Eastern Interconnection Planning Collaborative

EIPC Gas-Electric System Interface Study

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NERC Workshop: Gas Infrastructure Risk

July 10, 2018

LEVITAN & ASSOCIATES, INC.

MARKET DESIGN, ECONOMICS AND POWER SYSTEMS

Acknowledgement and Disclaimer

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Acknowledgement:

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Disclaimers:

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Overview

- Study Overview
- Study Highlights
- Baseline Assessment (Target 1)
- Adequacy Analysis (Target 2)
- Hydraulic Analysis (Target 3)
- Fuel Assurance Analysis (Target 4)
- Relevance of NERC Recommendations

Study Overview – Four Targets

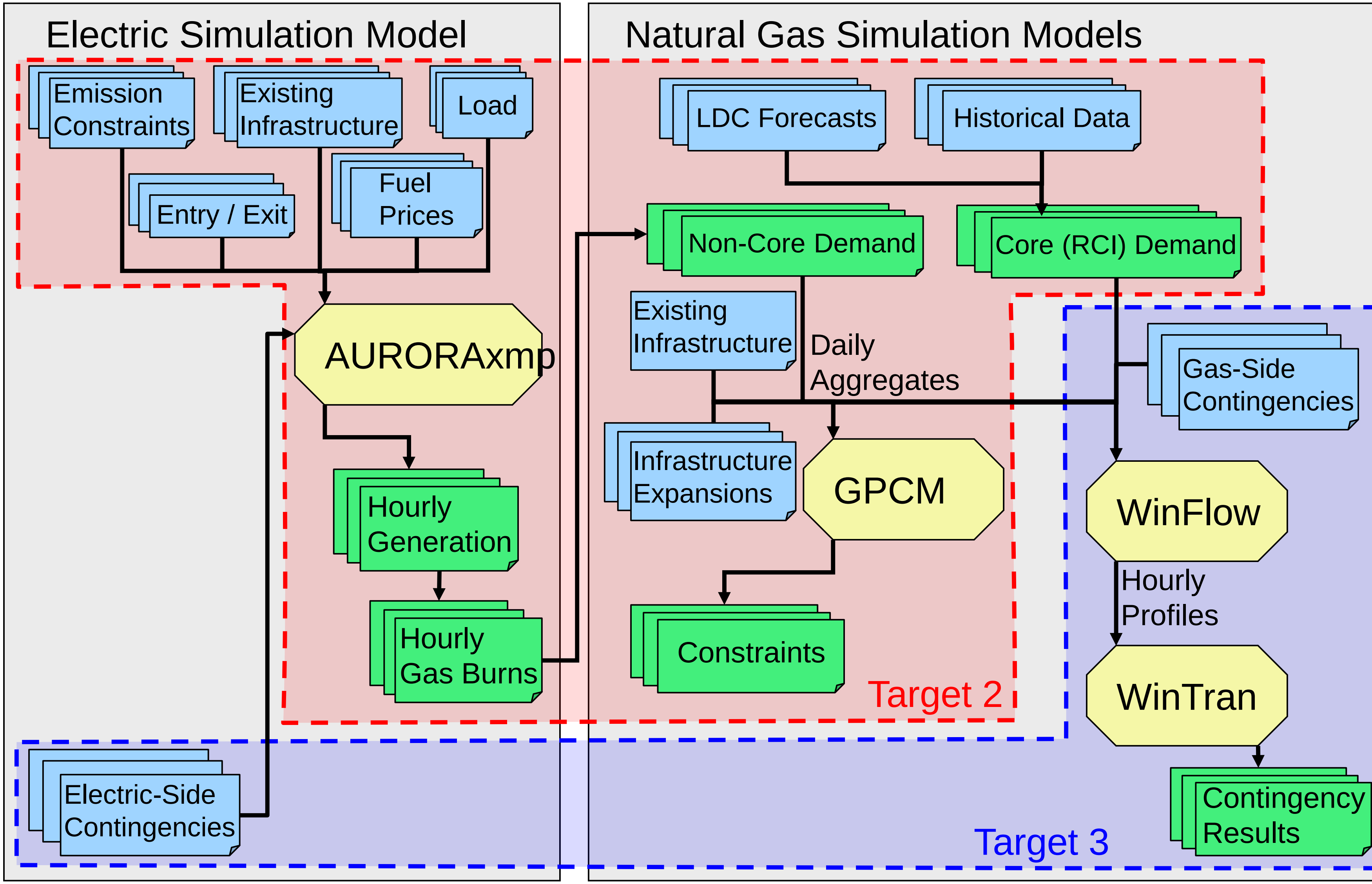
- Target 1: Develop baseline assessment of natural gas-electric system interfaces, interaction effects, and the current level of coordination between the electric and gas systems

- Target 2: Evaluate capability of the natural gas systems to supply the electric power sector fuel requirements over a five and ten year study horizon while serving higher priority firm shippers

- Target 3: Identify contingencies on the natural gas & electric systems that could adversely affect electric system reliability

- Target 4: Review operational / planning issues related to dual fuel capability, including the net benefits of fuel assurance alternatives

Model Framework



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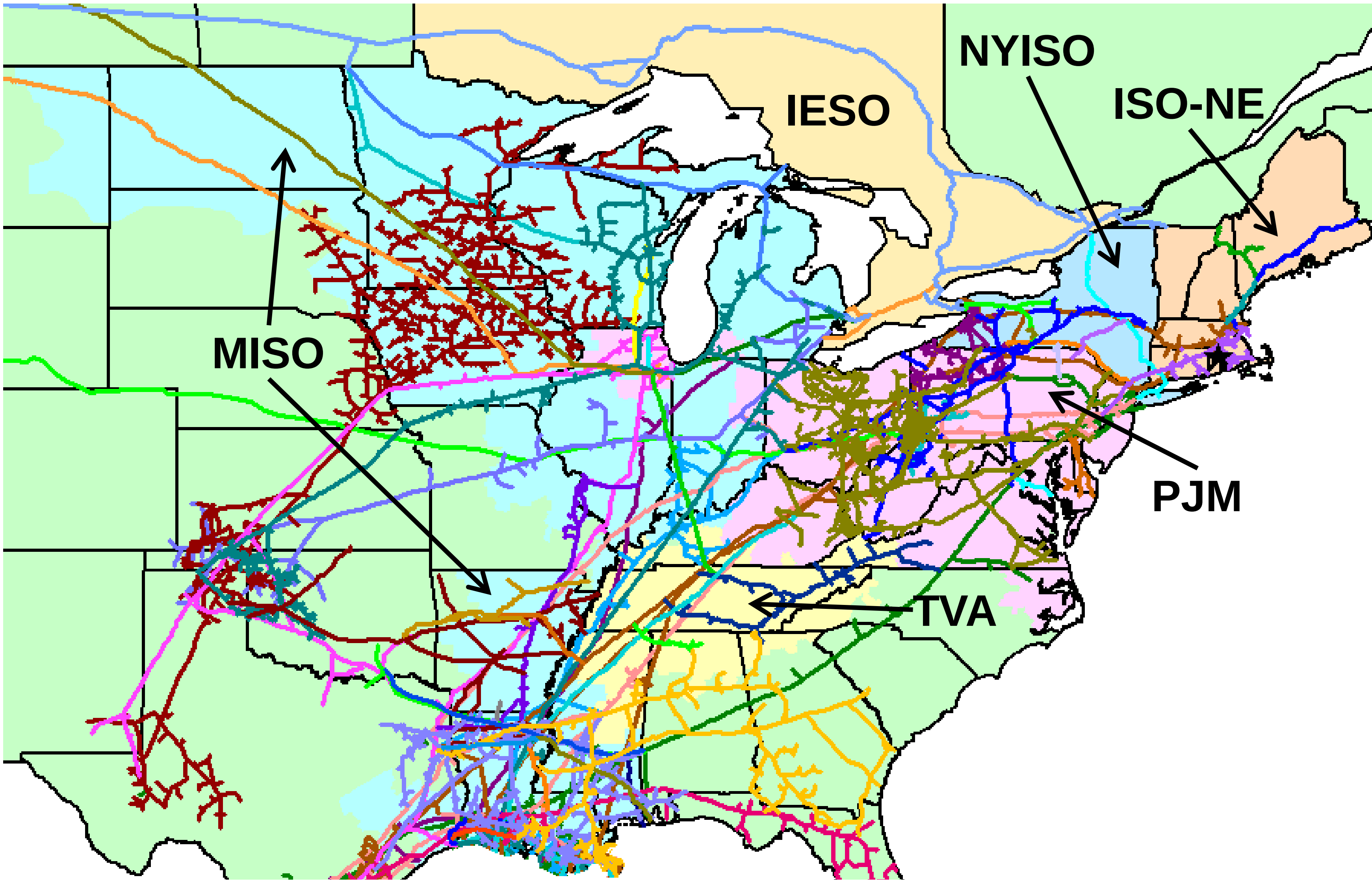
Study Highlights

- Character of service: Most generators do not hold firm transportation entitlements, except in TVA and Ontario, although some have fuel oil back-up. Target 4 analyzed fuel oil back-up on an economic basis.
- Gas infrastructure adequacy analysis: Constraints affect generation in ISO-NE, NYISO, EMAAC and SWMAAC
- Contingency analysis: Most gas contingencies allow time for PPAs to schedule alternative resources
- Fuel assurance: Dual-fuel capability less expensive than incremental FT in almost all cases
- Note: More than three years have elapsed since the input assumptions and study parameters were fixed. Results must be considered in that context.

Existing Natural Gas-Electric System Interfaces (Target 1)

Study Region – Pipelines and Participating PAs

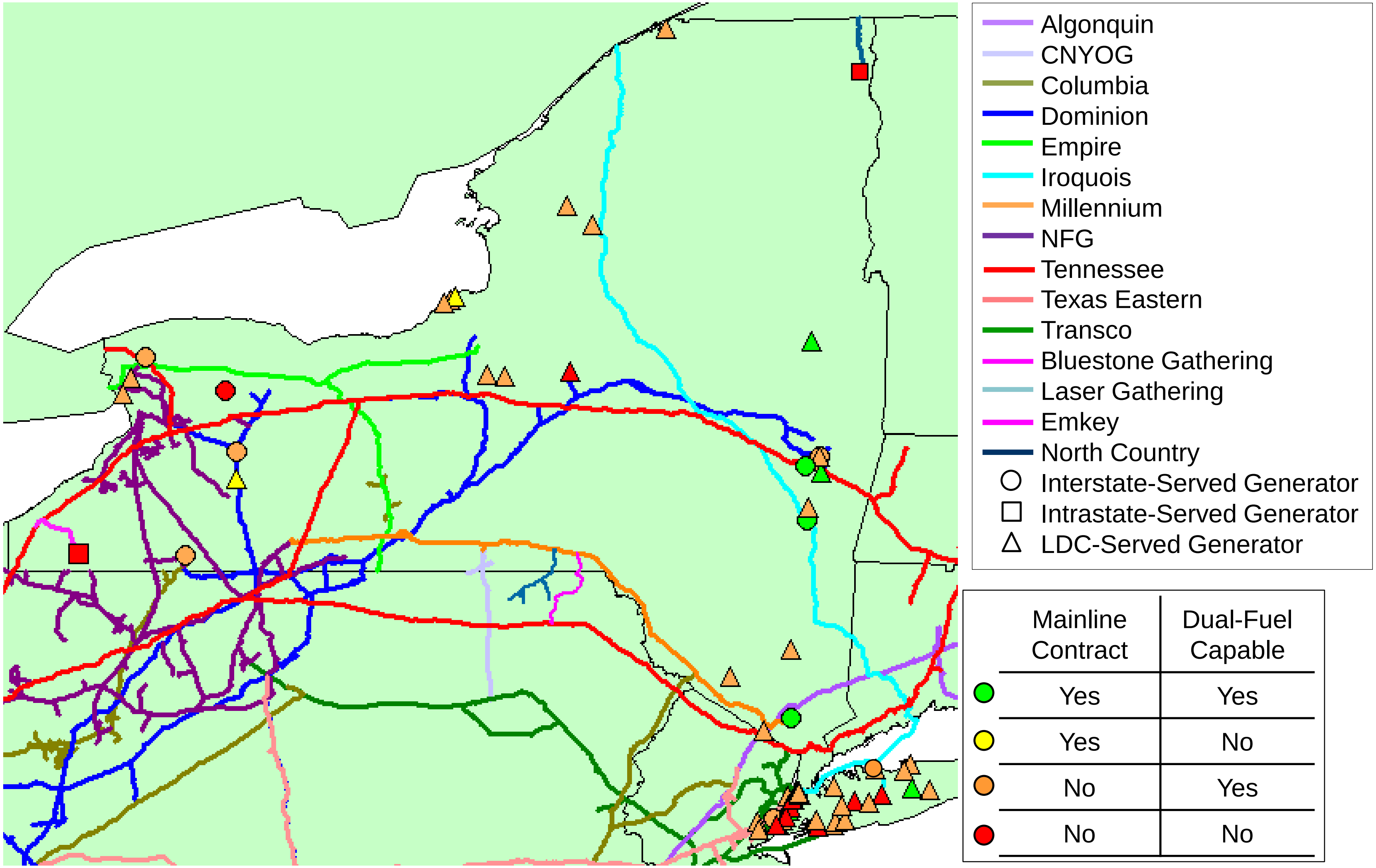


Generator Statistics By PPA

PPA	% GWh Gas (2012)	Total ICAP (GW)	Gas-Capable ICAP (GW)	% Total (GW)	Direct-Connect ICAP (GW)	LDC-Served ICAP (GW)
PJM	19%	185	78.7	43%	35.1	43.6
MISO	9%(N/C) / 52%(S)	177	68.0	38%	44.8	23.2
NYISO	45%	38	24.7	65%	7.4	17.3
ISO-NE	50%	35	18.6	54%	14.3	4.3
TVA	12%	34	10.6	31%	8.0	0.6
IESO	15%	33	9.9	28%	1.2	8.7
Total		502	208.5	41%	110.8	97.7

Note: N/C – MISO North & Central Regions, S = MISO South Region
Source: PPAs

NYISO Generator Contracting Practices



	Mainline Contract	Dual-Fuel Capable
	Yes	Yes
	Yes	No
	No	Yes
	No	No

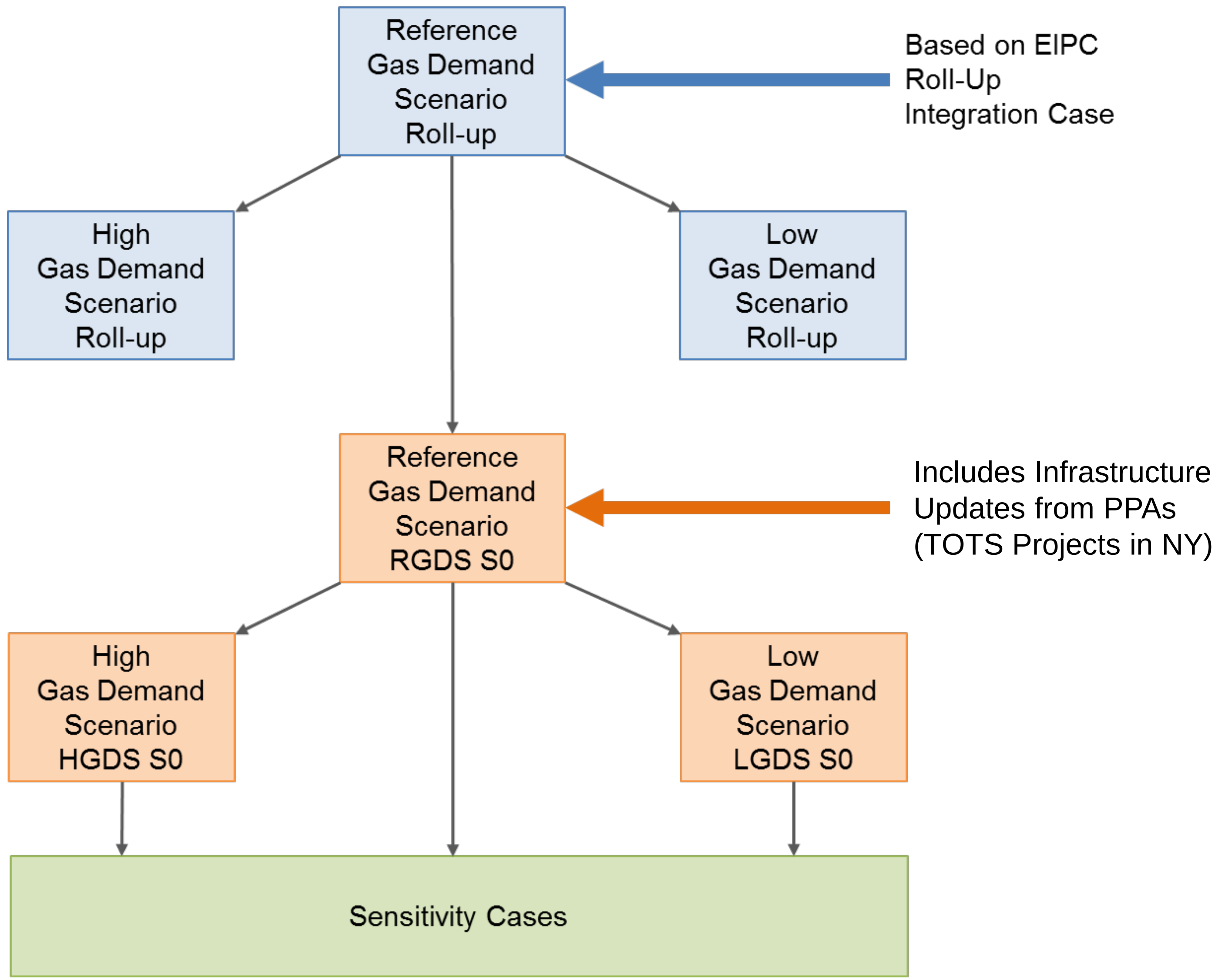
Gas-Electric Interface Attributes

	Criterion	IESO	ISO-NE	MISO	NYISO	PJM	TVA
Natural Gas Supply	Gas Supply Portfolio Diversity	Favorable	Unfavorable	Favorable	Favorable	Favorable	Neutral
	Pipeline Connectivity	Neutral	Unfavorable	Favorable	Favorable	Favorable	Neutral
	Conventional Storage Deliverability	Favorable	Unfavorable	Favorable	Neutral	Favorable	Neutral
	LNG Storage Capability	Neutral	Favorable	Neutral	Neutral	Neutral	Neutral
Electric-Gas Interface	Firm Transportation Entitlements	Favorable	Unfavorable	Neutral	Neutral	Neutral	Favorable
	Direct Pipeline Connectivity	Favorable	Favorable	Favorable	Neutral	Favorable	Favorable
Electric-Gas Tariff	Pipeline or LDC Penalties	Favorable	Unfavorable	Unfavorable	Unfavorable	Unfavorable	Unfavorable
	LDC Provision of Flexible Service	Favorable	Neutral	Neutral	Favorable	Favorable	Neutral
	Active Secondary Market	Unfavorable	Favorable	Favorable	Favorable	Favorable	Neutral

Legend	Favorable Relative to Other PPAs	Neutral	Unfavorable Relative to Other PPAs

Adequacy Analysis (Target 2)

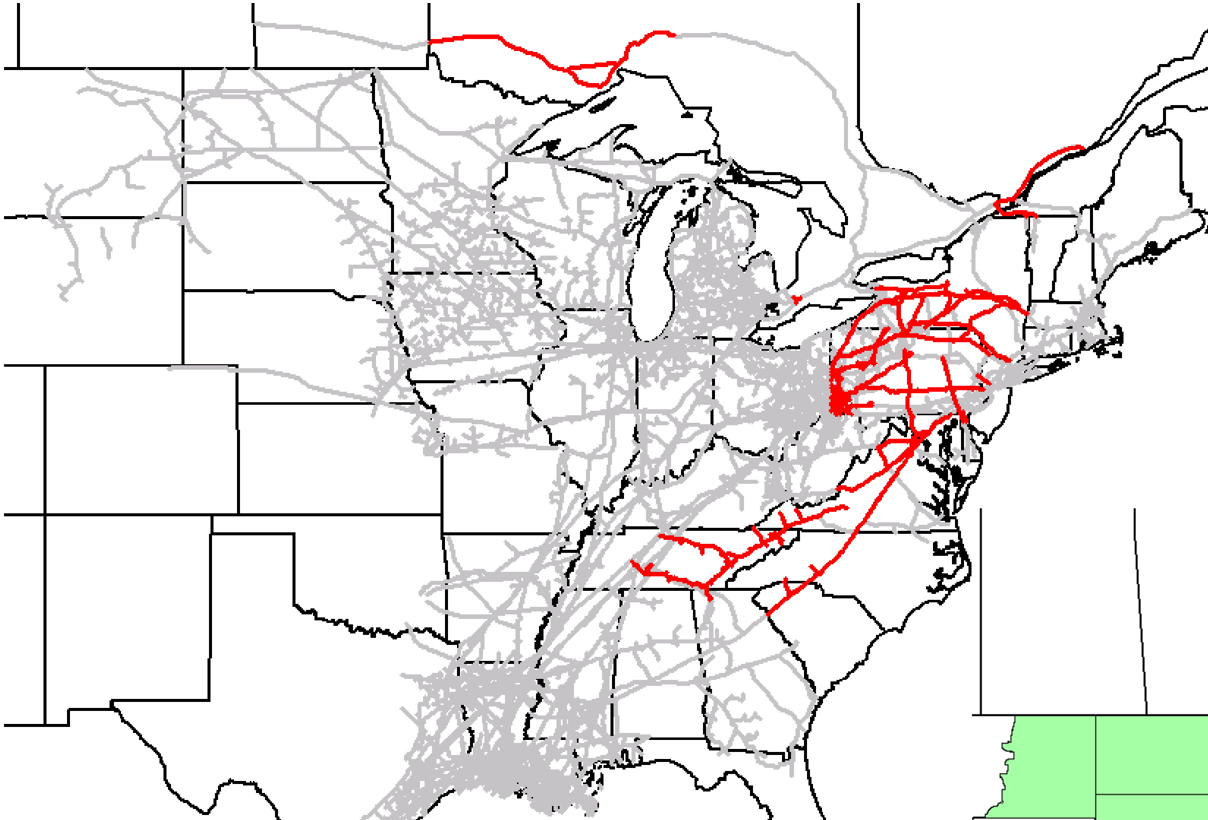
Scenarios and Sensitivities



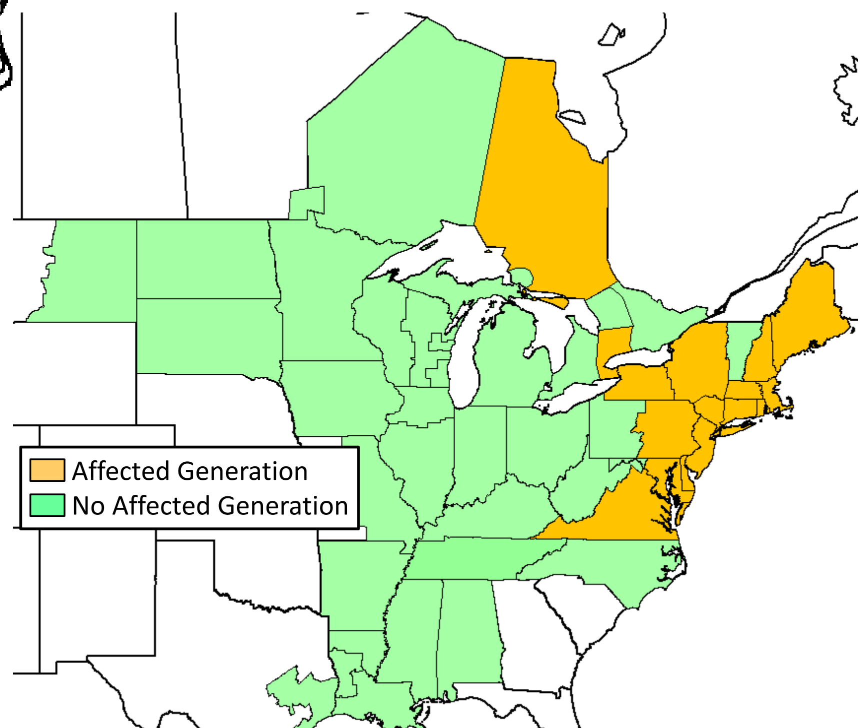
Sensitivities Tested

Sensitivity	Description
S1 (R/H/L)	Apply market gas prices for peak winter day
S2 (H/L)	Apply RGDS gas prices to HGDS or LGDS
S3 (R)	Significantly lower delivered gas prices
S5a (R)	Deactivation of add'l coal and nuclear, replaced by wind and solar
S5b (R)	Deactivation of additional coal and nuclear, replaced by imports of Quebec hydropower
S5c (R)	Deactivation of additional coal and nuclear, replaced by EE/DR
S9 (H)	Ontario nuclear units scheduled to be refurbished instead reach the end of life after 2018 and before 2023; Indian Point 2 & 3 retire by end of 2015
S13 (R)	Increased infrastructure to enable additional Marcellus/Utica flows to neighboring PPAs
S14 (R)	Increased gas storage availability and deliverability
S16 (R)	Increased sendout from Canaport and Distrigas LNG terminals
S18 (R)	High electric load growth
S19 (R)	High industrial gas demand
S23 (R)	Increased LNG exports from U.S. terminals
S30 (R/H)	Bar gas use in dual fuel resources
S31 (R)	Very cold snap with 90/10 electric and RCI gas demands
S33 (R)	S31 + high forced outage rate for coal and oil units
S34 (R)	Maximum gas demand on electric sector
S36 (R)	S33 + Selected nuclear units unavailable
S37 (R)	S13 + Canaport converted to LNG export facility

Constraints: Reference Demand Scenario Winter 2018



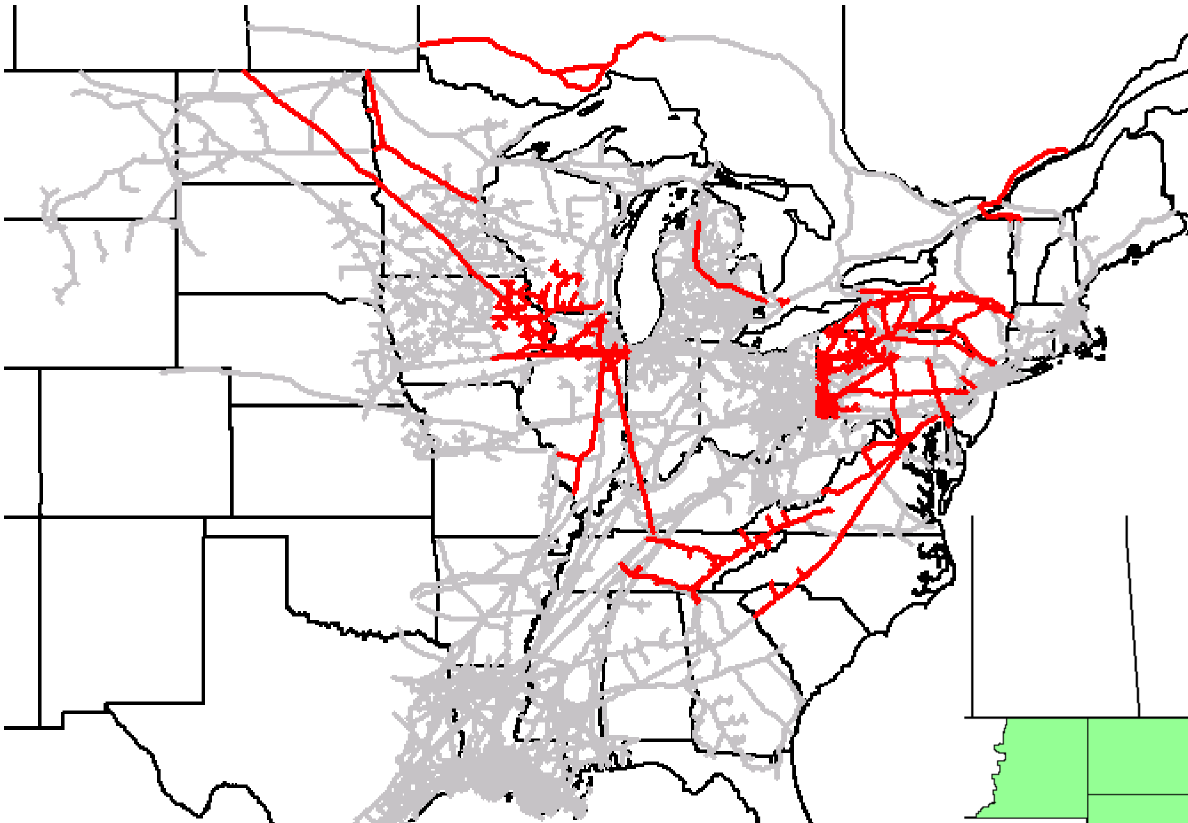
"Affected Generation" does not imply a risk to electric reliability



Peak Hour Unserved Generation Gas Demand: 165 MDth (27.6%)

Peak Hour Affected Generation: 21,707 MWh (26.8%)

Constraints: High Demand Scenario Winter 2018



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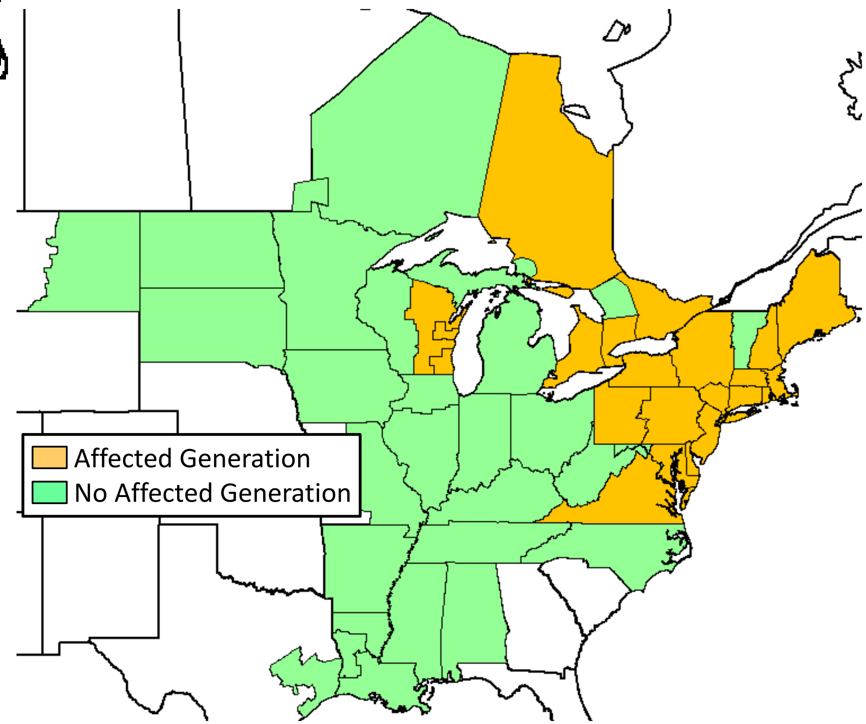
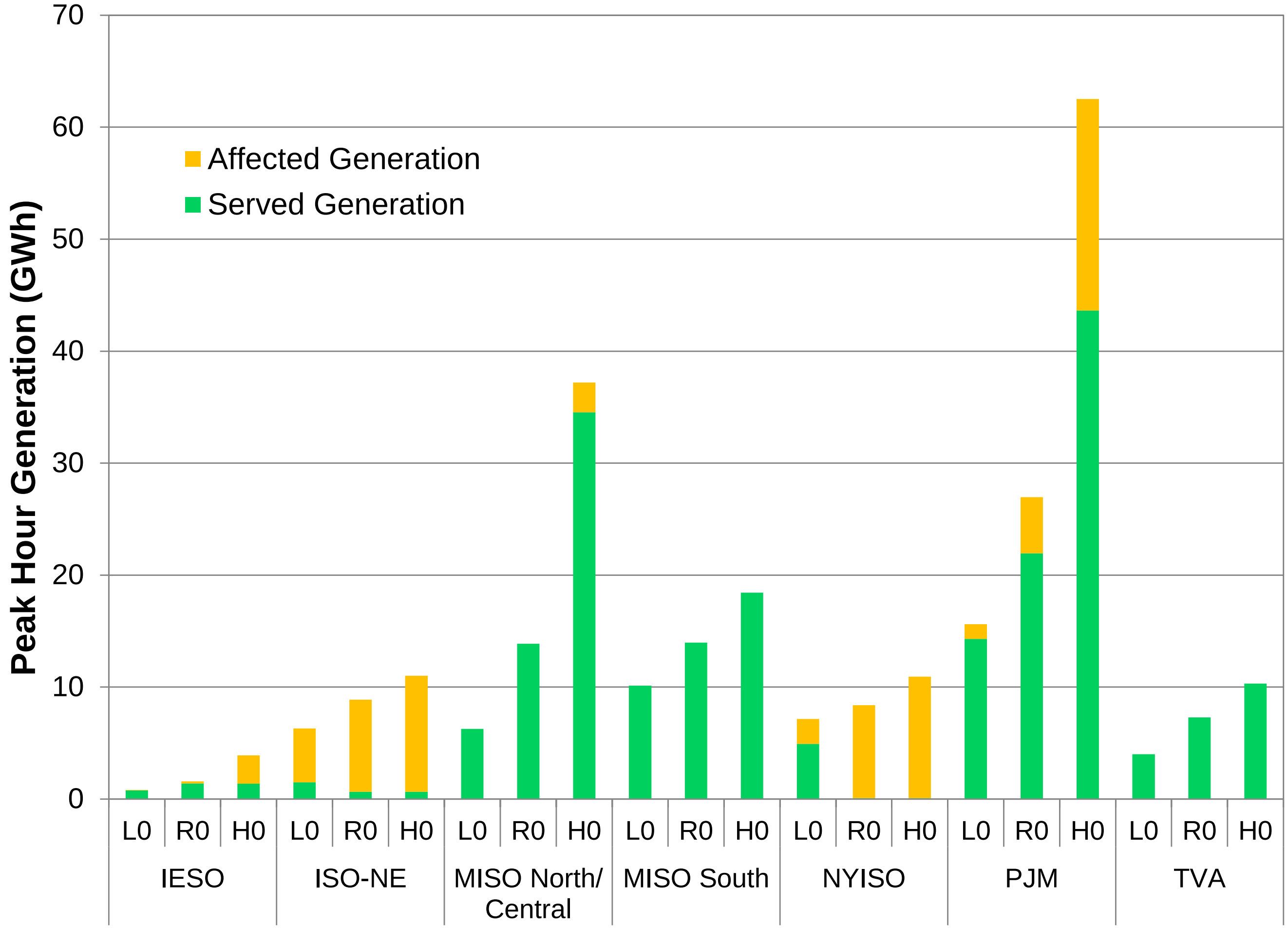


Peak Hour Unserved Generation Gas Demand: 351 MDth (29.4%)

Peak Hour Affected Generation: 45,269 MWh (29.3%)

Winter 2018: Affected Generation by Scenario

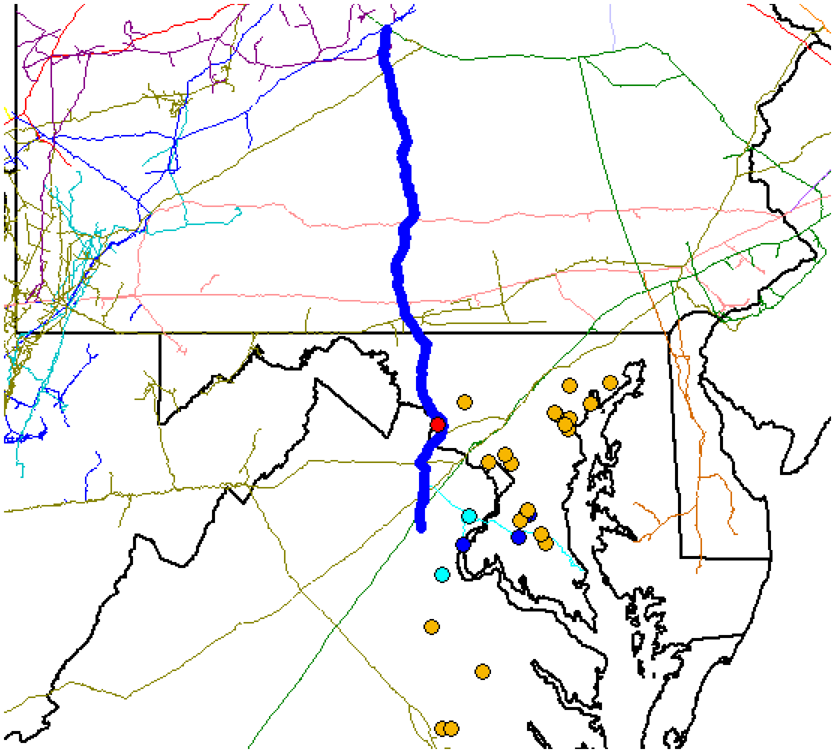


"Affected Generation" indicates the amount of energy for gas-fired generation that cannot be supplied due to the limitations of the pipeline system – which represents either full or partial scheduled requirements. Mitigation measures include switching to liquid fuel and/or redispatch.

