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Power Sector Transition: GHG Policy and Other Key Drivers

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ARKANSAS 111(D) STAKEHOLDER MEETING

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Purpose of Analysis: Impacts of GHG Regulation of Power Plants

- **Scoping/bounding analysis on power sector future w/ GHG regulation**
  - Not intended to predict/propose/endorse a level of stringency

- **Examine and compare impacts under a range of assumptions**
  - Range of emission limitation levels
  - Range of natural gas prices
  - Range of cost estimates for demand side energy efficiency
  - Range of potential future for existing nuclear fleet

- **BPC analysis is based on economic modeling of the power sector**
  - Using the Integrated Planning Model (IPM) run by ICF International
  - With assumptions and policy scenarios defined by BPC
  - On-going analysis will adapt to proposal after EPA guidelines in June 2014

GHG: Greenhouse Gas
BPC: Bipartisan Policy Center

Key Take-Aways

- **Magnitude of impacts from §111(d) largely dependent on EPA & state interpretations, technical analysis & decisions, as well as market factors**
- **Significant power sector carbon reduction is already baked into system**
- **Few new coal builds expected, even in the absence of GHG policy**
- **111(d) policy requiring only modest plant upgrades does little to reduce CO_2**
  - Many of the least efficient units are already slated to retire
  - Plant upgrades would likely increase coal generation
- **Potential for natural gas prices to be as influential as GHG policy**
  - Low gas prices have potential to make 111(d) policy non-binding
- **Demand-side energy efficiency may be an instrumental compliance strategy**
  - Highly dependent on price/availability
  - Lack of flexibility to reduce CO_2 with demand side EE significantly increases cost
- **Nuclear plant retirements beyond what is currently projected would raise costs and/or dampen CO_2 reductions achieved by §111(d) regulation**
- **Timing flexibility (e.g., emissions budget with banking) helps lower overall costs**

GHG: Greenhouse Gas
§111(d): Section 111(d) of Clean Air Act
CO_2: Carbon Dioxide
EE: Energy Efficiency

Caveats and Limitations

❖ Intention of scoping runs was bounding analysis

- Policy scenarios designed before EPA proposal and only intended to be rough bounding analysis of §111(d) impacts
- Magnitude of impacts from §111(d) will depend on many yet-to-be-determined factors, including EPA & state interpretations & decisions
- Limited cost/performance data and modeling limitations for HR upgrades
- Modeling does not assume that plant efficiency upgrades trigger NSR

❖ Analysis could underestimate costs

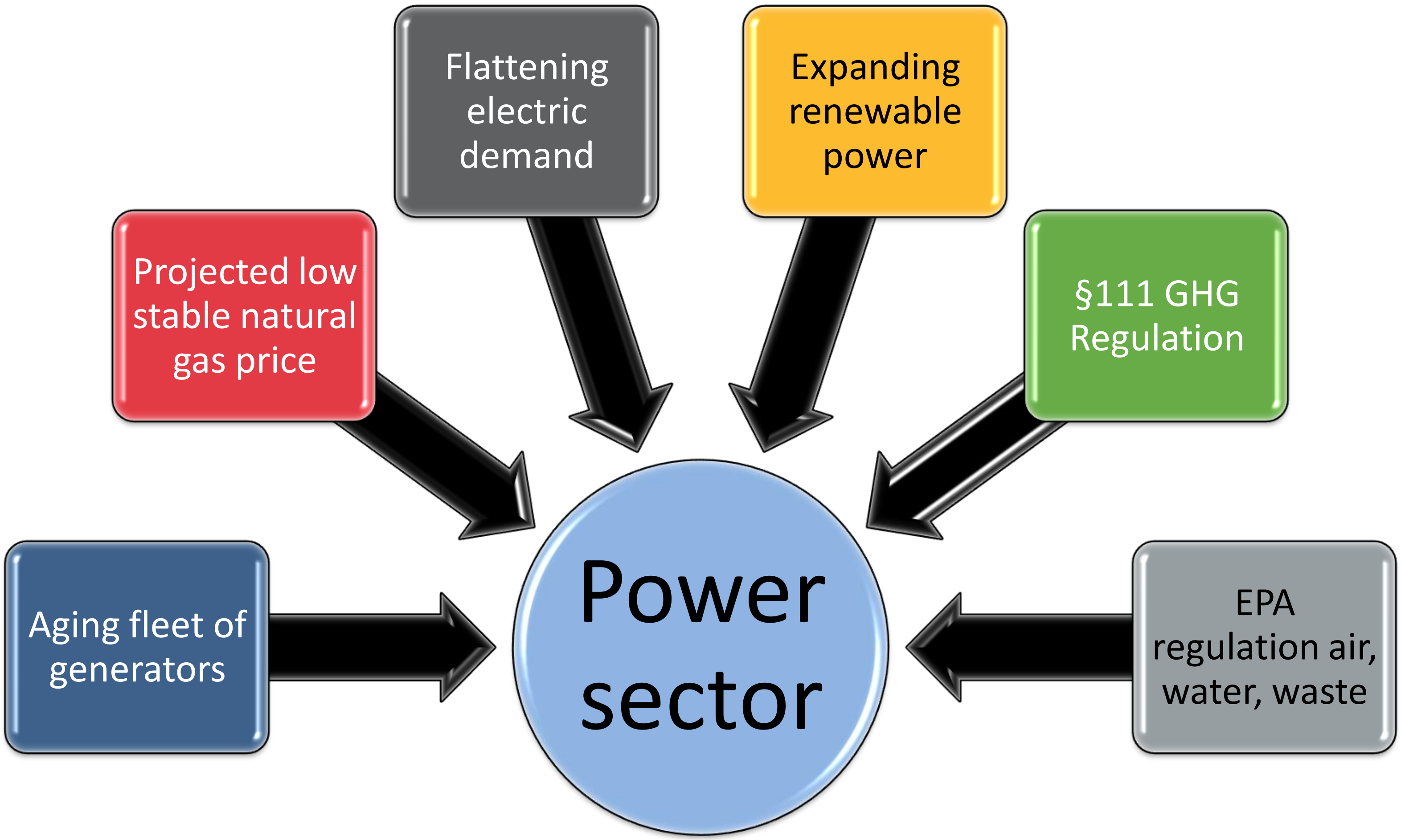
- Most policy runs assume national market-based policy, but a §111(d) approach with state variation would likely be less economically efficient

❖ Analysis could overestimate costs

- Very little innovation assumed in model & could significantly impact results
- Policy is not optimized for lowest cost solution
  - CO_2 price runs don't allow compliance timing flexibility

§111(d): Section 111(d) of Clean Air Act
HR: Heat rate
NSR: New Source Review
CO_2: Carbon Dioxide

Power sector transition driven by many factors



GHG: Greenhouse Gas
§111(d): Section 111(d) of Clean Air Act

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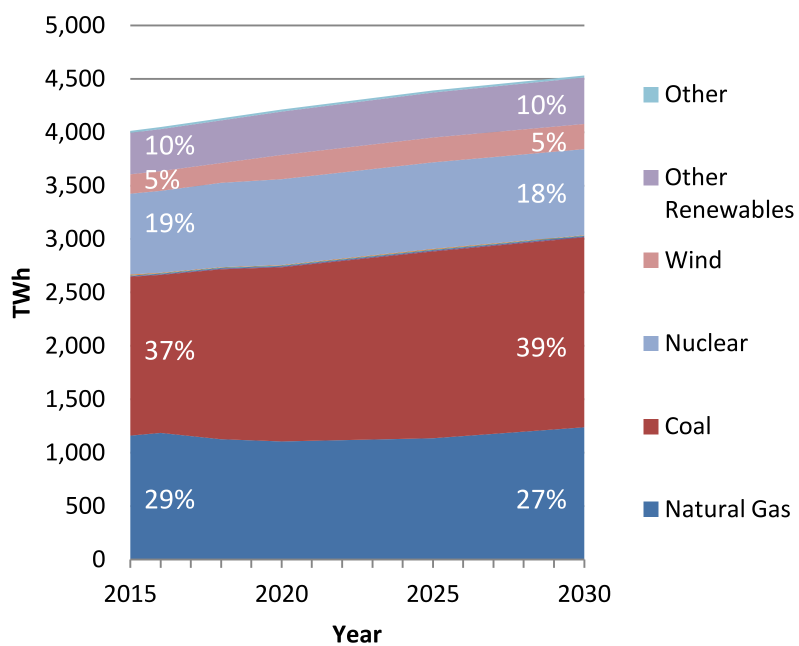
I. Reference Case:

Projected power sector future with market and regulatory factors, but no GHG policy

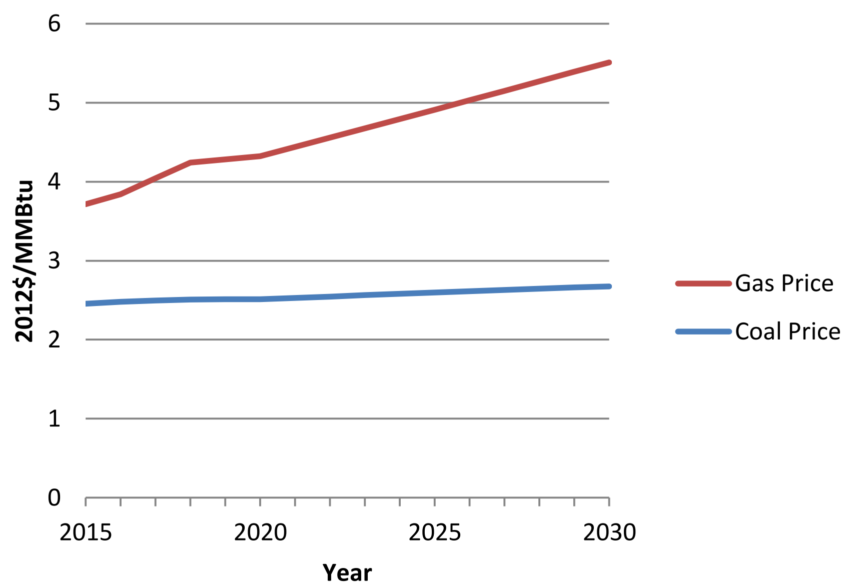
❖ Reference case largely based on EIA Annual Energy Outlook 2013

