resources are subject to fluctuations of nature and could become unavailable on some days or hours, which may require natural gas generators to dispatch immediately, baring other

[11] For details on the Aliso Canyon action plan, see: http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Action_Plan_to_Preserve_Gas_and_Electric_Reliability_for_the_Los_Angeles_Basin.pdf and http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-02/TN211671_20160527T164305_Aliso_Canyon_Update.pdf

measures to mitigate renewable intermittency. The higher the renewable generation volatility, the higher the requirements for standby ready natural gas supplies.

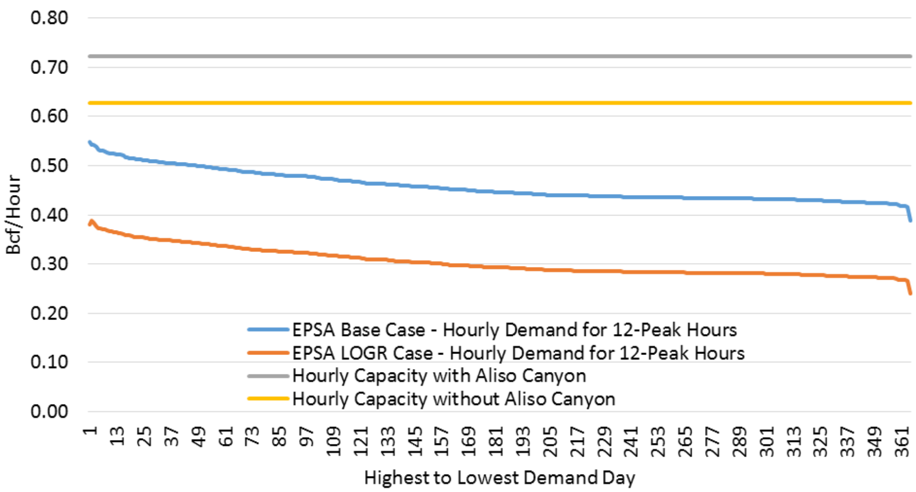
In 2035, with a total of 200 billion Kwh of annual renewable generation, average hourly renewable generation is approximately 22831 MWh.

If a certain percentage of this hourly renewable generation is not available, incremental pipeline capacity and supply needs are needed for gas fired power generators to compensate for the loss of renewable generation. For example, it is not atypical for wind or solar resources to exhibit a 10% swing of generation on an hour-to-hour basis, which could result in an incremental need of 0.3 Bcf/hour of additional gas supplies.

Under the EPSA Base Case Projections, demand for gas from the power sector increases moderately over time and the hourly requirements from the power sector nearly reach the storage availability without Aliso Canyon, which could result in possible power market disruptions.

Overall, as shown in Figure 19, there might not be sufficient surplus deliverability in the CA infrastructure to deal with the peak hourly power sector disruptions or uncertainties under both cases without Aliso Canyon.

Figure 19: Representative Hourly Demand Requirement with Condensed Power Demand (Bcf/Hour) California