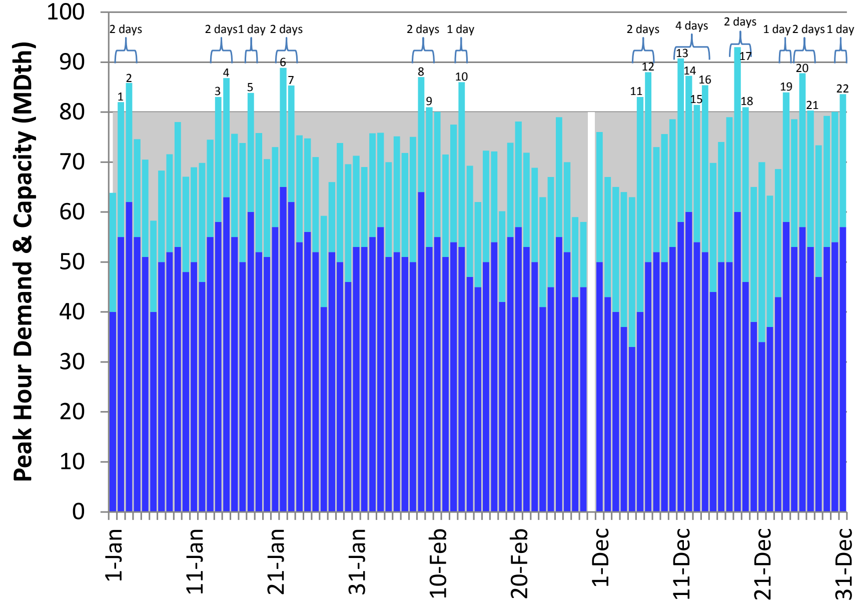
Frequency / Duration Analysis

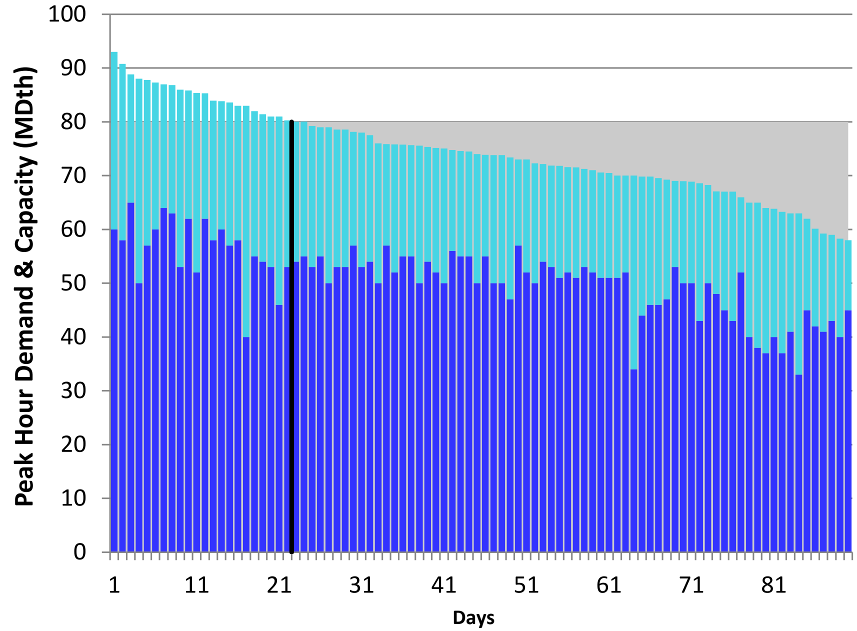
- F-D of seasonal constraints based on expected demand duration curves
  - Demand duration curves based on peak hour electric model results and historical RCI demand data
  - Duration curves for all demand provided through a constrained segment were combined to determine total daily peak hour demand
  - Daily peak hour conditions were analyzed for three winter and three summer months
  - Interconnection flows accounted for
- Forecast of RCI and electric gas demand is compared to the maximum flow capability of the segment to determine number and pattern of high congestion days
- Unserved demand allocated to genco loads

Frequency-Duration Results Format



- Dominion Southeast
- Direct-Connect Generator
- LDC-Served Generator
- Downstream Pipeline-Served Generator
- Downstream Pipeline → LDC-Served Generator





Note: Frequency-Duration charts are examples, not for this specific segment

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RGDS S0 Winter 2018: Frequency & Duration

Constraint	# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
Columbia Gas VA/MD	12	1	5	23
Columbia Gas W PA/NY	11	1	5	21
Constitution	5	1	12	25
Dominion Eastern NY	6	1	6	15
Dominion Western NY	1	4	4	4
Dominion Southeast	7	1	12	22
East Tennessee Mainline	7	1	2	9
Eastern Shore	11	1	10	51
Empire Mainline	5	1	12	21
Millennium	4	1	59	83
NB/NS Supply	13	1	20	58
Tennessee Z4 PA	10	1	7	30
Tennessee Z5 NY	2	31	59	90
Texas Eastern M2 PA South	10	1	15	50
Texas Eastern M3 North	10	2	7	39
TransCanada Ontario West	5	1	5	12
TransCanada Quebec	9	1	14	30
Transco Leidy Atlantic	8	2	23	59
Transco Z5	3	1	7	9
Transco Z6 Leidy to 210	5	1	3	8
Union Gas Dawn	2	1	3	4

Hydraulic Analysis of Contingencies (Target 3)

Contingency Selection

- Contingencies are low probability, high impact events
- Selected pipeline segments with congestion
- Each Region identified 2 to 5 gas-side contingencies and 3 to 8 electric-side contingencies:
  - Gas-side contingencies include compressor outages, pipeline ruptures, and loss of major storage deliverability
  - Electric-side contingencies include loss of transmission and major generator(s)
- Used hydraulic modeling to analyze 24 hours after the contingency to quantify affected generation and time-to-trip intervals

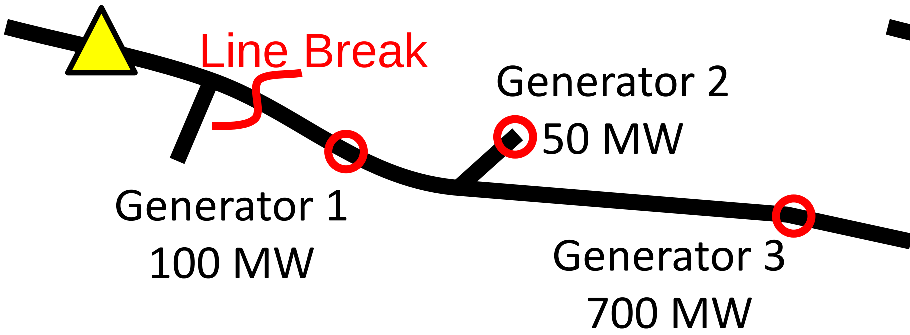
Contingency Mitigation

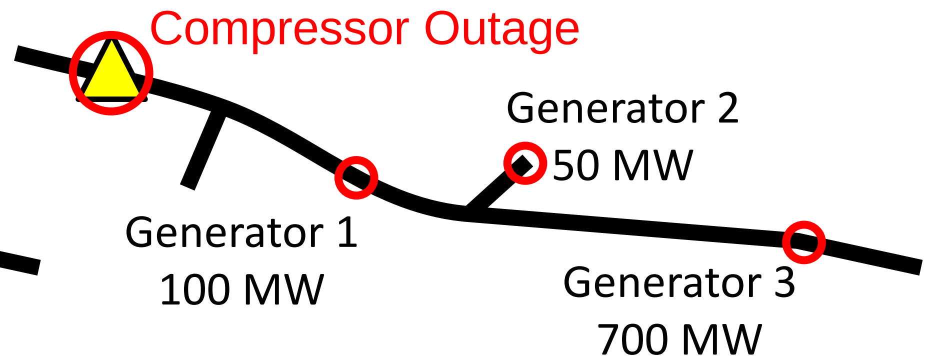
- Gas operator actions
  - Use line-pack
  - Increase interconnect flows from neighboring pipelines
  - Increase compressor station output
  - Reverse flow across key pipeline segments
- Other considerations (not included in the model solution)
  - Electric redispatch & switching to dual fuel
  - Enhanced communication between electric and gas pipeline operators
  - Possible pipeline tariff innovations
  - Continued efforts to promote harmonization of gas day and electric day scheduling procedures

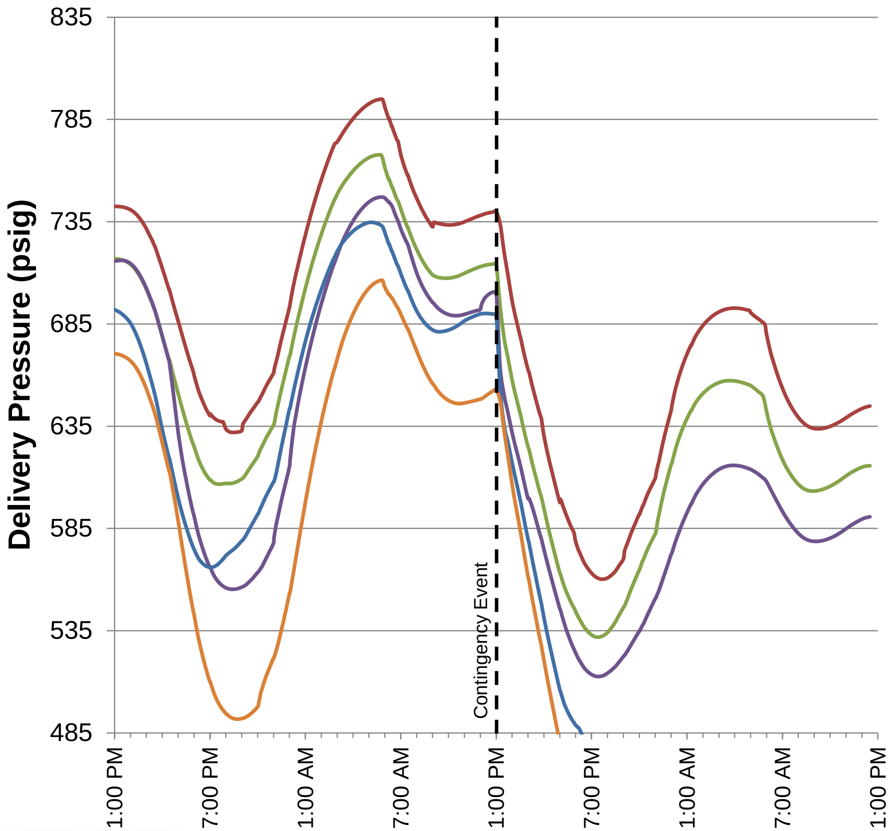
Gas-Side Contingency Analysis Results

- Types: line breaks, compressor outages, loss of supply, loss of storage
- Line breaks are the most impactful in each PPA

Example Contingency Result Outputs







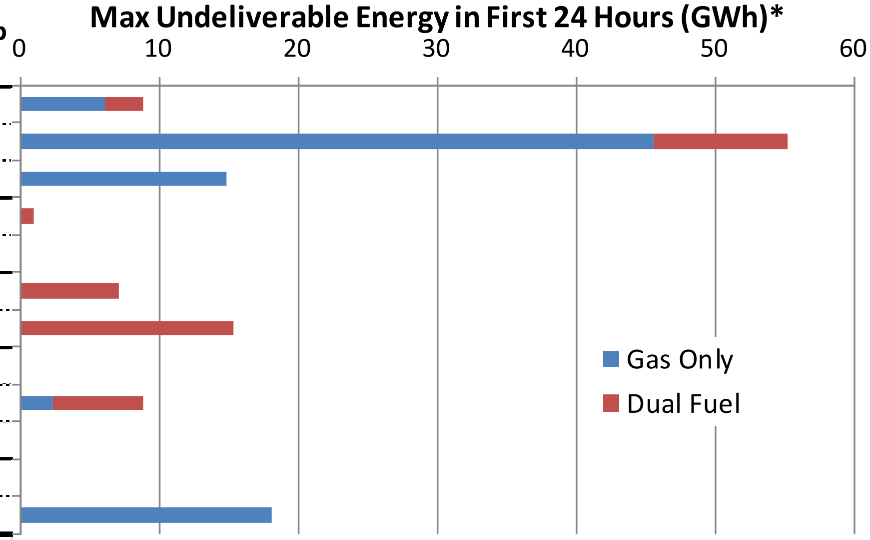
Plant	Time to Trip Following Contingency (h:m:s)	Scheduled Energy (MWh)	Undeliverable Energy (MWh)	Undeliverable Energy (%)
Plant 1	N/A	5,000	0	0
Plant 2*	3:30:00	2,500	2,200	88%
Plant 3	N/A	10,000	0	0
Plant 4*	N/A	15,000	0	0
Plant 5*	N/A	315	0	0
Plant 6	N/A	600	0	0
Plant 7	N/A	750	0	0
Plant 8	4:48:41	5,000	4,000	80%
Total			4,000 (gas only) 2,200 (dual fuel)	

Contingency Results Summary by Type

Reference Scenario, Winter 2018

Gas-Side Contingencies

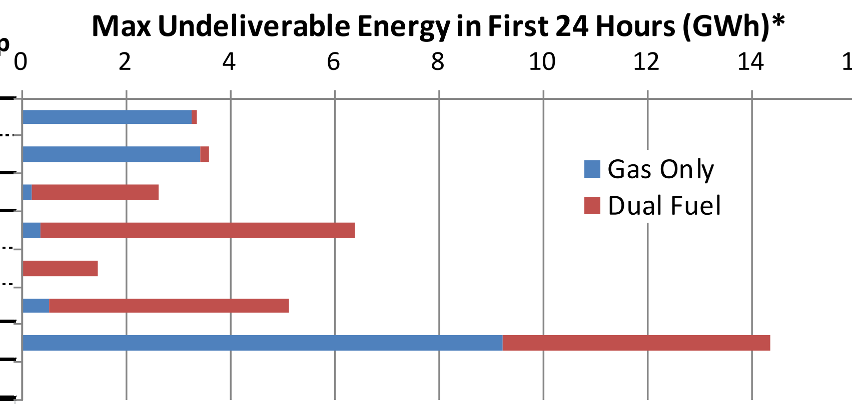
PPA	Type	# Tested	Shortest Time to Trip (h:m:s)
ISO-NE	Compression	3	3:52:47
	Line Break	3	0:11:03
	Supply	2	0:00:00
MISO	Compression	3	9:17:42
	Line Break	3	18:53:42
NYISO	Compression	3	12:22:51
	Line Break	3	0:54:20
PJM	Compression	1	None
	Line Break	6	0:03:00
	Storage	1	None
TVA	Compression	3	None
	Line Break	3	4:21:49



* Scheduled energy with undeliverable gas

Electric-Side Contingencies

PPA	Type	# Tested	Shortest Time to Trip (h:m:s)
ISO-NE	Generation	3	None
	Transmission	2	None
MISO	Generation	8	None
NYISO	Generation	3	10:48:17
	Transmission	2	None
	Gen + Trans	1	10:50:37
PJM	Generation	3	2:45:10
TVA	Generation	5	None



* Scheduled energy with undeliverable gas

Fuel Assurance Analysis (Target 4)

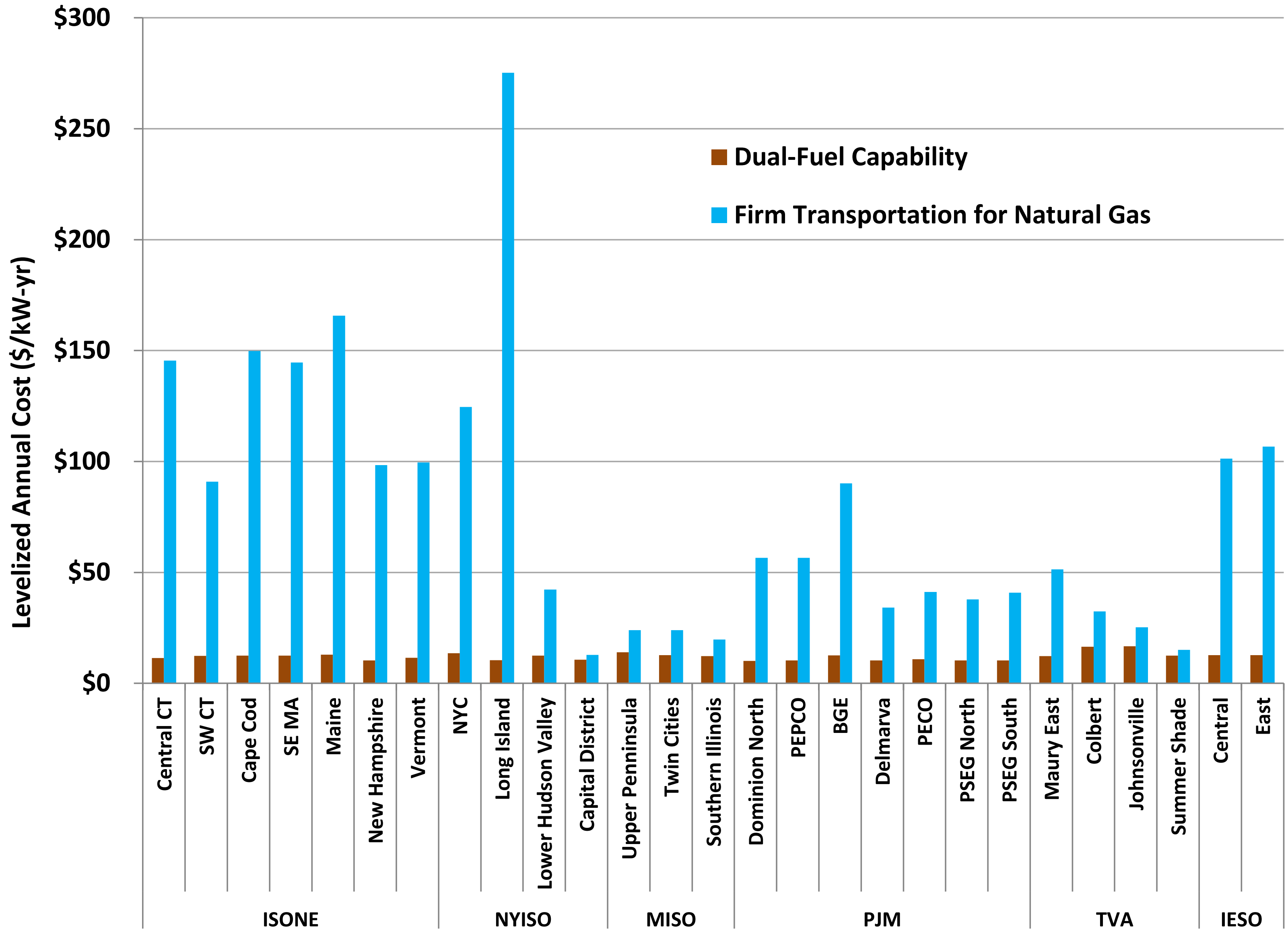
Dual-Fuel Capability Cost Inputs

- ULSD logistics by location
  - Depot identification
  - Transport mode (truck or barge)
  - New price based on rack price, shipping, demurrage
  - Labor cost factor and tax rates
  - Permit restrictions
- Target inventory and fuel storage tank volume
  - Expressed in days of full load burn
  - Location-specific variables
    - Severity of natural gas delivery constraint
    - Delivery lag (order to receipt) and potential weather delays
    - Expected capacity factor when operating on ULSD
    - Tank volume allowance for “lumpy” barge delivery size

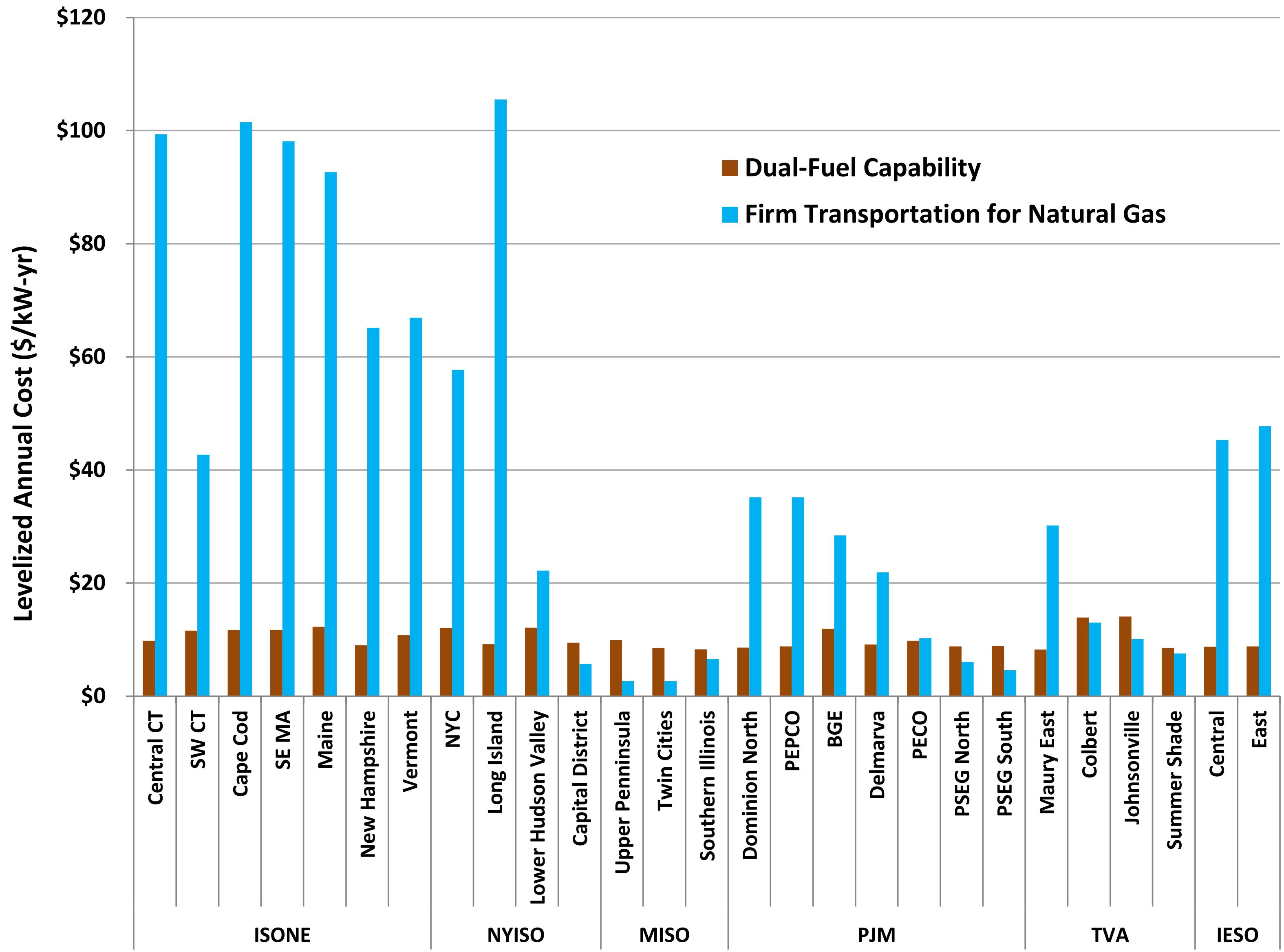
Fuel Assurance Analysis Results

- Cost of dual-fuel capability generally similar across locations
  - Variations between barge- and truck-supplied locations
- Cost of incremental FT varies across Study Region
  - Expensive in New England due to existing bottlenecks
  - Expensive at the local level (New York Facilities System, in particular)
- Dual-fuel capability typically much lower cost for a new combined-cycle (CC) plant than FT; far more pronounced for simple cycle (SC) plants
  - LDC-served generators additionally incur local facility improvement costs
  - Restrictive environmental permit requirements limit liquid fuel usage
  - Structural changes continue to improve ULSD replenishment logistics

Fuel Assurance Analysis: Simple Cycle



Fuel Assurance Analysis: Combined Cycle



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Relevance to NERC Recommendations

Many of the NERC Findings & Recommendations, are consistent with the findings of the EIPC G-E Study

For Example:

- Disruptions to natural gas facilities can have varying impacts on the electric system depending on location
  - EIPC found impacts to vary due to differences in gas and electric infrastructure, generator location (direct connect or through LDCs), availability of dual fuel, and the ability to redispatch non gas-fired generation
- Firm Transportation and dual-fuel capability provide higher levels of reliability for gas-fired generation
  - EIPC study confirmed the benefits of dual-fuel capability for electric reliability and found the cost of dual fuel capability to be much lower than FT for most of the Study Region

Relevance to NERC Recommendations (Cont'd)

- Many mitigation strategies are available to reduce the impact of gas disruptions
  - EIPC study methodology directly incorporated many gas mitigation measures and identified other potential measures on a qualitative basis
- Natural gas sources have become more diversified
  - EIPC study accounted for the impact of increased supplies of shale gas in the Northeast as well as known pipeline expansion facilities
- Comprehensive planning studies should consider loss of key natural gas facilities
  - EIPC study included both gas and electric contingency analysis to provide information for transmission planners to use in their NERC reliability assessments

Relevance to NERC Recommendations (Cont'd)

- FERC and others have encouraged gas and electric system operators to improve coordination procedures
  - EIPC highlighted the importance of increased coordination and information sharing between gas and electric system operators

For Further Information

- Detailed Reports covering each of the Study Targets are available on the EIPC website:
  - http://www.eipconline.com/gas-electric.html
- EIPC procedures for obtaining access to CEII data for Targets 2 and 3 can be found at:
  - http://www.eipconline.com/eipc-documents.html

QUESTIONS??

Eastern Interconnection Reliability Assessment Group (ERAG)

NERC TECHNICAL WORKSHOP – JULY 10, 2018

NERC OFFICE

JEFF MITCHELL, RF – ERAG CHAIR

What is ERAG?

- An agreement between the Regional Entities covering the Eastern Interconnection to conduct assessments.
- Formal agreement executed in 2006; revised Aug. 2016.
- Interim Designee per MOD-032 for the Eastern Interconnection development of power flow and dynamic planning models via the MMWG.
- Conducts independent assessments.

ERAG Regional Representatives

Eric Senkowicz– FRCC

Richard Becker – FRCC

Salva Andiappan – MRO

Dan Schoenecker – MRO

Michael Lombardi – NPCC

Paul Roman – NPCC

John Idzior – RF

Jeff Mitchell – RF, chair

Ted Franks – SERC, vice chair

Maria Haney – SERC

MIDWEST RELIABILITY ORGANIZATION

FRCC Florida Reliability Coordinating Council, Inc.

NPCC, Inc.

RELIABILITY FIRST

SERC Reliability Corporation

Planning Coordinator Peer Review in 2017

- Inform ERAG on Planning Coordinators transmission study efforts.
- Helps to avoid duplication of efforts by others.
- Leverage awareness of existing and current studies.
- Promotes a learning environment.
- Promotes building relationships.

ERAG Regional Gas Disruption Assessment

Scope of Activities - Phases

1. Information gathering
2. Review and analyze the information
3. Planning Coordinator presentations on their efforts
4. Possible transmission assessment
5. Report development

Phase 1 - Information Gathering

- Eastern Interconnection Planning Collaborative (EIPC) presented their efforts on a joint conference call with ERAG on Feb. 23, 2018.
- ERAG conducted a survey of the EI Planning Coordinators. The survey contained questions regarding addressing the NERC recommendations in the report.
- All applicable Planning Coordinators responded.

Phase 2 – Review & Analyze Information

- EIPC has completed detailed transmission analyses by members and gas hydraulic studies using a consultant.
- Most Planning Coordinators have addressed the NERC recommendations.
- A few small Planning Coordinators plan to address the recommendations later this year or early 2019.

Phase 3 - PC Discussion in 2018

- Voluntary for Planning Coordinators to present their efforts in a group meeting.
- Scheduled for September 25-26.
- Address NERC recommendations in the report.
- Share other efforts at the meeting.
- Any future plans for further work.

Phase 4 - Transmission Study in 2019?

- ERAG will consider performing transmission studies after completion of the Planning Coordinator workshop and make a decision in early 2019.
- May simulate pipeline disruption(s) effect on the electric transmission system.
- Thermal and reactive analyses considered.
- ERAG has limited resources for detailed studies.

Phase 5 – Report Production

- Report production will begin after analysis is completed for the survey results and continue through the Planning Coordinator workshop and possible transmission studies.

Schedule

- Information gathering – Q1/Q2 2018
- Analyze information – Q2/Q3 2018
- Planning Coordinator workshop – end of Q2 2018
- Possible transmission studies – Q1 2019
- Report production and release – Q2 2019


Thank you

Western Interconnect Gas – Electric Interface Study

Wood Mackenzie
A Verisk Business

Public Report Presentation

2018

Project Background & Context

Background

In 2017, WECC commissioned Wood Mackenzie, E3, and Argonne National Labs to undertake an evaluation of the reliability of the gas/electric interface in the Western Interconnection.

This study consisted of multiple work-streams:

1) Identifying and modelling the impact of potential power system vulnerabilities stemming from gas system disruptions
2) Evaluating potential mitigation options and their associated costs and capabilities for reducing such impacts
3) Identifying reliability risks associated with gas contracting strategies as well as existing market rules & protocols
4) Providing reasonable and actionable recommendations for WECC and key stakeholders

Context

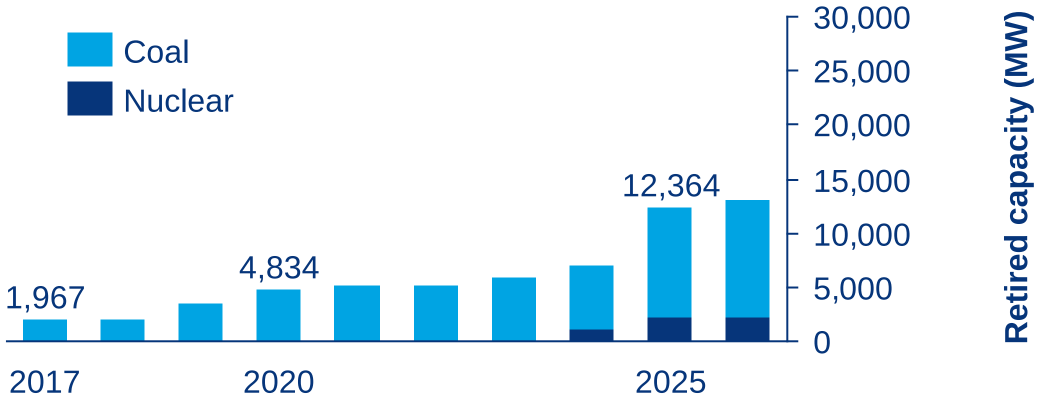
- **In the West, we have entered a period in which it is both possible and reasonable to aspire to low wholesale power costs and steady reductions in emissions**
- **However, the transition away from large, baseload nuclear and coal generation towards more intermittent resources places a considerable potential strain on overall system reliability**
- **In this context, natural gas generation will take on an increasingly important role due to its flexibility and ability to compensate for the variability of renewable resources**
- **Consequently, the ability of the gas/electric systems to handle both everyday variability as well as unforeseen disruptions becomes critical for ensuring energy security in the West**

The configuration of the gas/electric system combined with the loss of Aliso Canyon will create region-wide reliability issues that need to be addressed

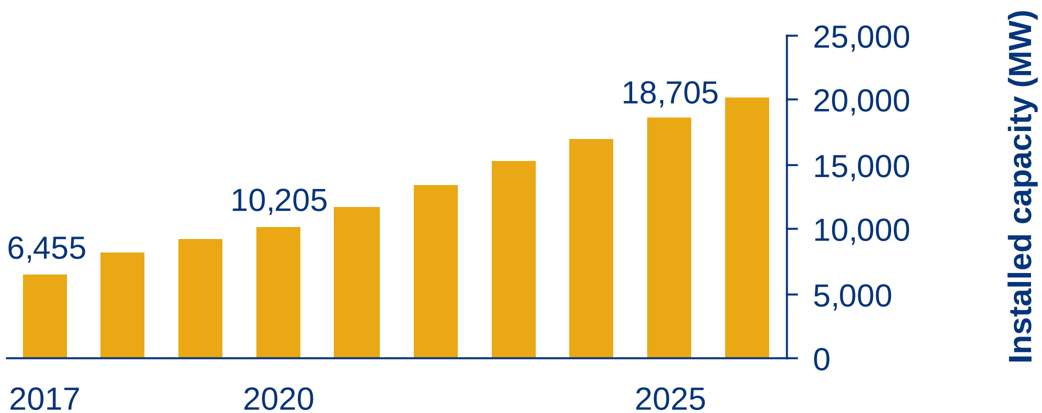
Baseload retirements and load growth will drive natural gas demand growth, creating constraints on the gas system	• Prior to the 2015 gas leak, the 86 bcf of market-area gas storage available at Aliso Canyon played a key role in managing system volatility and reliability • Renewables additions help mitigate but do not replace the increased need for firm, dependable resources stemming from the 11 GW of coal and nuclear retirements • Pipeline flow analysis indicate concerns around volumetric constraints, which limits daily operational flexibility
Absent key balancing with storage, Southern California and the Desert Southwest are at risk from disruptions of the gas system	• The Desert Southwest (DSW) and Southern California regions are particularly at risk from disruptions of pipeline infrastructure or gas production • The Pacific Northwest (PNW) is more resilient to major gas system disruptions, largely owing to market area gas storage (in OR, WA and Northern CA) and electric transmission connectivity
There is no silver bullet: a portfolio of mitigation solutions will be necessary to address the reliability risk	• A combination of physical solutions will be required: investments in renewable generation, battery storage, demand response programs, gas infrastructure and storage as well as dual-fuel fired generation • Improved regional coordination, reserve adequacy accounting, curtailment priorities and forecasting would decrease market frictions and improve the ability of the system to respond to disruptions and day-to-day variability

The Western grid is being transformed through retirements of baseload resources and additions of solar and wind generation

Cumulative West Coal/Nuclear Retirements to 2026



Cumulative New CA Solar Capacity through 2026

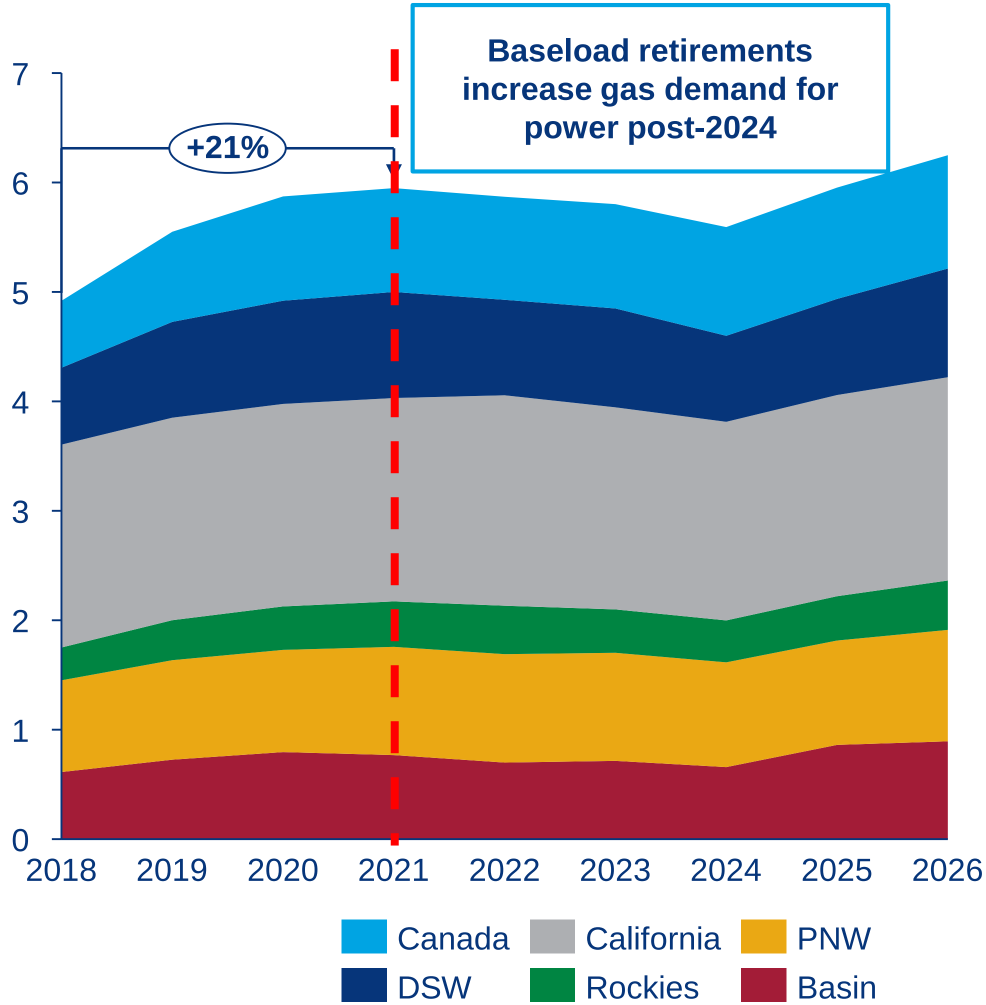


- **9 GW of coal and 2.2 GW of nuclear generation is projected to be retired by 2026**
- **Up to 20 GW of new solar (utility & distributed generation) is projected to be installed in California by 2026**
- **Bulk electricity storage will play an increasing role, but there is little clarity on the scale and timing**

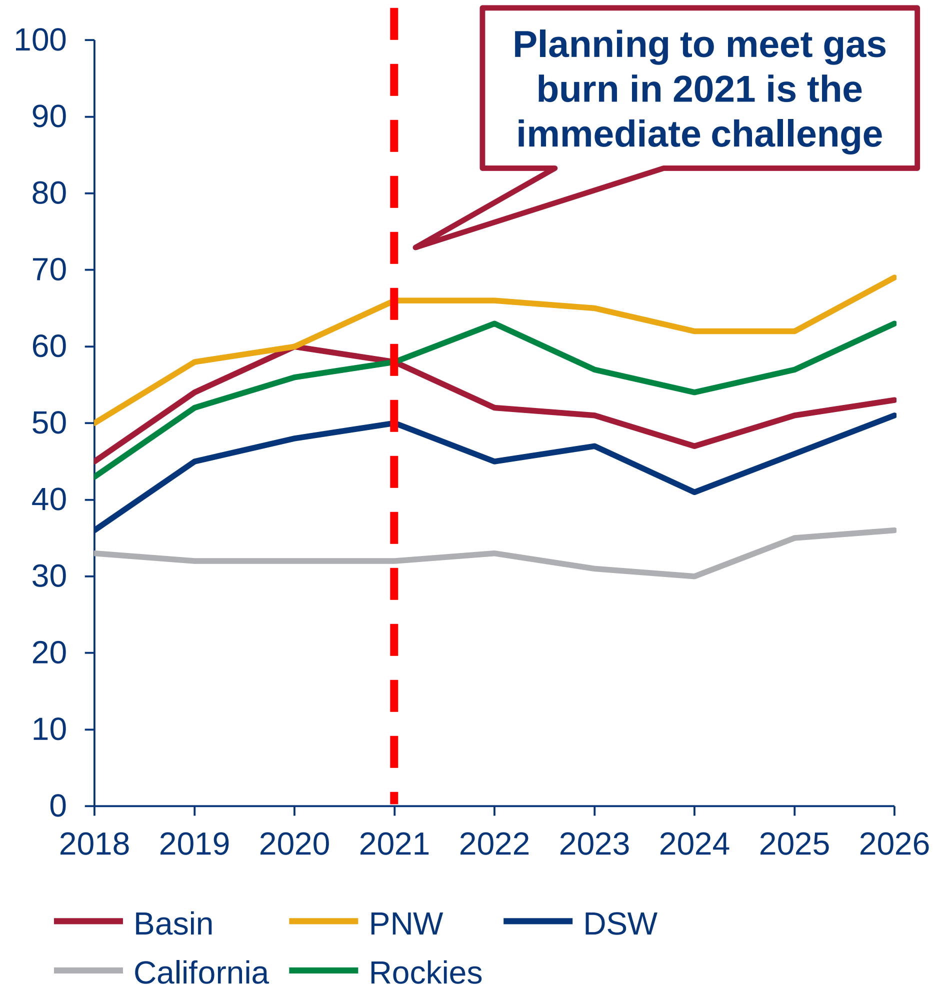
Source: WECC 2026 Common Case

Gas burn for power could increase by ~21%* or slightly more than 1.0 bcfd through 2021

Western Interconnection gas power burn (bcfd)



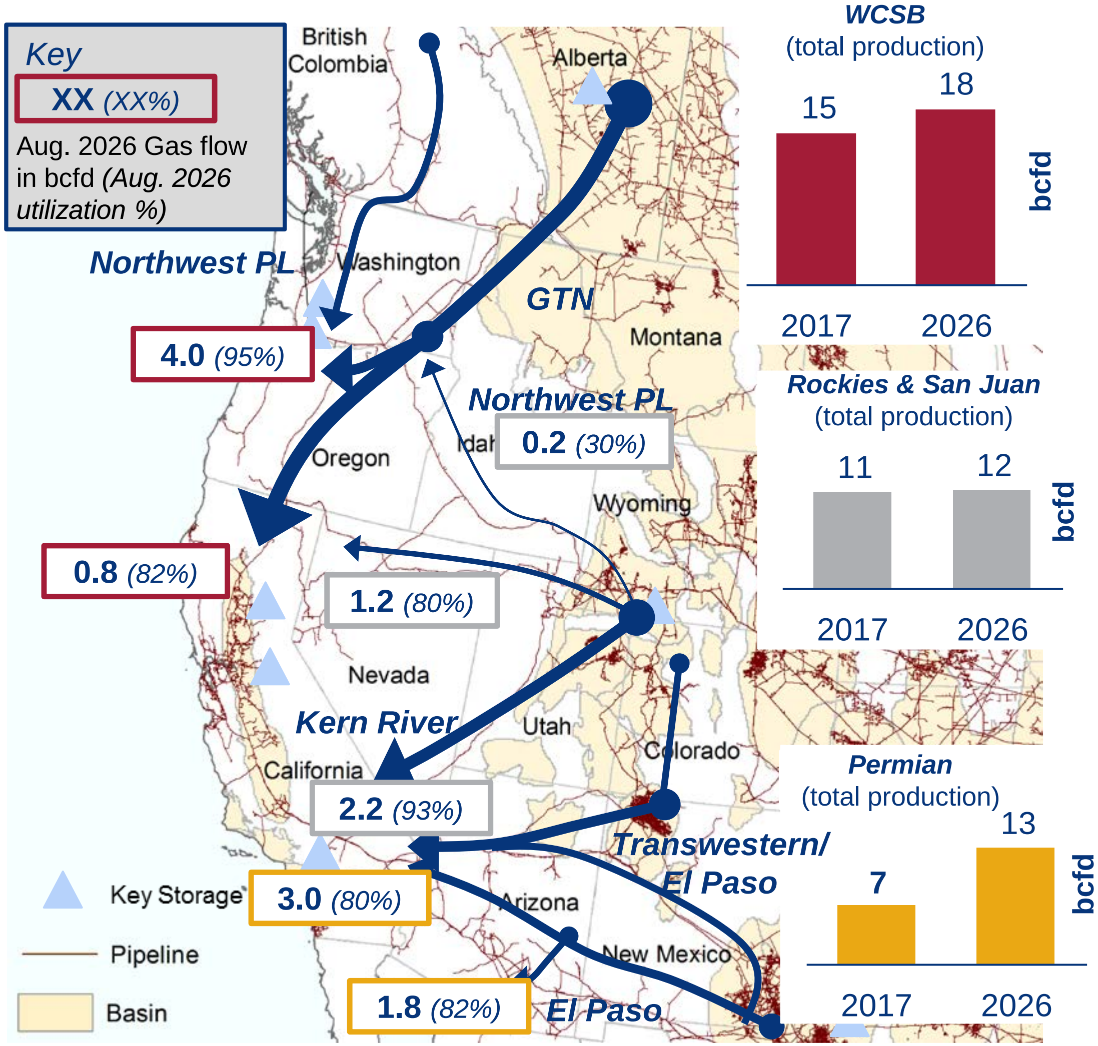
Average CCGT capacity factors (%)



Source: Wood Mackenzie, E3 based on 2026 WECC Common Case
*Purely on an energy, not capacity, basis keeping gas burn flat through 2021 would require 26 GW of solar power

The Western Interconnection and other West Coast natural gas markets become increasingly dependent on 7 long-haul pipelines and 3 supply basins