- No GHG policy assumed
- Percent contribution from each generation type remains fairly consistent
- Modest growth in total generation to accommodate modest load growth
- Coal remains dominant generation fuel

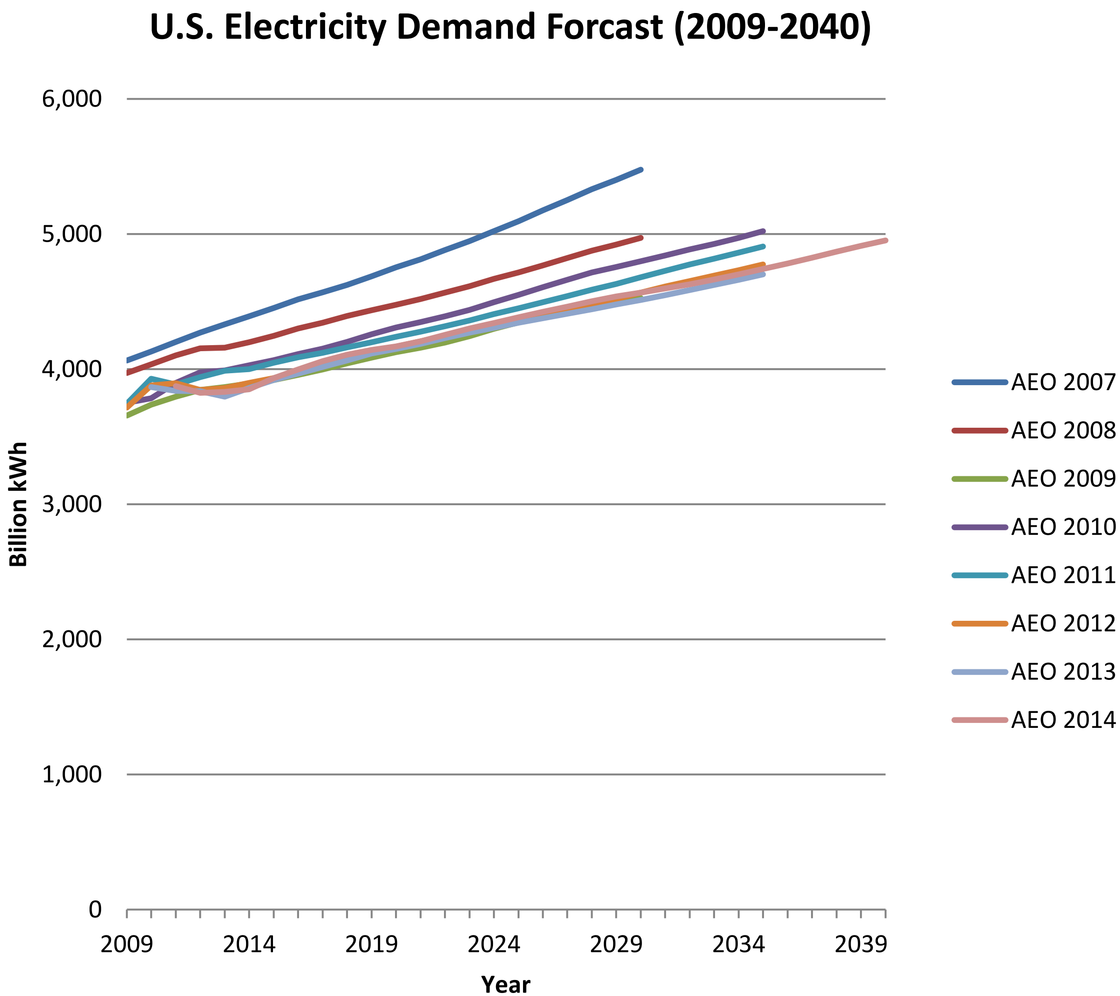
U.S. Generation Mix (Reference)



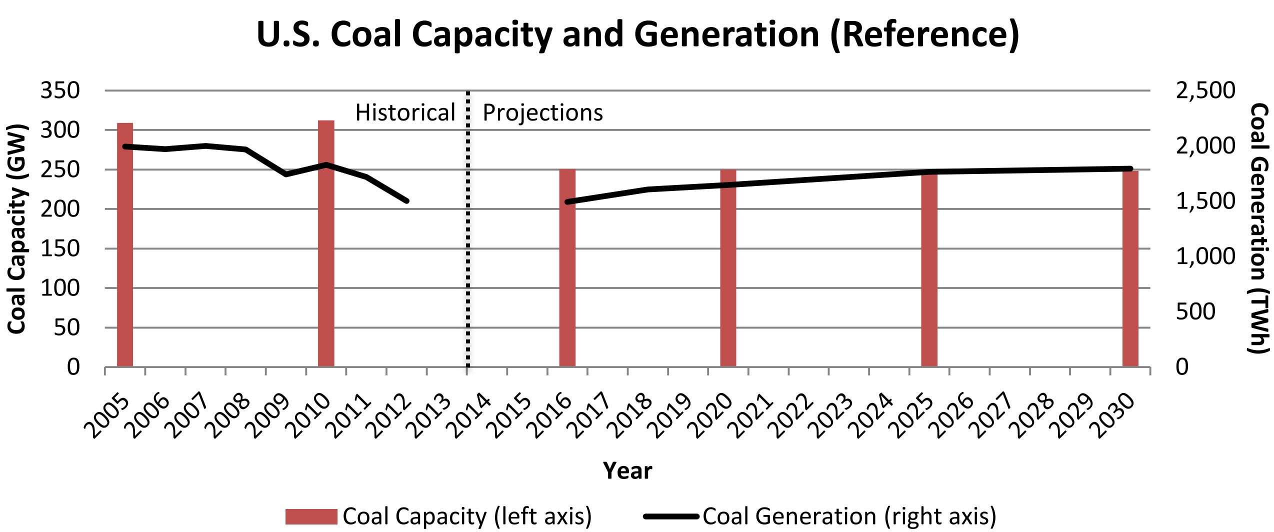
U.S. Average Minemouth Coal Price & Henry Hub Gas Price (Reference)

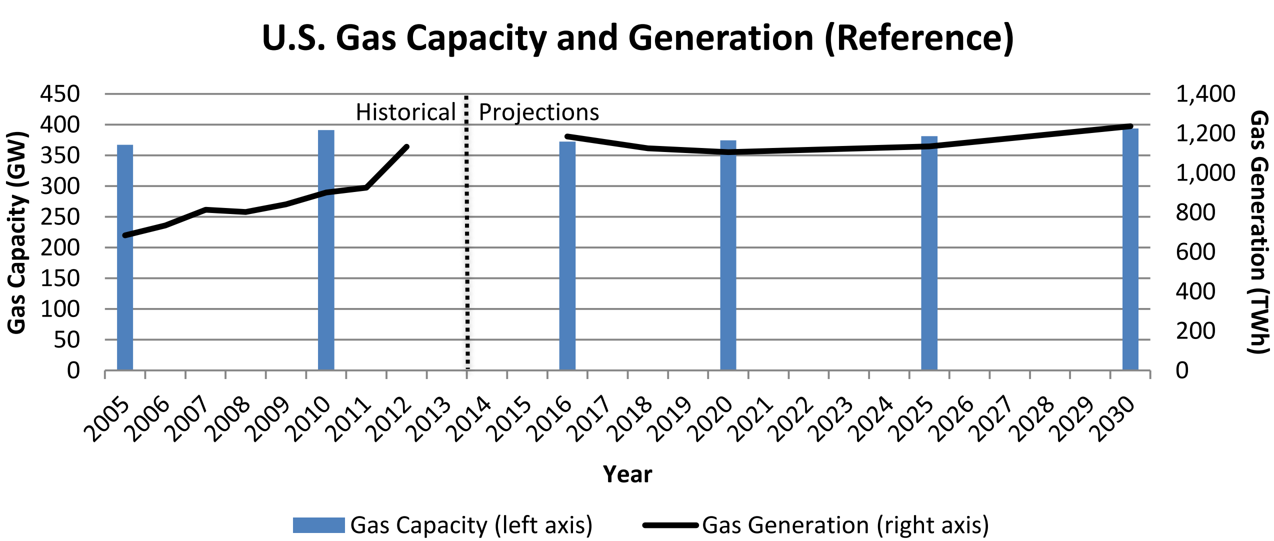


EIA: Energy Information Administration
GHG: Greenhouse Gas



- **Forecasts of the expected demand for electricity have continued to fall over recent years**





Reference (no GHG policy)

- **Even with significant coal retirements by 2016, coal generation holds steady**
- **Low electricity demand growth helps to dampens need for new capacity investment, even with significant retirements underway**

GHG: Greenhouse Gas

II. Modeled Policy Scenarios:
GHG regulation

No GHG Policy	GHG Policy	Sensitivities based on $12/ton
	Unit Retrofit	Low Gas $
		High Gas $
Reference	$12/ton	Low Nuclear
	$43/ton	High $ EE

Unit Retrofit

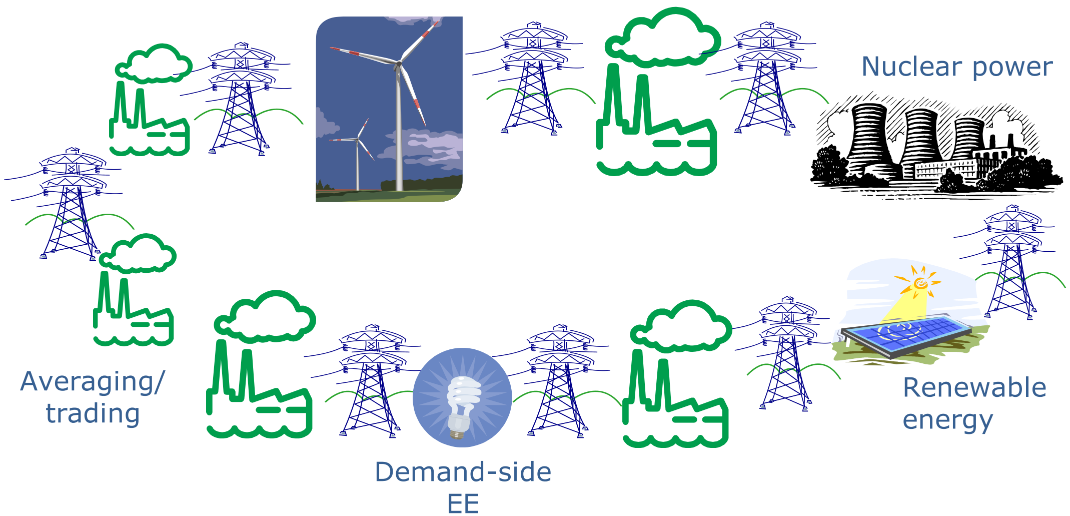
Limited flexibility
Stringency from on-site unit retrofits