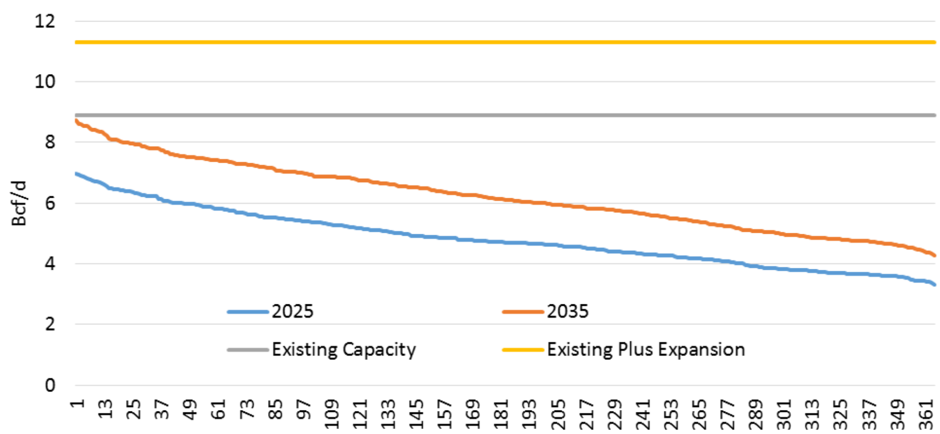
Gulf Coast and South Atlantic

EPSA LOGR Case projects nearly 11 Bcf/d of LNG volumes will be exported out of the Gulf Coast LNG terminals by 2035. Under the EPSA Base Case, the LNG volumes are projected to exceed more than 25 Bcf/d. As the traditional natural gas supply region, the existing, reversing, and expanding natural gas pipeline capacity to the Gulf Coast region would have sufficient infrastructure to meet the regional demand and the LNG exports under the EPSA LOGR Case. However, there may be needs for incremental infrastructure to meet the LNG export assumptions under the Base Case.

High-turn salt dome storage facilities in the Gulf Coast currently can provide up to 51 Bcf/d of deliverability to the region. The capacity is currently under-utilized and/or under contracted.[12] These storage facilities can be utilized to provide supplies to the LNG export terminals, eliminating needs to construct long transportation back to the production basins.

Under the EPSA Base Case, the South Atlantic is projected to have exceptional demand growth from the power sector. ICF assessed if the key South Atlantic states, South Carolina, North Carolina and Georgia will have sufficient natural gas infrastructure to meet the demand increase. Based on current pipeline capacity and expected new projects that could deliver into these states, ICF did not identify incremental capacity needs to meet the demand growth in these three states, as illustrated in Figure 20.

Figure 20: North Carolina, South Carolina, and Georgia Load Duration Curves – 2025 and 2035 – EPSA Base Case



[12] The recent expansions in storage capacity in the Gulf region were extremely low cost expansions from existing high deliverability fields.

CONCLUSIONS

ICF reviewed the historical utilization of storage capacity in the U.S. and observed that due to the exceptional production growth from shale resources and moderate demand growth, storage facilities in some regions are currently underutilized. Even with the extreme conditions of the 2013/2014 Polar Vortex winter, U.S. storage inventory levels recovered quickly to within normal range for the 2014/2015 winter season.

After analyzing the demand projections for the EPSA LOGR Case and Base Case, ICF identified very limited aggregated market needs for incremental storage capacity in the U.S. The recent slowdown of planned capacity expansions imply that this is consistent with market expectations.

EPSA LOGR Case projects very moderate growth in residential and commercial demand, at approximately 0.3% per year, which does not increase the peak demand levels or raise demand seasonality. Demand from the power sector is decreasing over time; overall, there is very limited need for incremental natural gas infrastructure in general and storage capacity in particular. However, regional needs may exist for natural gas infrastructure and/or storage capacity to meet the needs from the power sector. Improved utilization of storage capacity is expected to support renewable generation under the Base Case.

EPSA Base Case projects increased needs for natural gas demand, mainly from power sector growth in the South Atlantic region and LNG exports out of the Gulf Coast. As demand from other regions remains flat, the incremental needs for storage capacity remain low. Expected demand from these sectors could improve the utilization of current capacity in the Gulf coast states, however, no incremental storage development is expected.

On a regional basis, ICF identifies continued infrastructure constraints in New England, which, under the EPSA LOGR Case, could be solved by LNG peak shaving facilities and/or a combinations with pipeline expansions, or LNG imports. Under the EPSA Base Case, a solution that could address long duration constraints, such as a natural gas pipeline expansion.

In California, current infrastructure is sufficient to meet demand needs under both the EPSA Base Case and HOGR Case. If Aliso Canyon is out of commission, however, California could face peak hour constraints because power plants take daily fuel needs in condensed hours. Extremely high reliance on renewable generation could also increase needs for flexible supply sources, which may render Aliso Canyon necessary for reliability purposes.

LNG exports out of the Gulf Coast under the EPSA HOGR Case and power demand growth from South Atlantic will improve the utilization of high deliverability storage facilities in the Gulf. However, large scale expansions are not expected.