West US & Canada Gas Pipes & Producing Basins



Source: Wood Mackenzie

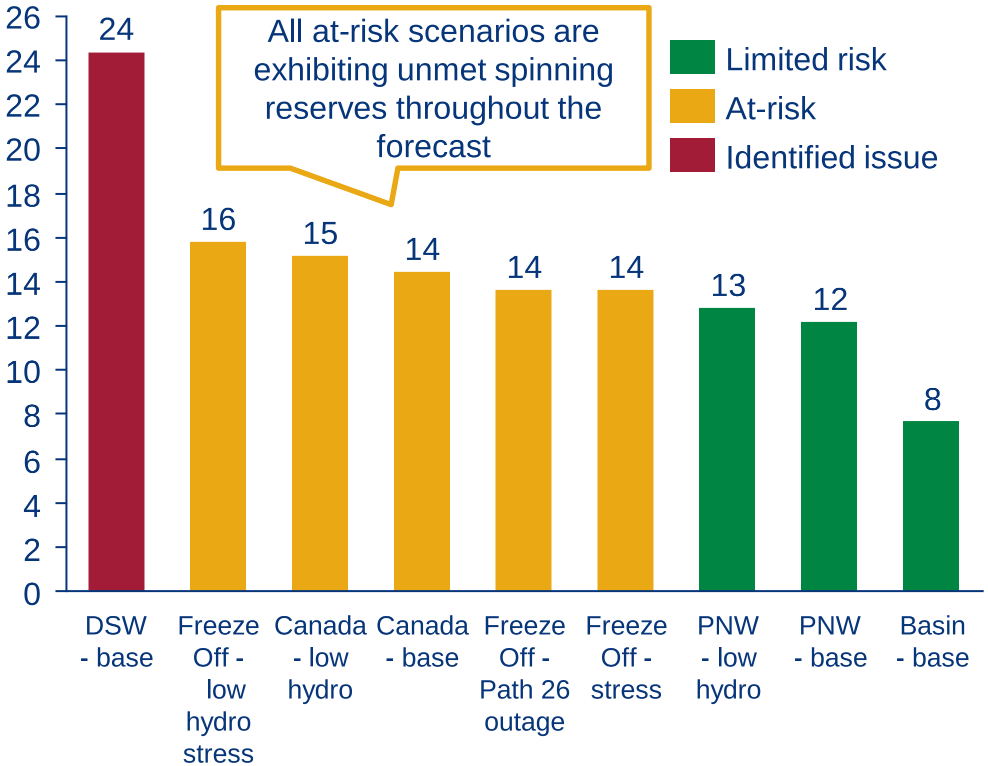
- **The West is blessed with access to diverse and economic supply sources between Western Canada, Permian and Rockies plays**
  - » Combined reserves of 350 tcf available at less than \$4/mmbtu for dry gas and \$50/bbl for associated gas
- **However, several major interstate pipelines are already highly utilized (<75% on annual basis)**
- **Western Canada remains a critical supply source for the Western US demand centers**
- **Greater reliance on Permian gas increases reliability risks in Desert Southwest and Southern California**
- **Market area underground gas storage is a key resource**

The study evaluated 5 key base cases representing major disruptions to the Western Interconnection as well as 5 additional sensitivities

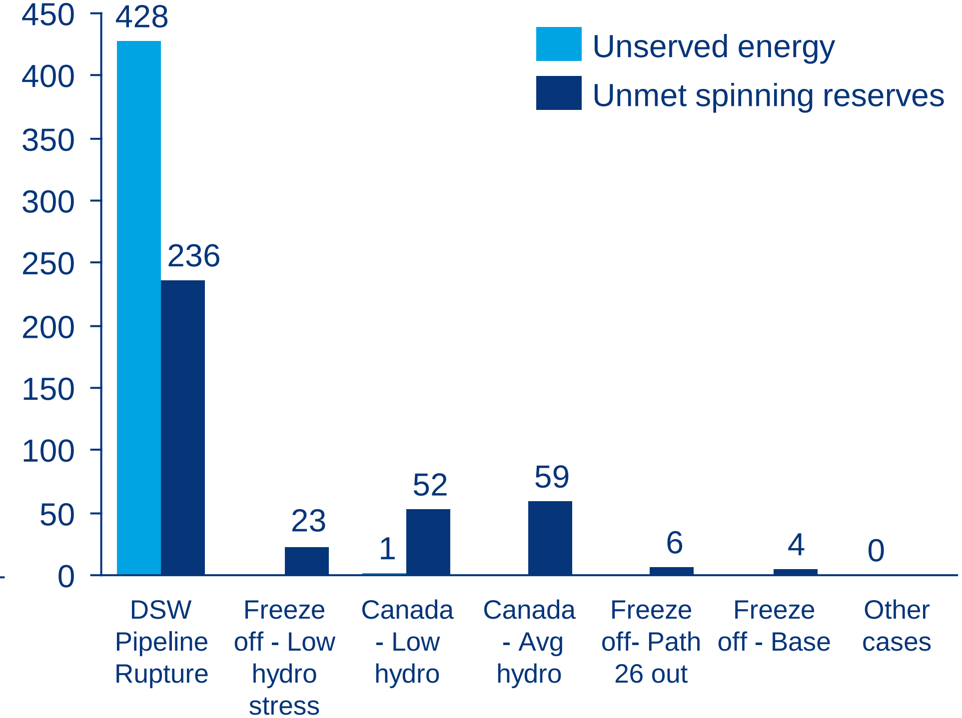
	Regional focus	Base (N-1) Case	N-2 case
Disruption on a PNW pipeline	Pacific Northwest	Disruption at the US/Canada border (or upstream) receipt point on the system	Low hydro conditions
Seismic event disrupting Alberta supply	Pacific Northwest	M6+ earthquake in the Rocky Mountain House area, that disrupts natural gas production in Alberta	Low hydro conditions
Disruption on a Basin pipeline	Basin/ California	Disruption on the critical mainline section downstream of the supply basin and upstream of the demand centers	Low hydro conditions
Disruption on a DSW pipeline	Desert Southwest/ Southern CA	Disruption on critical Southern NM section of DSW pipeline	NA
Winter supply freeze-off in the Permian & San Juan	Desert Southwest	Week-long winter supply freeze-off in the Permian and San Juan basins reducing supply by 1.5 bcfd, higher residential gas demand. 15% of generation in AZ/NM unavailable due to freezing conditions	Low hydro conditions / Transmission outage from CA wildfire

The Southwest disruptions constitute the primary vulnerabilities within the Western Interconnection that we have identified to date

Outage nameplate capacity (GW)



Unserved energy & unmet reserves (GWh)



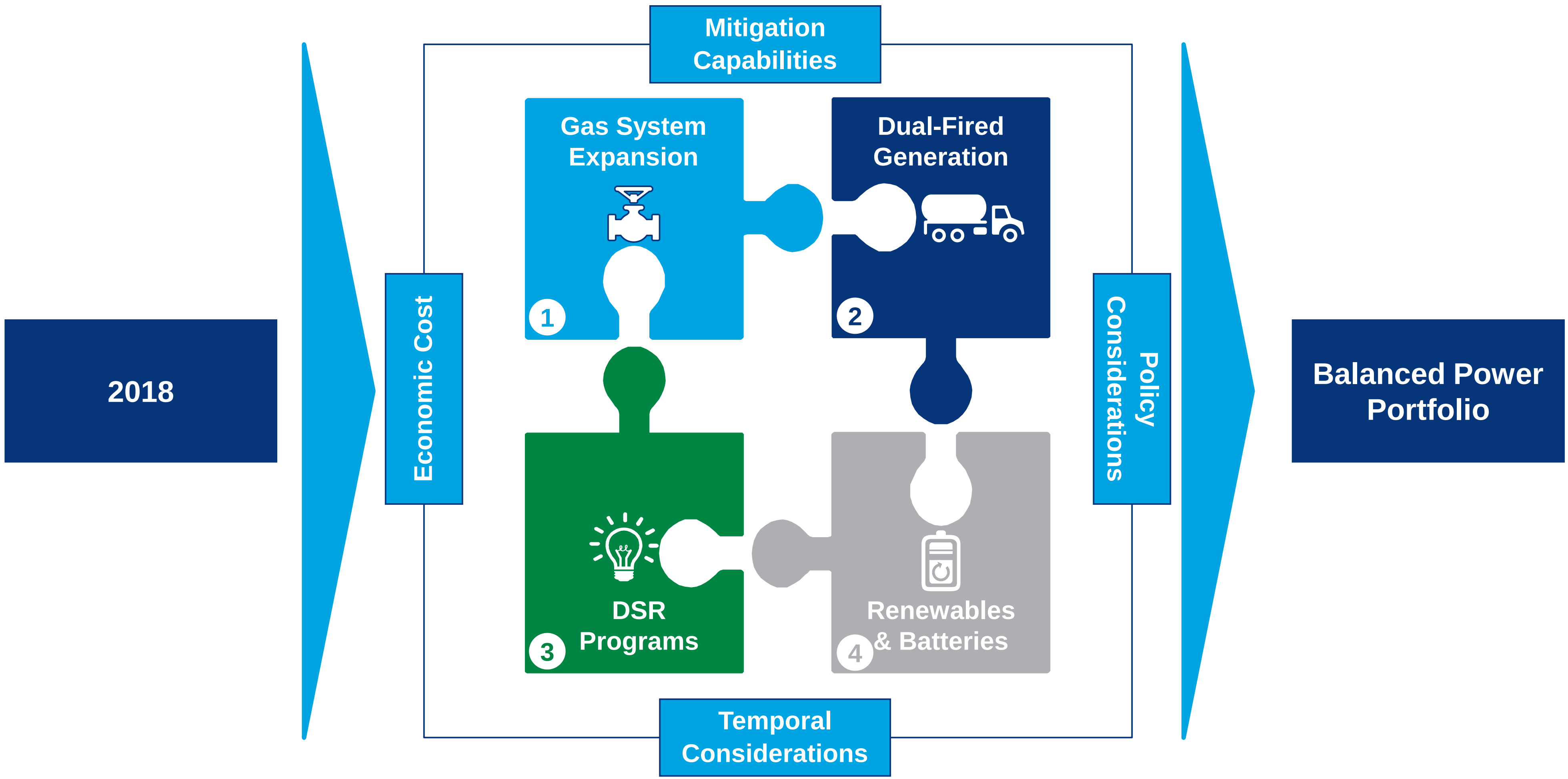
	DSW Pipeline Rupture	Freeze off - Low hydro stress	Canada - Low hydro	Canada - Avg hydro	Freeze off- Path 26 out	Freeze off - Base	Other cases
Unrisked Economic Impact[1] ($US bn)	$27.4	$2.2	$3.4	$3.7	$0.8	$0.6	$0
Risked Economic Impact[2] ($US bn)	$1.1	$0.27	$0.002	$0.02		$0.6	$0

Unserved energy in the DSW scenarios results from the configuration of the gas network, which limits deliverability in isolated "islands" of power plants in Phoenix and Southern California

Notes : (1) Economic impact estimated based on cost of unserved energy in each state for each type of demand sector
(2) Risked Economic Impact estimated based on probability of each disruption
Source: Argonne National Labs , E3, Wood Mackenzie

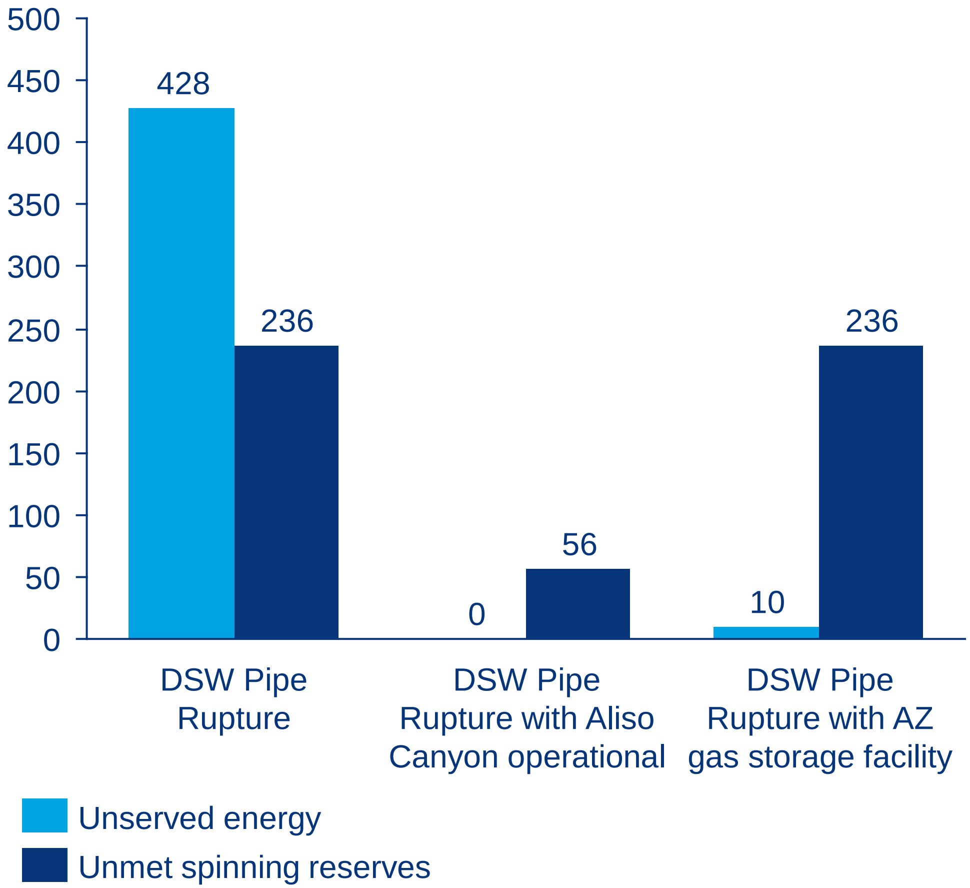
Meeting the future needs of the Bulk Power System in the Western Interconnection reliably and at lowest cost will require a portfolio of options

Option Evaluation



The availability of gas storage facilities located in key demand basins significantly decreases the impact of a DSW pipeline disruption

Unserved energy & unmet reserves (GWh)



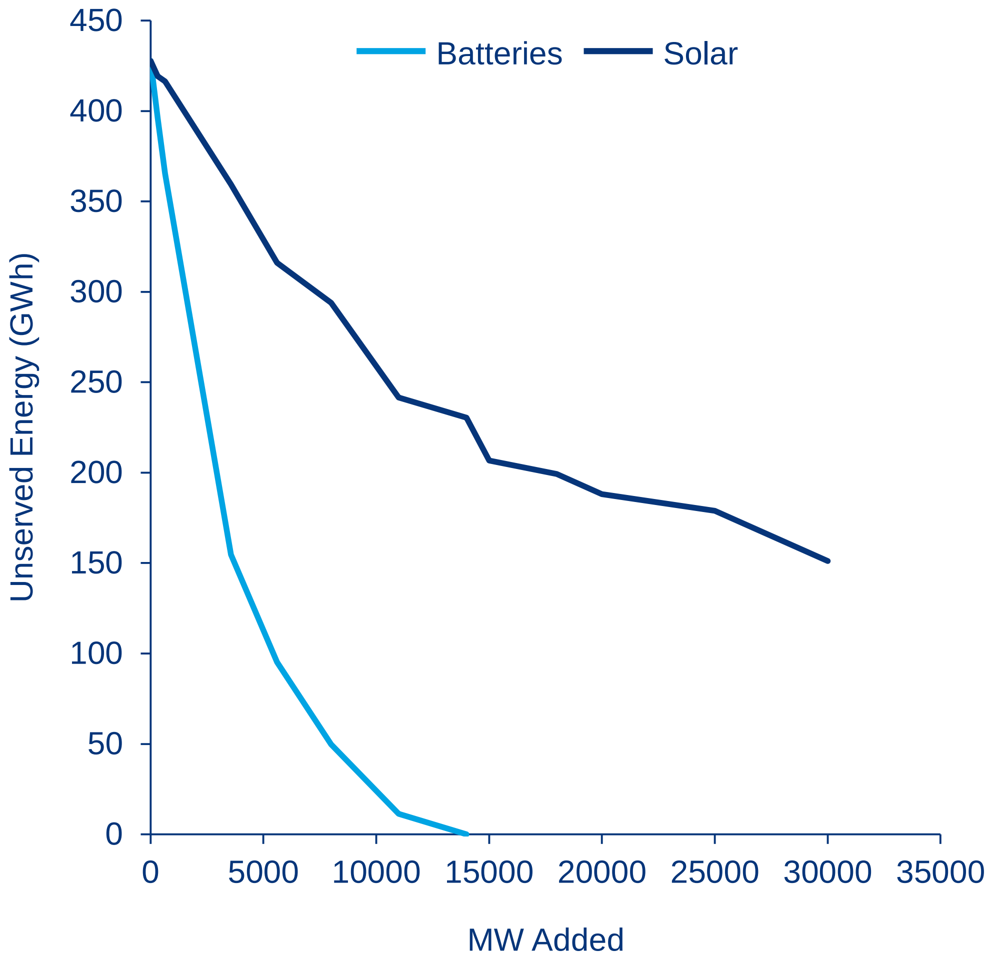
- **The study modelled two alternative cases of the DSW pipeline disruption to examine the impact of the availability of gas storage in key locations**
  - » The first case keeps Aliso Canyon operating at the current limitations on its working capacity and withdrawal rate
  - » The second case models an additional underground natural gas storage facility in the Phoenix, AZ area, based on the open season proposed by Kinder Morgan

Case	Working capacity *(mmcf)*	Max withdrawal rate *(mmcfd)*
DSW base case	**Aliso Canyon decommissioned**	
Aliso Canyon operational	**24,000**	**800**
AZ Gas Storage	**4,000**	**400**

Source: Argonne National Labs , E3, Wood Mackenzie

It will be necessary to bridge the path to battery storage implementation with other mitigation options

Mitigation Capability of Battery & Solar Additions



- **We estimate that ~14 – 15 GW of 4-hr battery storage would need to be installed to mitigate all unserved energy in the EPNG scenario**
  - » The associated capex of installing the battery storage needed to compensate for the DSW pipeline disruption scenario is estimated to be ~$12 – $18 bn
- **The limitations of solar capacity to flex on peak hour demand yield diminishing returns**
  - » Consequently, solar capacity by itself is not able to completely compensate for impacts from the EPNG disruption
- **A feasible, explicitly articulated path forward utilizing a combination of mitigation options is critical for bridging to proposed renewables targets in a safe and reliable manner**

Source: E3

Reconciliation and improvement of natural gas/electric coordination will be key to maximizing ability to manage increased gas demand

	Recommendations	Benefits
Improved Regional Coordination	• Conduct regional contingency planning exercises led by WECC to prepare for a number of disruption scenarios	• Maximizes compensation ability for utilities across the Western Interconnection
Resource Adequacy Assessment	• Greater transparency of firm contracting and linkage to power plants served in firm reserve reports	• Allows for more robust planning processes, especially as gas and power capacity dynamics tighten
Curtailment Priorities	• Re-visit classification of electric generation as “non-core” end-use • Designation of plants critical to grid reliability as core end-use	• Ensuring that critical power plants are not the first to be curtailed allows for additional flexibility for compensation via transmission
Forecasting & Execution	• Require intra-day LDC core load balancing to ensure fair implementation of OFOs and penalties • Additional clarity around interstate pipeline curtailment protocol	• Higher accountability for prior-day forecasting allows easier utility operation • Explicit interstate curtailment protocols allow for better contingency planning
Gas-Electric Day Mismatch	• Split weekend nomination period into daily blocks, resulting in a 7-day nomination cycle	• A feasible step for both gas and electric sides that would minimize response lead times over the weekend period

Source: Wood Mackenzie, E3

Disclaimer

- This report has been prepared for WECC by Wood Mackenzie Incorporated. The report is intended solely for the benefit of WECC and its contents and conclusions are confidential and may not be disclosed to any other persons or companies without Wood Mackenzie's prior written permission.

- The information upon which this report is based has either been supplied to us by WECC or comes from our own experience, knowledge and databases. The opinions expressed in this report are those of Wood Mackenzie. They have been arrived at following careful consideration and enquiry but we do not guarantee their fairness, completeness or accuracy. The opinions, as of this date, are subject to change. We do not accept any liability for your reliance upon them.

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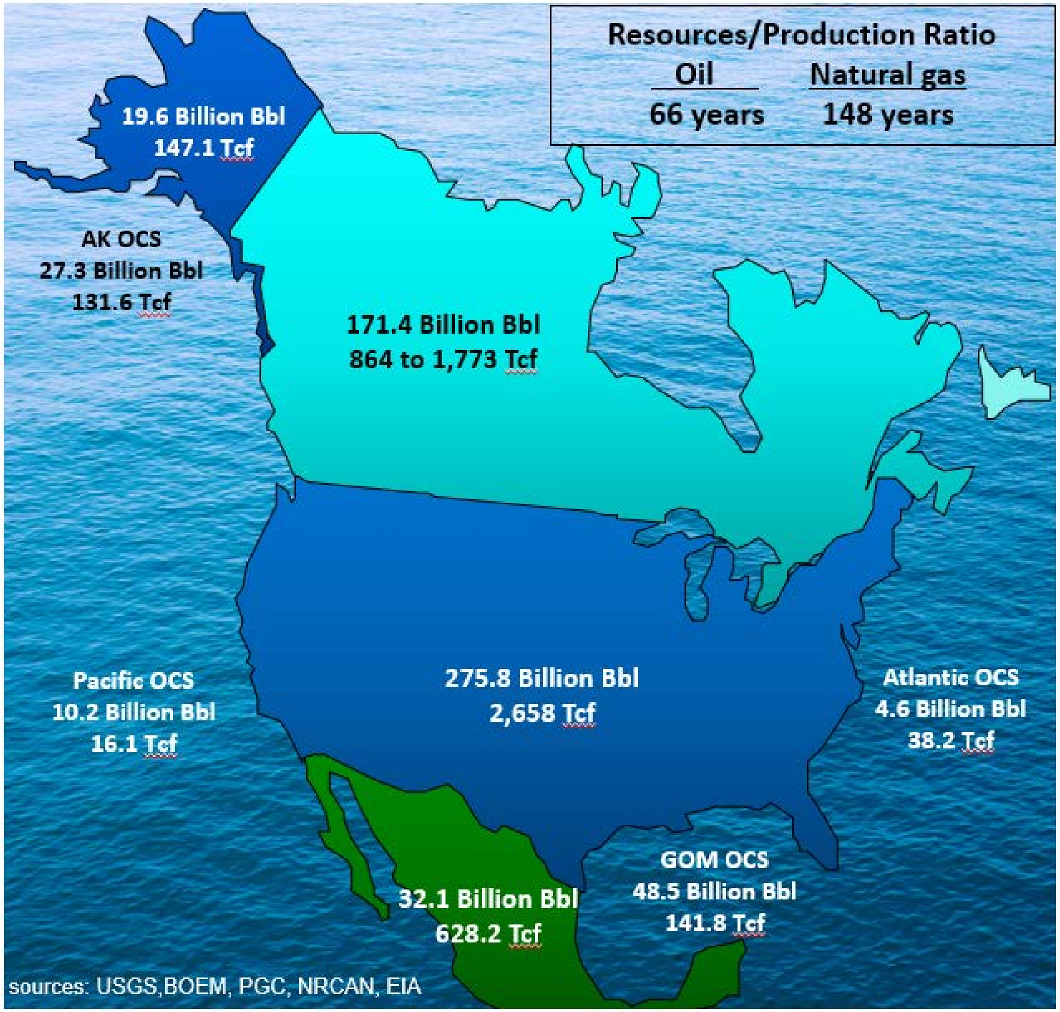
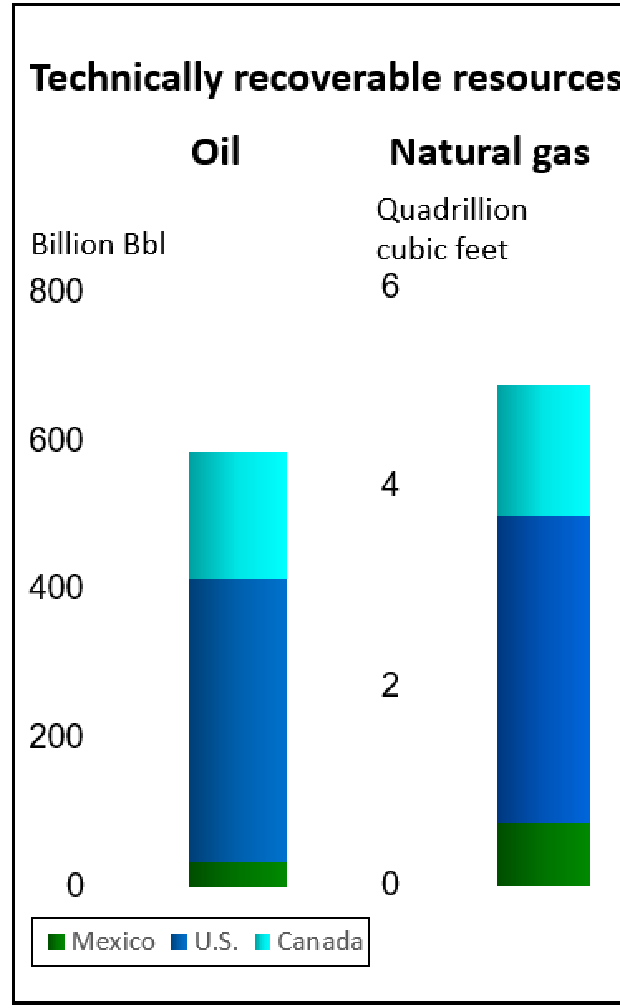
NATURAL GAS POWERING AMERICA PAST IMPOSSIBLE

1220 L Street, NW • Washington, DC 20005-4070 • www.api.org

Todd Snitchler
Group Director, Market Development
American Petroleum Institute

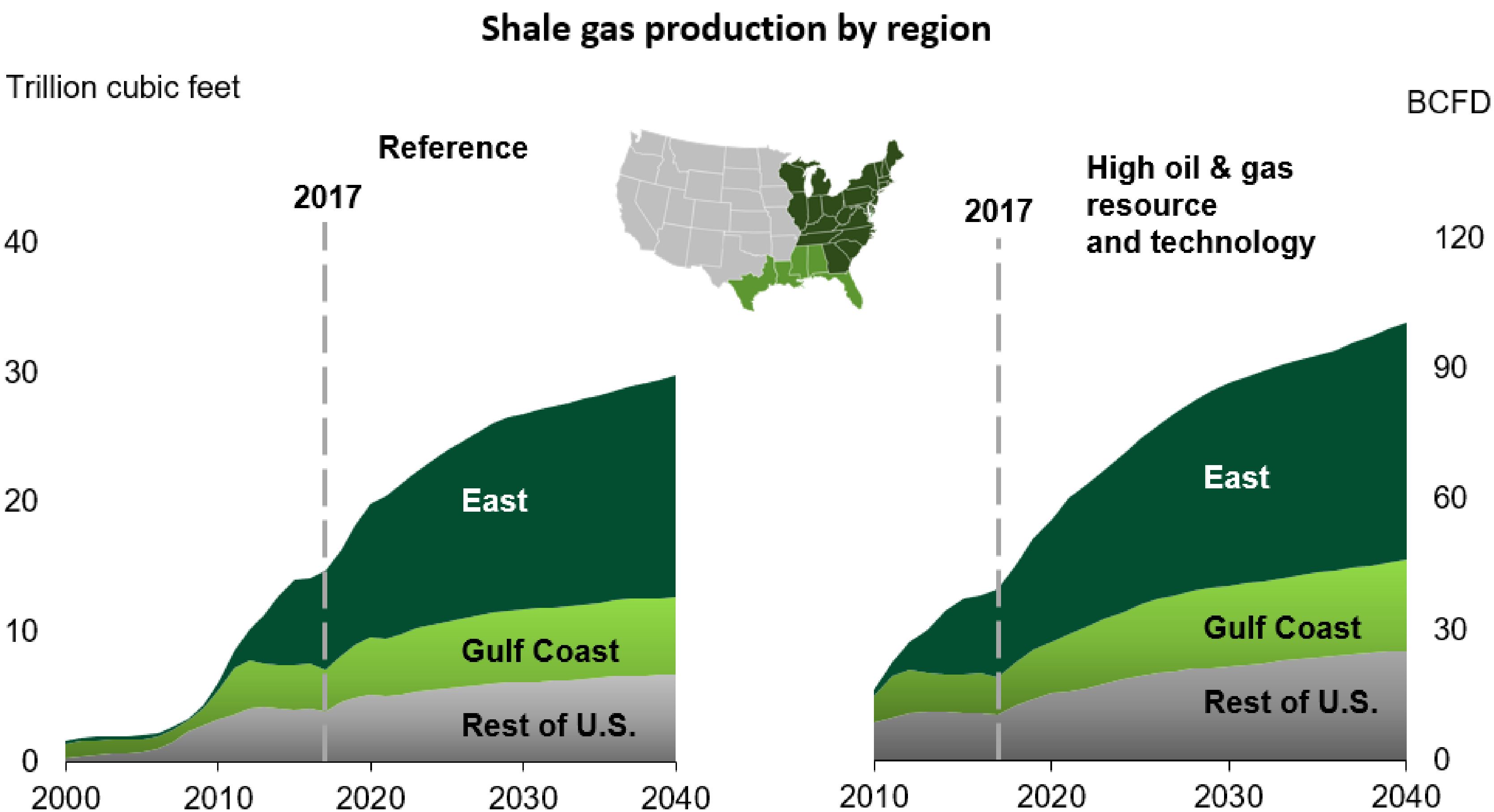
North America's technically recoverable natural gas & oil resources





- Based on technically recoverable resources and 2016 production levels, North America has 66 years of oil and 148 years of natural gas

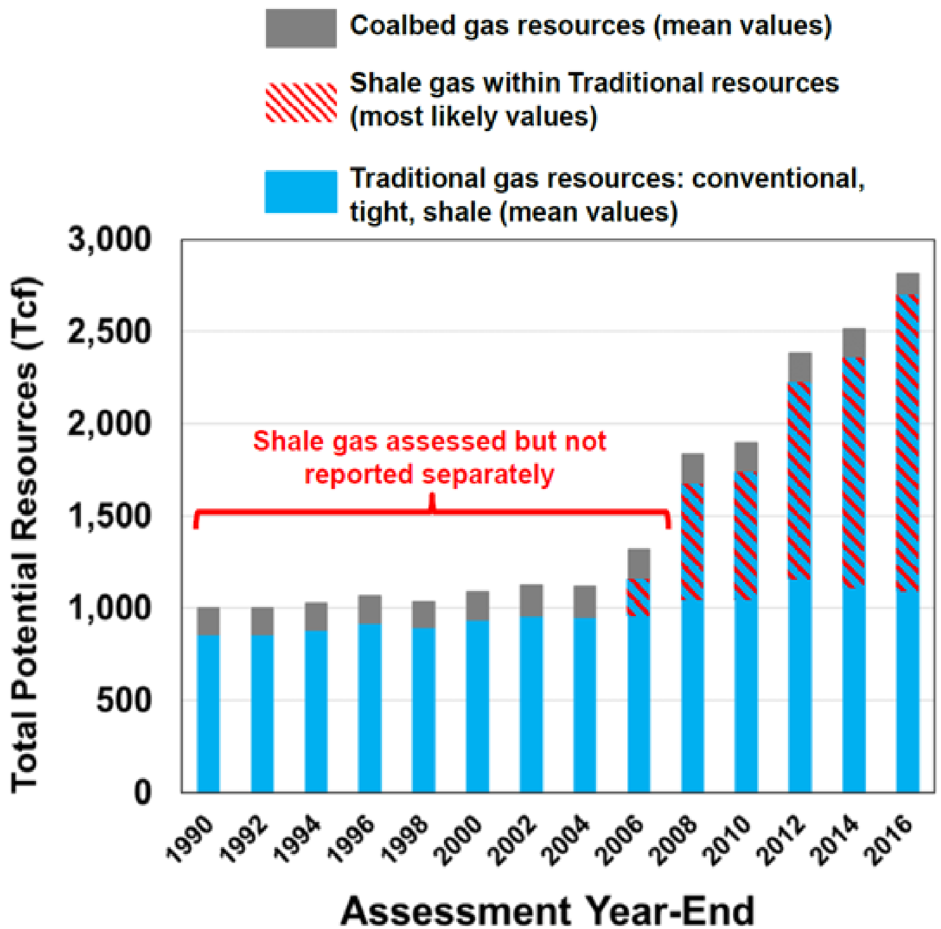
EIA expects the East to dominate U.S. natural gas production

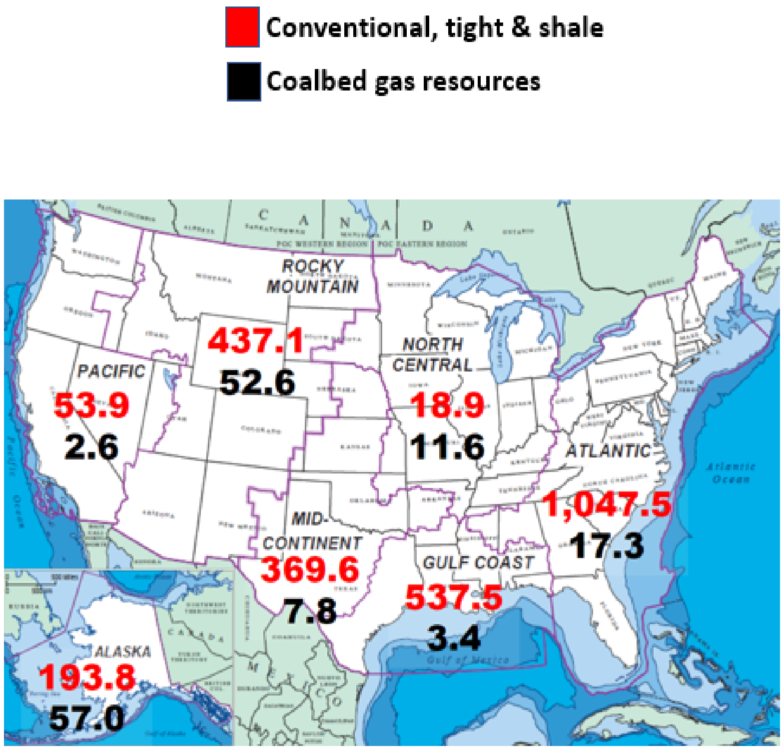


source: U.S. EIA AEO (2018)

- Continued development of the Marcellus and Utica plays in the East is the main driver of growth in total U.S. shale gas production across most cases

The onshore U.S. natural gas resource base nearly doubled in the past decade due to shale gas





source: Potential Gas Committee

- Gas resources have grown continuously since 2004, and shale gas has driven the increases

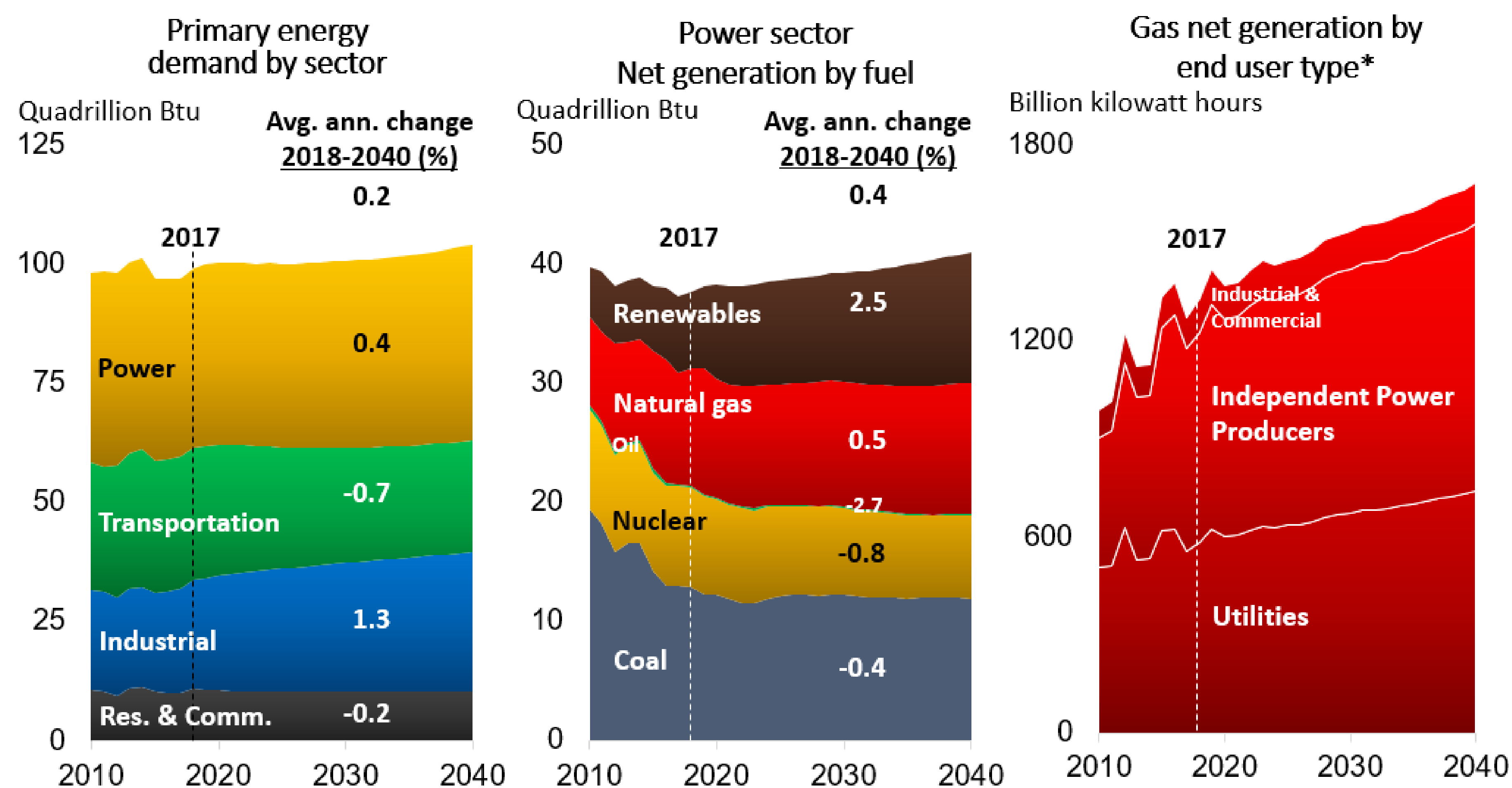
U.S. natural gas and oil proved reserves of U.S.-based companies

Crude oil proved reserves, top companies

Natural gas proved reserves, top companies

source: Oil and Gas Journal, OGJ 150 (2017)

EIA's Reference case projects U.S. electric power demand and natural gas use to sustain growth