Compliance options:
- plant efficiency investments
- modest natural gas co-firing
- modest biomass co-firing

Other policy scenarios

Full system-wide flexibility
Stringency set by reductions up to $/ton

Compliance options:
- plant efficiency, co-fire/conversions, plus
- shift to cleaner generation
- demand-side energy efficiency



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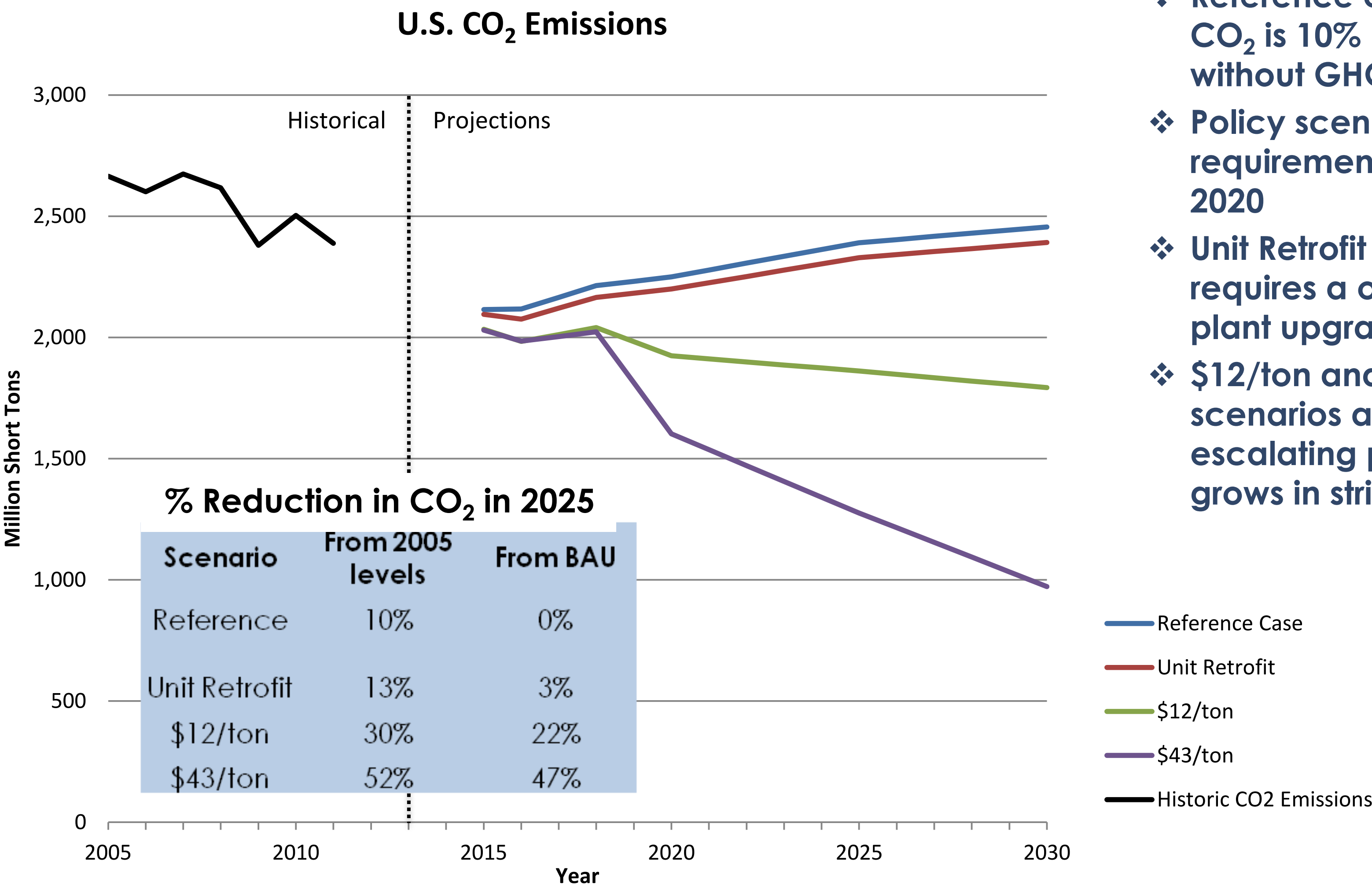
III. Results of Modeled Policy Scenarios



% Reduction in CO_2 in 2025

Scenario	From 2005 levels	From BAU
Reference	10%	0%
Unit Retrofit	13%	3%
$12/ton	30%	22%
$43/ton	52%	47%

- **Reference case 2025 CO_2 is 10% below 2005 without GHG policy**
- **Policy scenario requirements begin 2020**
- **Unit Retrofit scenario requires a one-time plant upgrade**
- **$12/ton and $43/ton scenarios apply an escalating price that grows in stringency**

CO_2: Carbon Dioxide
GHG: Greenhouse Gas

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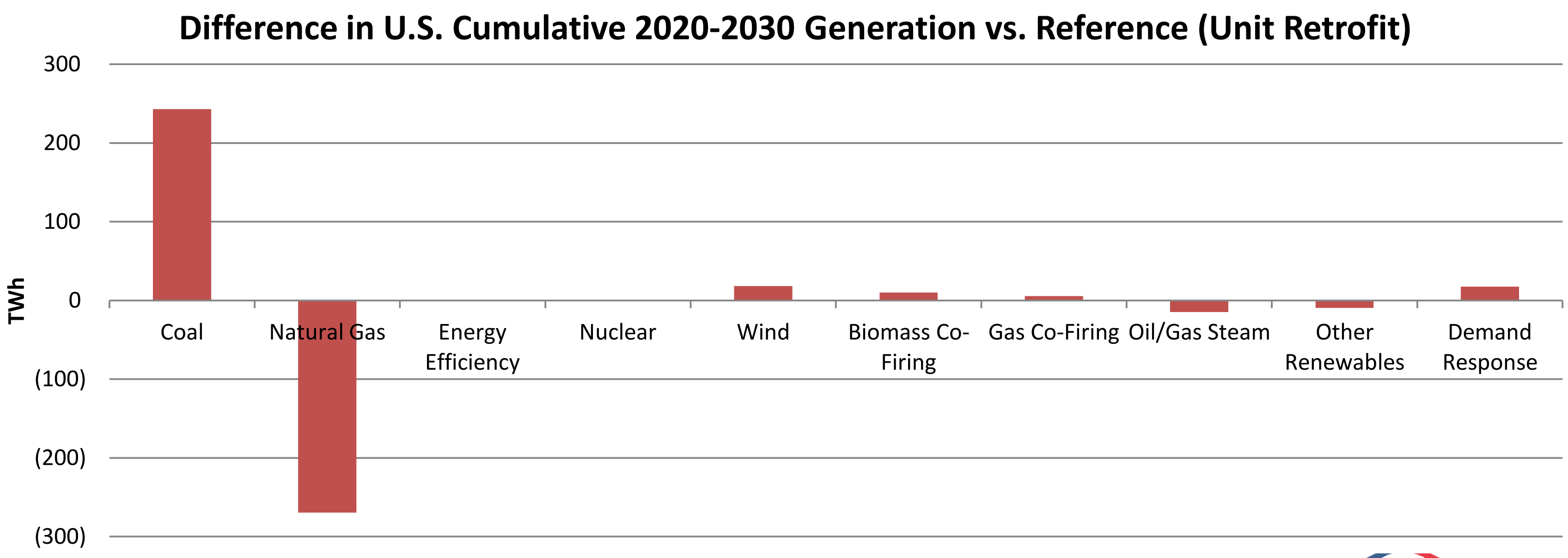
IV. Scenario 1: Unit Retrofit

Unit Retrofit scenario: modest changes from Reference case

- **By 2025, 3% CO2 reduction compared reference (13% below 2005 level)**
- **Between 2020-2030:**
  - 1% increase in cumulative generation from coal
    - Plant efficiency upgrades = more electricity generated per ton of coal
  - 2% decrease in gas generation
    - Plant upgrades at coal units allow them to better compete with gas
  - Slightly fewer coal retirements (2 GW fewer 2015-2030)