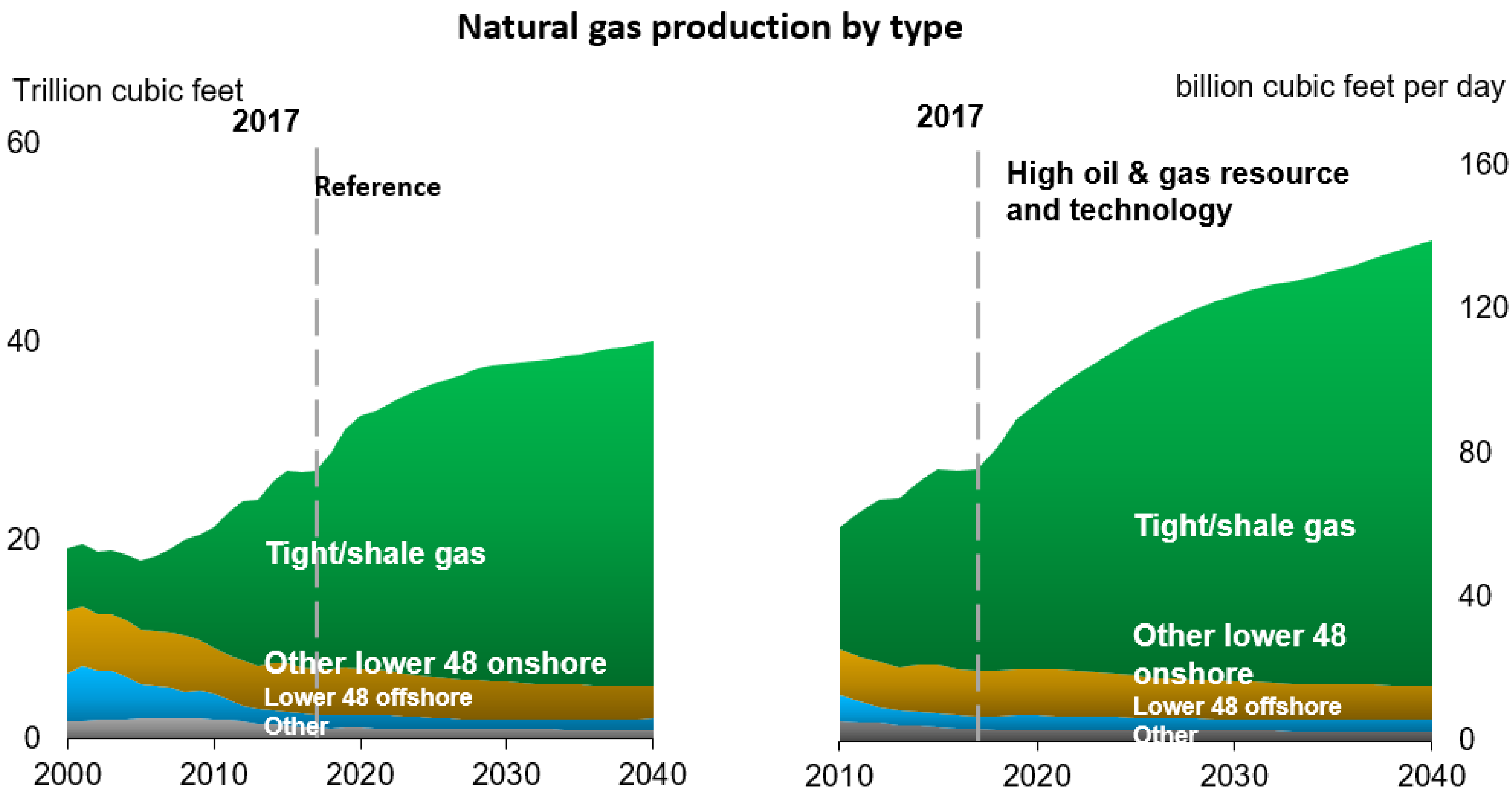


source: EIA AEO (2018) and API calculations

*Holds shares constant after 2017

- EIA expects natural gas and renewables to gain share for decades to come

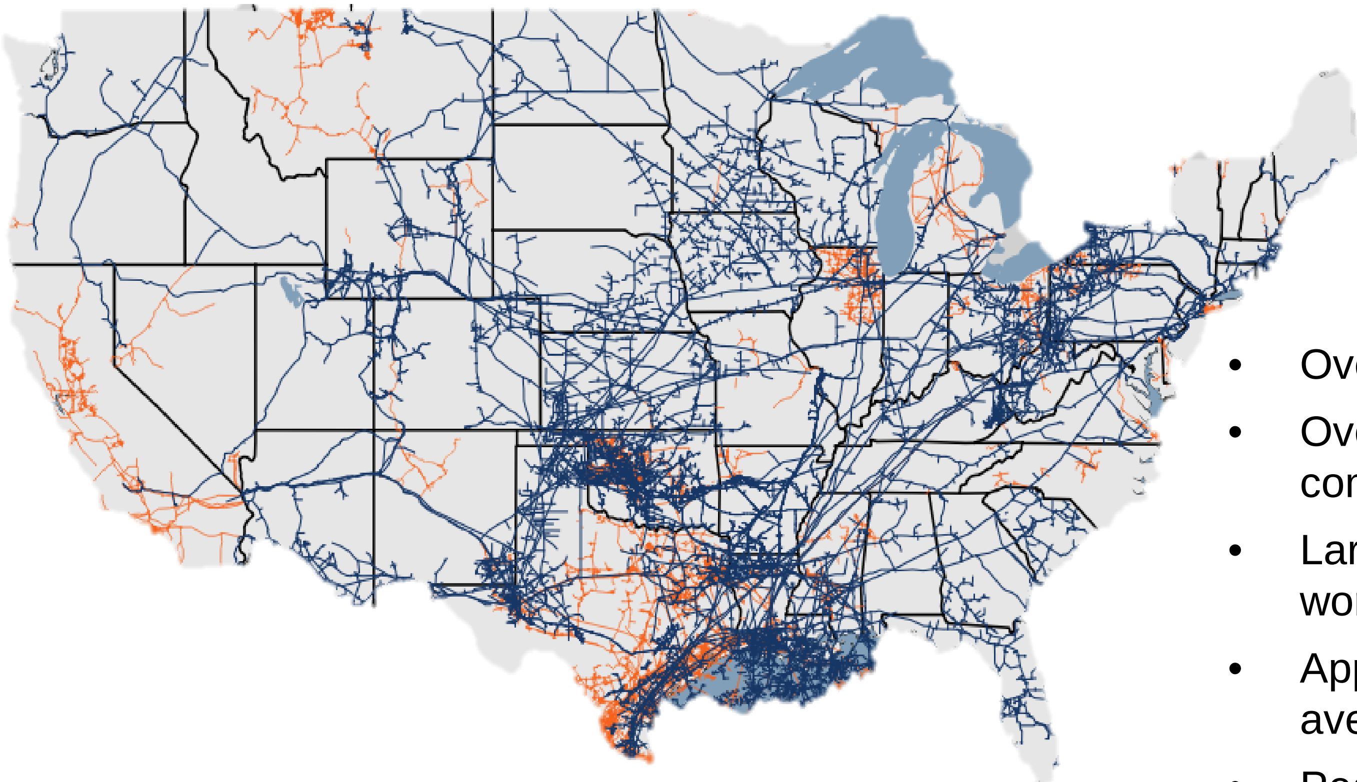
The EIA projects that tight oil and shale gas production will remain dominant technologies through 2050



source: U.S. EIA AEO (2018)

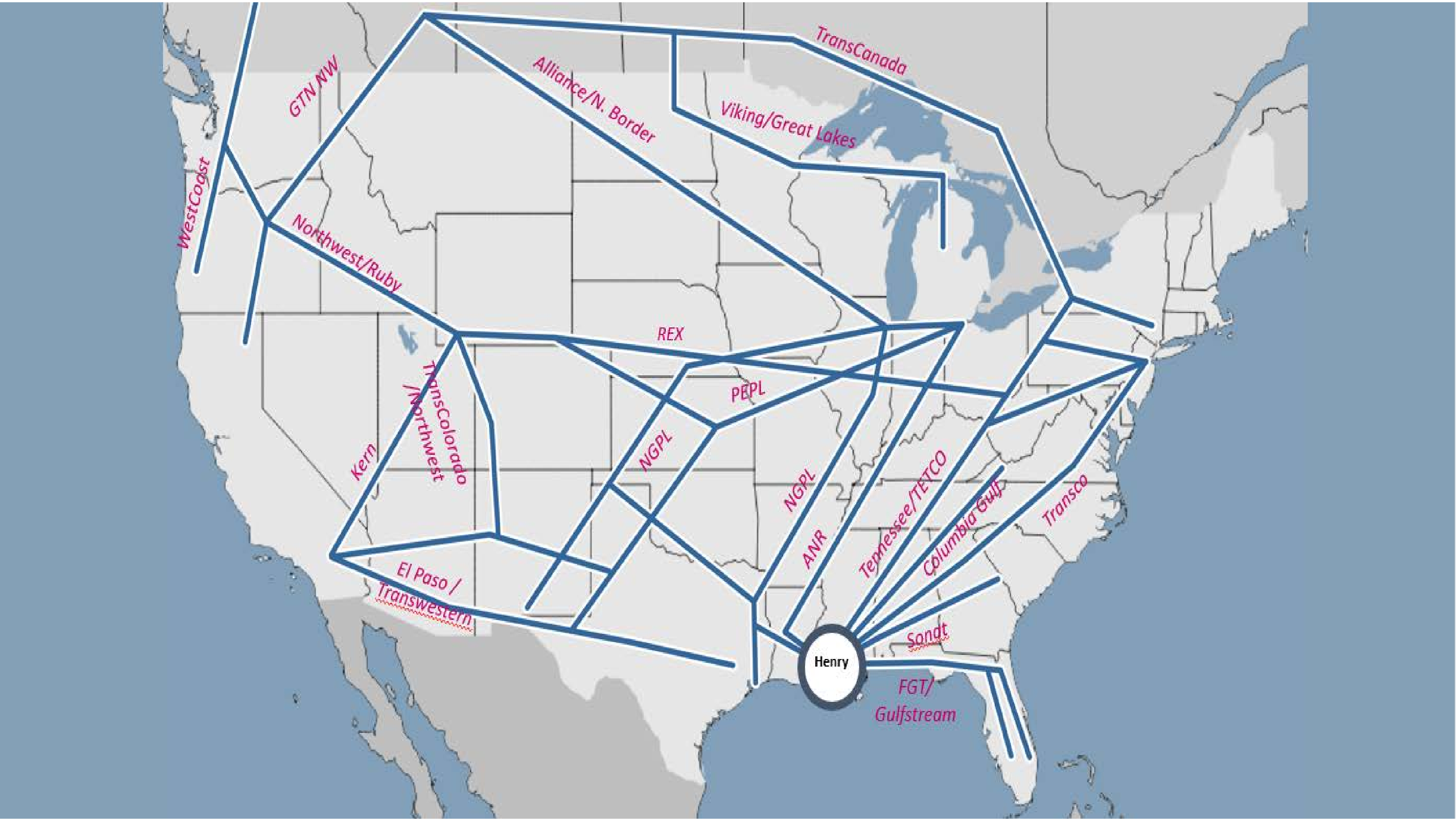
- Upgraded resource assessments have driven the EIA's projections of tight oil and shale gas growth

The US Natural Gas Industry Is Enormous

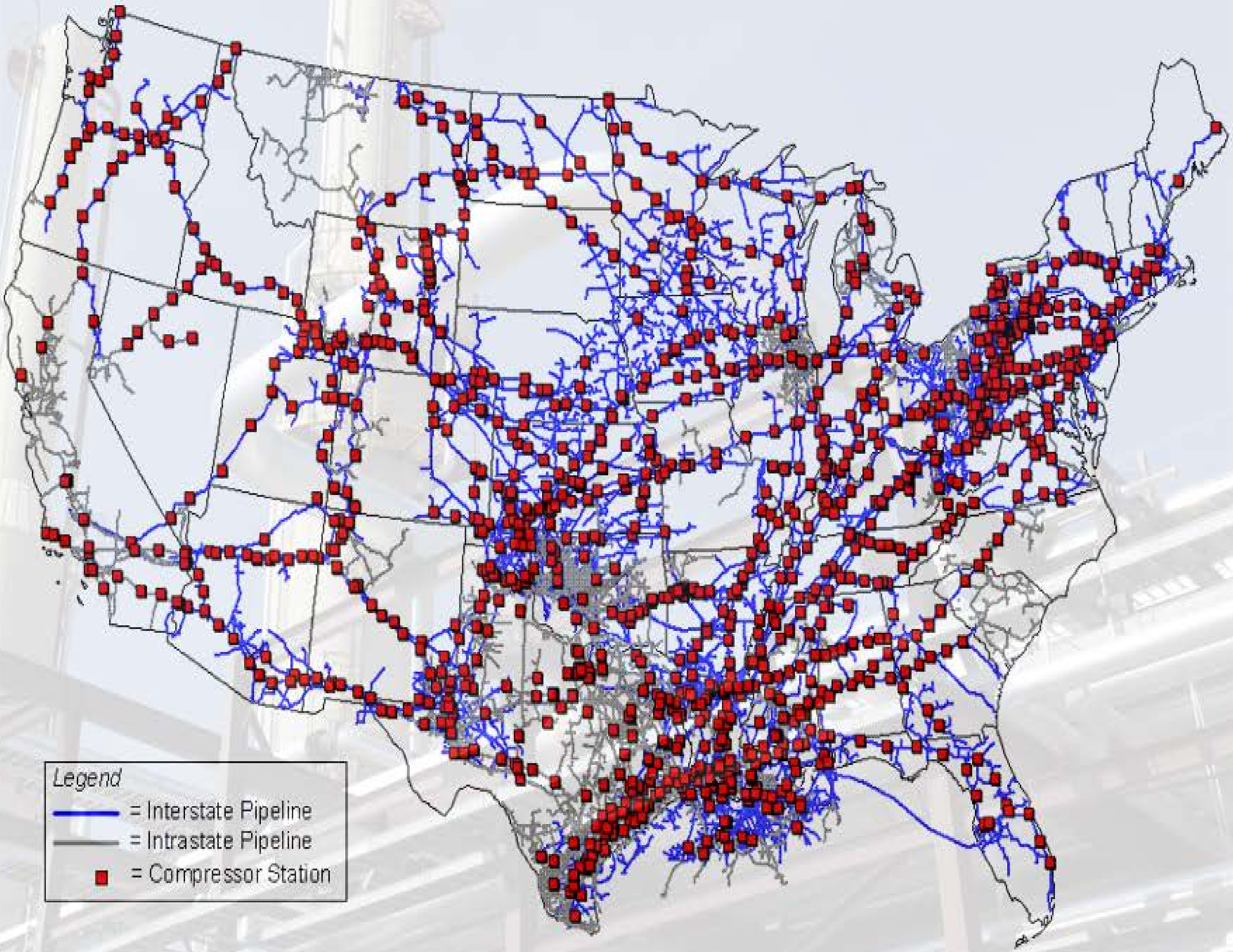


- Over 300,000 miles of pipe
- Over 200 transmission companies
- Largest gas market in the world
- Approximately 75 Bcf/day average
- Peak flow of over 100 Bcf/day
- Equivalent to 600,000 MW of combined-cycle capacity

The Market—Major Pipeline Corridors and Henry Hub

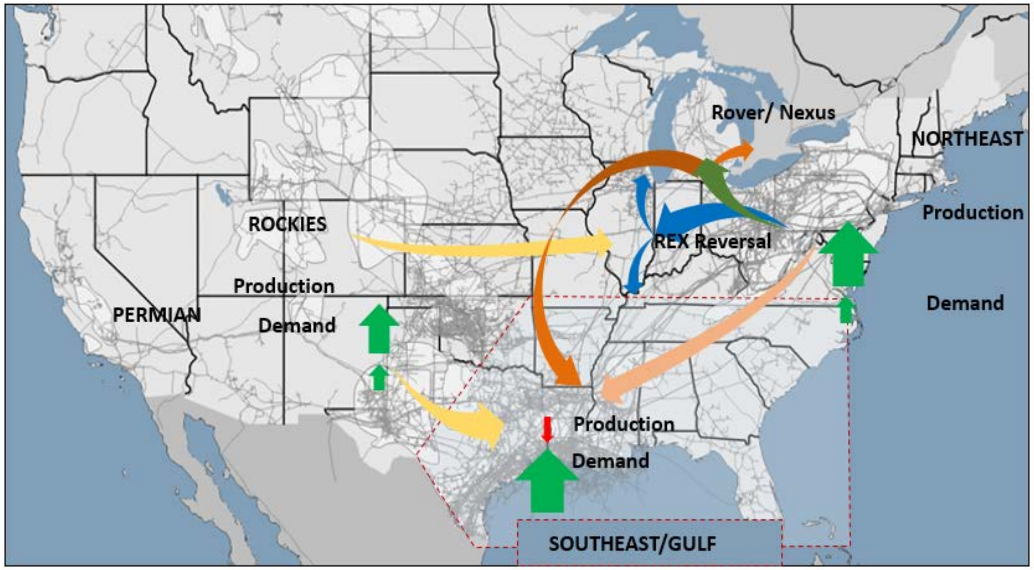


Compressor Stations



Production Growth Flows To SE, Midwest

- The REX Reversal already pushes into the upper Midwest and the Southeast
- With no alternative markets, Rockies gas will continue to move east into the Midwest
- The next wave of Marcellus/Utica production growth will move to Michcon/Nova via Rover and Nexus creating supply surpluses in the Midwest
- Midwest surpluses will compete with Permian associated gas production and Appalachian gas moving on pipeline reversals to the Gulf Coast
- Midwest surpluses will further aggravate oversupplies competing for the only growth market in North America – the Southeast/Gulf



Natural Gas Market Structure

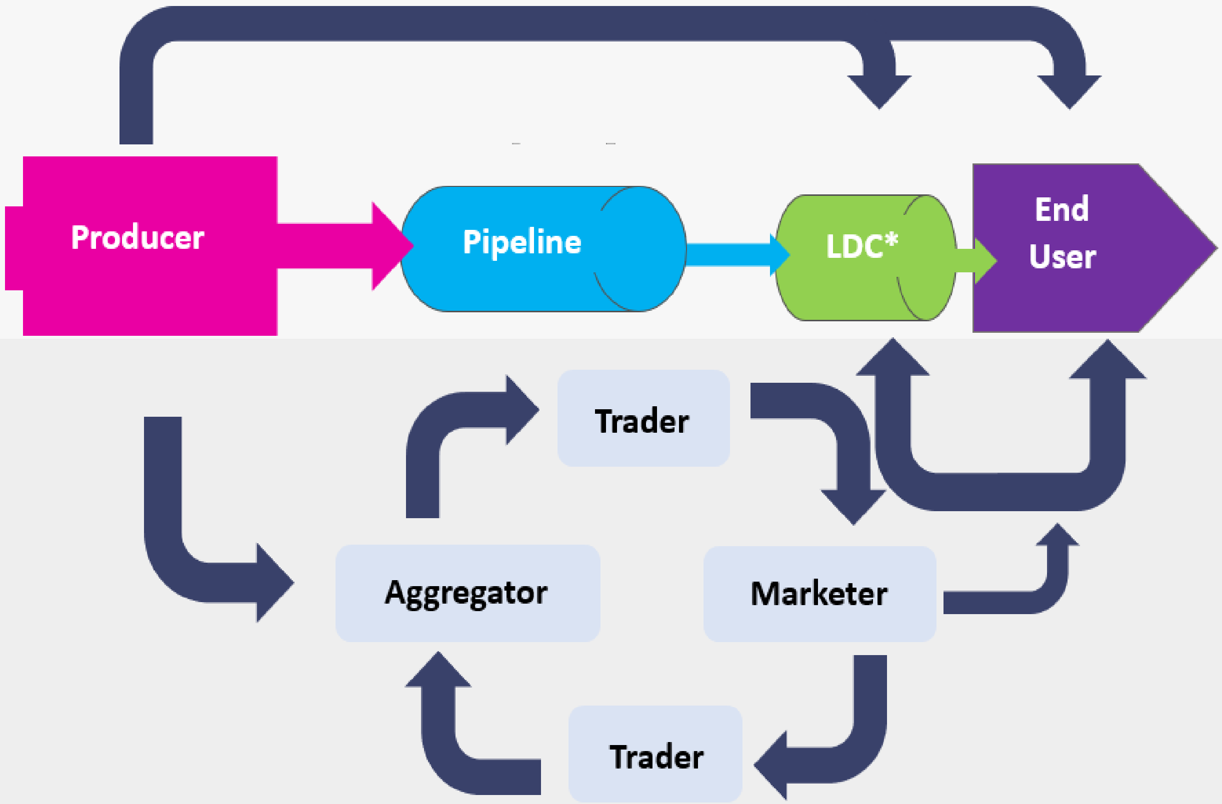
Who Does What?

Physical

Physically, gas flows producer to pipeline, to LDC, to end user.

Commercial

But commercially, since restructuring under FERC Order 636 in 1993, the dynamics have gotten pretty complicated.



* Local Distribution Company

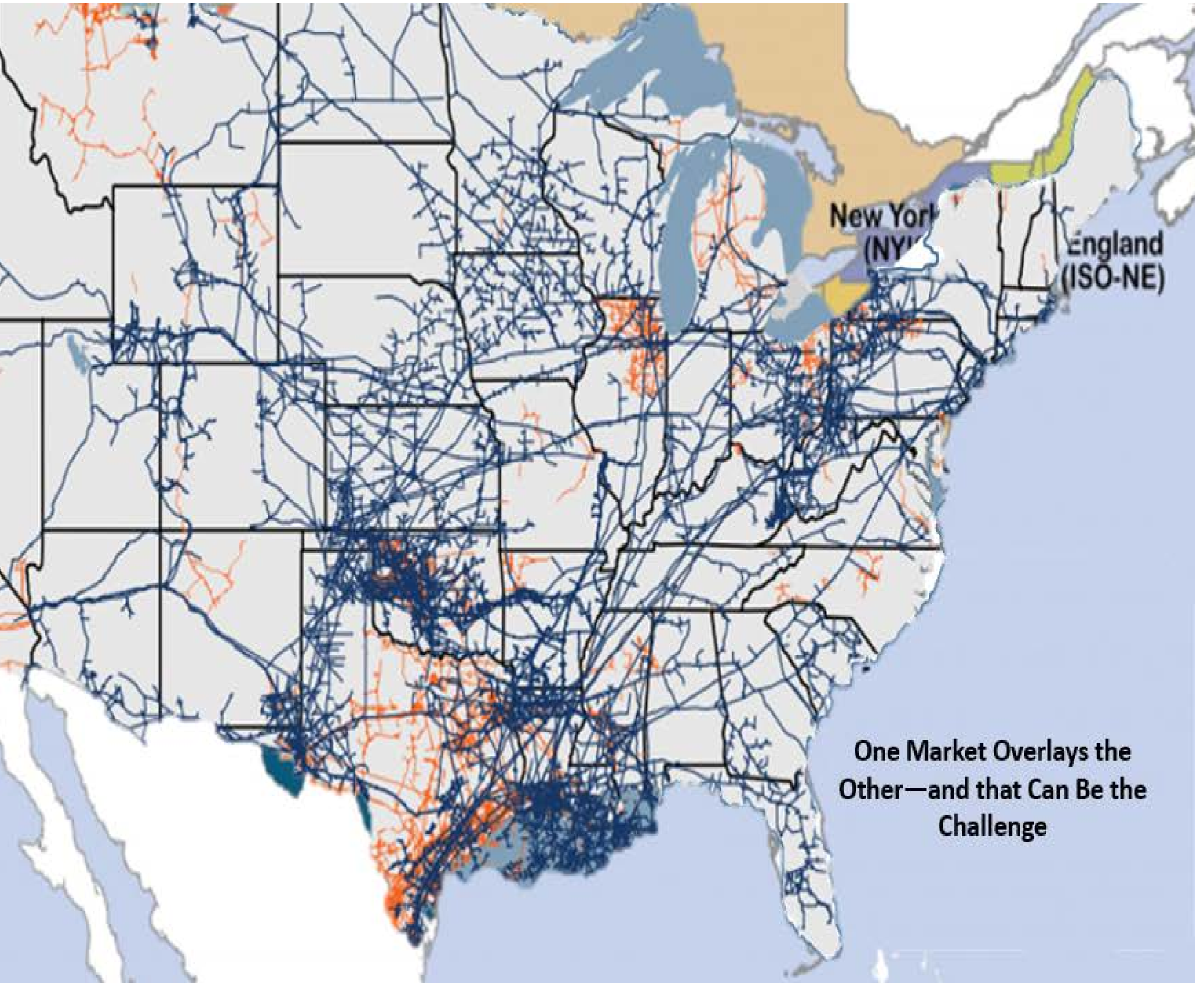
Comparing Power Markets and the Pipeline Industry

Pipelines and Gas

- Uniform National market, very transparent
- Some tailoring, but fairly uniform regulated terms
- Flexible across multiple sectors and regions
- Can move gas across the nation with predictable terms

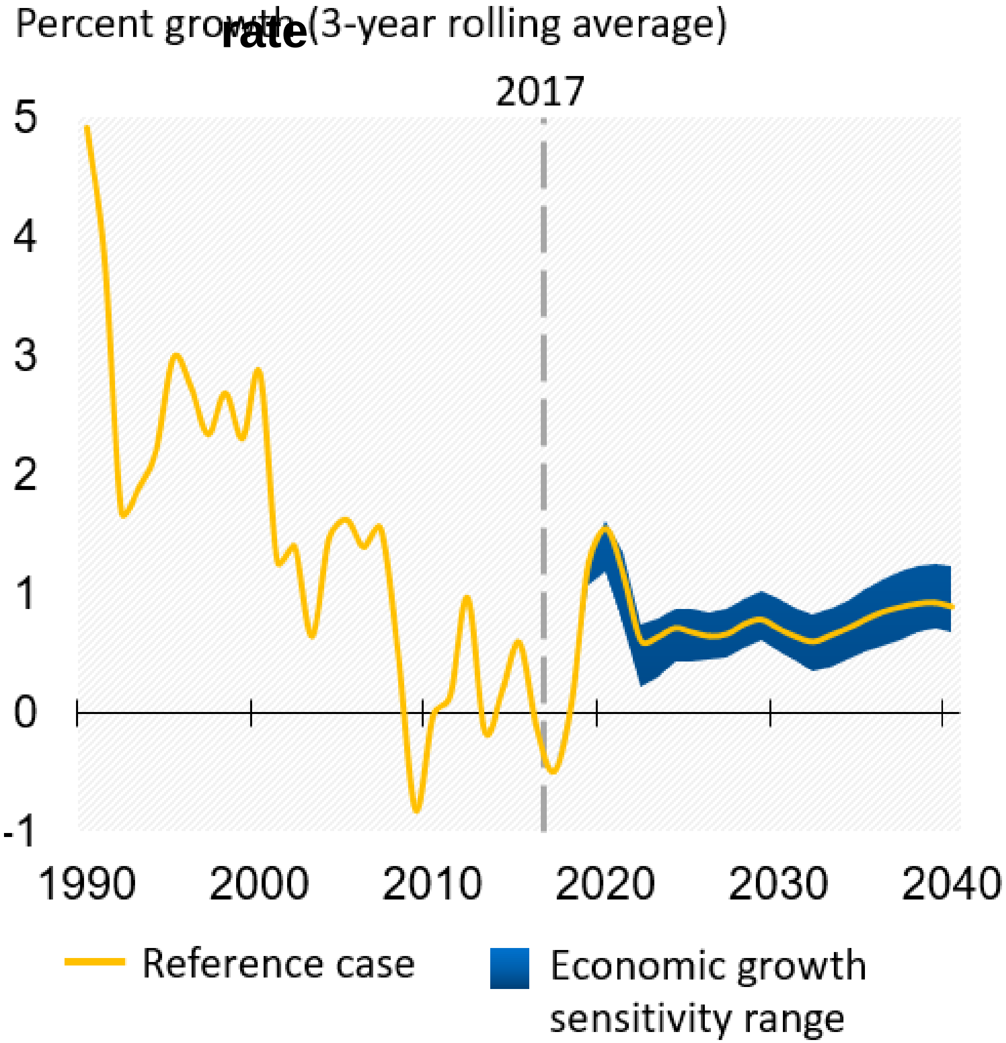
Power Markets

- Regional, Tailored to meet regional needs
- Some are transparent, some not
- Sometimes hard to move between regions
- Significant variation in rules among regions



After decades of slowing growth, the EIA expects U.S. electricity demand to grow for decades to come

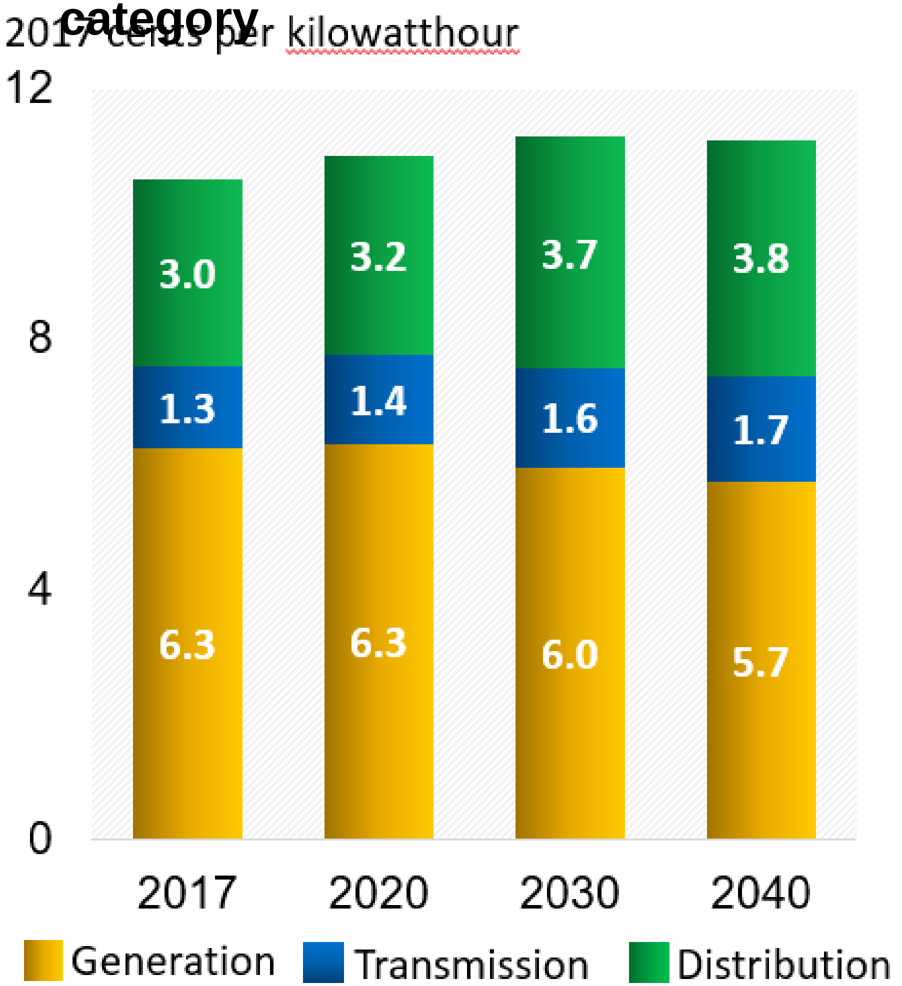
Electricity use growth rate



- Electricity demand is driven by economic growth and increasing efficiency
- Historical demand slowed with high efficiency gains
- Electricity demand growth sustained going forward without structural changes to the light duty vehicle fleet

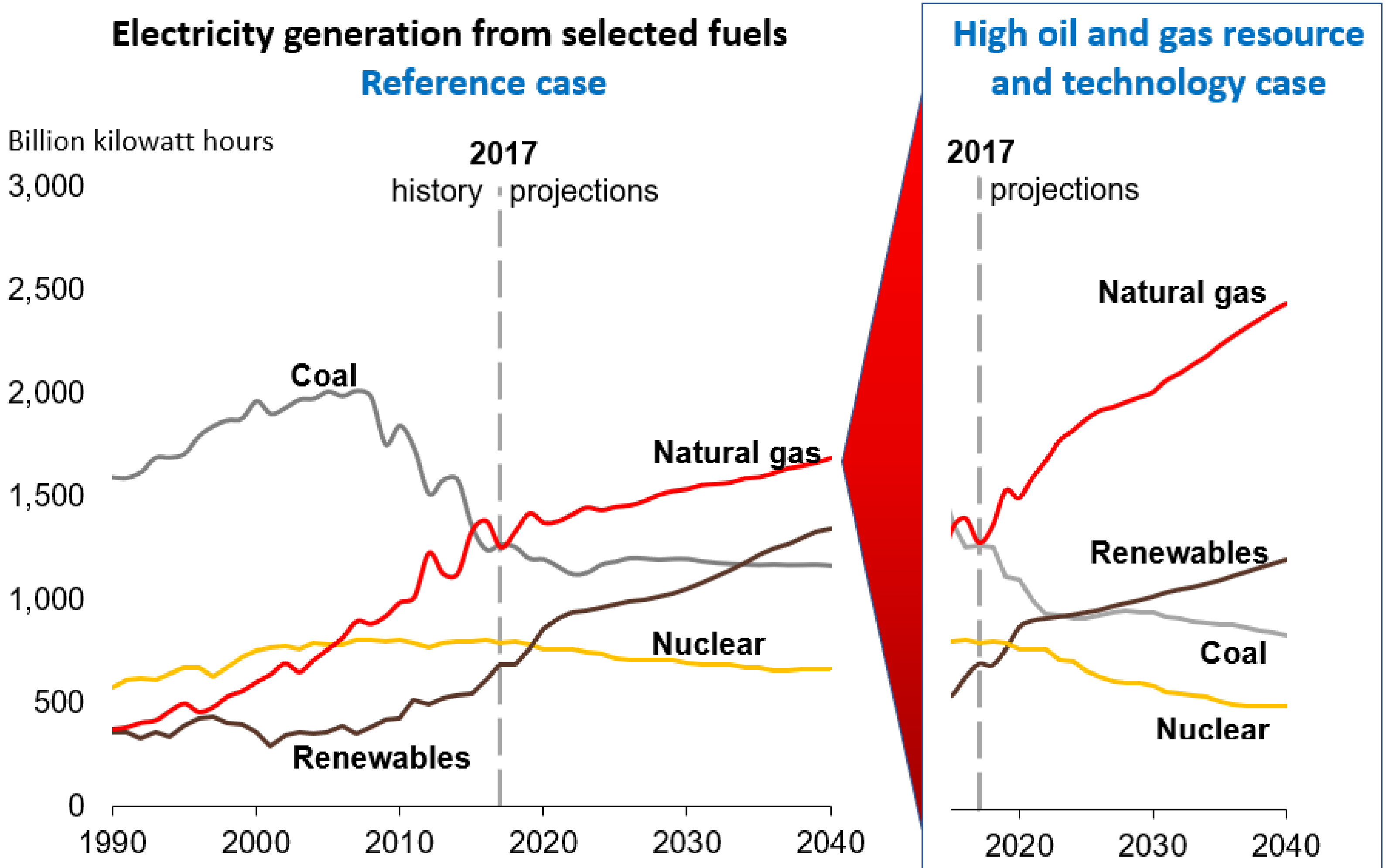
After decades of slowing growth, the EIA expects U.S. electricity demand to grow for decades to come

Electricity prices by service category



- EIA expects relatively flat prices (10.6 to 11.8 cents per kilowatthour (kWh)) overall, but the category mix shifts
- Transmission and distribution costs increase due to the need to replace aging infrastructure and upgrade the grid
- Generation represents the largest share of the price of electricity and is projected to decrease with continued low natural gas prices and increased generation from renewables

With high resources and technology, EIA projects generation from natural gas could rise 89% by 2040



source: EIA AEO (2018)

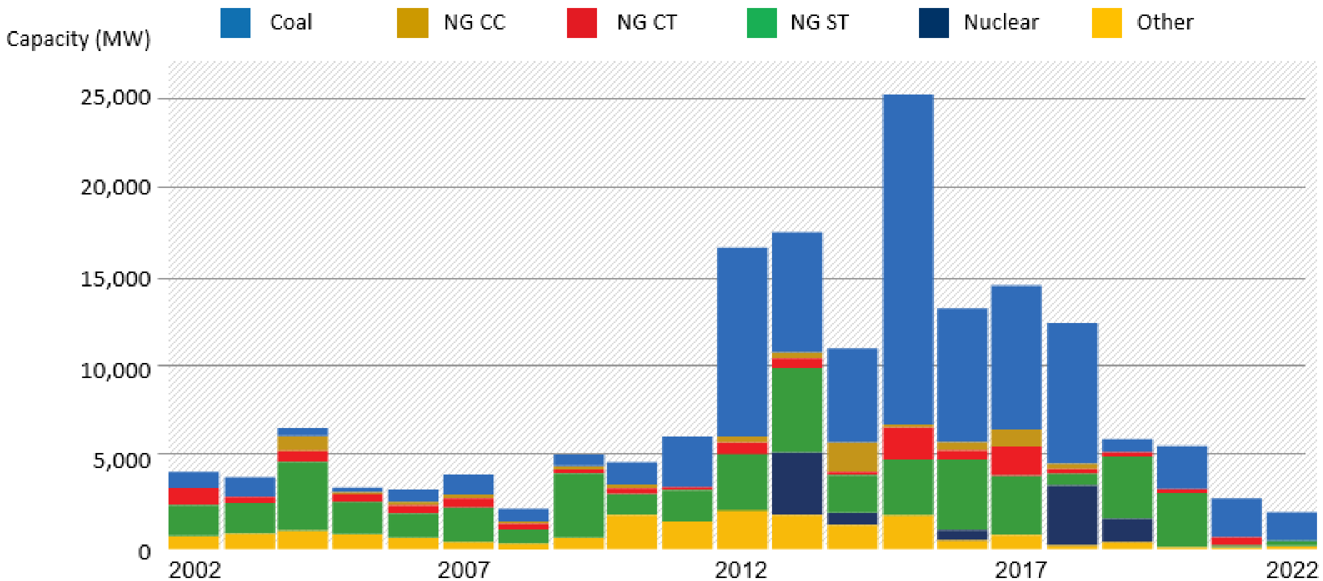
- The high oil and gas resource and technology case assumes the Estimated Ultimate Recovery (EUR) from tight oil, tight/shale gas rises by 50%

Grid resilience, reliability improved in 2017 despite unprecedented generation capacity retirements over the past five years

NERC: State of Reliability 2018 – Key Findings

- North America's bulk power system showed improved resilience during the NERC category 5 events
- No loss-of-load due to cyber or physical events
- Emerging risks from inverter disconnects
- Decreased trend of transmission outages and protection system mis-operations rates

Generation unit retirements by source



source: U.S. DOE Staff Report on Electricity Markets and Reliability (2017)

Natural Gas Pipeline Resilience

NERC Technical Workshop| Gas Infrastructure Risk and Associated Recommendations
Session 2: Natural Gas Paradigm| July 10, 2018

Donald Santa

President & CEO

Interstate Natural Gas Association of America

Natural Gas Pipeline Resilience: What Happens When Pipelines Fail?

- Pipeline failures are a rarity.
- Still, real world examples of pipeline failures demonstrate the resilience of the natural gas transmission and storage sector.

Texas Eastern Delmont Outage (2016)

- Primary firm service was affected for only one day.
- Draws on natural gas storage downstream of the affected pipeline mitigated the immediate impact of the incident.
- Incident occurred on a looped system, which enabled the operator to restore a significant amount of service within 11 days.
- Full capacity was restored before the onset of the winter heating season.

Leach XPress (2018)

- '[T]he closure of the pipeline has had little or no effect on Appalachian gas production as more than 1 Bcf/d of production that previously left the region by way of Leach XPress has been routed to other Northeastern takeaway pipelines."

Gas Daily, July 5, 2018

Bomb Cyclone and Cold Snap
(December 2017-January 2018)

- Pipeline customers with firm service experienced complete reliability between their contracted receipt and delivery points (primary firm service).
- Isolated force majeure events did not affect service to firm customers. Gas storage and work arounds covered any shortfalls.

Bomb Cyclone and Gas-Fired Generation

- “There were no reported firm capacity restrictions during this period, and all force majeure events were related to generators with interruptible capacity.” –PJM Cold Snap Performance
- “Market design changes and winter preparedness actions help Northeast and Mid-Atlantic electricity markets handle January’s bomb cyclone weather event.” –EIA Northeastern Winter Energy Alert
- “The lower outage rate in natural gas CP resources…could be an indication that those resources had prepared better for weather events through increased firmness of transportation capacity and supply, along with a greater diversity of natural gas supply resources and delivery options.” –PJM Analysis of Capacity Performance

Cyber Threats to Pipeline Operations: Fiction and Fact

- **Fiction** – "The President is Missing"
- **Fact** – Pipeline design and the physical characteristics of natural gas provide layers of protection against catastrophic failure.
- **Fact** – Cyber-related interruption of natural gas deliveries likely would be short duration.

Single Point of Disruption Report

- In total, conclusions accurately characterize the natural gas system.
- As noted in the report, more detailed analysis of contracting practices, generator characteristics and physical infrastructure would be needed to determine whether a particular cluster of generators presents a BPS concern.
- To the extent that enhanced natural gas infrastructure is the answer, the voice of NERC and the electric power sector in overcoming economic and political barriers is critical.

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Interstate Natural Gas Association of America
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AGA 100 YEARS

Natural Gas

Pipeline Resilience

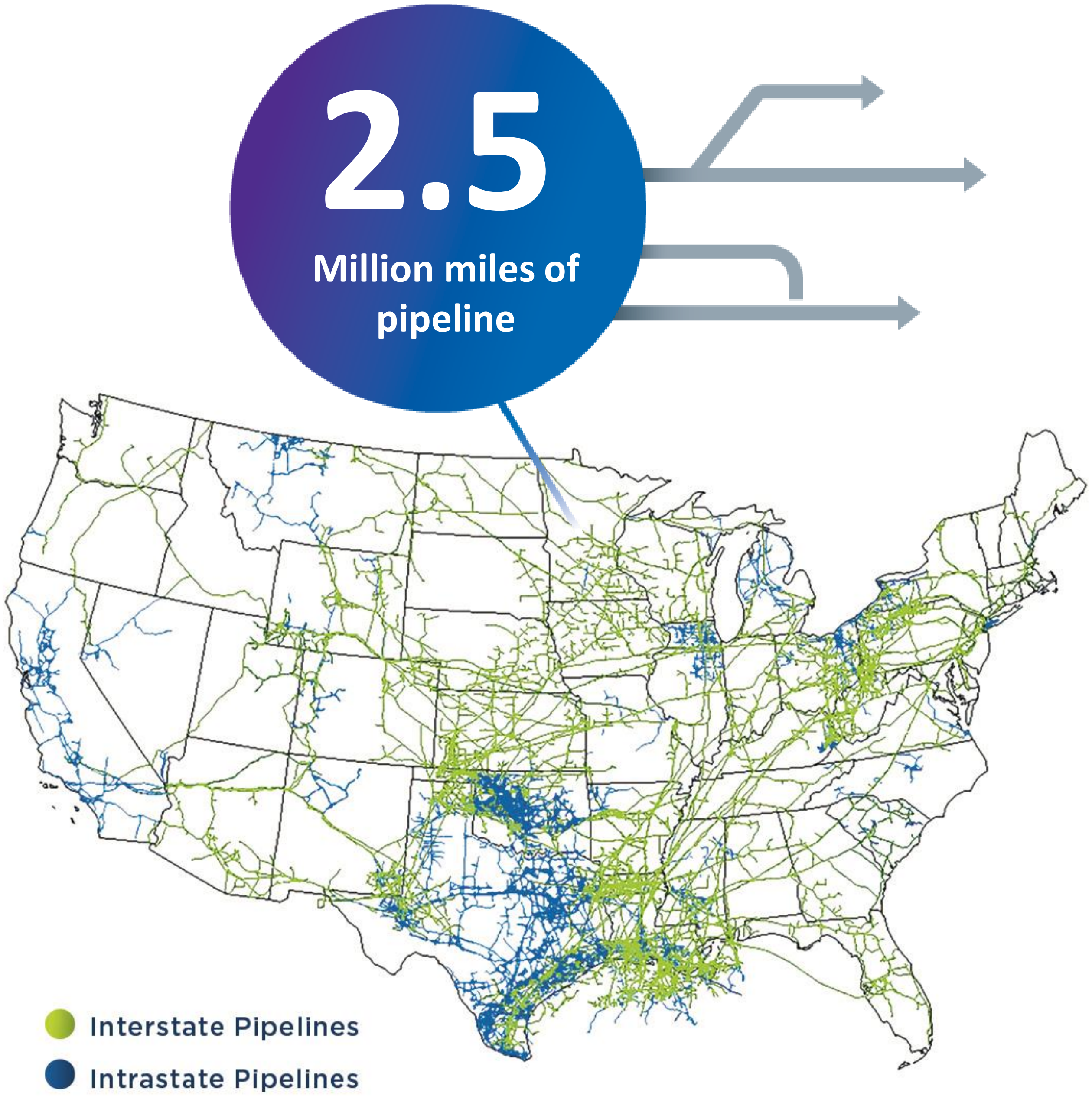
Distribution

Rob Mims
Managing Director, Information Security
Southern Company Gas
Atlanta, GA| July 11, 2018

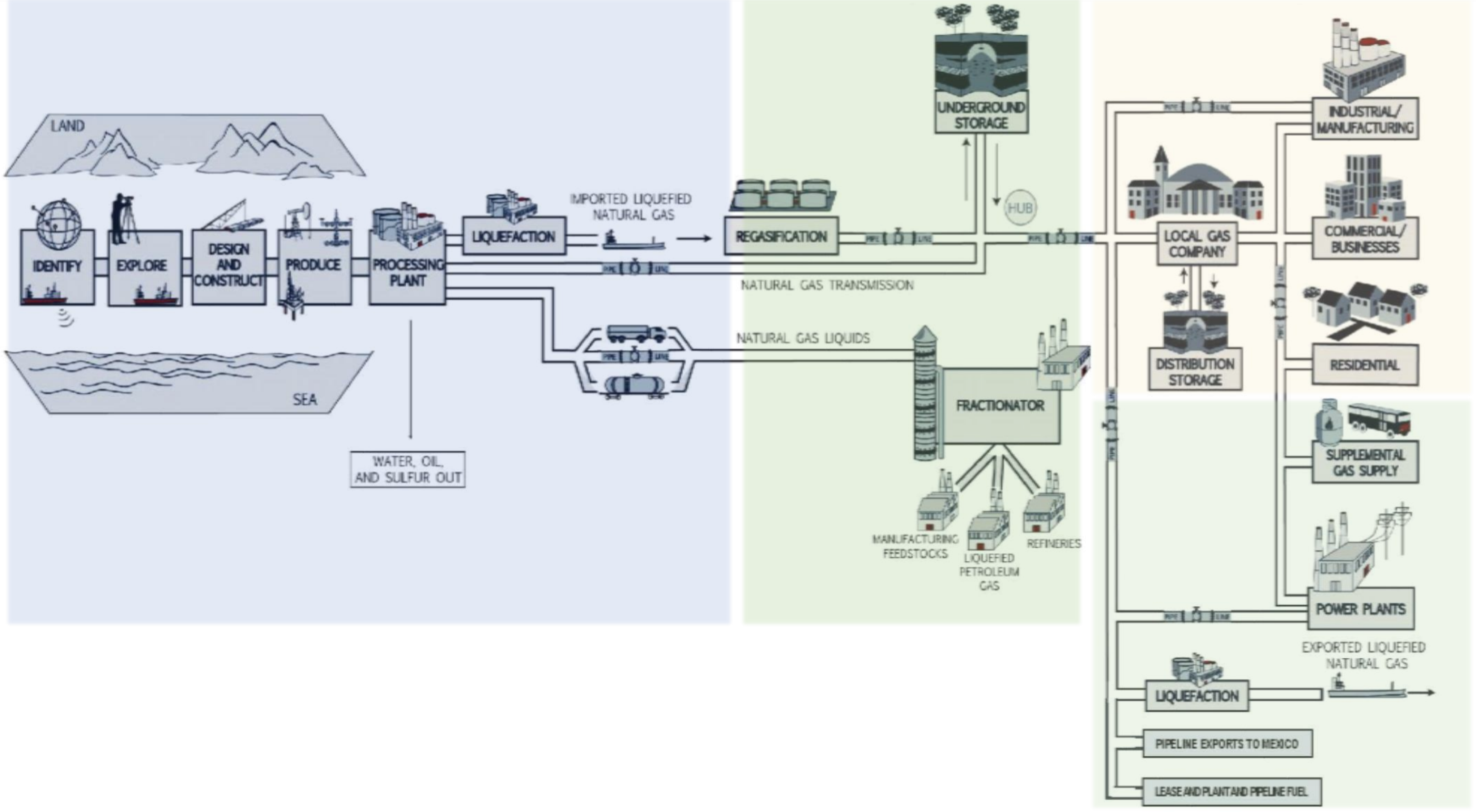
Safely Transported Across the Country

Natural gas pipelines:
- transport approximately one-fourth of the energy consumed in the U.S.
- the safest form of energy delivery in the country

Natural gas is delivered to customers through a 2.5 million-mile underground pipeline system. This includes 2.2 million miles of local utility distribution pipelines and 300,000 miles of transmission pipelines that stretch across the country.

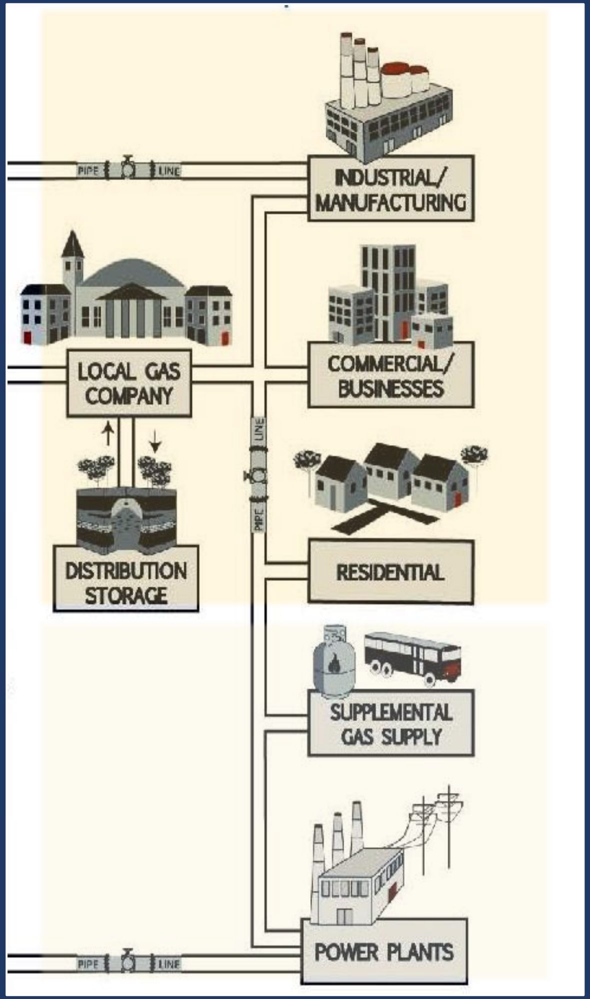


Wellhead to Burner-tip



The supply chain model is provided as a courtesy of API, "Oil & Natural Gas Industry Preparedness Handbook, 2013"

Wellhead to Burner-tip



Natural Gas Pipelines – The Basics

- Difference between natural gas and electricity
  - Operations – molecules vs. electrons
  - Contracts & Regulatory Tariff Agreements
  - Resilience upfront
- All Hazards, not just cyber
- Aliso Canyon – unique energy market

Cyber and Physical Security Initiatives

- AGA Commitment to Cyber and Physical Security
- Information Sharing
  - DNG-ISAC and ONG-ISAC
  - Automated information sharing technology
- TSA Pipeline Security Guidelines
- Peer Cyber Reviews
- AGA Cyber Metrics Program
- Cybersecurity Capability Maturity Model

Emergency and Incident Response

- Exercises
  - Individual Companies
  - State/Regional
  - National (e.g., ClearPath/GridEx)
- Incident Response
- PHMSA Control Room Management
- Mutual Assistance
  - Cyber Mutual Assistance

In July 2017, the Natural Gas Council released a joint report that provides a practical guide to the operational measures, physical characteristics and contractual underpinnings of the natural gas system's exceptional record of reliability and resilience.

Resilient

- Natural gas utilities develop comprehensive plans and manage assets, operations and contractual portfolios.
- Physical firm natural gas supply arrangements, firm natural gas transportation contracts and firm natural gas storage provide customers and communities with the safe, reliable delivery of natural gas.
- The natural gas pipeline network is predominantly underground and protected from extreme weather events.
- Built-in redundancies through pipeline interconnections and back-up mechanisms mean a single-point failure on the system would typically have a localized effect, if any.

Underground Natural Gas Storage

North American Electric Reliability Corporation

July10, 2018

Catherine Washabaugh
catherine.washabaugh@dot.gov
UGS Implementation Team
USDOT / PHMSA

Who Is PHMSA?

- The Pipeline and Hazardous Materials Safety Administration (**PHMSA**)
  - Under the U.S. Department of Transportation
    - ✓ **Pipeline Safety Office**
    - ✓ Hazardous Materials Safety Office
  - Natural Gas Pipeline Safety Act of 1968 provided the federal government the safety authority over pipelines and underground storage

Who Is PHMSA?

- PHMSA's Office of Pipeline Safety (OPS)
  - Provides Safety Oversight for the Nation's 2.6 Million Miles of Pipeline Infrastructure
    - ✓ Natural Gas
    - ✓ Hazardous Liquid
    - ✓ Liquefied Natural Gas (LNG)
    - ✓ Underground Storage Facilities

How Does PHMSA Work With States?

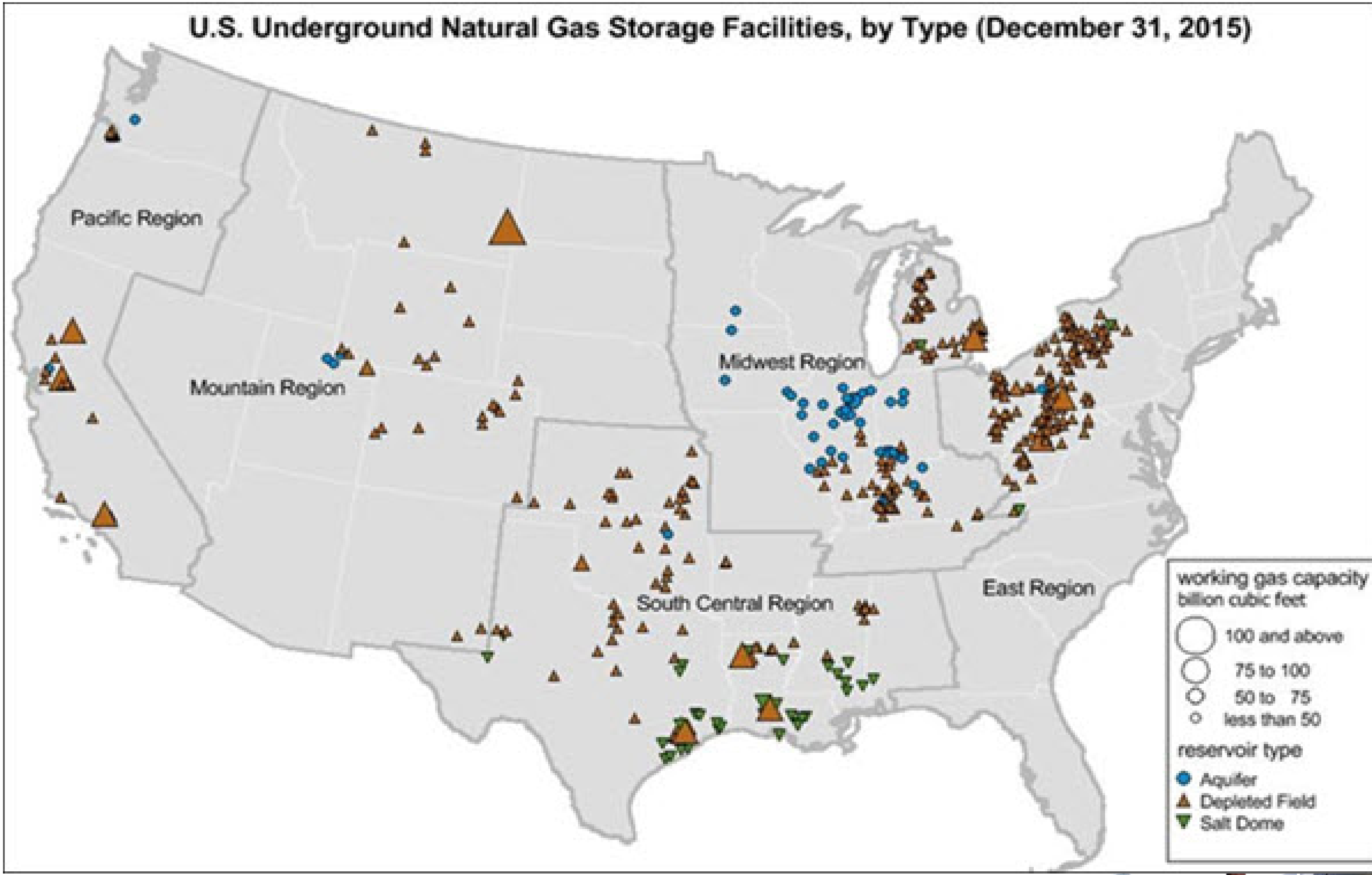
- State Safety Programs through Certification/Agreements with PHMSA Oversees Approximately 80 Percent of the Infrastructure Under PHMSA's Safety Authority

- All States except Alaska and Hawaii Participate in PHMSA's Pipeline Safety Program

- PHMSA has been working with States Since 1968

Underground Natural Gas Storage

- Critical role in our ability to have Energy Independence
- Buffers seasonal variations in supply & demand
- Significant growth in domestic shale gas has prompted renewed interest and investment
- NG Storage increased 16% between 1995 - 2014
- In 2016, value of natural gas in storage was $15+ billion


U.S. Underground Natural Gas Storage Facilities, by Type (December 31, 2015)
Pacific Region
Mountain Region
Midwest Region
South Central Region
East Region
working gas capacity
billion cubic feet
100 and above
75 to 100
50 to 75
less than 50
reservoir type
Aquifer
Depleted Field
Salt Dome

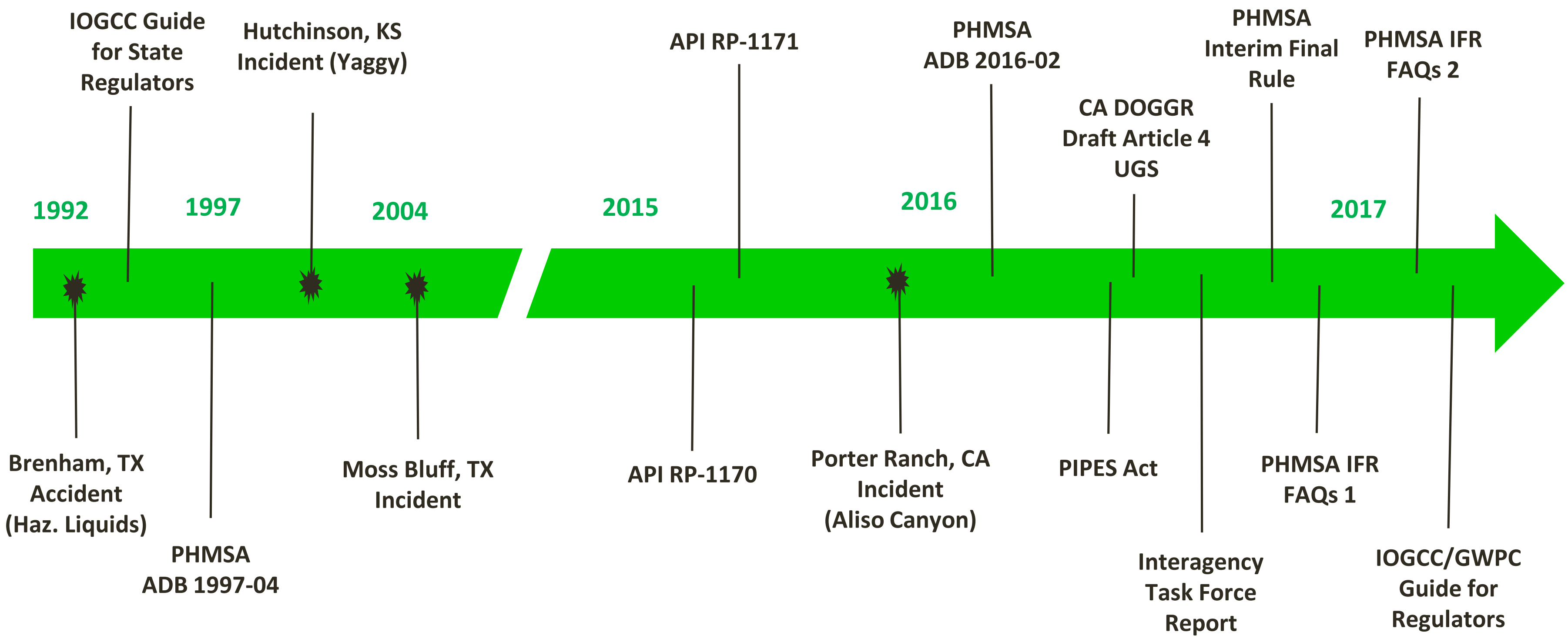
General Statistics

- 127 Operators
- 4800 BCF Working Capacity
- 403 Storage Fields
- 224 Interstate & 179 Intrastate
- 87% Reservoir-Aquifer, 13% Salt Domes
- 17516 Wells

States Statistics

- UGS facilities in 31 States
  - 25 with intrastate assets
- Top 10 States with largest number of Storage Facilities:
  - PA, MI, TX, IL, WV, NY, KY, OH, IN, LA
- Top 10 States with largest Working Gas Capacity:
  - MI, TX, LA, PA, CA, IL, WV, OH, MS, MT

Timeline of Significant Events



“To protect people and the environment by advancing the safe transportation of energy and other hazardous materials that are essential to our daily lives.”

Pipes Act of 2016

- Protecting our Infrastructure of Pipelines and Enhancing Safety
- Establish regulations and inspection program for Underground Natural Gas Storage
- Develop inspection criteria and related training for both federal and state inspectors

Interim Final Rule

Incident at the Aliso Canyon facility in California discovered on October 23, 2015

- Section 12 of the PIPES Act of 2016
- Docket No. PHMSA-2016-0016
- Published December 19, 2016
- Effective January 18, 2017

Stay of Enforcement

- Federal Register Notice, June 20, 2017
- In the interim, and for one year after the final rule, PHMSA will not issue enforcement citations for:
  - Failure to meet provisions that are non-mandatory in API RPs 1170 and 1171
  - Non-compliance with the requirement to justify and document deviations from the non-mandatory provisions

Final Rule in Development

- Take broad assortment of comments into consideration
- Will account for the final disposition of non-mandatory aspects of the RPs
- Interim Final Rule in play until the content and effective dates of the Final Rule are issued

Local or State Permits and Licenses

- UGS Operators interact with local, state and other federal agencies
- The new regulations do not supersede permits, certifications or licenses for UGS facilities that are required by local, state or other federal agencies

States Participation

- State Regulators for UGS mostly not the agencies responsible for topside horizontal pipelines
- Similar, but separate Program, for State Reimbursement
- States in 2018 Program
  - Certification : AR, MN, PA-PUC
  - Agreement : CA, IL, KS
  - Additional States expected in 2019

Initial Regulatory Inspections

- Initial inspections by PHMSA or States
- Based on Interim Final Rule, less Stay of Enfr.
- Focus on written procedures and implementation plans
- General Compliance Date : January 18, 2018
- Inspections began in March of 2018

Wide variability of operating practices in the storage industry

- Regulations are objectives to be achieved by the Operator for their Storage Facility
- These regulations are generally performance-based requirements
- Operators are expected to “personalize“ their programs to site-specific equipment, history, operating and environmental conditions

Risk Assessment
Qualitative or Quantitative models

- Neither the regulations or the RPs prescribe how an operator is to perform risk analysis
- The Operator should be able to substantiate the specific site data and process used to conduct risk assessments, analysis and resulting conclusions

PHMSA : Web Links

- **http://opsweb.phmsa.dot.gov**
  - Operator Notifications
  - Event Reporting
- **https://primis.phmsa.dot.gov/ung/index.htm**
  - Major Incidents
  - Key Documents
  - FAQs
  - Locations Map

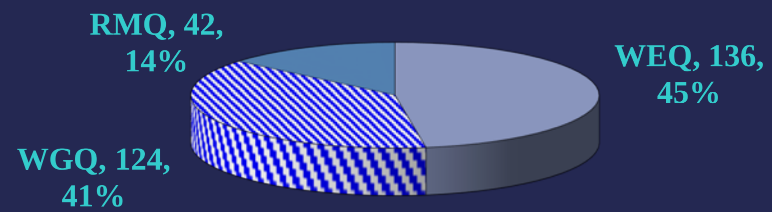
North American Energy Standards Board

NERC Technical Workshop – July 10, 2018

- Gas Infrastructure Risk and Associated Recommendations

Organizational Characteristics:

- Membership Base



- Relationship with DoE, FERC and state regulatory commissions
  - WEQ Standards – more than 2000
  - WGQ Standards – more than 1500
  - Retail Standards – more than 600
- Open Process

Typical Process:

- Request/Directive
  - FERC, FERC Chairman's Office, National Petroleum Council, National Academy of Sciences
- NAESB Board Scoping Exercise
  - Gas-Electric Interdependency Committee, Gas-Electric Harmonization Committee, Gas-Electric Harmonization Forum…
- Result
  - Standards, Report, Combination

Request by FERC Chairman Wood (2003-2006)

Request/Driver	Result
FERC Chairman Wood's Letter – November 2003 "…one of the most critical [standards development areas] is the need for the electric and natural gas sectors to work together to resolve scheduling timeline differences, particularly with respect to intra-day gas nominations."	<u>Standards</u> WEQ/WGQ Communication Standards <u>Report</u> Report on Potential Solutions for Better Coordination 1. Indexed-Based Capacity Release 2. Additional Intraday Nomination Cycle(s) 3. Increased Receipt/Delivery Point Flexibility 4. Modify Requirements so the Organized Electric Markets Clear in time to Nominate in Timely Cycle 5. Require Generators that Offer into day ahead Market to Have Appropriate Commercial Arrangements to fulfill Obligations 6. Develop Coordinated Definitions

FERC Order No. 698 (2007-2008)

Request/Driver	Result
FERC Order No. 698 – June 2007 <u>Adopted</u> WEQ/WGQ Communication Standards <u>Directed Standards to Support</u> 1. Indexed-Based Capacity Release 2. Increased Receipt/Delivery Point Flexibility 3. Additional Intraday Nomination Cycle(s)	<u>Standards</u> 1. Standards to Support Indexed-Based Capacity Release 2. Standards to Support Increased Receipt/Delivery Point Flexibility <u>Report</u> Report on Efforts to Consider Additional Intraday Nomination Cycle(s)

Request by National Petroleum Council (2011-2012)

Request/Driver	Result
National Petroleum Council Study – September 2011 <u>Directed Standards to Support</u> 1. Business practices that improve the coordinated operations of the two industries and reduce barriers that hamper the operation of a well-functioning market 2. Increase the transparency of wholesale electric power and natural gas markets 3. Address the issue of what natural gas services generators should hold, including firm transport and storage, and what services pipeline and storage operators should provide to meet the requirements of electricity generators as well as compensation for such services for pipeline and storage operators and generators	<u>Report</u> Report on Potential Areas for Standards Development 1. Market timelines and coordination of scheduling 2. Flexibility in Scheduling 3. Provision of Information: i. the status of generation and pipeline capacity, ii. access to critical infrastructure information needed by electric service providers in curtailment conditions, including information on gas-fired generators, and iii. decision-enabling tools related to contingency response and day-of-service operations.

FERC NOPR – March 2014 (2014)

Request/Driver	Result
FERC Notice of Proposed Rulemaking – March 2014 <u>Directed Standards to Support</u> Modifications to the gas day and gave the electric and gas industries 180 days to propose an alternative to the following: 1. The start of the Gas Day be moved from 9:00 am to 4:00 am Central Clock Time (CCT) 2. The Timely (day ahead) Nomination Cycle be moved from 11:30 am to 1:00 pm CCT to allow utilities to finalize their day ahead schedules prior to the close of the period. 3. Two additional intra-day nomination periods be introduced to the current nomination schedule.	<u>Standards</u> 1) Standards to Support Commission's Proposal Related to the Timely Nomination Cycle 2) Standards to Support one Additional Intraday Nomination Cycle and Modified Others <u>Report</u> Report on Efforts to Develop Standards that Modify the Start Time of the Gas Day

FERC Order No. 809 (2015-2017)

Request/Driver	Result
FERC Order No. 809 – April 2015 <u>Adopted</u> Standards Proposed by NAESB in Response to March 2014 NOPR <u>Directed Standards to Support</u> "…explore the potential for faster, computerized scheduling when shippers and confirming parties all submit electronic nominations and confirmations, including a streamlined confirmation process if necessary."	<u>Report</u> Report on Efforts to Develop Standards to Support Faster Computerized Scheduling, including: 1. Standardizing Confirmation Methods 2. Standardizing How Hourly Quantities Special Services are Offered

Key Factors for Success

- Strong Drivers
  - Regulatory Mandate
  - Policy Directive
  - Executive Level (Board) Support
- Open and Equal Participation
  - Balance in Decision Making
  - Transparency

Looking Forward

National Academy of Sciences Report of Electric System Resiliency: Natural Gas and Electric System Interdependencies

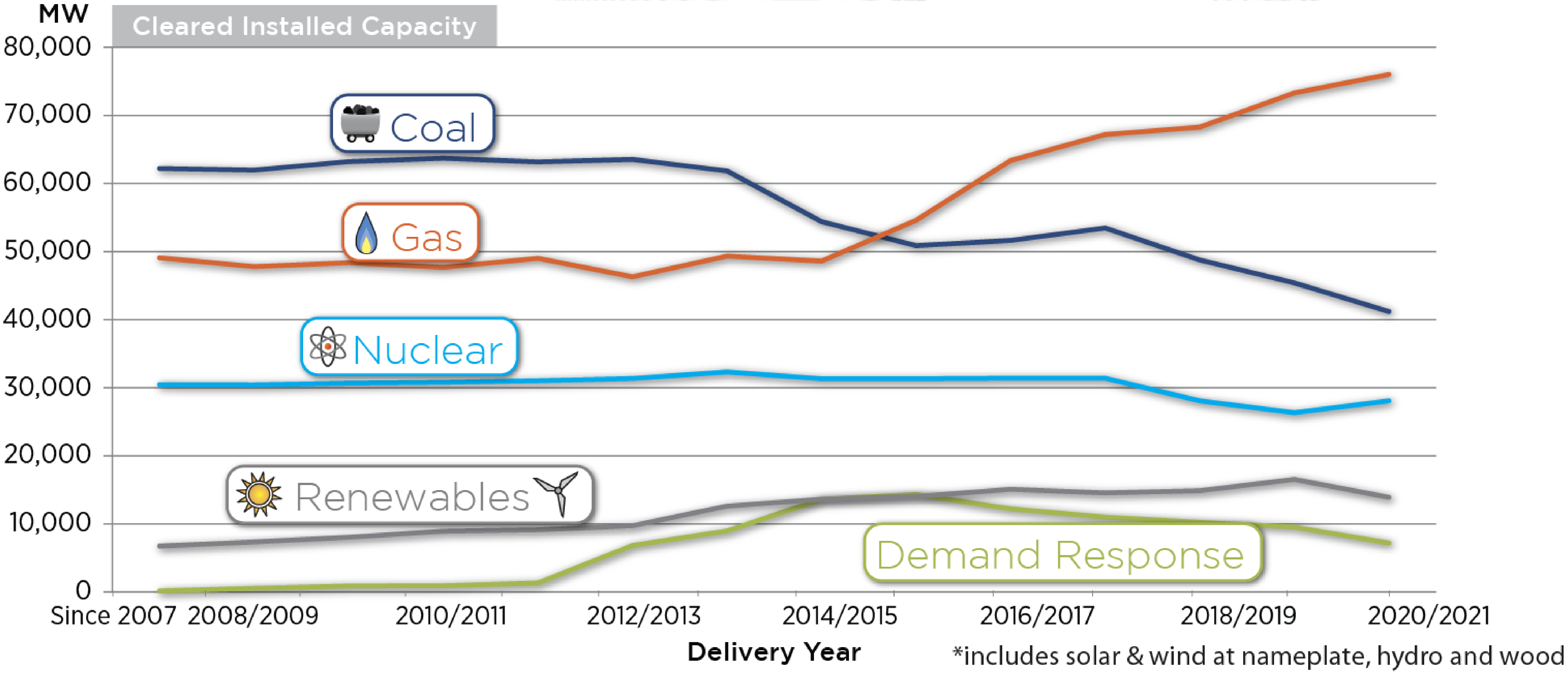
- The Federal Energy Regulatory Commission and the North American Energy Standards Board, in conjunction with industry stakeholders, should further prioritize their efforts to improve awareness, communications, coordination, and planning between the natural gas and electric industries. Such efforts should be extended to consider explicitly what recovery strategies should be employed in the case of failed interdependent infrastructure. Fuel diversity, dual fuel capability, and local storage should be explicitly addressed as part of these resilience strategies.

Questions?

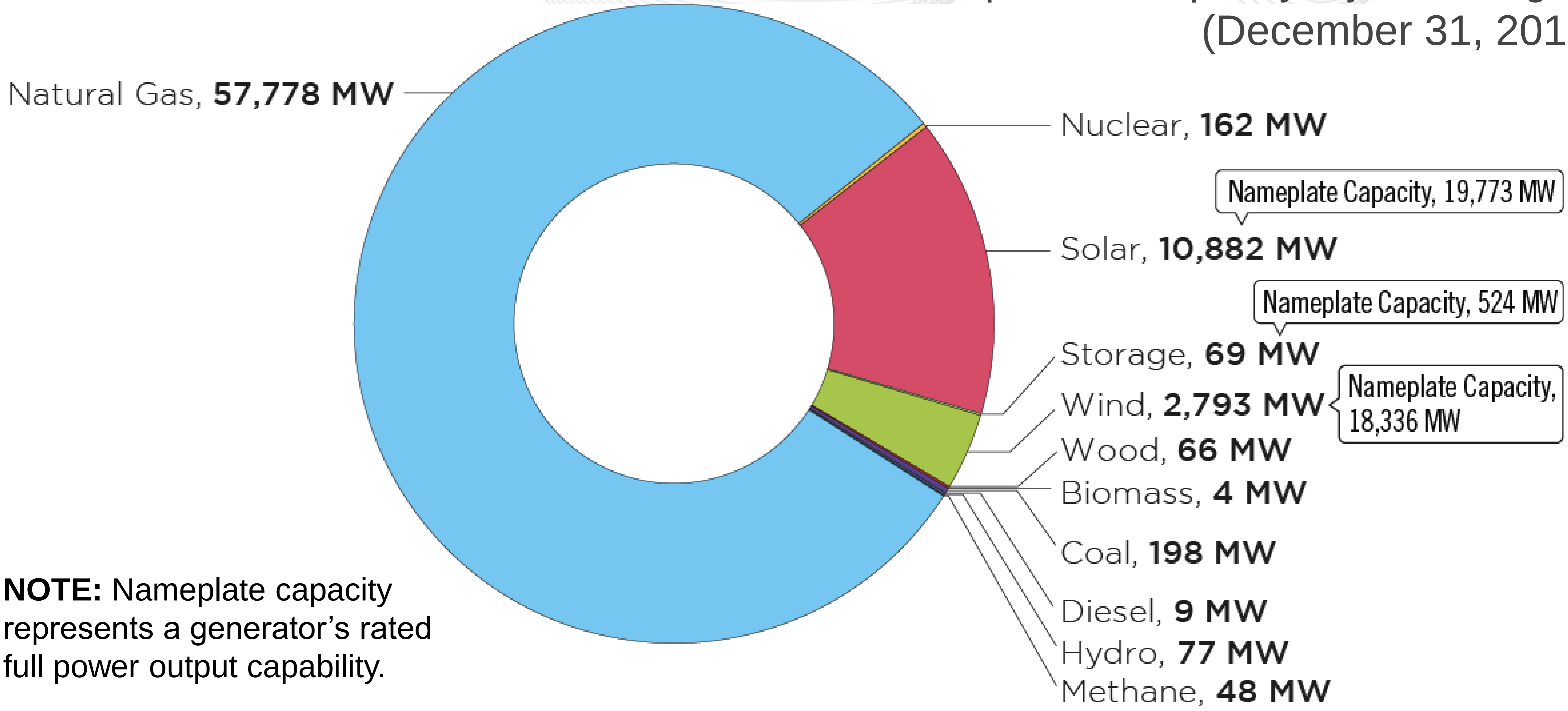
PJM Natural Gas Generation and Fuel Assurance

NERC Technical Workshop
July 10, 2018
Brian Fitzpatrick
Sr. Lead Fuel Supply Analyst

Cleared Installed Capacity



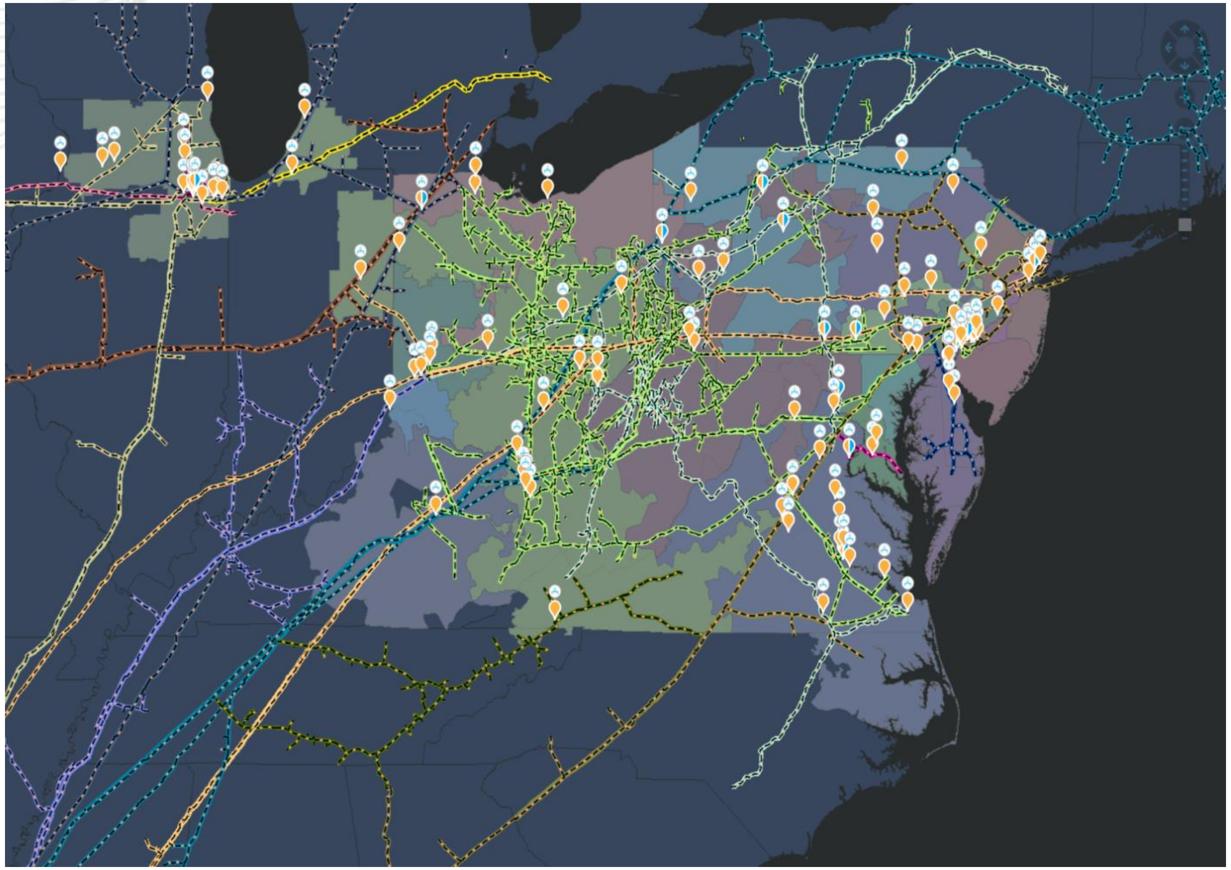
Queued Generation Fuel Mix- Requested Capacity Injection Rights (December 31, 2017)



NOTE: Nameplate capacity represents a generator's rated full power output capability.