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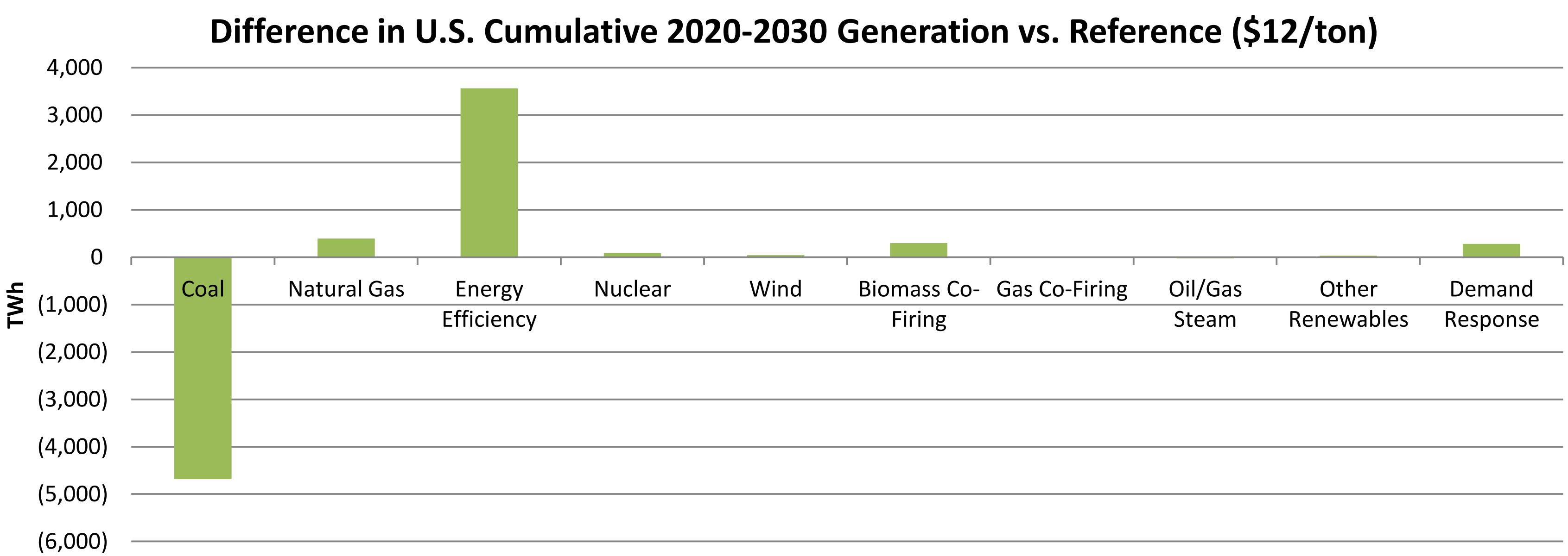
V. Scenario 2: $12/ton

$12/ton scenario: significant changes from Reference case

- **By 2025, 30% CO_2 reduction from 2005 level**
- **Between 2020-2030:**
  - 25% decrease in cumulative generation from coal
  - Demand-side efficiency makes up for >¾ of the coal decrease
  - Modest increase in natural gas generation and biomass co-firing
  - 69 GW of additional coal retirements in 2015-2030



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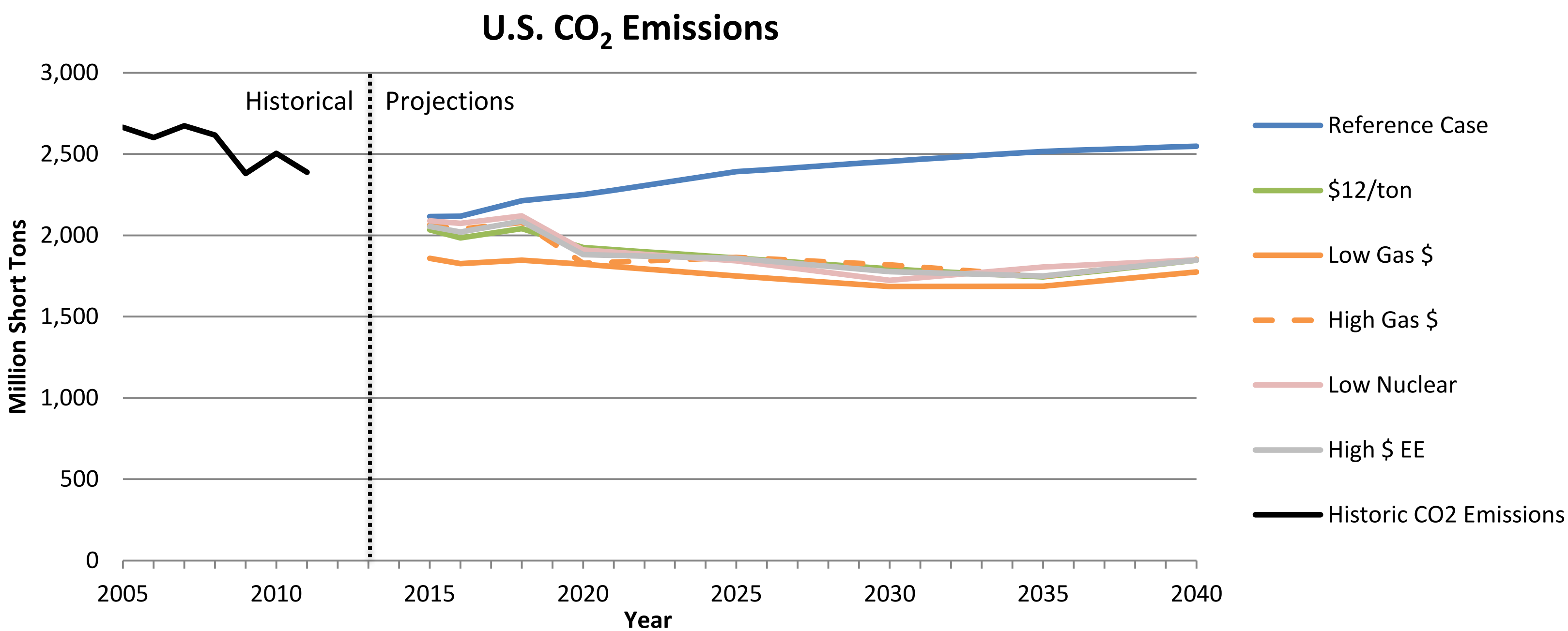
VI. Relative influence of key drivers

Natural gas prices
Cost/availability of demand-side EE
Fate of existing nuclear fleet

Sensitivity runs vary assumptions to understand relative impacts

- Implemented as an emissions cap set at 2020-2040 CO_2 trajectory from $12/ton policy scenario, with national emissions trading & banking
- Four sensitivity cases – high and low natural gas price, high-cost energy efficiency, and additional retirement of existing nuclear plants

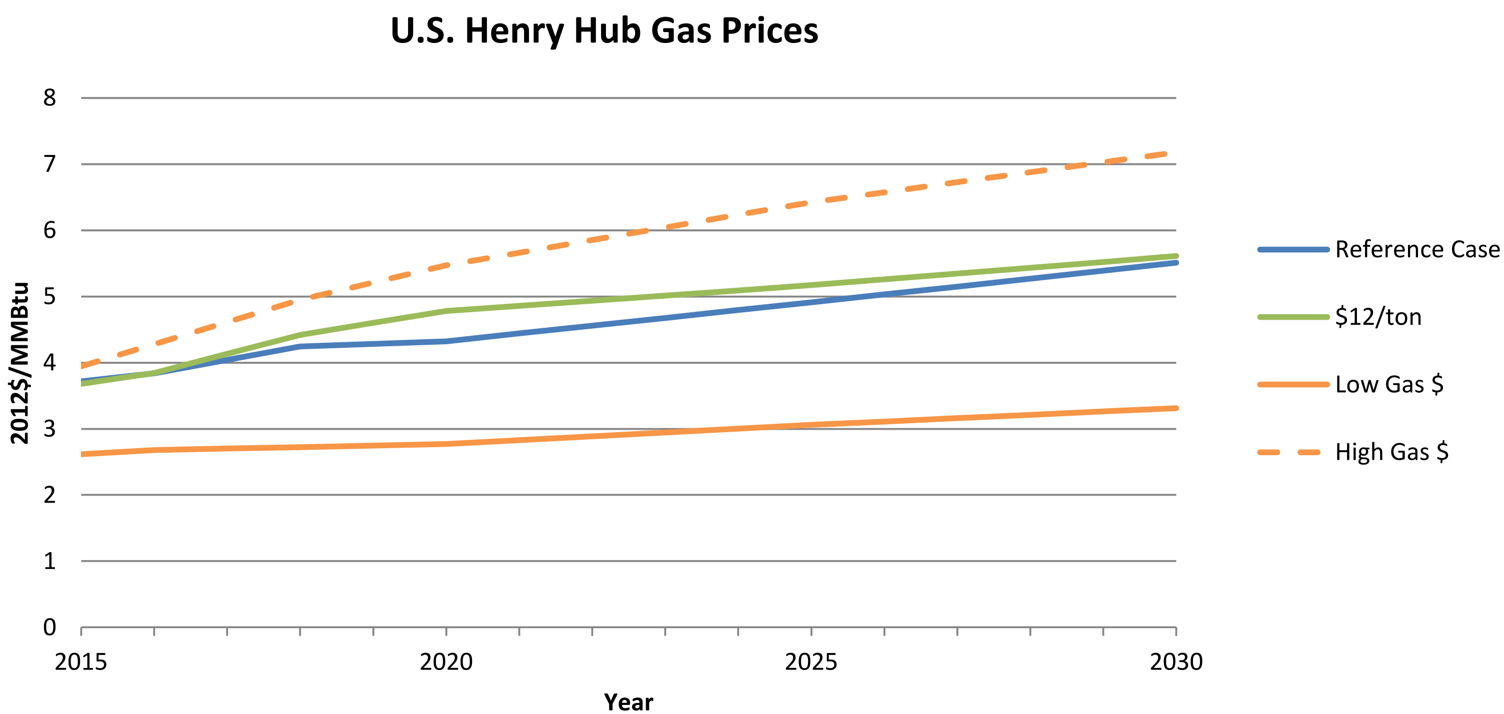


- The cap is not binding in the low gas price case – the low gas price drives CO_2 below the required level

CO_2: Carbon Dioxide

Natural Gas Price

- Natural gas price is a key determinant of the generation mix and wholesale electricity prices
- High and low gas price sensitivities are based on EIA's AEO 2013 gas supply cases