Gas Delivery Topography

- 15 Interstate Pipelines
- 32 Local Distribution Companies
- 420 Natural Gas Fired Generators
- 70 GW Natural Gas Fired Generation
  - 75 percent served via interstate pipeline
  - 24 percent served via local distribution company
  - <1 percent served via gathering systems

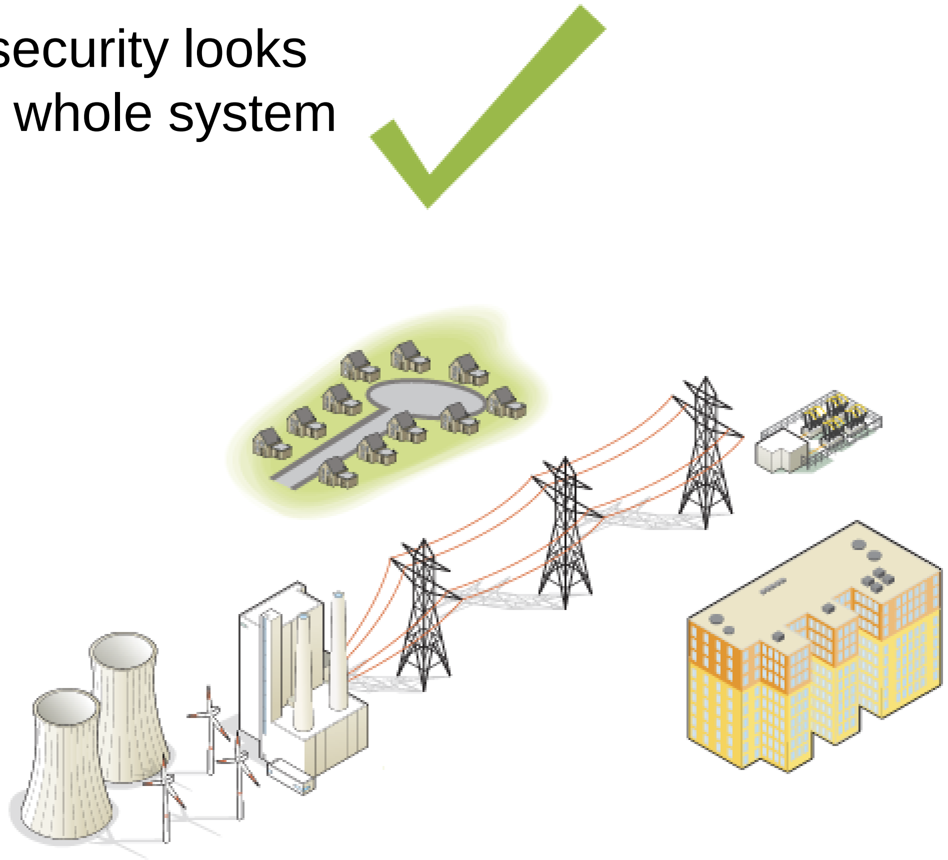


PJM Actions to Address Reliability and Fuel Security

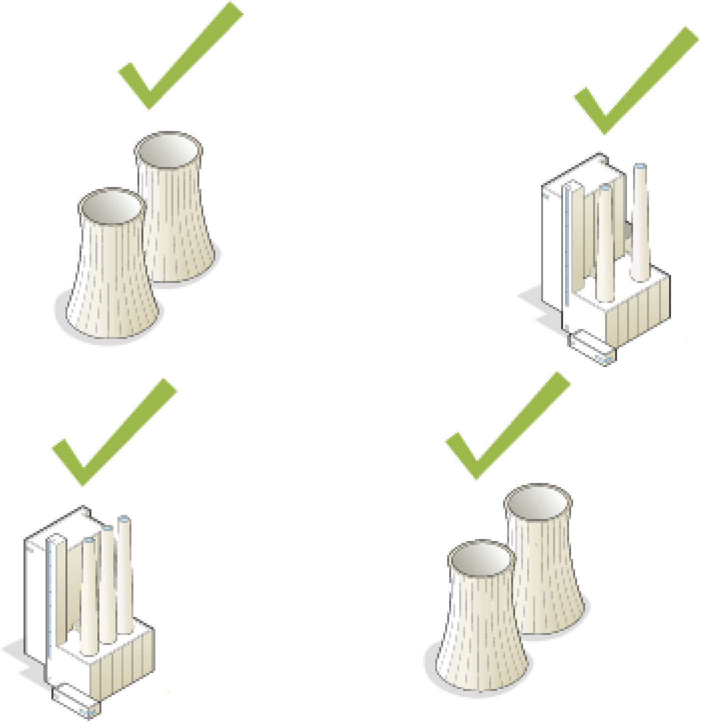
- Capacity Performance
  - June 2016-May 2021phase in period
  - Incent generators to invest in firm fuel delivery/plant improvements
- Gas Electric Coordination
  - Increased communications with pipelines and Local Distribution Companies
    - FERC Order 787/Memorandum of Understanding
    - Outage coordination
  - Tool development to improve operational awareness of natural gas pipeline conditions
- Hourly Offers (November 2017)
  - Allows generators to update offers hourly as prices change
- Day Ahead Award Timing (April 2016)
  - Moved from 4:00pm to 1:30pm

Fuel Security vs. Capacity Performance

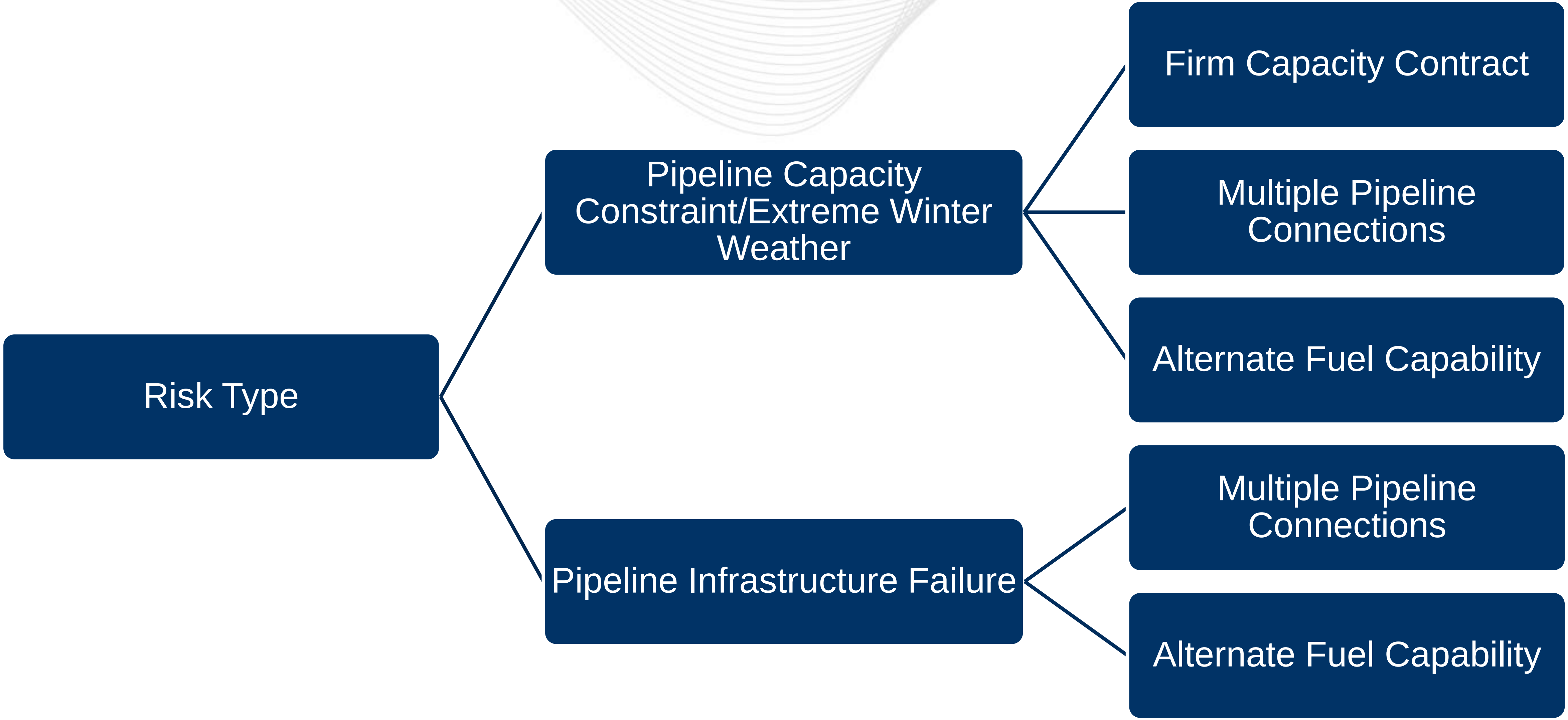
Fuel security looks at the whole system



Capacity Performance looks at each unit individually



Fuel Supply Risk Assessment



FOCUS

1. Define fuel security **as risks in fuel delivery** to critical generators.
2. Reaffirm the **value of markets to** achieving a cost-effective, fuel-secure fleet of resources.
3. **Identify fuel security risks** with a primary focus on resilience.
4. Establish **criteria to value fuel security** in PJM markets.

APPROACH

1. **Phase 1: Analysis**
Identify potential system vulnerabilities and develop criteria to address them.

2. **Phase 2: Modeling**
Model incorporation of vulnerabilities into PJM's markets.

3. **Phase 3: Ongoing Coordination**
Address specific security concerns identified by federal and state agencies.

TIMING

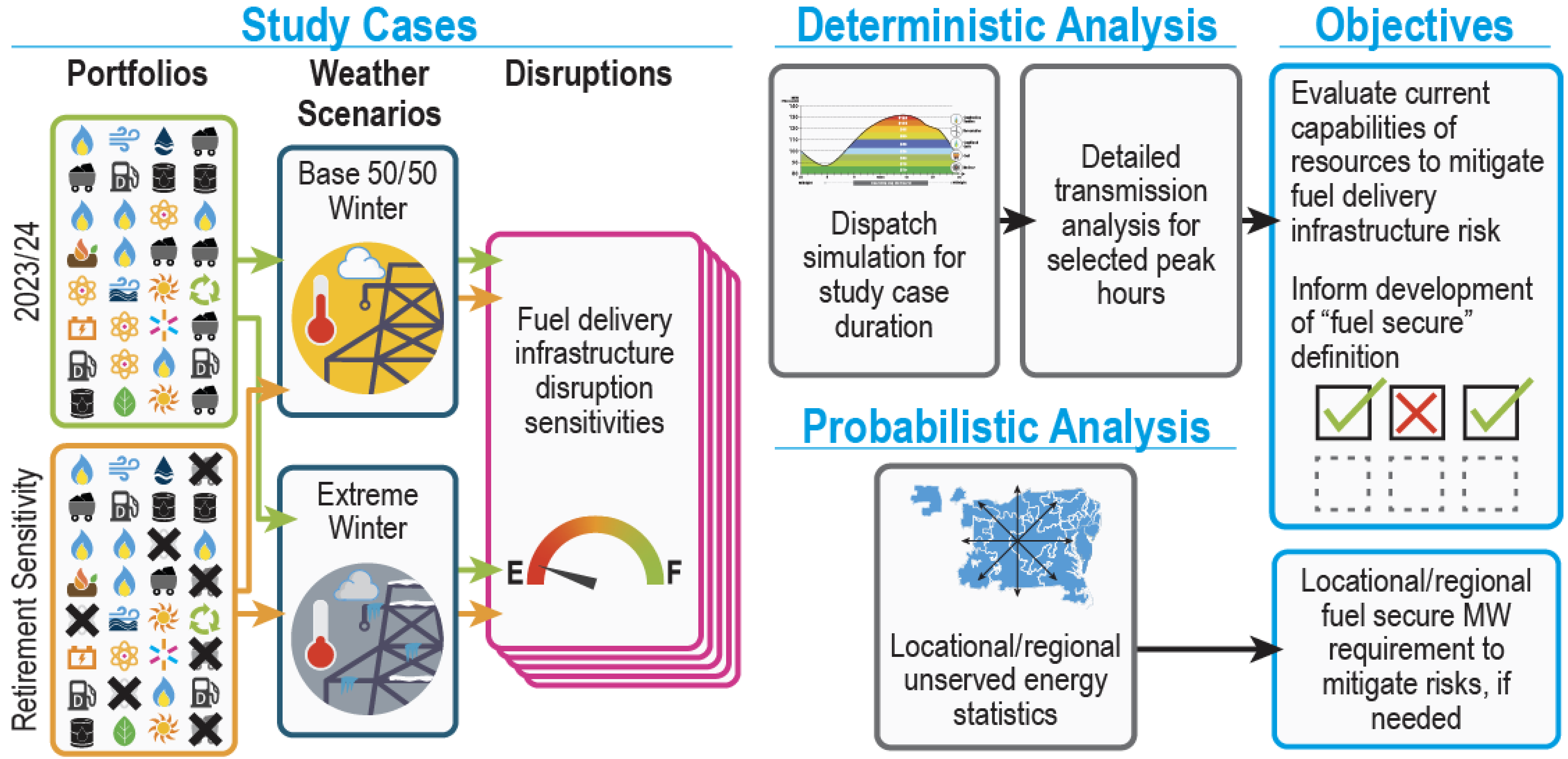
May–July 2018:
Analysis

Aug.–Oct. 2018:
Modeling/Market Design

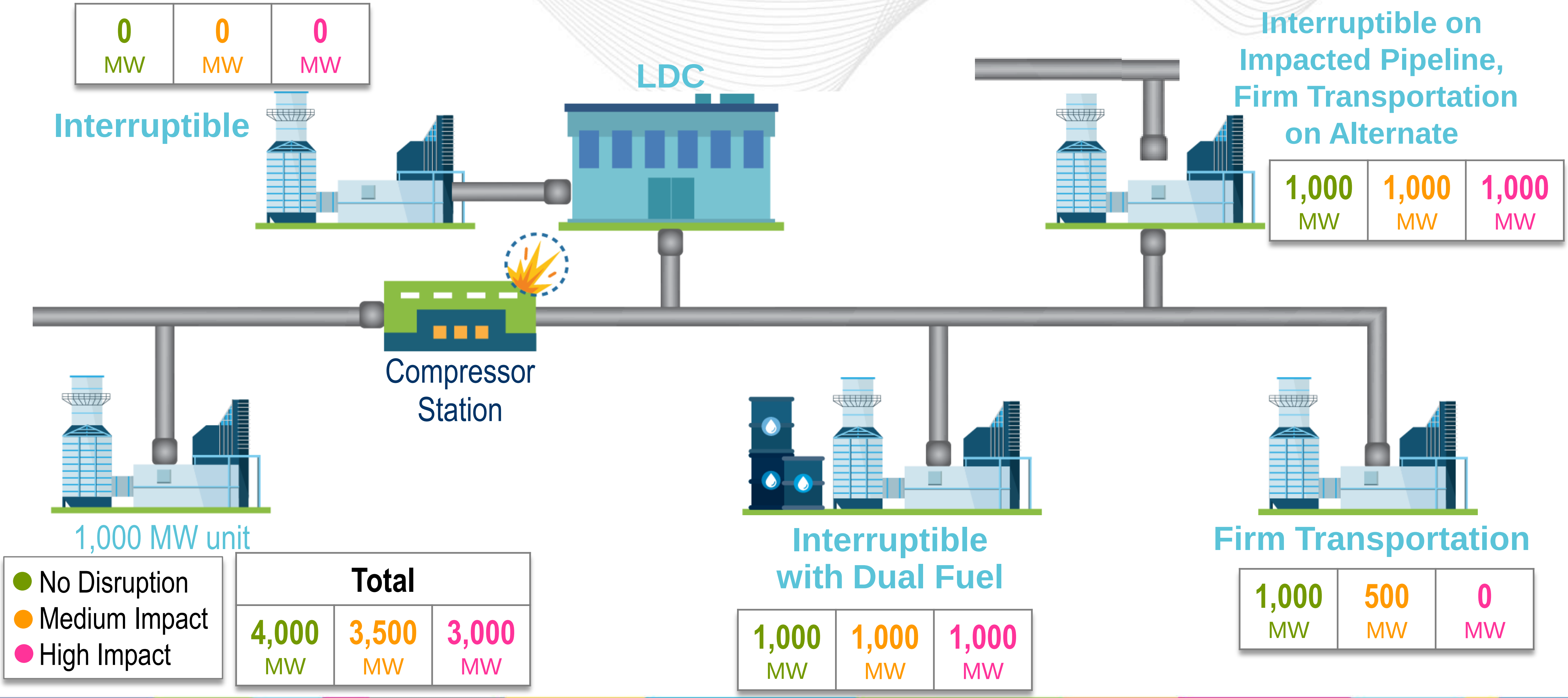
Nov. 2018–March 2019:
Ongoing Coordination

January 2019: FERC filing

Approach Overview



Extreme Winter Scenario – Generic Example



Going Forward – Potential Opportunities

- Increased collaboration between ISO/RTO, interstate pipelines and LDCs on tabletop exercises/disruption scenarios/system restoration planning
  - Periodic (annual) exercises
  - Control room to control room communications
- Alternative scheduling options for natural gas generators
- Higher scheduling priority for certain critical NG generators
- NERC TPL Standards review/modification
  - Uniform approach to identification of and planning for NG pipeline disruption duration

Going Forward – Potential Opportunities

TPL-001-4 Example:

3. Wide area events affecting the transmission system based on system topology, such as:

a. Loss of two generating stations resulting from certain conditions:

i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation *for x days or more for common causes such as problems with similarly designed pipeline infrastructure.*

ii. Loss of the use of a large body of water as the cooling source for generation.

iii. Wildfires.

iv. Severe weather, e.g., hurricanes, tornadoes, etc.

v. A successful cyber attack *whose impacts last for x days or more.*

vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.

JULY 10, 2018 | ATLANTA, GA

ISO New England Identifies Growing Fuel-Security Risk as the Power System Undergoes Rapid Transformation

2018 NERC Technical Workshop

Peter Brandien

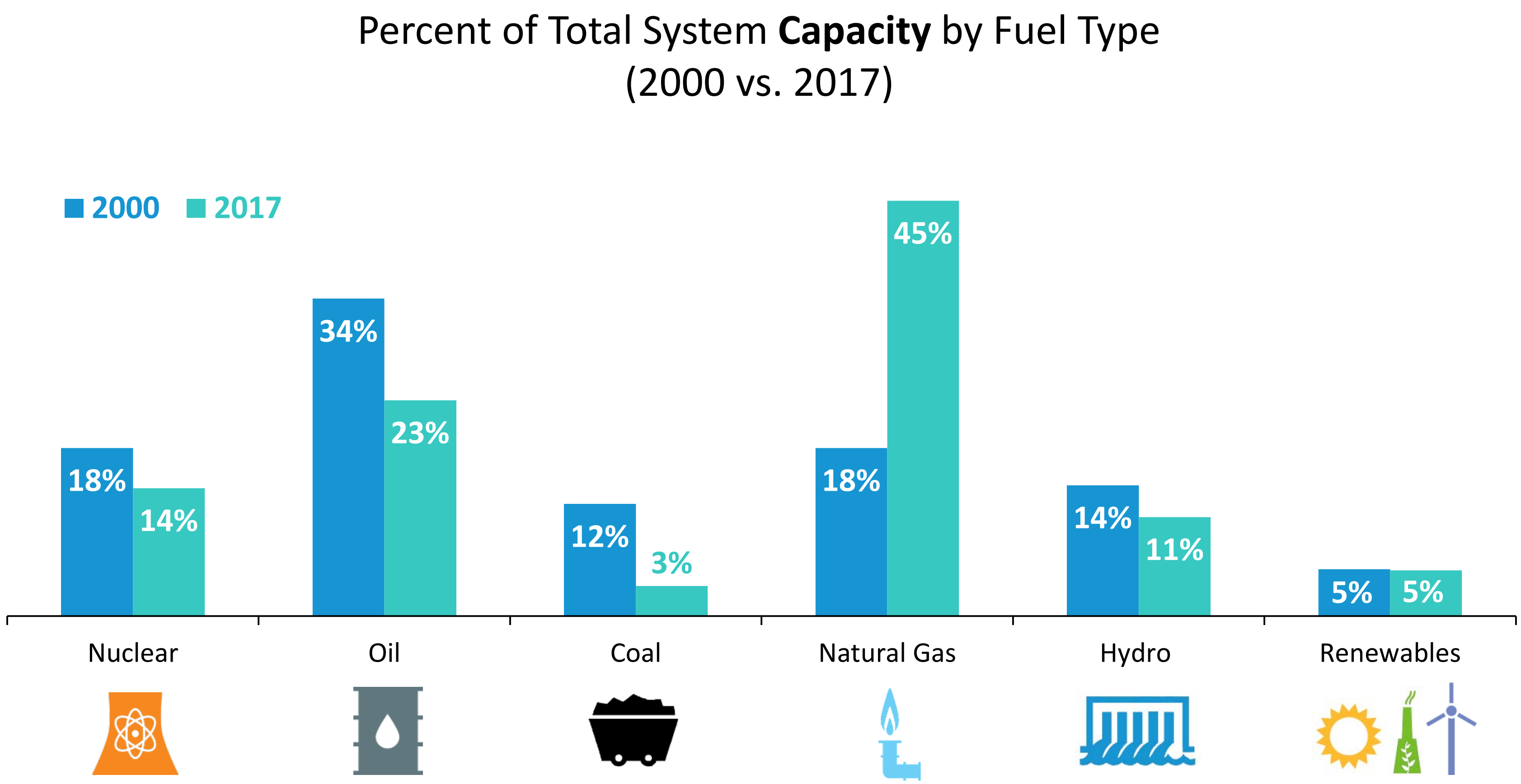
VICE PRESIDENT, SYSTEM OPERATIONS

KEY MESSAGES

- The New England power system is changing rapidly
  - Shifting away from resources with on-site fuels (coal, oil, nuclear) toward resources with just-in-time fuel (natural gas) and resources that are weather dependent (wind and solar)
- The ISO's operational analysis and experience show the region trending in a negative direction with regard to fuel-security risk
  - Left unaddressed, price volatility and threats to reliability will worsen during winter months
- Reliability must be ensured during the multi-decade transition to renewable energy and, in particular, winter energy supplies must be firmed up
  - Modifications to the wholesale market design will be needed to pay for reliability services; states will play a key role in enabling infrastructure or relieving operational constraints

Dramatic Changes in Power System Resources

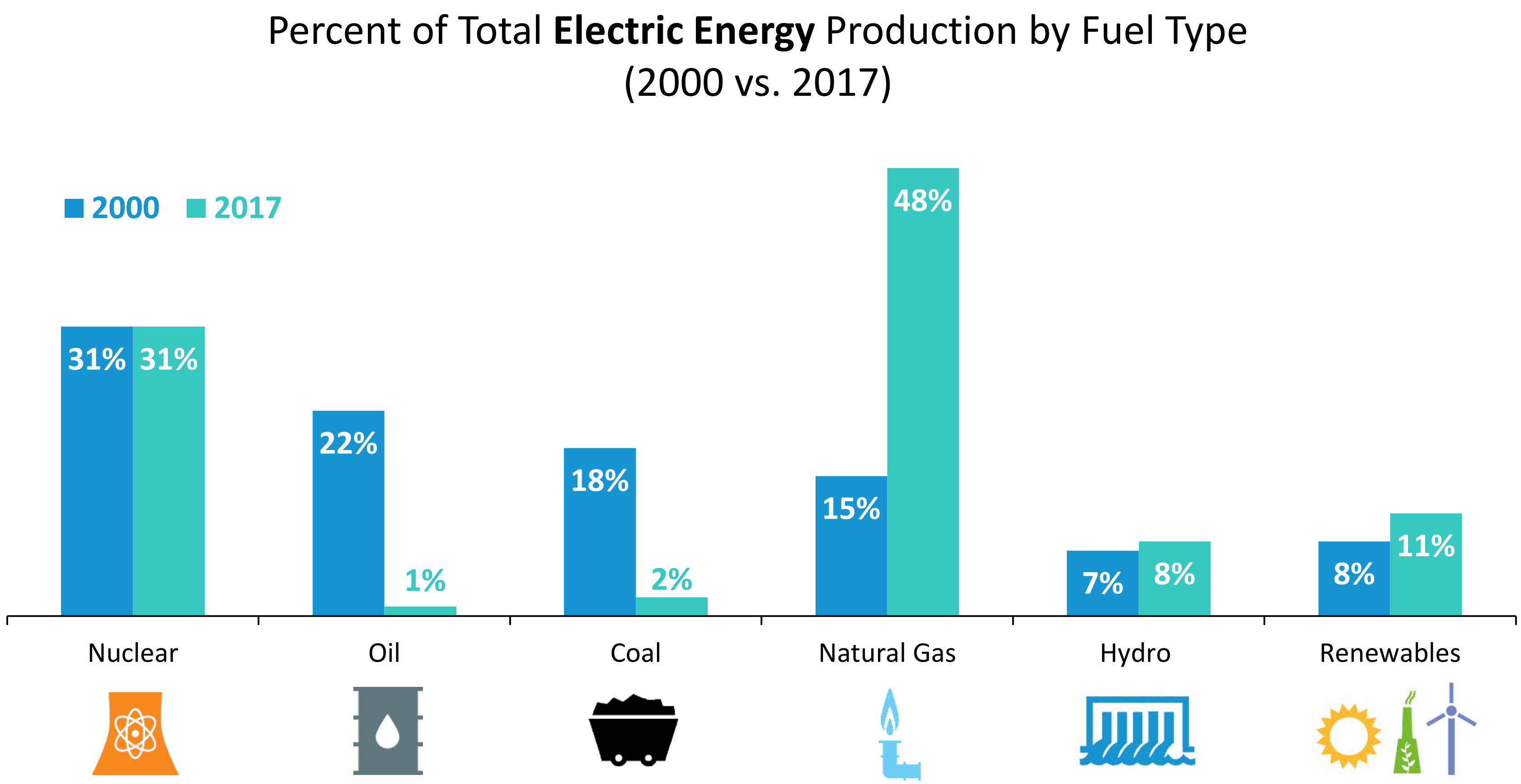
The resources making up the region's installed generating capacity have shifted from nuclear, oil, and coal to natural gas



Source: 2017 CELT Report, Summer Seasonal Claimed Capability (SCC) Capacity
Renewables include landfill gas, biomass, other biomass gas, wind, grid-scale solar, municipal solid waste, and miscellaneous fuels.

Dramatic Changes in the Energy Mix

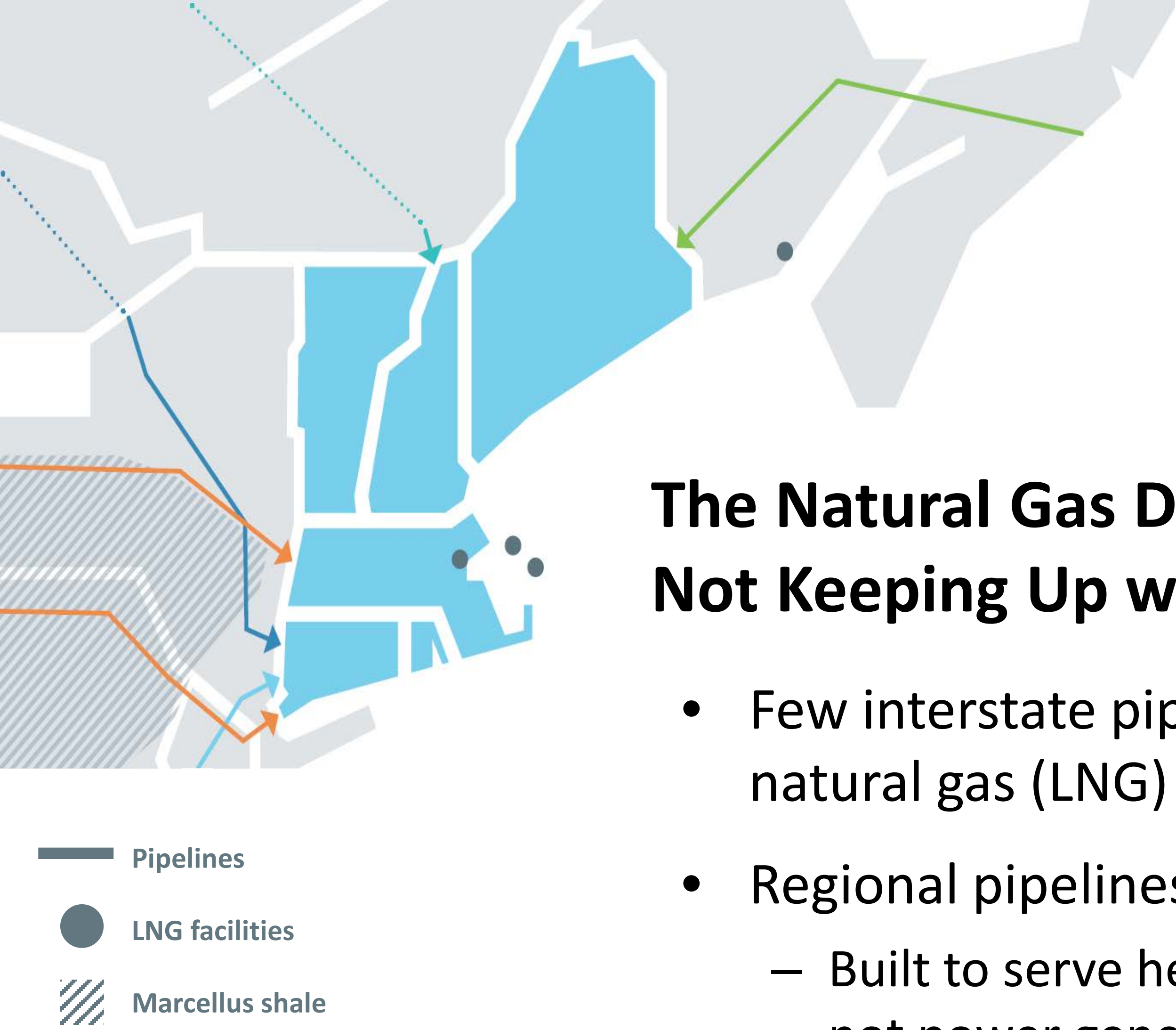
The fuels used to produce the region's electric energy have shifted as a result of economic and environmental factors



Source: ISO New England [Net Energy and Peak Load by Source]
Renewables include landfill gas, biomass, other biomass gas, wind, grid-scale solar, municipal solid waste, and miscellaneous fuels.
This data represents electric generation within New England; it does not include imports or behind-the-meter (BTM) resources, such as BTM solar.

Since 2013, More Than 4,600 MW of Generation Have Retired or Announced Plans for Retirement in the Coming Years

- More than **5,000 MW** of remaining coal and oil are at risk of retirement
- These resources have played a **critical** role in recent winters when natural gas supply is constrained in New England

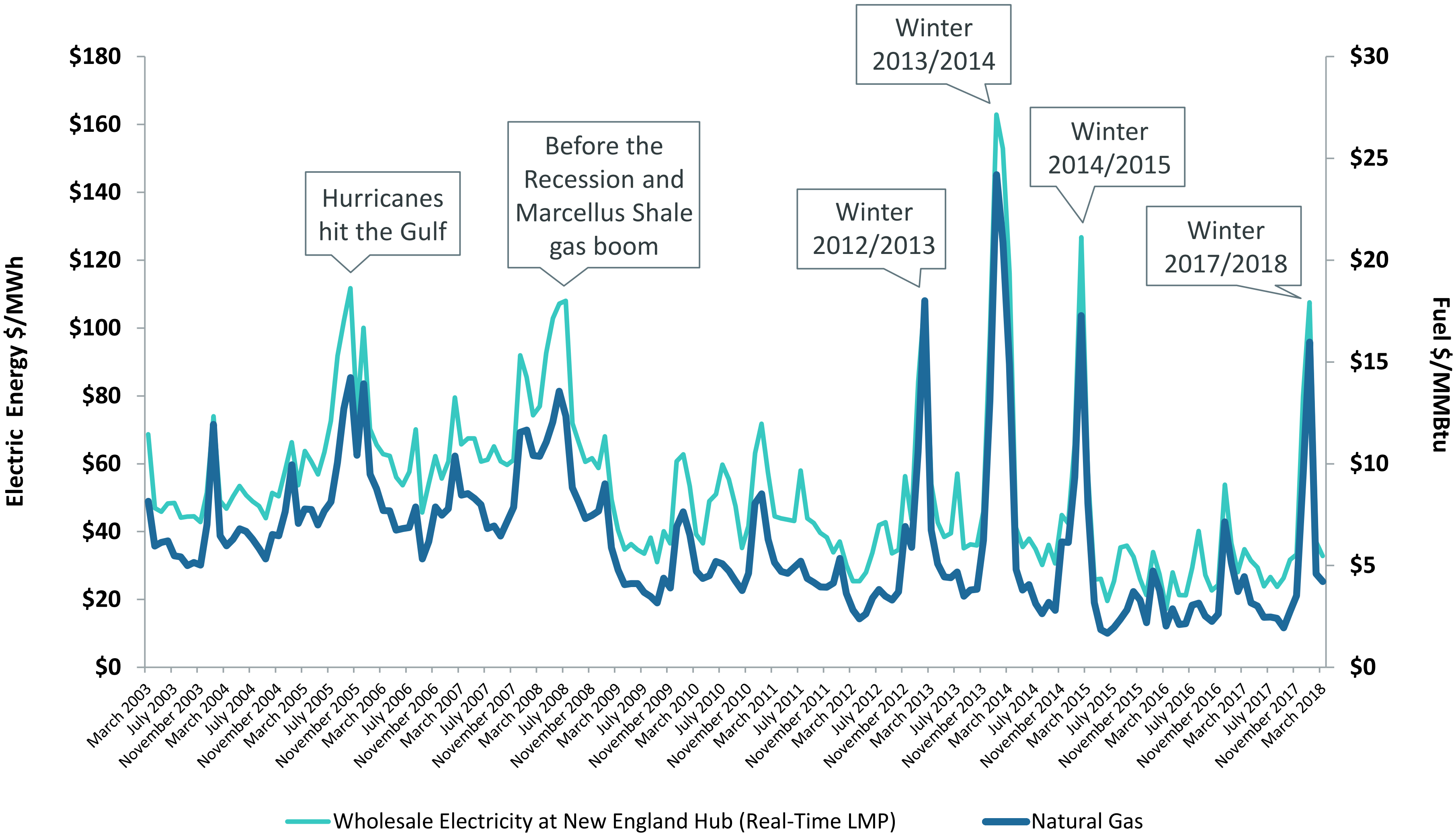


Source: ISO New England

The Natural Gas Delivery System Is Not Keeping Up with Demand

- Few interstate pipelines and liquefied natural gas (LNG) delivery points
- Regional pipelines are:
  - Built to serve heating demand, not power generation
  - Running at or near maximum capacity during winter

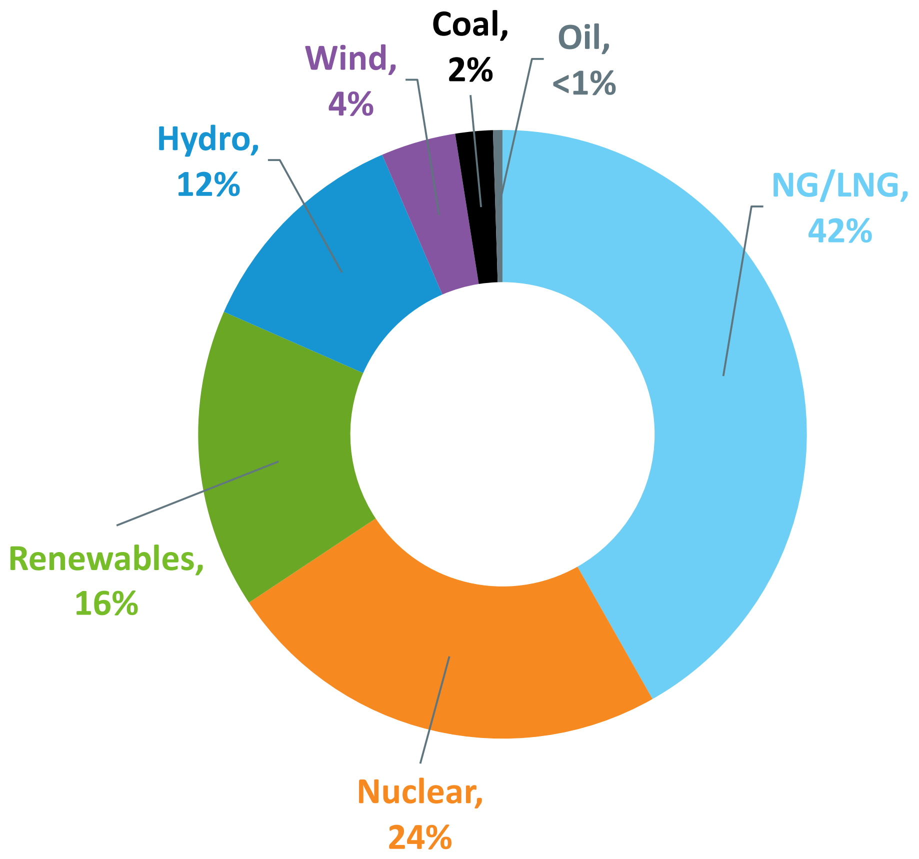
Fuel Infrastructure Constraints Are Driving Greater Volatility in the Wholesale Energy Market



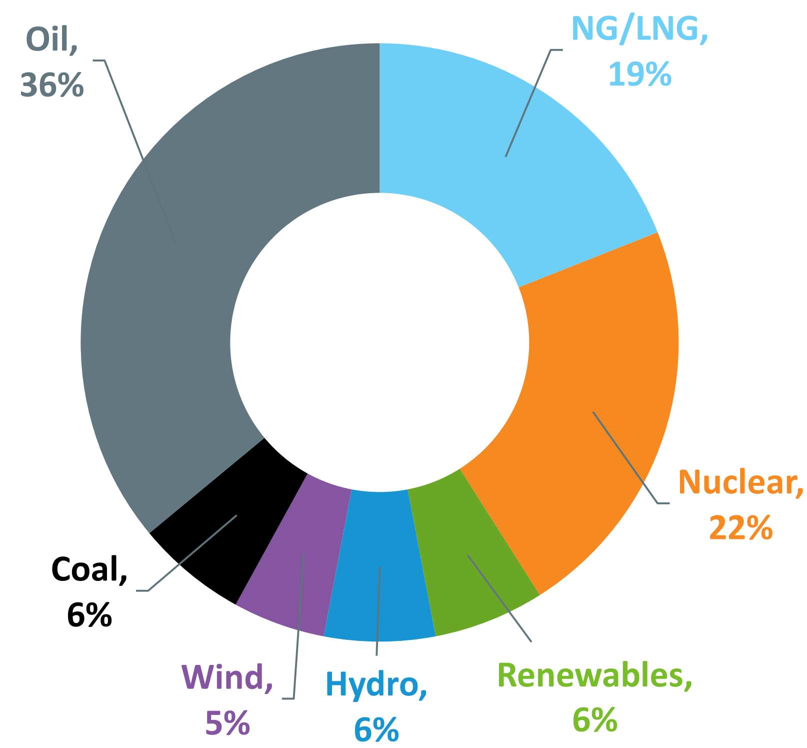
Dramatic Shift in the Fuel Mix During Cold Spell

Gas and oil fuel price inversion led to oil being in economic merit and base loaded; as gas became uneconomic, the entire season's oil supply rapidly depleted

Fuel Mix on December 21, 2017

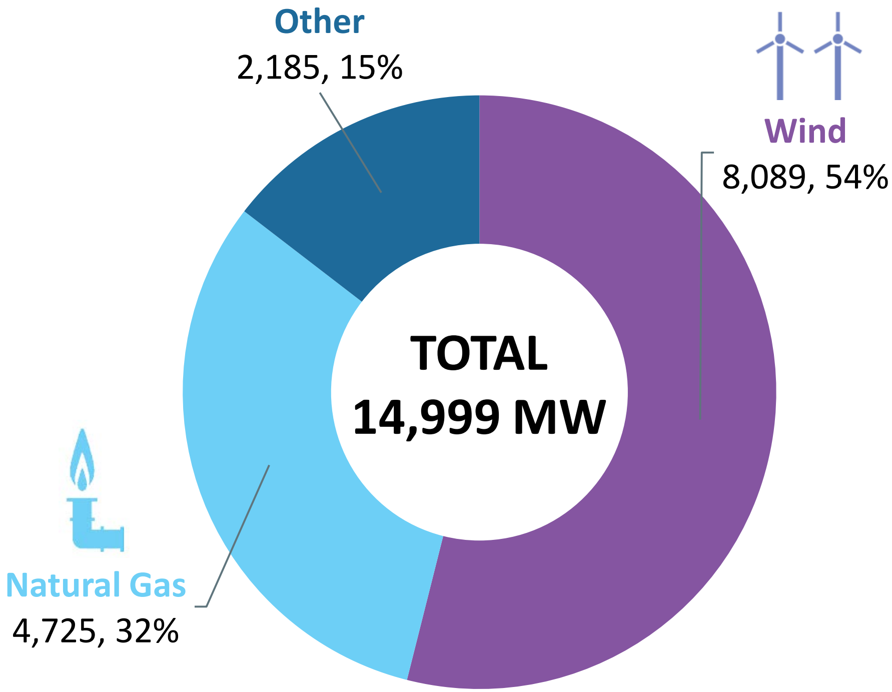


Fuel Mix on January 6, 2018



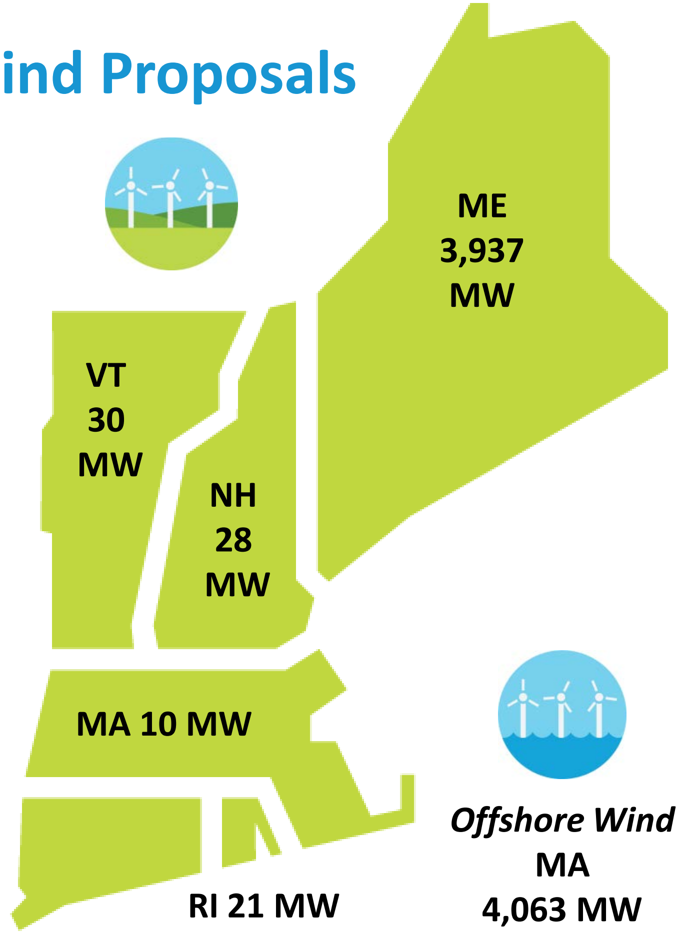
Wind Power Now Comprises More Than Half of New Resource Proposals in the ISO Interconnection Queue

All Proposed Generation



Source: ISO Generator Interconnection Queue (April 2018)
FERC and Non-FERC Jurisdictional Proposals; Nameplate Capacity Ratings
Note: Some natural gas proposals include dual-fuel units (oil). Other includes solar, battery storage, hydro, biomass, and fuel cell proposals.