EIA: Energy Information Administration
AEO: Annual Energy Outlook

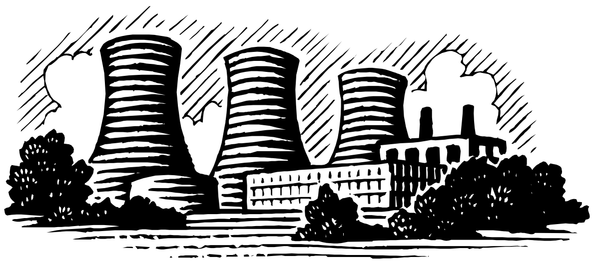
Demand Side Energy Efficiency

- **The cost & availability of demand side energy efficiency are critical in determining its influence as a §111(d) compliance option**
- **Estimates of the cost/availability of demand side energy efficiency vary***
  - LBNL, March 2014: 2.1 cents/KWh (range: <1 – 5 cents/KWh)
  - ACEEE, April 2014: 1.7-3.2 cents/KWh
  - NRDC based on Synapse (2011): 2.3-3.2 cents/KWh
  - ACCCE based on Alcott and Greenstone (2012): 11 cents/KWh
  - Studies vary in methodology. Most estimates include only program costs. Some, such as ACCCE, include total resource costs, which are ≈182% of program cost.
- **To test importance of demand-side EE cost, we varied the assumed cost**
  - $12/ton case: demand side EE is available to utility at 2.3-3.2 cents/KWh
  - High $ EE case: demand side EE is available to utility at 11 cents/KWh
  - If greater supply or lower cost (than 2.3-3.2 cents/KWh) EE is available, EE could play even stronger role in compliance and lower compliance cost

§111(d): Section 111(d) of Clean Air Act
NRDC: Natural Resources Defense Council
LBNL: Lawrence Berkeley National Laboratory
ACEEE: American Council for an Energy-Efficient Economy
ACCCE: American Coalition for Clean Coal Electricity

Existing Nuclear Fleet

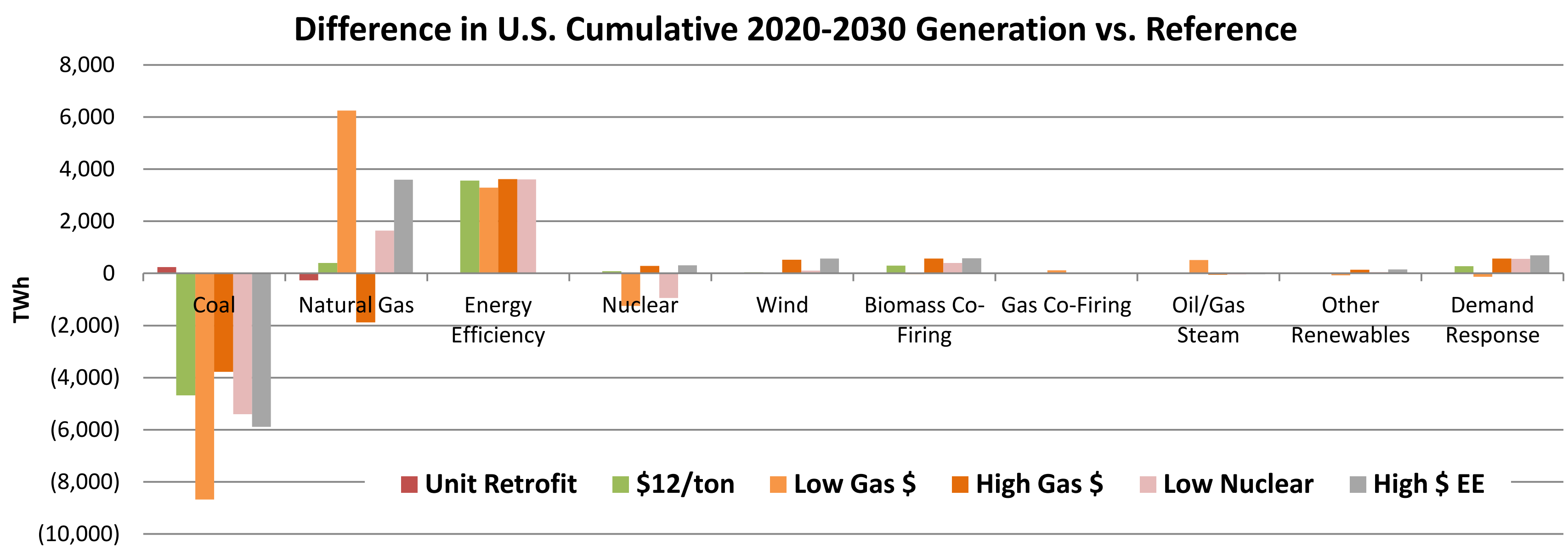
- **Market conditions may threaten the economics of nuclear plants, particularly merchant plants operating in competitive markets**
- **Retirement of existing nuclear facilities implies a loss of zero-carbon baseload power & will increase the cost of compliance for a given CO_2 reduction level**
- **To test the relative influence, the low nuclear sensitivity case assumes:**
  - An additional 7 GW of vulnerable nuclear plants retire in 2015-2016
    - In Reference case, 1 GW retire between 2015-2020
  - No existing nuclear plant is re-licensed at 60 years
    - Between 2015-2040, 51 GW nuclear capacity retires beyond the Reference case



CO_2: Carbon Dioxide

Relative impact of assumptions on generation choices

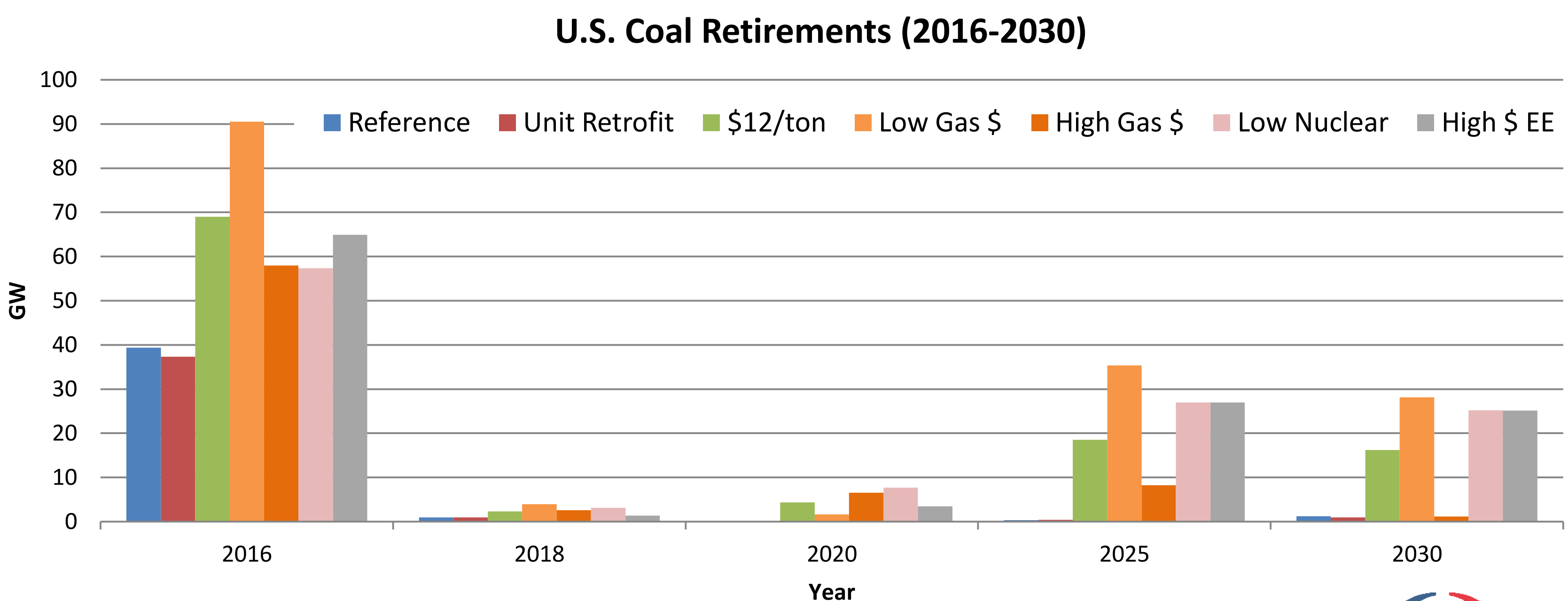
- **Gas price is a key driver of generation mix**
  - Low gas price reduces both coal and nuclear generation
  - High gas price replaces some gas use with coal, nuclear, wind, and biomass
- **At reasonable $, demand-side EE is primary compliance strategy**
  - Use of demand-side EE was consistent across scenarios
  - However, High $ EE (11 cents/KWh) resulted in *no* energy efficiency



GHG: Greenhouse Gas
EE: Energy Efficiency

Relative impact of assumptions on coal retirement

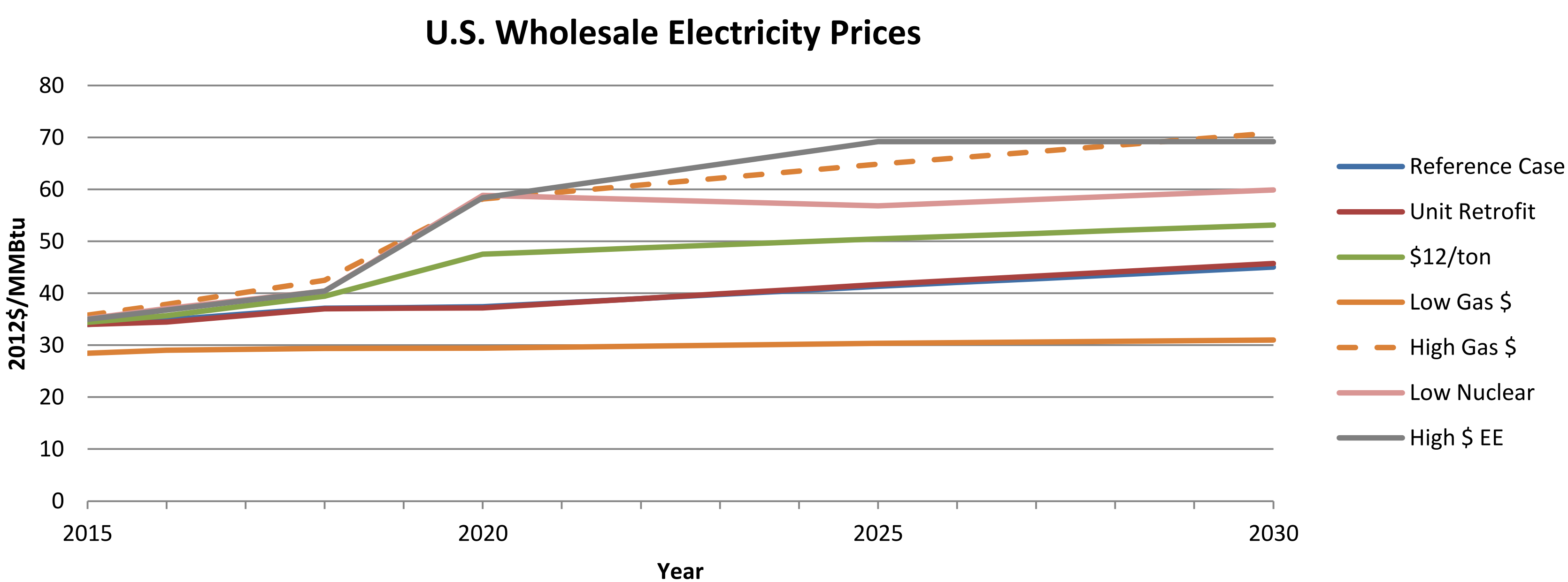
- ❖ **Retirements vary significantly depending on gas price**
  - Low gas price results in highest coal retirements in 2016 and later years
  - High gas price retires less coal than $12/ton scenario
- ❖ **Lack of demand side EE reductions delays some retirements**
  - Without the demand reductions achieved with demand side EE, the High $ EE case delays some coal retirements to later years



GHG: Greenhouse Gas
EE: Energy Efficiency

Relative impact of assumptions on wholesale electricity prices

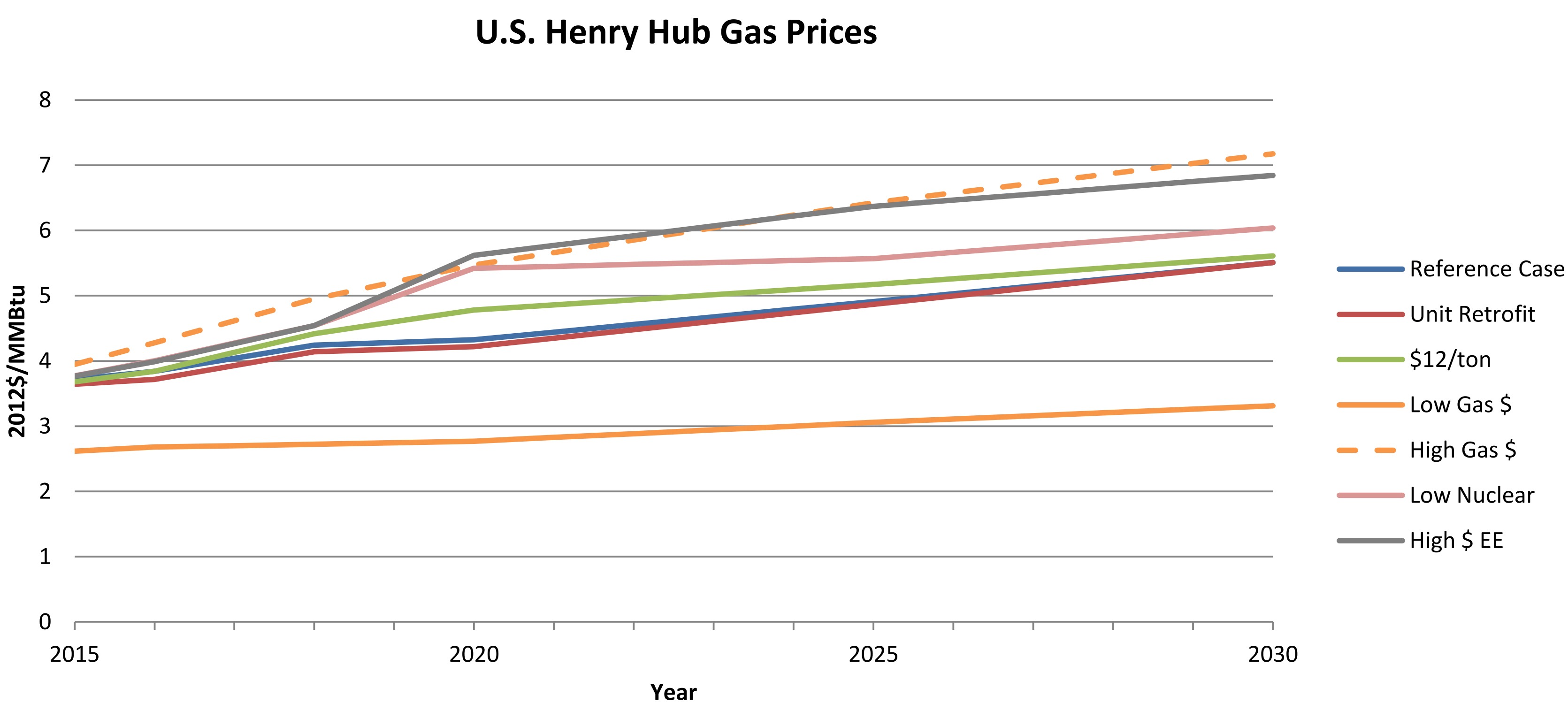
- **Lack of demand side EE results in the highest cost**
  - Because no EE is adopted with the High $ EE assumption, it is representative of a policy without flexibility to chose demand side EE
- **Wholesale price impacts of policy highly dependent on gas prices**
  - Low gas price results in lowest price and lowest CO_2
  - High gas price increases cost twice as much as GHG policy



EE: Energy Efficiency
GHG: Greenhouse Gas
CO_2: Carbon Dioxide

Relative impact of assumptions on natural gas prices

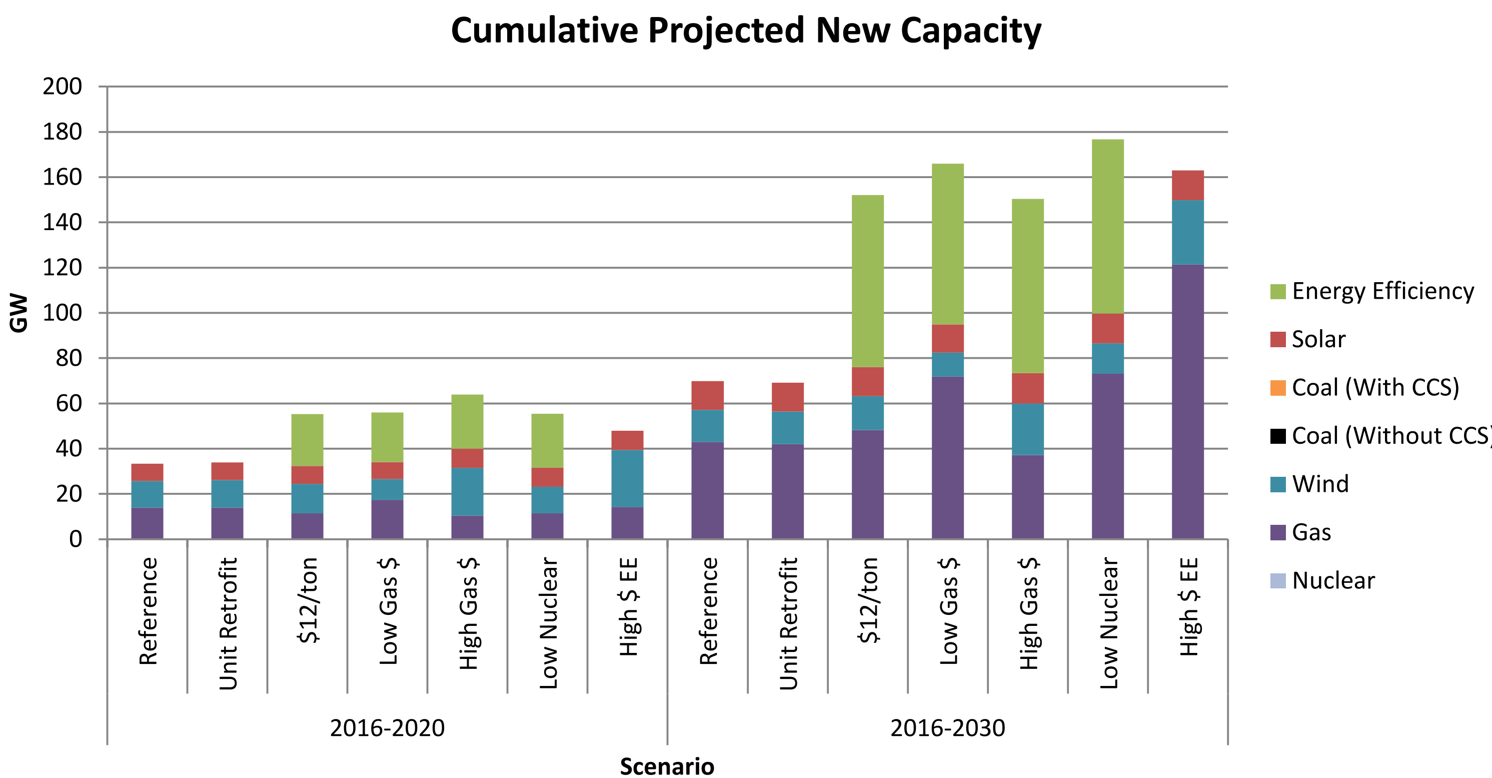
- **Natural gas prices in High Gas $ and Low Gas $ are imposed as an input**
  - In all other runs, gas prices are projected as an output
- **Lack of demand side EE as compliance option leads to highest gas prices**
  - Because, w/out EE, natural gas generation is primary compliance strategy



EE: Energy Efficiency

Relative impact of assumptions on projected new capacity

- **Without demand side EE, more new wind and gas generation gets built**
- **High gas prices limit construction of new gas generation**
  - Instead, rely more on new wind and existing coal