Wind Proposals



Note: Some wind proposals include battery storage.

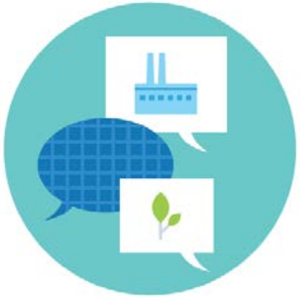
Market Enhancements to Address Gas-Electric Interdependence and Fuel Delivery Constraints

- ISO New England has implemented a number of **market initiatives** to coordinate the gas and electric markets and price fuel constraints
  - Better alignment of the day-ahead market with gas day
  - Intra-day offers
  - Increased operating reserve constraint pricing
  - Capacity market incentives called "Pay for Performance"
- ISO New England administered an out-of-market **Winter Reliability Program** prior to implementation of "Pay for Performance"
  - Provided compensation for oil inventories, LNG, or demand response
- **"Pay for Performance"** is intended to incent asset owners to make the necessary fuel arrangements/investments
  - Dual-fuel capability
  - Oil in the tanks prior to winter
  - Forward contract for LNG

Operational Actions to Address Gas-Electric Interdependence and Fuel Delivery Constraints

- Significant gas-electric coordination
  - Daily discussion with gas control centers
- Developed “Gas Usage Tool”
  - Inputs gas pipeline capacity and estimates gas LDC demand
  - Uses gas generation demand coming out of day-ahead market
  - Provides indication of whether additional gas is available
- Compare nominated gas versus day-ahead commitment for each generator
- Monitor LNG storage levels
  - Must be done manually by adding deliveries versus send outs
  - Track LNG tankers movement throughout the Atlantic Ocean
- Fuel surveys for all oil-only, dual-fuel, and coal units
  - Monitor inventories and replenishment
  - Communicate with oil import terminals on availability of oil for generators
  - Surveys start off monthly but shift to daily when using oil units
  - Daily call with asset owners to track replenishment when inventories are low

The ISO Is Pursuing Three Tracks to Address Fuel-Security Challenges



- <u>Immediate</u>: Seek a **waiver from FERC** to retain specific units to ensure fuel security (not currently allowed under the ISO tariff)
- <u>Short-term</u>: Working with stakeholders, develop **criteria** to retain additional resources for fuel security under the ISO tariff
  - File tariff changes by end of 2018 so they are in place before the March 2019 retirement de-list bid deadline for FCA #14
- <u>Long-term</u>: Working with stakeholders, develop a **market-based solution** that will ensure sufficient firm energy to maintain reliability in the winter
  - Needed resources and infrastructure will be **compensated through the market**, rather than through reliability contracts

Note: FCA #14 will be held in February 2020 for the resources needed during the June 1, 2023 – May 31, 2024 Capacity Commitment Period.

Questions

APPENDIX

FUEL SECURITY

- Ensuring adequate fuel for generators is the most **pressing** challenge to future grid reliability
- Launched in the fall of 2016, ISO New England's *Operational Fuel Security Analysis* shows the region is **trending** in a negative direction with regard to fuel-security risk

Addressing Fuel-Security Risks Is Vital to Ensuring Reliability through the Grid's Rapid Transformation

- The analysis examines **23** possible fuel-mix combinations during the 2024-2025 winter, and quantifies each case's **fuel-security risk**
  - *i.e.,* the number and duration of energy shortfalls that would require implementation of emergency procedures to maintain reliability

- The study assumed **no** additional natural gas pipeline capacity to serve generators would be added during the study timeframe
- The study seeks to illustrate the **range of potential risks** that could confront the power system if fuel and energy were constrained during the winter

Study Modeled Wide Range of Resource Combinations Considering Five Key Fuel Variables

1. 

Retirements of coal- and oil-fired generators (the study assumes that New England will have no coal-fired power plants in winter 2024/2025)

2. 
Imports of electricity over transmission lines from New York and Canada

3. 
Oil tank inventories (i.e., how often on-site oil tanks at dual-fuel power plants are filled throughout the winter)

4. 

Level of liquefied natural gas (LNG) injections into the region’s gas delivery and storage infrastructure

5. 
Level of renewable resources on the system

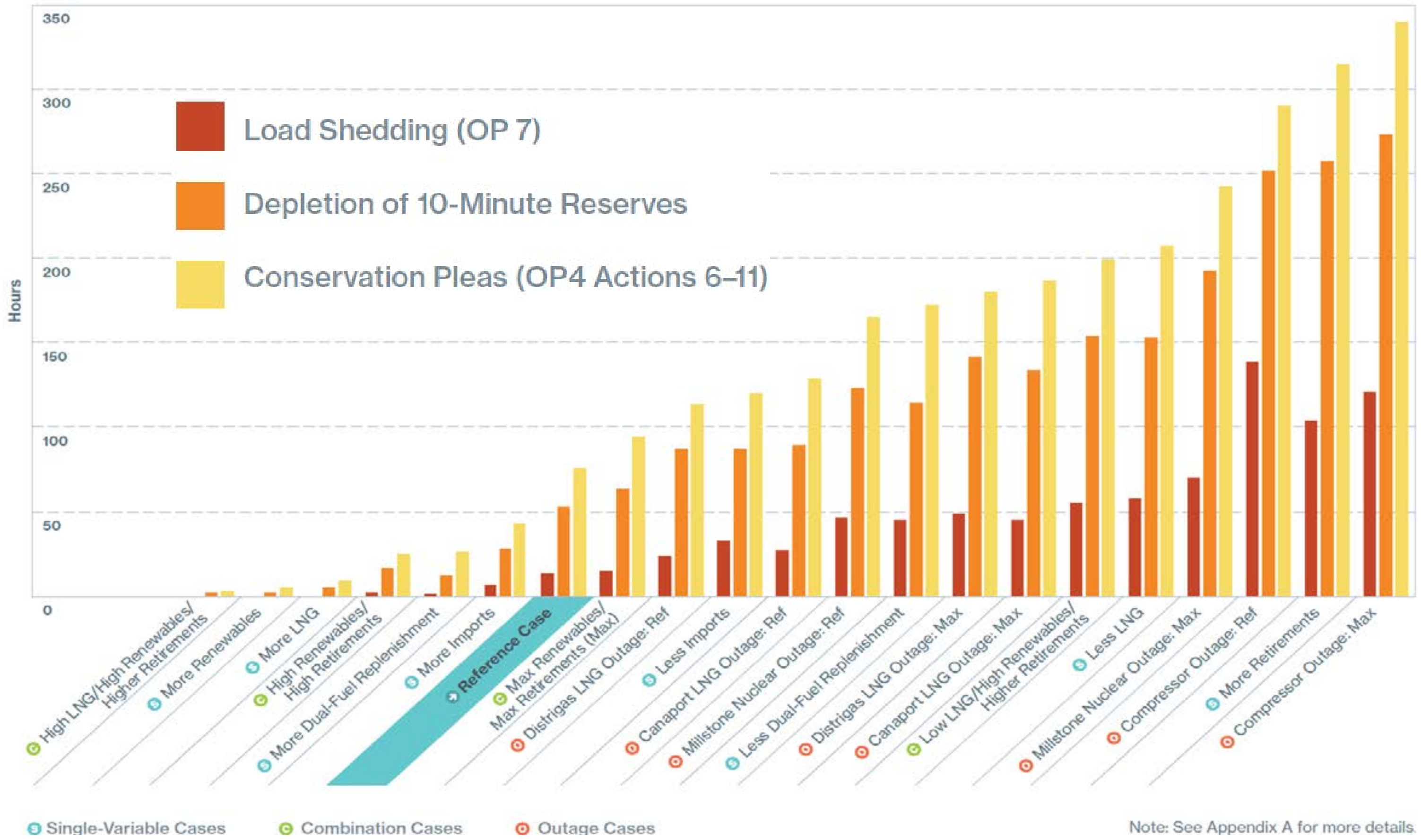
Study Suggests Six Major Conclusions

1. **Outages**: The region is vulnerable to the season-long outage of any of several major energy facilities.
2. **Key Dependencies**: As we retire more resources, reliability becomes heavily dependent on LNG and electricity imports; more dual-fuel capability is also a key reliability factor.
3. **Logistics**: Timely availability of fuel is critical, highlighting the importance of fuel-delivery logistics.
4. **Risk**: All but four of 23 scenarios result in load shedding, indicating a trend towards increased fuel-security risk.
5. **Renewables**: More renewables can help lessen fuel-security risk but are likely to drive oil-and coal-fired generator retirements, requiring high LNG imports to counteract the loss of stored fuels.
6. **Positive Outcomes**: Higher levels of LNG, imports, and renewables can minimize system stress and maintain reliability; delivery assurances for LNG and imports, as well as transmission expansion, will be needed.

22 of the 23 Scenarios Led to Emergency Actions

Load shedding was required to protect the grid in 19 of the 23 scenarios

Hours of Emergency Actions under Modeled Scenarios, Ordered Least to Most



Note: This chart does not include the two boundary cases, both of which are unlikely to develop. The low (i.e., positive) boundary case was the only scenario requiring no emergency actions. The high (i.e., negative) boundary case resulted in the most hours of emergency actions by far.

Recent Cold Weather Period Reinforces Findings in *Operational Fuel-Security Analysis*

- During the recent cold weather period (from December 26 to January 8), gas and oil **fuel price inversion** led to oil being in economic merit and base loaded, leading to rapid depletion of the region's oil supply
- Fuel delivery **logistics** became a concern
  - Heating customers get priority for oil and gas
  - Storms can delay trucked oil and LNG tankers
  - Truck drivers face restrictions on driving time

- With oil being base loaded, **emissions** limitations became a concern for several oil-fired generators

Fuel Security Presents Structural, Regulatory, and Market-Design Challenges

- The ISO assumed fuel-security challenges could be addressed by **improving performance incentives** for generators and that additional fuel infrastructure would be built (e.g., dual fueling); however, investment in adequate fuel infrastructure has stalled
- A number of the states are creating **additional emissions restrictions**, further limiting the use of fossil-fired resources
- Fuel infrastructure is shared between heating and electric industries and **reaches capacity during cold weather**
  – Logistics of fuel deliveries become very complex and prone to congestion and delays, significantly increasing operational risk
  – Forward contracting is needed to ensure availability of infrastructure and timely provision of the commodity

Fuel Security Presents Structural, Regulatory, and Market-Design Challenges, *continued*

- Fuel suppliers have **insufficient incentives** to meet demand from *spot* customers (e.g., electric generators) during cold weather conditions
- The ISO has ***no jurisdiction* over fuel infrastructure** and has to seek fuel adequacy through appropriate incentives/obligations for generators, who generally do not have a long-term view on fuel supply
- Non-gas generation (and fuel infrastructure) is retiring in the **absence of sufficient incentives** to provide the reliability services needed during cold weather periods

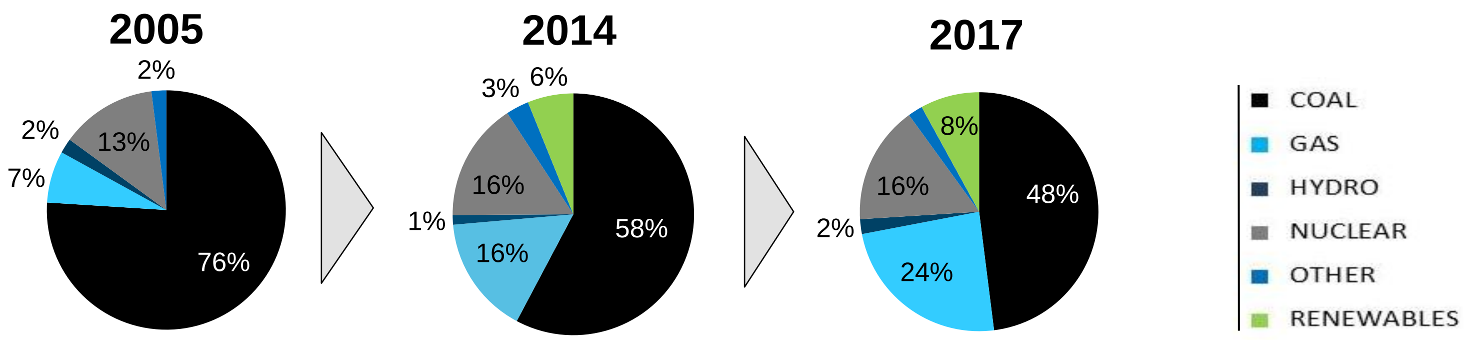
MISO Gas-Electric Coordination Overview

NERC Technical Workshop

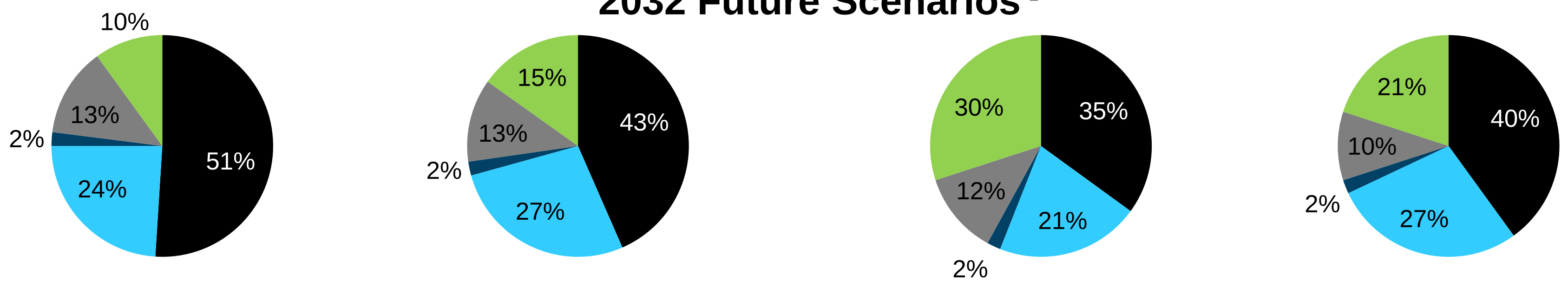
July 10, 2018

The generation fleet in the MISO region has been evolving; MISO efforts continue to anticipate and plan for the future

MISO Generation Portfolio Evolution (% Share of Energy)



2032 Future Scenarios [1]



Limited Fleet Change
Stalled generation fleet changes. Limited renewables additions driven solely by existing RPS under limited demand growth.

Continued Fleet Change
Continuation of the renewable addition and coal retirement trends of the past decade.

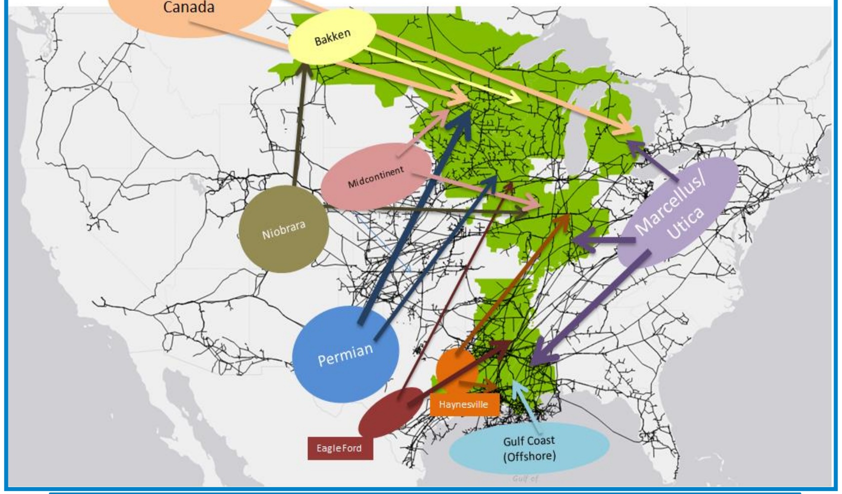
Accelerated Fleet Change
Renewables and demand side technologies added at a rate above historical trends. Fleet changes result in a 20% CO_2 emission reduction.

Distributed & Emerging Tech
New renewable additions largely distributed and storage resources co-located with largest sites.

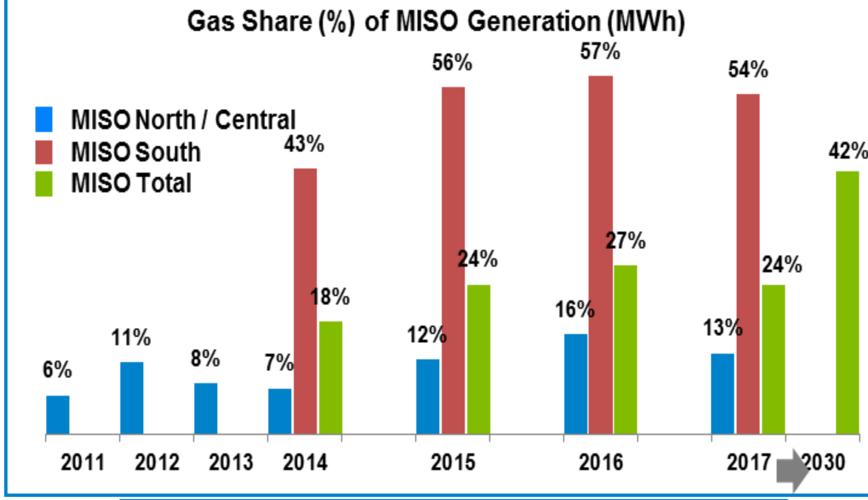
1. *% share of energy in 2032 is based on the set of assumptions defined for MTEP18 Future scenarios collaboratively with MISO stakeholders*

Though MISO is favorably situated in the gas grid, there are additional considerations with increased reliance on gas

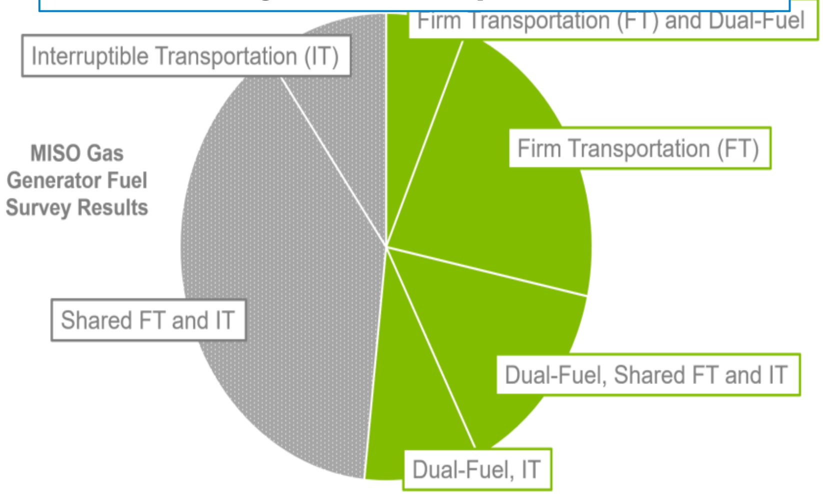
MISO Favorable Location on Gas Grid



Increasing Reliance on Gas



Contracting and Backup Fuel Practices



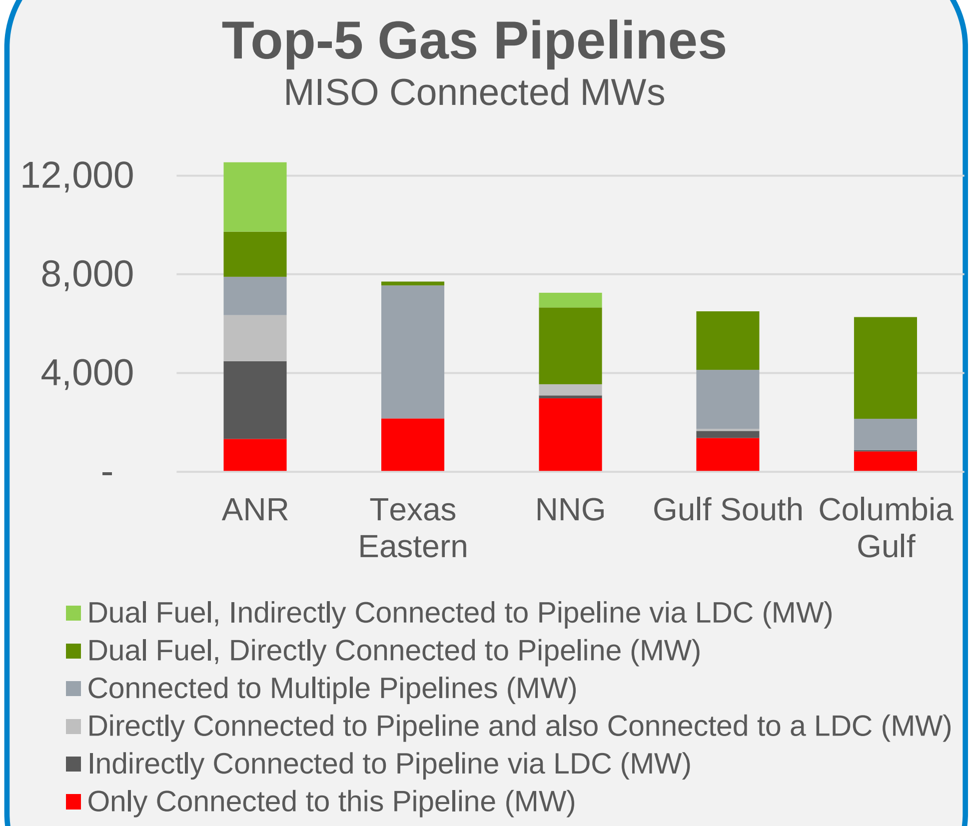
Gas-Electric Characteristics

- Just-in-time delivery through various fuel management approaches
- Various fuel risks and mitigation across the region
- Potential common mode of failure
- Oppositions to Gas infrastructure projects
- Major industry differences between gas and electricity

1. % gas share in 2030 represents a range of sensitivity scenario outcomes by varying gas prices, coal retirement and renewable growth

MISO continues to make steady progress on gas contingencies to assess potential reliability risk

- Incorporated in planning studies since 2015, involvement in industry studies and dialogue
- Using the gas generator survey, MISO can help scope vulnerability
- Exposure to gas contingencies is greatly dependent on gas topology and mitigation levers
- Access to accurate data in a useful format helps support system reliability and resilience



MISO has incorporated natural gas disruptions in various planning studies since 2015

- Assess system impact of extreme events for TPL-001-4 standard compliance

NERC TPL-001-4 Extreme Event Analysis

- Evaluate potential LOLE impact under largest gas pipeline contingencies

Resource Adequacy Impact Analysis

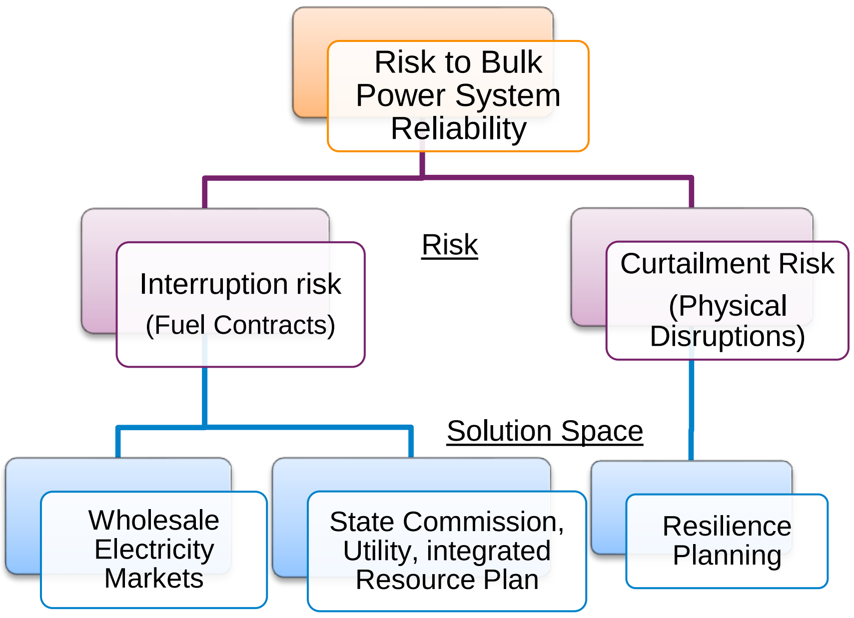
- Assess the system reliability performance for anticipated operating horizon

Coordinated Seasonal Assessment

Current planning studies have found no major reliability risk driven by gas pipeline contingencies evaluated

Study

- MISO currently uses 31 gas contingencies, as extreme events, to evaluate transmission needs and risk
- Contingencies list is reviewed and updated annually based on geographic clustering, external studies, historic events, and transmission owner/planner feedback



Results

- No cascading resulted from gas pipeline events in MTEP15,16,17 TPL analyses
- No impact found in 2017/18 Winter CSA assessment
- No meaningful reliability limitations found in LOLE analysis of one extreme event (full pipeline outage in current resource portfolio), as annotated in FERC resilience responses*

*"Only in one scenario, under the extreme and long-term event of the loss of the largest natural gas pipeline for the entire summer peak season, was a slightly elevated regional loss of load risk observed." MISO response in AD18-07 Page 27, Filed 03/09/2018

MISO's ongoing activities include study initiatives to assess additional gas disruptions

Collaboration with Industry and Stakeholders

- Create detailed catalogue of historical events and refine gas system contingency list
- Estimate probability and impact and identify possible mitigations
- Update information on gas topology and system parameters

To help address:

- How to ensure data accuracy and transparency in a useful format ?
- At what point does increased dependence on gas create a severe contingency risk?
- How could such risks be integrated into operations and planning to improve reliability?

Questions?

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RELIABILITY CORPORATION

Gas & Electric Coordination

Mike Knowland
ISO New England, Forecast and Scheduling Supervisor
July 10, 2018

RELIABILITY | ACCOUNTABILITY

About the ORS

- Reps from all Reliability Coordinators
  - Generally from RC Control Rooms
- Report to OC – provide operational guidance and oversight to reliability-based tools
- Work to ensure operational coordination:
  - Reliability impacts of congestion, scheduling, emergency coordination
  - Review Operating Events
- Key Deliverables Include:
  - Guidelines and Reference Documents related to operational coordination or best practices

Reliability Guidelines

- Reflect the collective experience, expertise and judgment of the industry.
- The objective of the reliability guidelines is to distribute key practices and information on specific issues critical to promote and maintain a highly reliable and secure bulk power system (BPS).
- Reliability guidelines are not binding norms or parameters to the level that compliance to NERC's Reliability Standards are monitored or enforced. Rather, their incorporation into industry practices are strictly voluntary.
- Voluntary adoption of guidelines can help demonstrate effective controls.

Guideline Content:

- Establish Gas and Electric Industry Coordination Mechanisms
- Preparation, Supply Rights, Training and Testing
- Establish and Maintain Communication Channels
- Intelligence and Situational Awareness

Establish Coordination Mechanisms

- Establish Contacts
  - Most important aspect of gas and electric coordination
- Communication Protocols
  - FERC Order 787 allows sharing non-public information
- Information Exchange:
  - Real-Time operating information (both verbal and electronic)
  - Outage planning
  - Sharing normal, abnormal, and emergency conditions to ensure implications are understood
- Coordinate Procurement timelines
  - Align the “Gas Day” with electricity markets when/if possible

Establish Coordination Mechanisms

- Identify Critical Components
  - Review and adjust load shed plans
- Operating Reserve
  - Consider losses of fuel forwarding facilities
  - Risk based procurement

Preparation

- Assessments:
  - Developing a detailed understanding of where and how the gas infrastructure interfaces with the electricity industry
  - Understand how electric resources depend on gas pipelines:
    - Level and quantity of capacity service
    - Understand priority of electric load
    - Identify gas contingencies – identify single contingencies and how gas contingencies may impact electric system restoration
- Emergency Testing and Training
  - Consider gas dependencies for operator training, voltage reduction testing, etc.
- Generator testing
  - Dual fuel auditing

Preparation

- Capacity and Energy Assessments
  - Similar to existing practices, adding impact of fuel restrictions
  - Energy analysis accounting for depleting resources
- Winter Readiness Reviews
  - Seasonal readiness training
  - Fuel availability, emergency plans, weather forecasts, freeze protection, environmental permitting, fuel surveying protocols, unit availability
- Extreme Weather Readiness Reviews
  - Response to extreme summer events (e.g. hurricanes)

Establish Communications

- Industry Coordination
  - Upcoming operations, outage coordination, status updates
  - Communication protocols for normal, abnormal, emergency conditions
- Emergency Notification to Stakeholders
  - Proactive notification for enhanced situational awareness
  - Coordinated response by electric, gas, and regulatory communities

Situational Awareness

- Fuel Surveys and Energy Emergency Protocols
  - Determination of energy adequacy
  - Establish basis for additional communication
- Fuel Procurement
  - Comparing expected electric operations to scheduled gas (if available)
  - Establish basis for additional communication
- Gas System Visualization
  - Control room displays
  - System arrangement via one-line displays

Questions and Answers

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Applicability

Howard Gugel, Senior Director of Standards and Education

NERC Technical Workshop

July 10, 2018

RELIABILITY | ACCOUNTABILITY




Overview

- TPL-001-4
- TOP-002-4
- IRO-008-2
- VAR-001-4.2
- BAL-502-RF-03

- Requirement R2 Part 2.1.4 (steady state) and 2.4.3 (stability)
  - … the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :
    - Real and reactive forecasted Load.
    - Expected transfers.
    - Expected in service dates of new or modified Transmission Facilities.
    - Reactive resource capability.
    - Generation additions, retirements, or other dispatch scenarios.
- Table 1 Extreme Event consideration:
  - Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.

TOP-002-4

- Requirement R1
  - Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs).
- Requirement R4
  - Each Balancing Authority shall have an Operating Plan(s) for the next-day that addresses:
    - Expected generation resource commitment and dispatch
    - Interchange scheduling
    - Demand patterns
    - Capacity and energy reserve requirements, including deliverability capability
- Requirement R6 (TOP) and R7 (BA) submit to RC

IRO-008-2

- Requirement R1
  - Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area.

- Requirement R2
  - Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load.

- Requirement R1
  - The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall
    - 1.3 Include the following subject matter and documentation of its use:
      - 1.3.2 Resource characteristics:
      - 1.3.2.1 Historic resource performance and any projected changes
      - 1.3.2.2 Seasonal resource ratings
      - 1.3.2.3 Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.
      - 1.3.2.4 Resource planned outage schedules, deratings, and retirements.
      - 1.3.2.5 Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.
      - 1.3.2.6 Criteria for including planned resource additions in the analysis

- Requirement R1
  - The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall
    - 1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:
      - 1.4.1 Availability and deliverability of fuel.
      - 1.4.2 Common mode outages that affect resource availability
      - 1.4.3 Environmental or regulatory restrictions of resource availability.
      - 1.4.4 Any other demand (Load) response programs not included in R1.3.1.
      - 1.4.5 Sensitivity to resource outage rates.
      - 1.4.6 Impacts of extreme weather/drought conditions that affect unit availability.
      - 1.4.7 Modeling assumptions for emergency operation procedures used to make reserves available.
      - 1.4.8 Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

Questions and Answers

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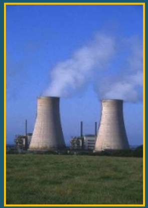
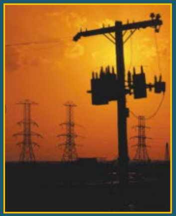
Framing the Issues:
Natural Gas and Electric System Interdependencies

Sue Tierney

DOE Electricity Advisory Committee Meeting – June 7, 2017



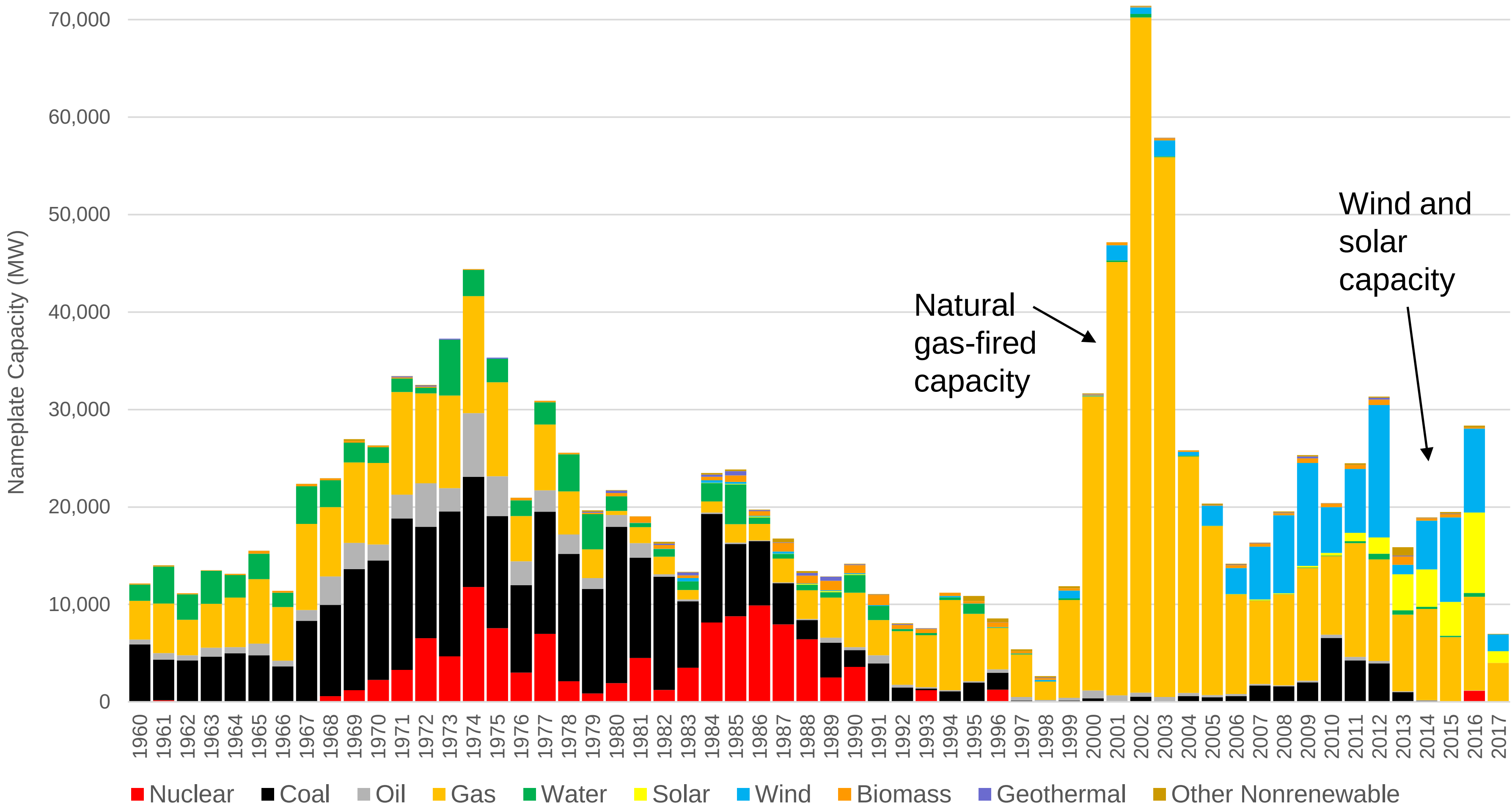



Conventional wisdom

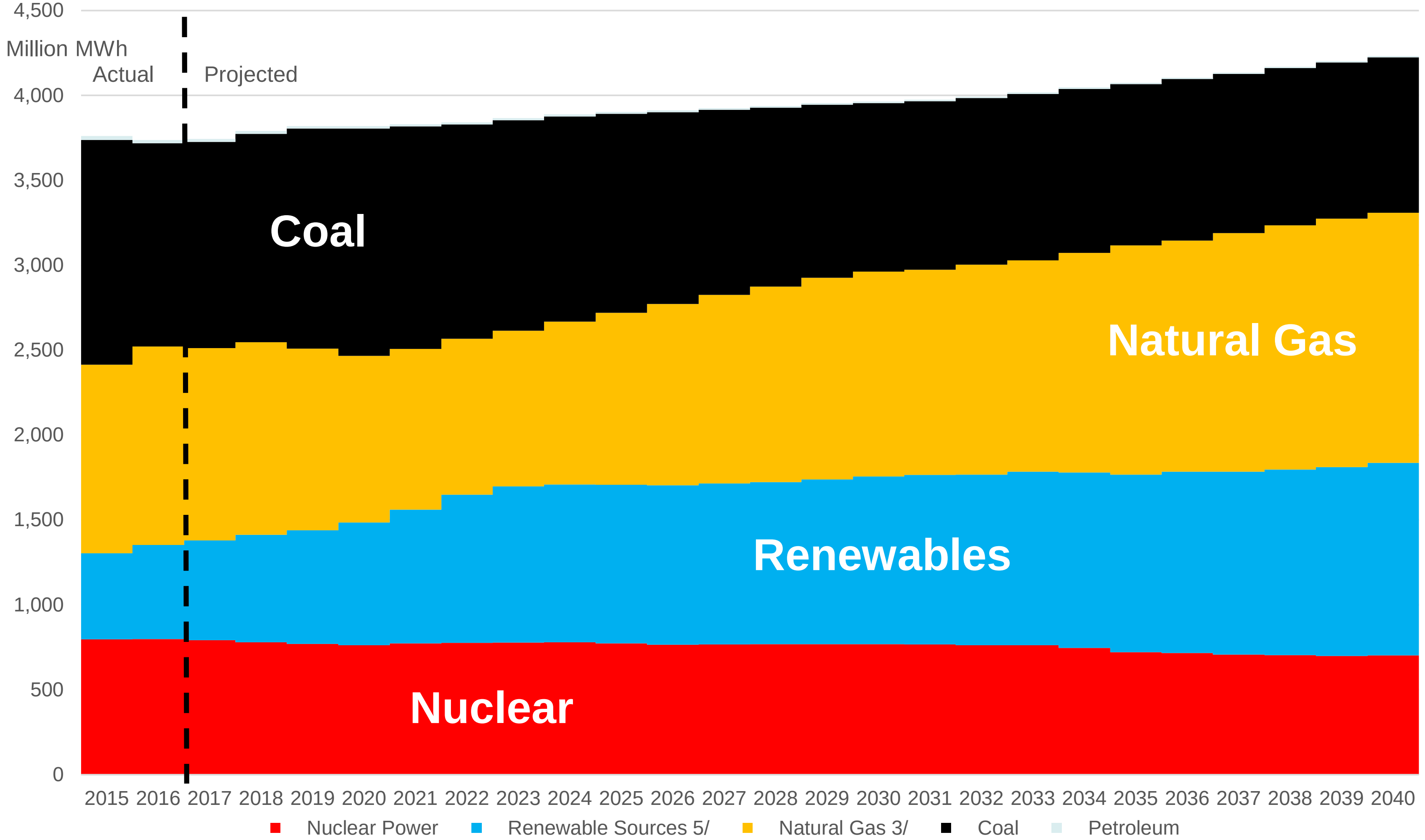
At least in the near term, the U.S. natural gas industry and the U.S. electric industries are and will continue to be highly interdependent:

- **The electric industry will become even more dependent upon natural gas than it has been in the past**

Generating capacity additions by fuel type (1960-2017)



Electricity generation by fuel (2015-2040) (EIA AEO 2017)



EIA generation data

Conventional wisdom

At least in the near term, the U.S. natural gas industry and the U.S. electric industry are and will continue to be highly interdependent:

- The electric industry will become even more dependent upon natural gas than it has been in the past
- **The natural gas industry will rely on power sector demand for a growing and important share of its market for some years to come**

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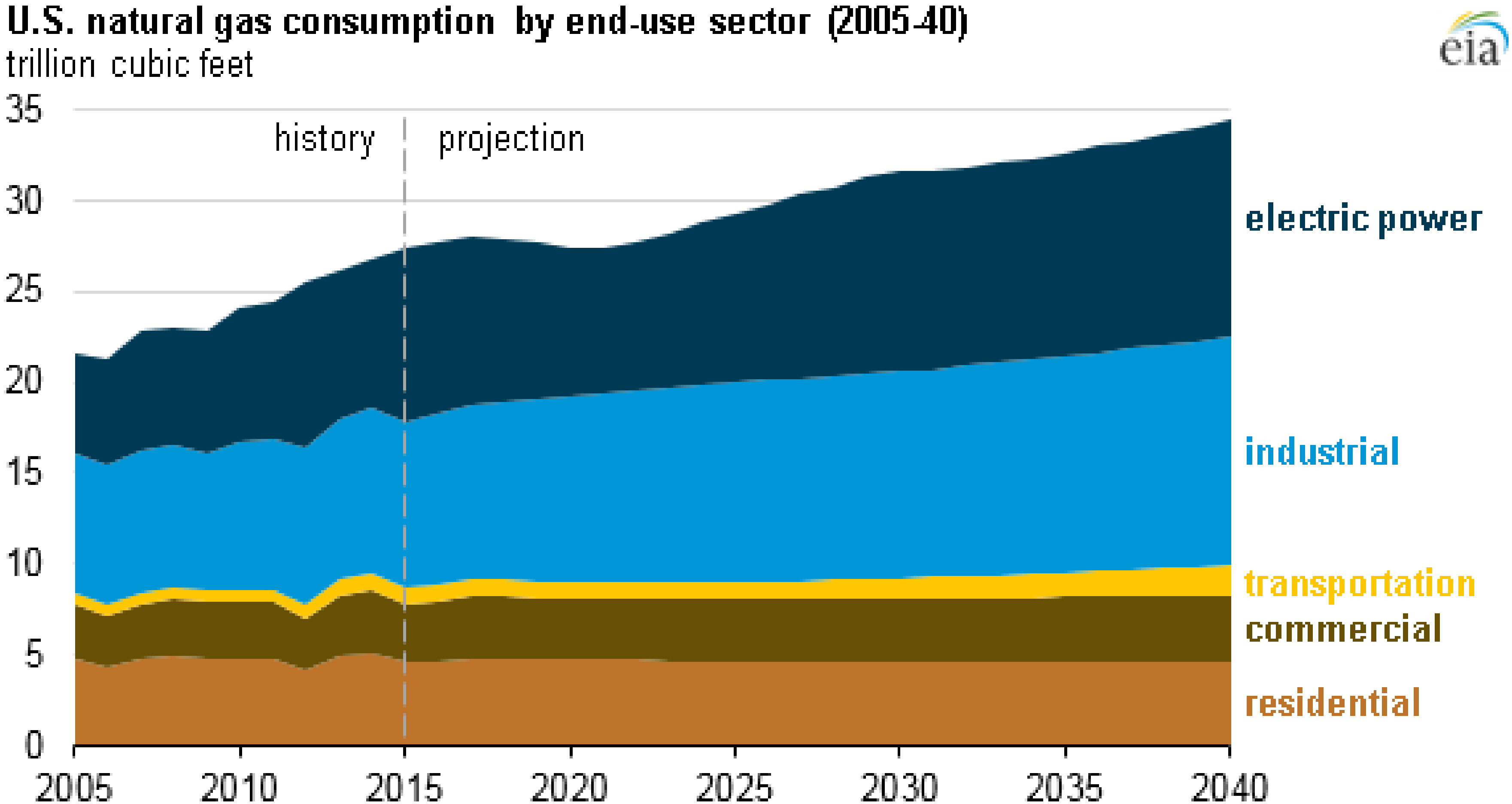
Natural gas:
Estimated consumption by sector (EIA AEO 2017)



https://www.eia.gov/todayinenergy/detail.php?id=26412

This figure does not show the increasing role of LNG exports as part of the industry's market outlook.