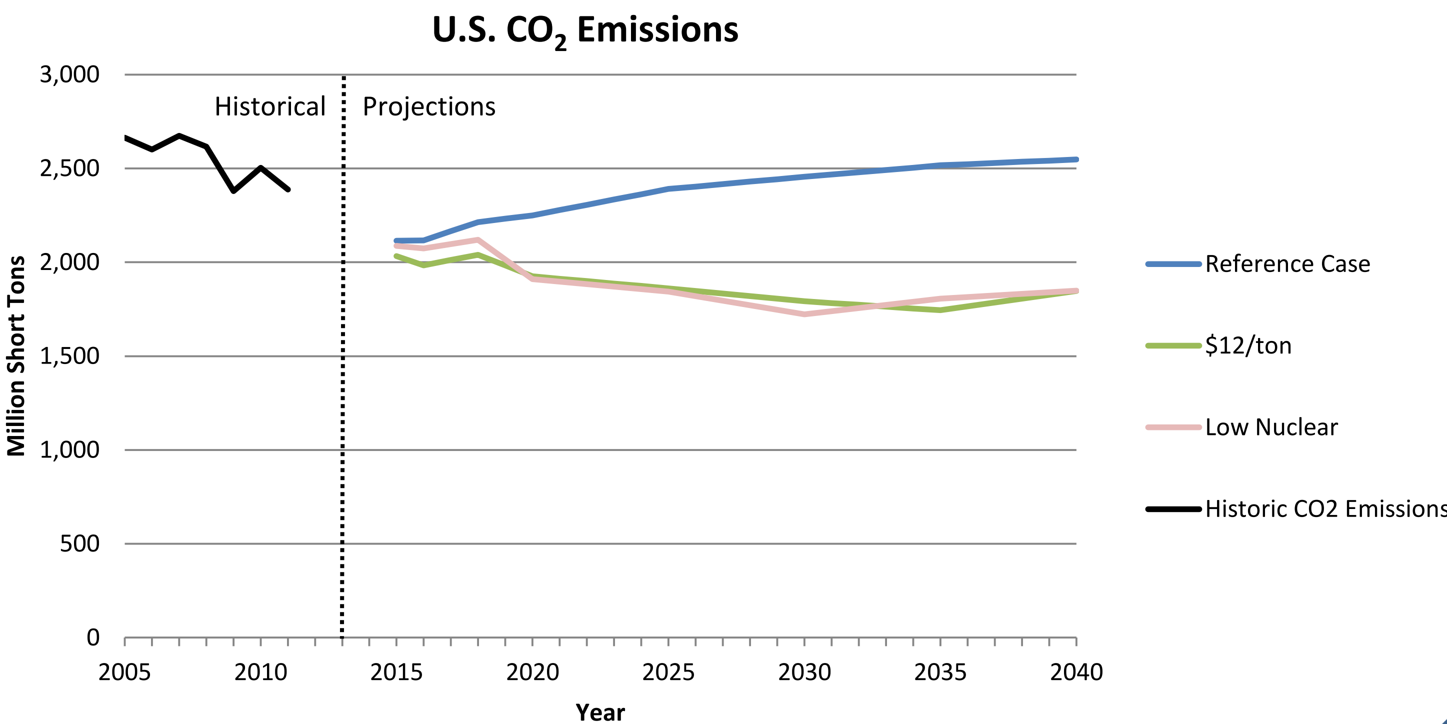


*Firm planned new capacity is included in modeling assumptions and not projected new capacity

EE: Energy Efficiency

Impact of extra nuclear retirements on emissions and electricity prices

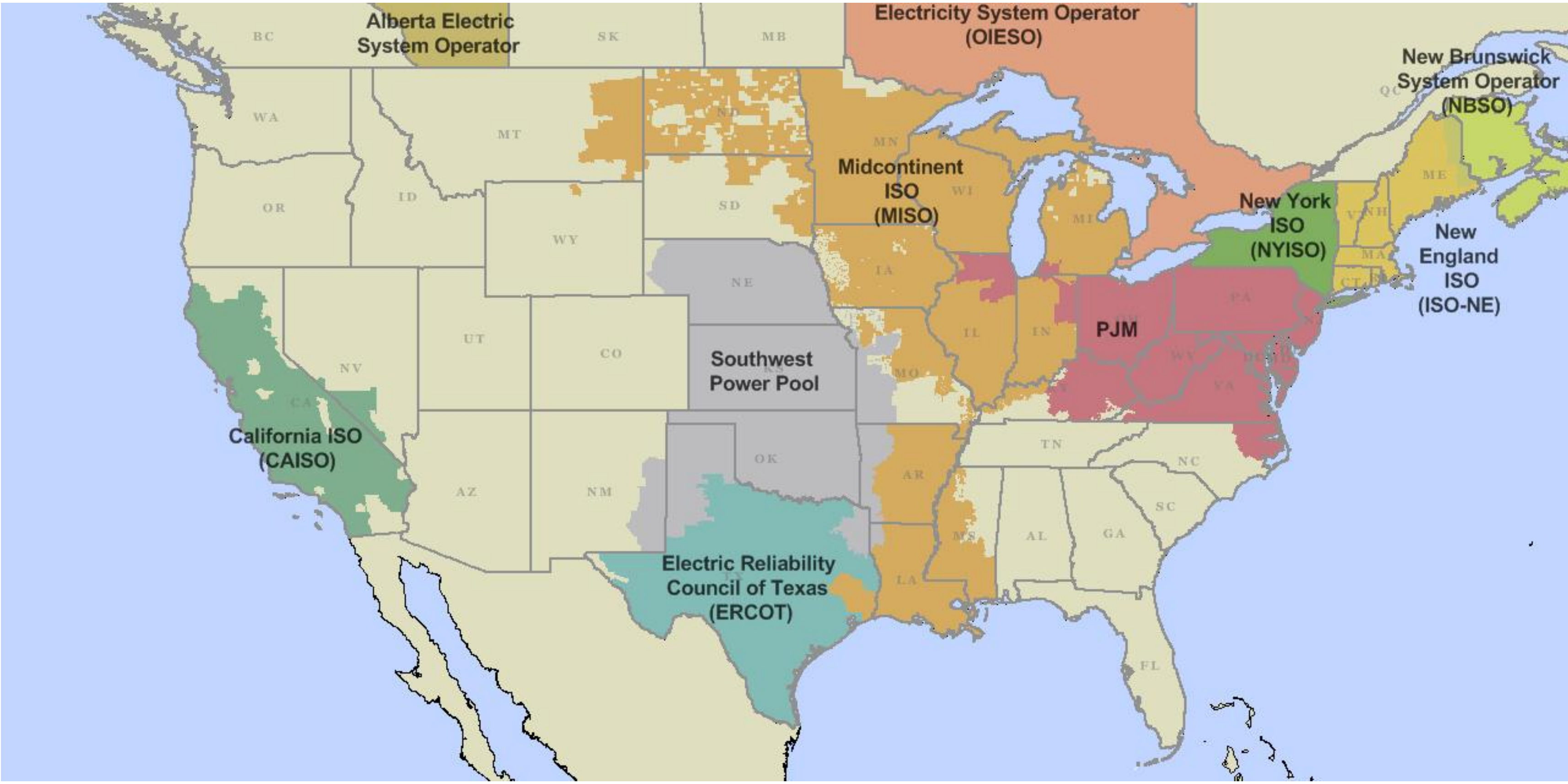
- Assumed 2016 drop in nuclear capacity & retirements at age 60, leads to average 15% increase in wholesale electricity prices between 2020-2030
- The timing flexibility of the emissions budget in the low nuclear case allows extra CO_2 reductions in the beginning to offset higher emissions later, when reductions are more expensive due to nuclear retirements



CO_2: Carbon Dioxide

VIII. Regional Impacts of Modeled Scenarios

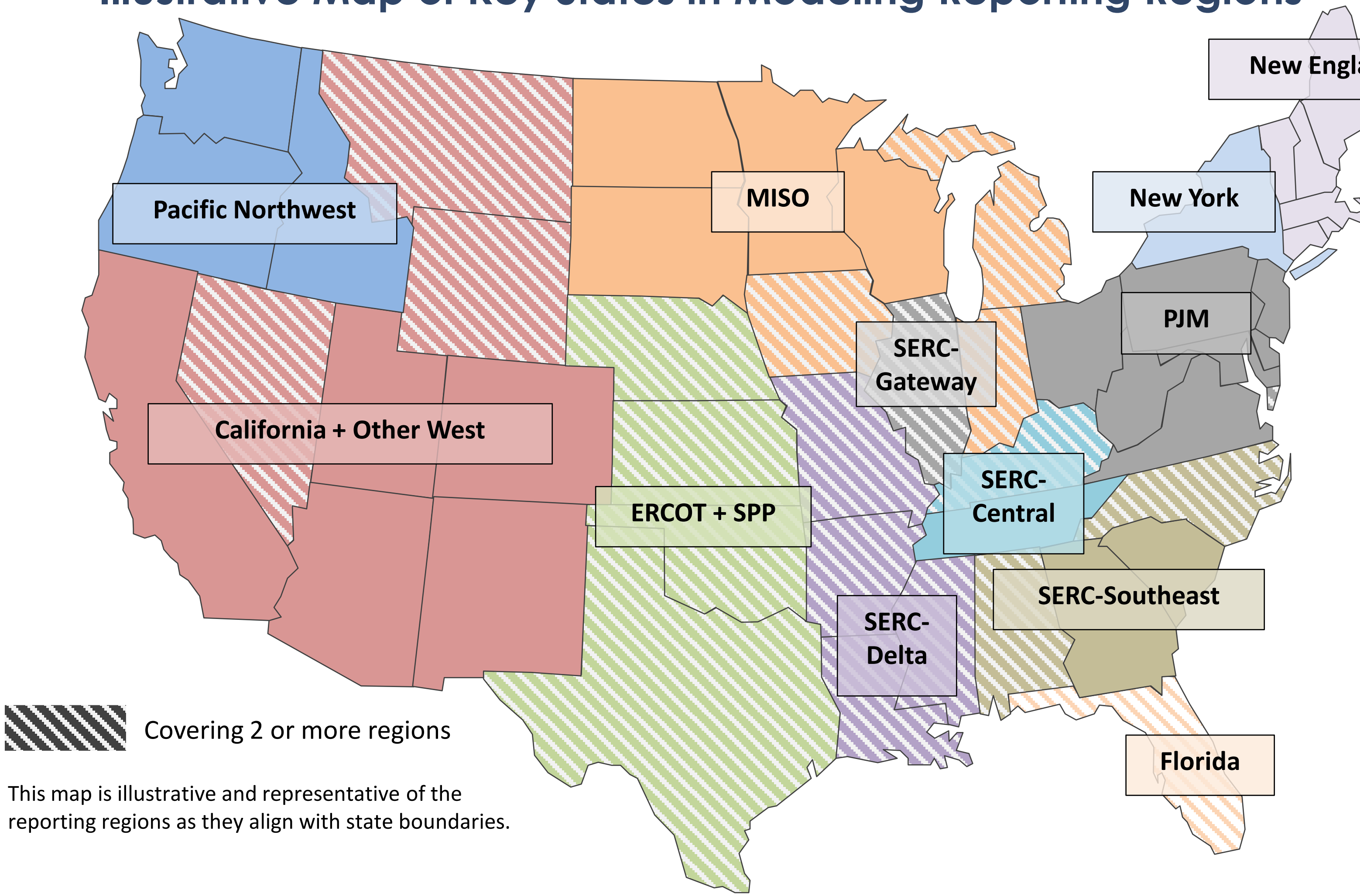
North American Regional Transmission Organizations