Similarities across the electric and gas industries

- **Both have separated the delivery function from commodity supply**
- **Both allow for market-based prices for commodity supply with regulated cost-of-service transmission service**
- **Both have federally regulated transmission service (FERC)**
- **Both have state-regulated local distribution companies**
- **Both have predominantly private ownership of assets**
- **Both have systems that cross the country**
- **Both have regionally markets that are substantially varied**

Differences:
Physical footprint with implications for regulatory history

Natural gas:

- **Reflects a history of needing to connect production regions to distant consumption regions**
- **Federal siting of interstate pipelines – but increasingly contentious and controversial certification proceedings**

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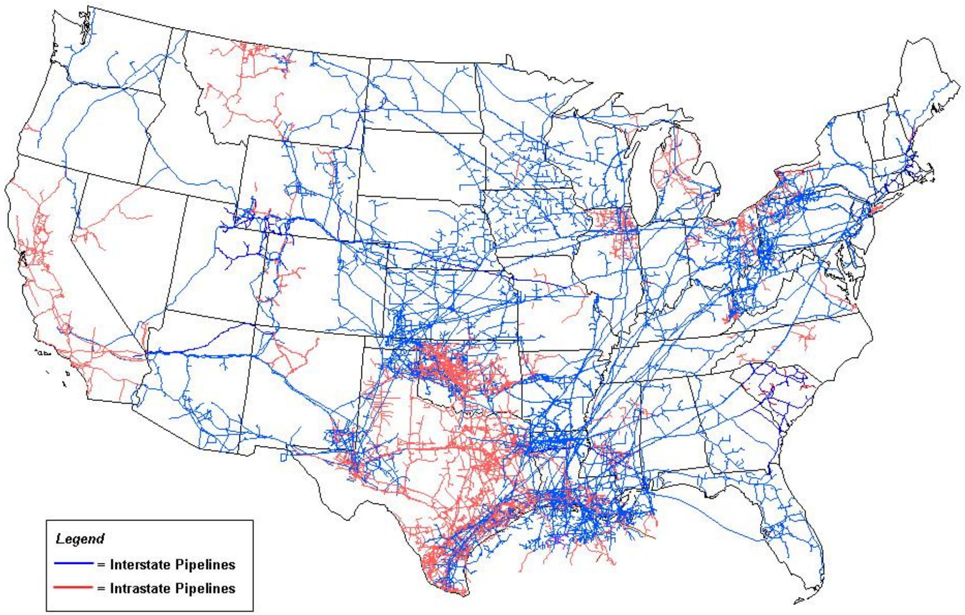
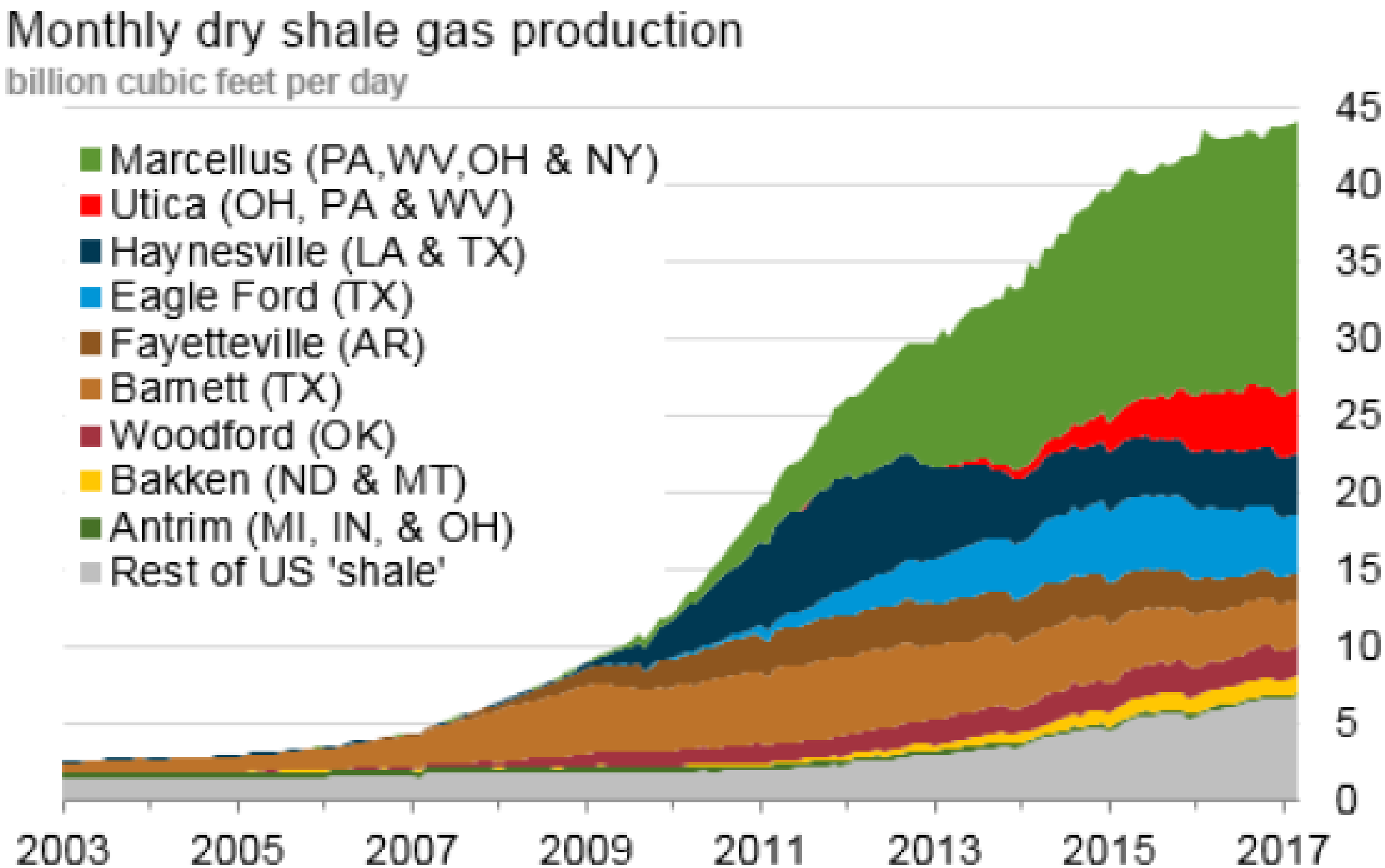
Natural gas pipeline system



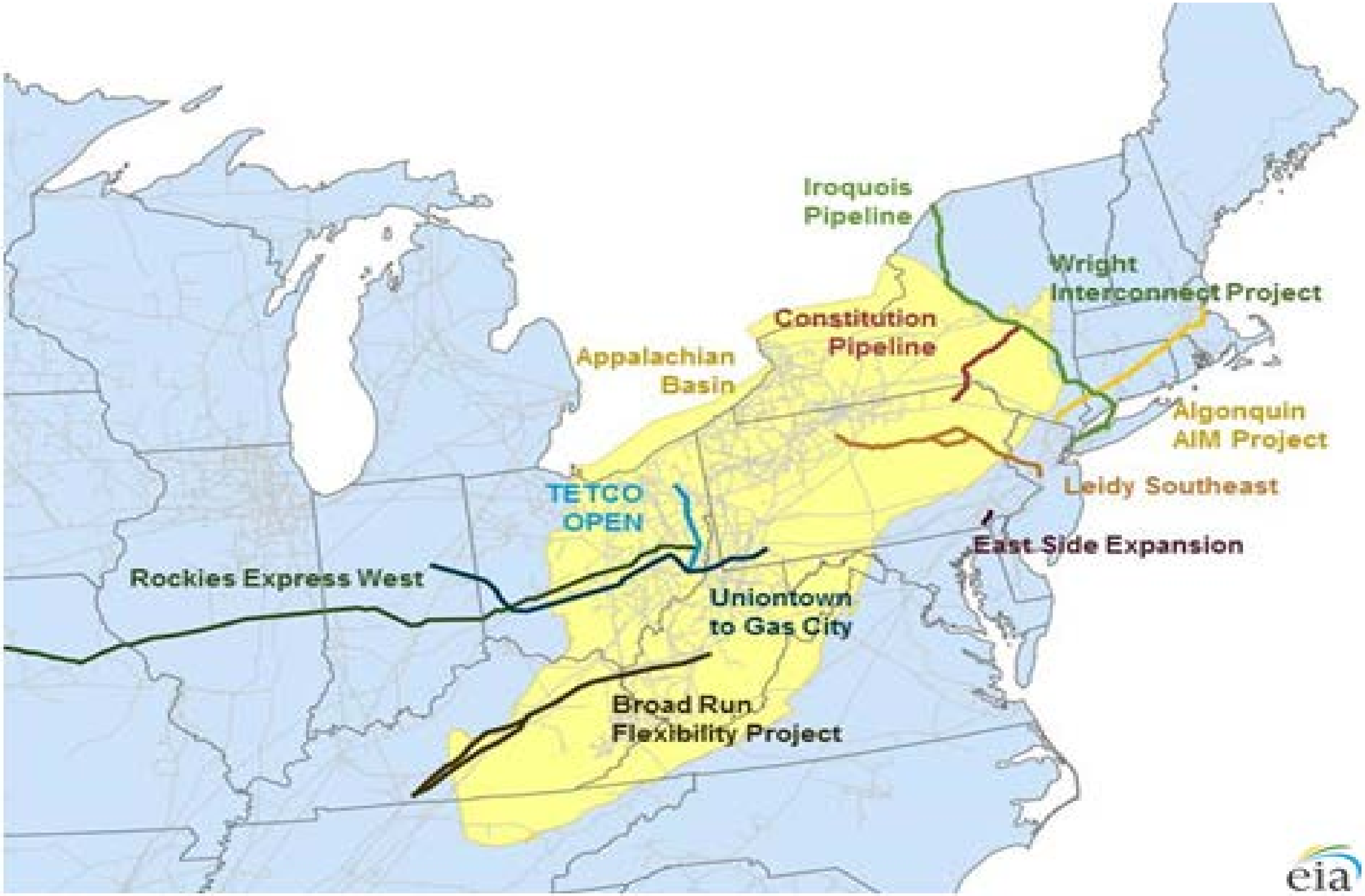
Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

Natural gas (shale) production: changing regions



Sources: EIA derived from state administrative data collected by DrillingInfo Inc. Data are through March 2017 and represent EIA's official shale gas estimates, but are not survey data. State abbreviations indicate primary state(s).

Natural gas pipelines:
Existing and planned in the Appalachian Basin



https://www.eia.gov/todayinenergy/detail.php?id=24732

Differences:
Physical footprint with implications for regulatory history

Natural gas:

- Reflects a history of needing to connect production regions to distant consumption regions
- Federal siting of interstate pipelines – but increasingly contentious and controversial certification proceedings

Electricity:

- **Rooted in local generation serving local end users (with fuel moved to power plant locations from source)**
- **State siting of interstate power lines – with long-standing challenges to approvals**

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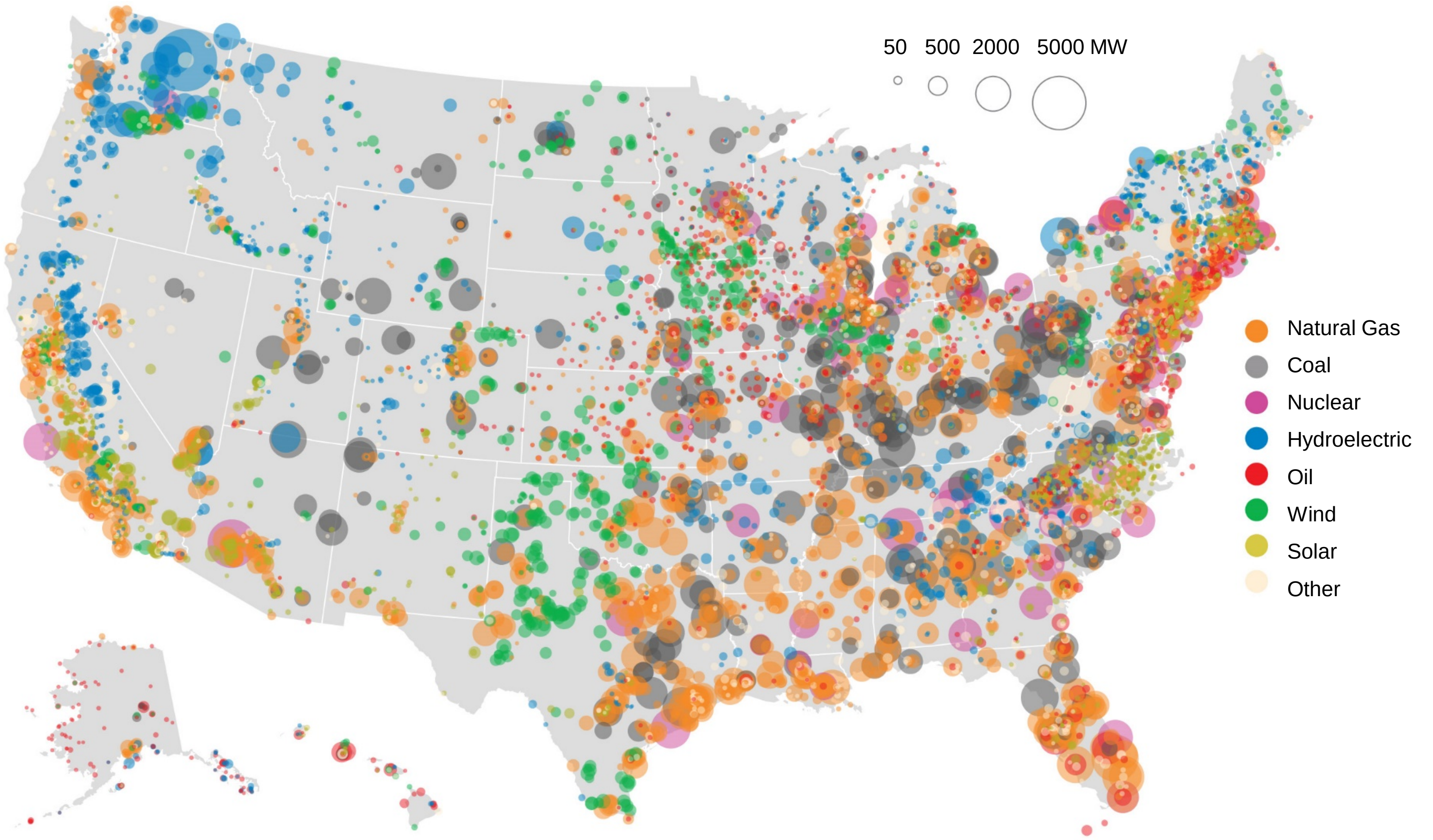
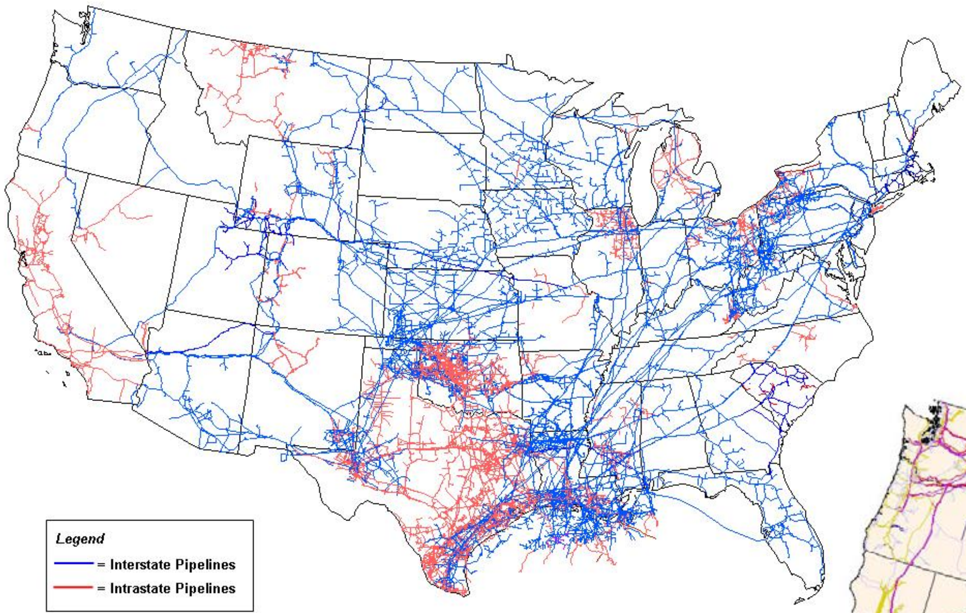
Electric generating facilities



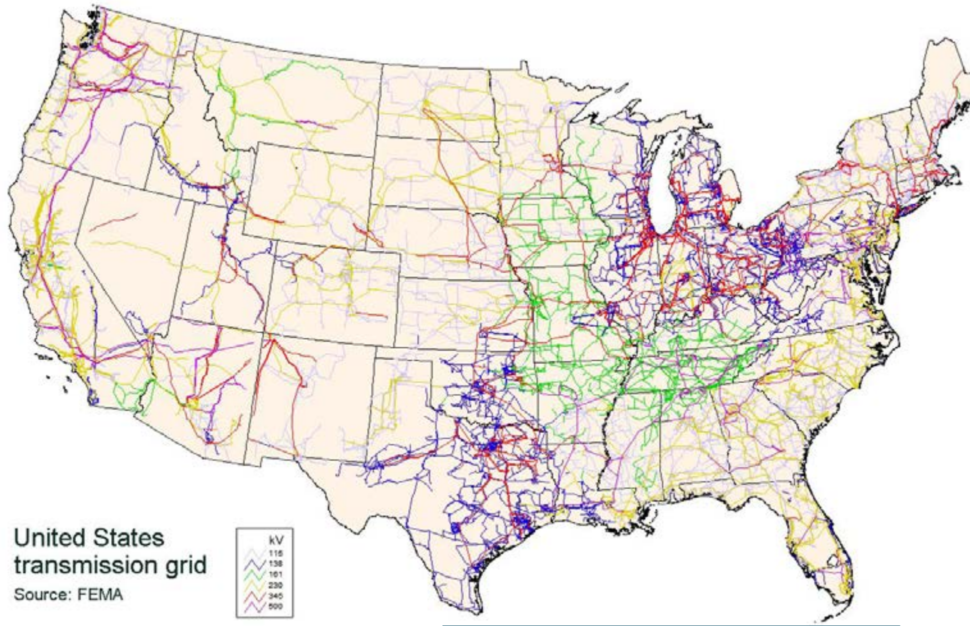
https://www.washingtonpost.com/graphics/national/power-plants/?utm_term=.1081aaa2322d

Natural gas pipeline system



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

Electric transmission grid



Differences: Network versus lateral systems

Electricity:

- **Physically interconnected and networked bulk-power system with power flows linking supply and demand within each Interconnection (East, West, Texas).**

Natural gas:

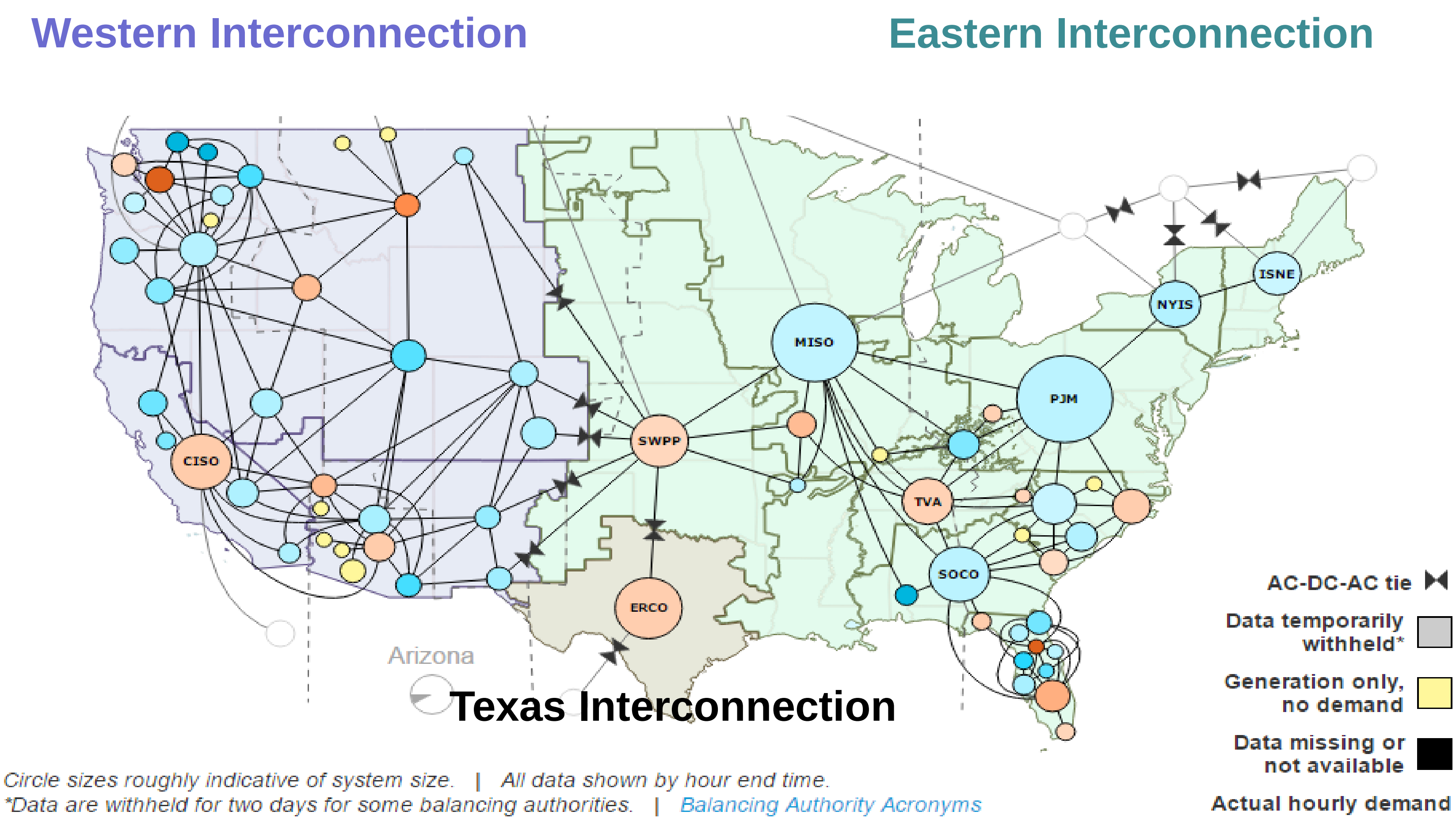
- **Long-distance pipeline systems owned by individual companies with end-users served by that company's system, with limited numbers of transfer points along the lateral systems.**

Differences: Network versus lateral systems

Electricity:

- **Physically interconnected and networked bulk-power system with power flows linking supply and demand within each Interconnection (East, West, Texas).**

Electricity: Integrated systems in the 3 Interconnections



Circle sizes roughly indicative of system size. | All data shown by hour end time.
**Data are withheld for two days for some balancing authorities. | Balancing Authority Acronyms*

Differences: Network versus lateral systems

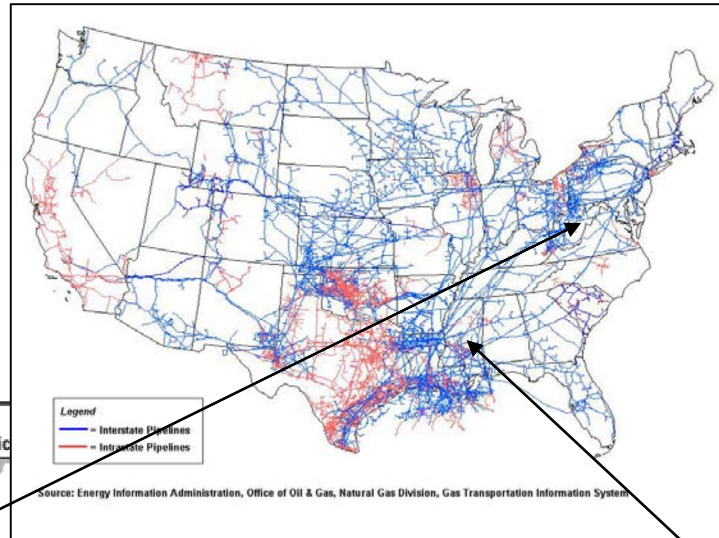
Electricity:

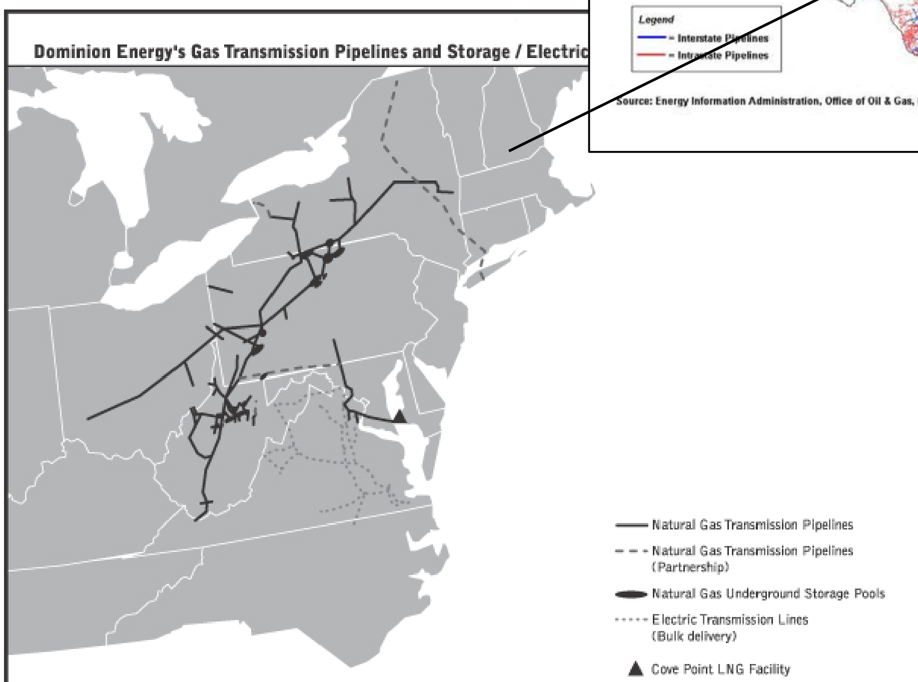
- Physically interconnected and networked bulk-power system with power flows linking supply and demand within each Interconnection (East, West, Texas).

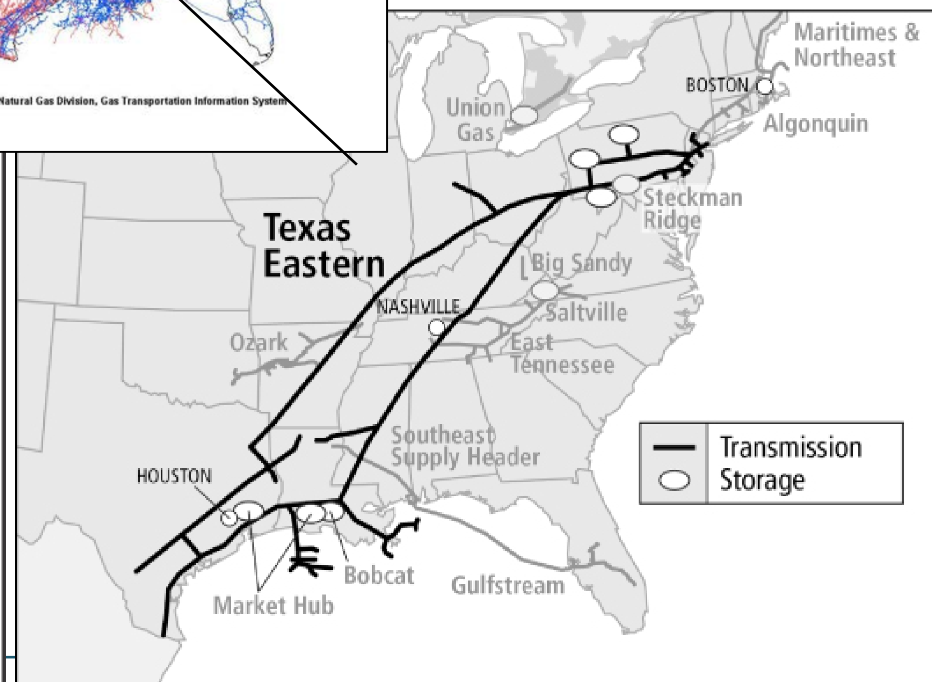
Natural gas:

- **Long-distance pipeline systems owned by individual companies with end-users served by that company's system, with limited numbers of transfer points along the lateral systems.**

Examples of two interstate pipeline systems: Dominion Energy's and Texas Eastern's (Enbridge/Spectra)



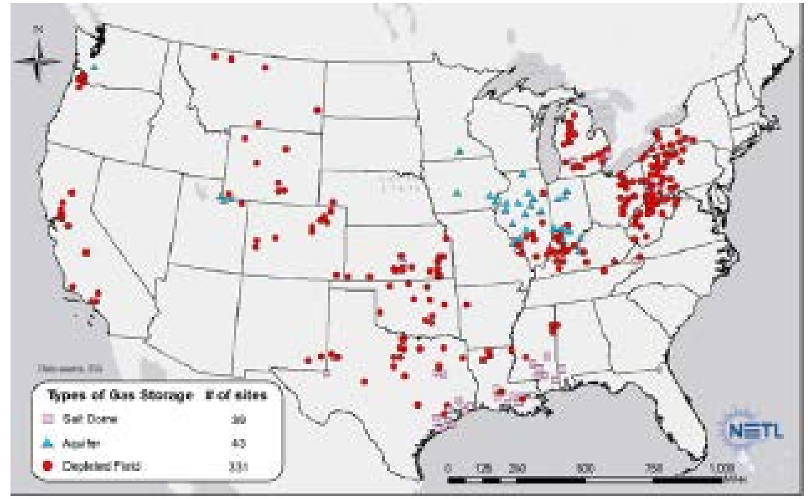




Differences: Storage capability

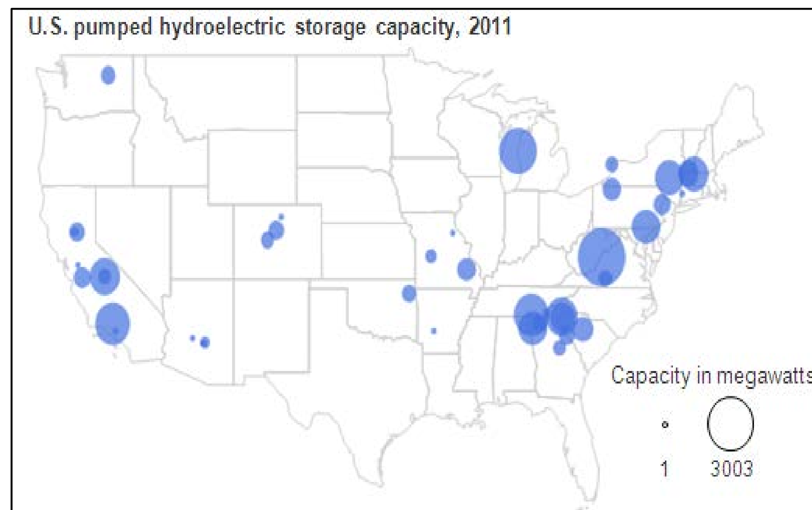
Natural gas:

- **Considerable regional storage allowing for seasonal draw-down**



Electricity:

- **Historically, the primary storage technology was pumped storage – designed for intra-day draw down**
- **Emerging technologies with injections/withdrawals over very different time scales**



Differences: Commodity markets

Natural gas:

- **Unregulated upstream production**
- **Competitive commodity prices**
- **Demand highly sensitive to price**

Electricity:

- **Regulation of production through FERC's regulation of sales for resale**
- **Market-based prices subject to FERC review**
- **Demand is somewhat sensitive to price**

Differences: Many more….

Universal service:

- Natural gas does not have universal service
- Electric utilities have obligation to serve and retail universal service

Demand outlook:

- Natural gas demand is growing overall, but flat demand in LDC markets
- Electricity demand is flat at retail and wholesale levels

Market and operational time scales:

- Natural gas moves at a 15-20 mile/hour pace on the interstate system
- Electricity operates in fractions-of-seconds time scales

Differences: One more….
Industry reliability organizations and standards

Natural gas:

- **No mandatory industry-wide reliability organization**
- **Operating standards reflect a combination of FERC policy, NAESB standards and business practices of companies**

Electricity:

- **Since EPACT 2005, FERC/NERC mandatory reliability standards cover a wide range of planning, operational, communications, cyber and other issues**
- **Utilities and other industry participants have numerous voluntary agreements for cooperative support for reliability purposes**
- **States largely hold resource adequacy requirements – with FERC's role in RTO markets with a capacity market design**

Some implications for electricity:

Issues relating to market design, operational schedules and coordination issues – e.g.,:

- In some regions – incentives vary for generators’ committing to firm transportation on interstate pipelines
  - Vertically regulated markets with rate-based generation: more likely to elect firm transportation service on pipelines
  - Merchant generators with at-risk investment in RTO markets: less likely to have financial incentives to invest in firm gas transportation service, and may rely on alternatives

Some implications for electricity:

Issues relating to market design, operational schedules and coordination issues – e.g.,:

- **In some regions – chicken-and-egg timing problems**
  - **Generators need to commit to move gas volumes before knowing whether their offers into organized daily power markets have been accepted**
  - **Generators need to offer prices into such energy markets without fully knowing the price of their natural gas**
  - **Instances where gas customers with firm gas transportation service face potential (or real) curtailments under certain circumstances**
  - **FERC, NAESB, industry participants have been considering and are still wrestling with how to address these issues**

Final thoughts on implications for electricity:

To date, the industries have evolved and adapted to changing conditions:

- **Entities responsible for electric system reliability continue to evolve market designs, practices, agreements to assure system reliability.**

There will be continuing need to stay ahead of changing conditions in the two industries

- **On the gas-industry and the electric-industry sides**

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Session 4:
Potential Solutions & Discussions

Sue Tierney

Technical Workshop on Gas Infrastructure Risk and Associated Recommendations

NERC - July 2018

Starting observations

- **This is a big deal – with important implications for the US economy, energy systems and national security.**
  - **But not in the way it's being characterized in recent "base-load" discussions in Washington.**
  - **It's an issue involving both physical assets and systems, and human systems.**
  - **Even with good assets and systems in place, more work is needed because the economy and critical services depend upon power supply and energy delivery.**

Starting observations

- **The solutions are not simple (technically, institutionally, culturally)**
  - **Risks result from combination of factors: market, physical, operational, institutional, and informational.**
  - **The issues are broader than FERC and NERC jurisdiction.**
  - **The solutions are broader than what FERC and NERC can address.**
  - **Solutions involve a diverse set of actors, with none having authority to address the full range of risks.**

Actors and arenas

Department of Energy · Federal Energy Regulatory Commission

Department of Energy · United States of America

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

National Association of Regulatory Utility Commissioners · Dedicated to Public Service · 1889

NAESB

U.S. Department of Homeland Security
Transportation Security Administration

United States Congress

What can actors do today? NERC

- Do what NERC does well (in light of its jurisdiction):
  - Convenings (do more)
  - Assessments (do more)
  - Guidance (do more, be more concrete)
  - Not get out over its skis (e.g., standards for natural gas)

What can actors do today? Electric industry

- Do what grid operators and planners can do well (but could do better:
  - Analyze “what if” scenarios (do more involving combinations of conditions/events that stress the system)
  - Conduct more comprehensive regional emergency-preparedness exercises, simulate extreme events and physical and cyber attacks affecting fuel delivery and grid performance
- Do what regulators can do well (but could do better):
  - Consider new definitions of resource adequacy
  - Develop metrics for resilience of bulk power & distribution systems and performance
  - Require more analyses of complex contingent events

What can actors do today? Gas industry

- **Do what delivery-facility owners/developers/operators can do well (but could do better):**
  - **Offer various commercial products to firm up supply**
  - **Don’t assume that more pipes and firm transportation agreements are all that’s needed for fuel assurance**
  - **Collaborate on regional studies/scenario analyses to consider consequences of and solutions to attacks on systems**
- **Do what regulators and energy departments could do well (or better):**
  - **Require least-cost solutions to fuel assurance**
  - **Don’t assume that market rules and arrangements are enough**
  - **Consider authority to address fuel-assurance in certificates**

What do (could) actors do today but needs more focus:

- **National and regional "visioning" processes (DOE & DHS?)**
  - **Systematically imagining and assessing plausible large-area, long-duration grid disruptions (including relating to fuel assurance) that could have major economic, social, and other adverse consequences. [NAS rec*]**
- **State and regional energy offices and regulators**
  - **Establish a standing capability to identify vulnerabilities, identify strategies to reduce local vulnerabilities, develop strategies to cover costs of needed upgrades, and help the public to become better prepared for extended outages. [NAS rec]**

* National Academies of Sciences, Engineering & Medicine, "Enhancing the Resilience of the Nation's Electricity System," 2017.

What can't/don't actors do today but is needed:

- New reliability/security protocols, standards and requirements for gas facilities? (Congress? FERC? TSA?)
  - E.g., Standardized methods for sharing system status
- Require and conduct more gas/electric regional assessments? (DOE? FERC? All grid operators with major gas reliance? Gas industry?)
- Improve tools? (DOE? Grid operators? Gas industry?)
  - situational awareness across multiple gas/electric systems
  - modeling of gas/electric system operations
  - assessments of dependence of critical services served by key electric/gas assets

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