Source: FERC

- **Some Arkansas generating unit operations in**
  - Midcontinent Independent System Operator (MISO)
  - Southwest Power Pool (SPP)

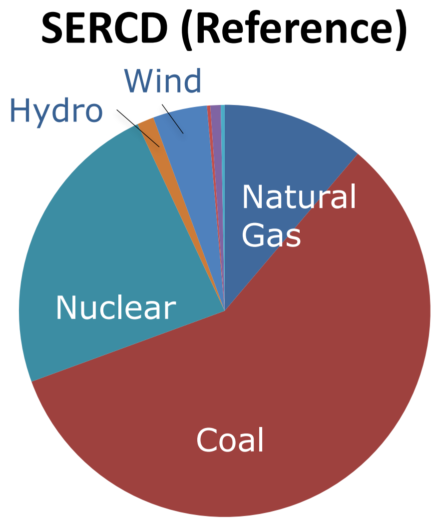
Illustrative Map of Key States in Modeling Reporting Regions

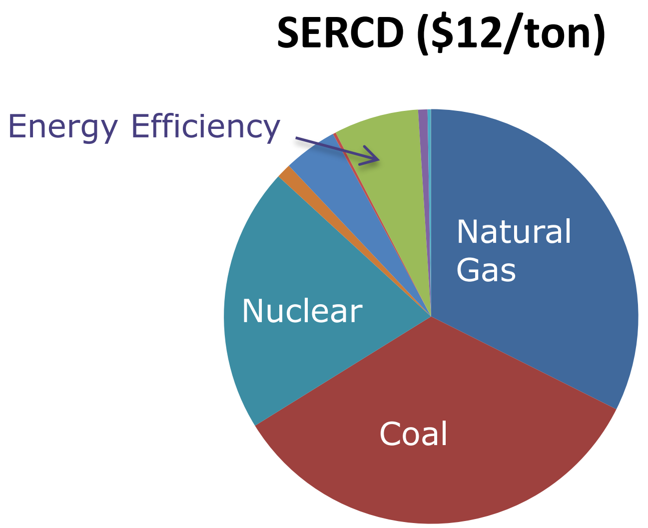


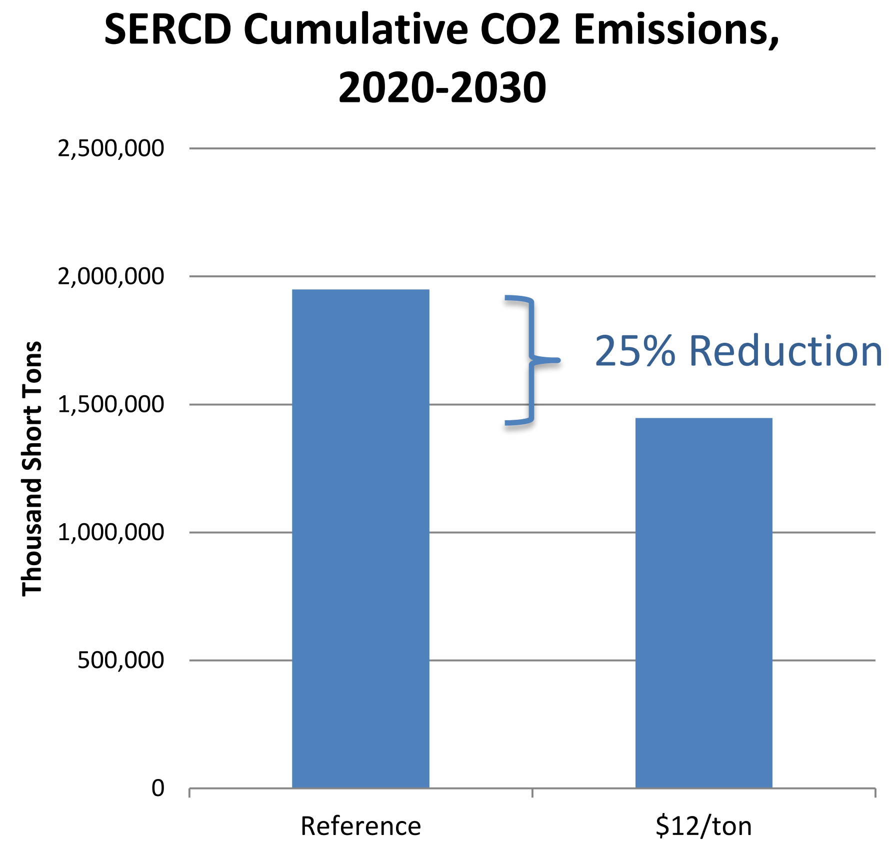
This map is illustrative and representative of the reporting regions as they align with state boundaries.

For purposes of reported regional results from this modeling exercise, electric generating units in Arkansas are included in “SERC-Delta” and “SPP” regional results.

Regional 2025 Generation Mix and Cumulative CO_2 Emissions

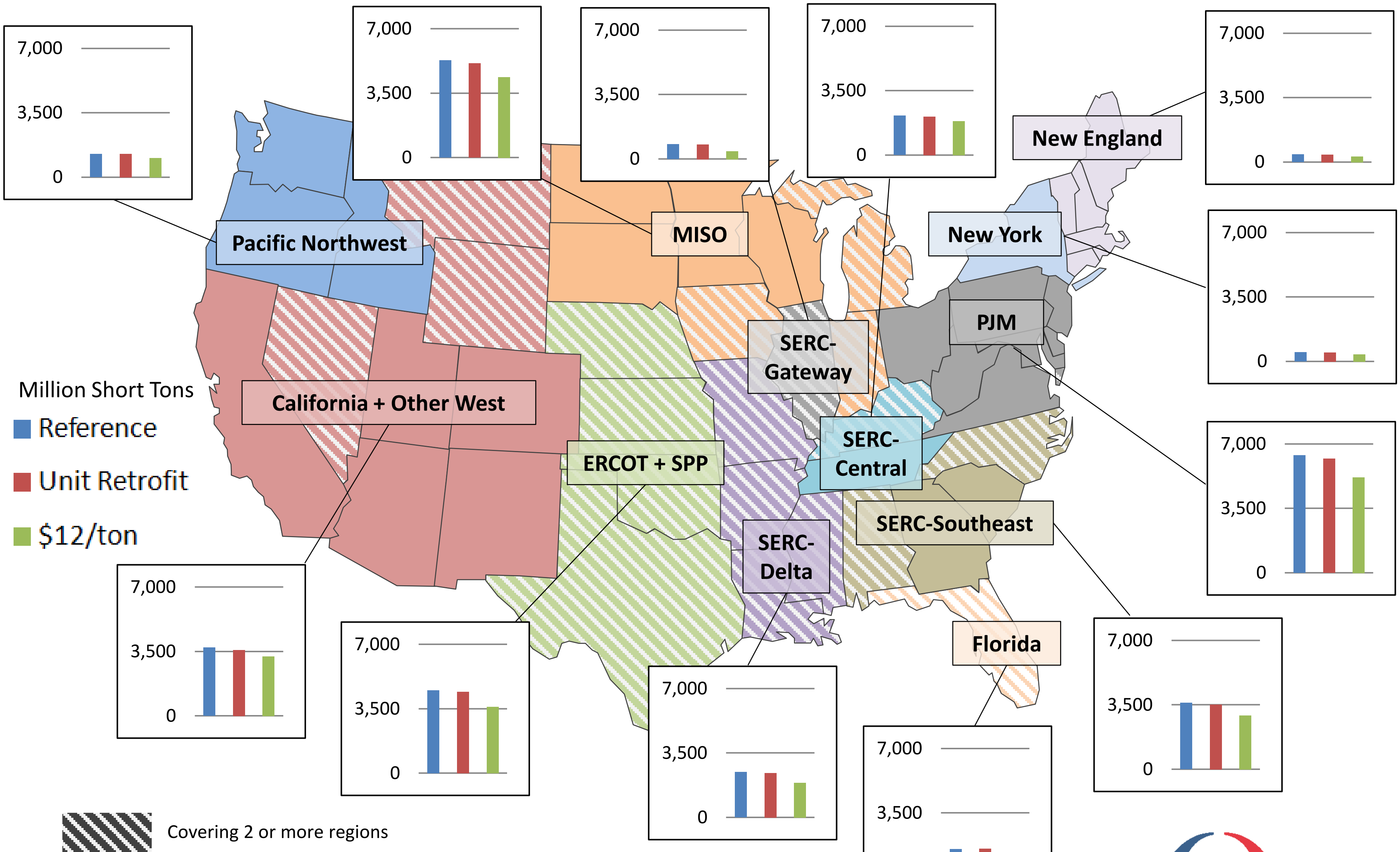






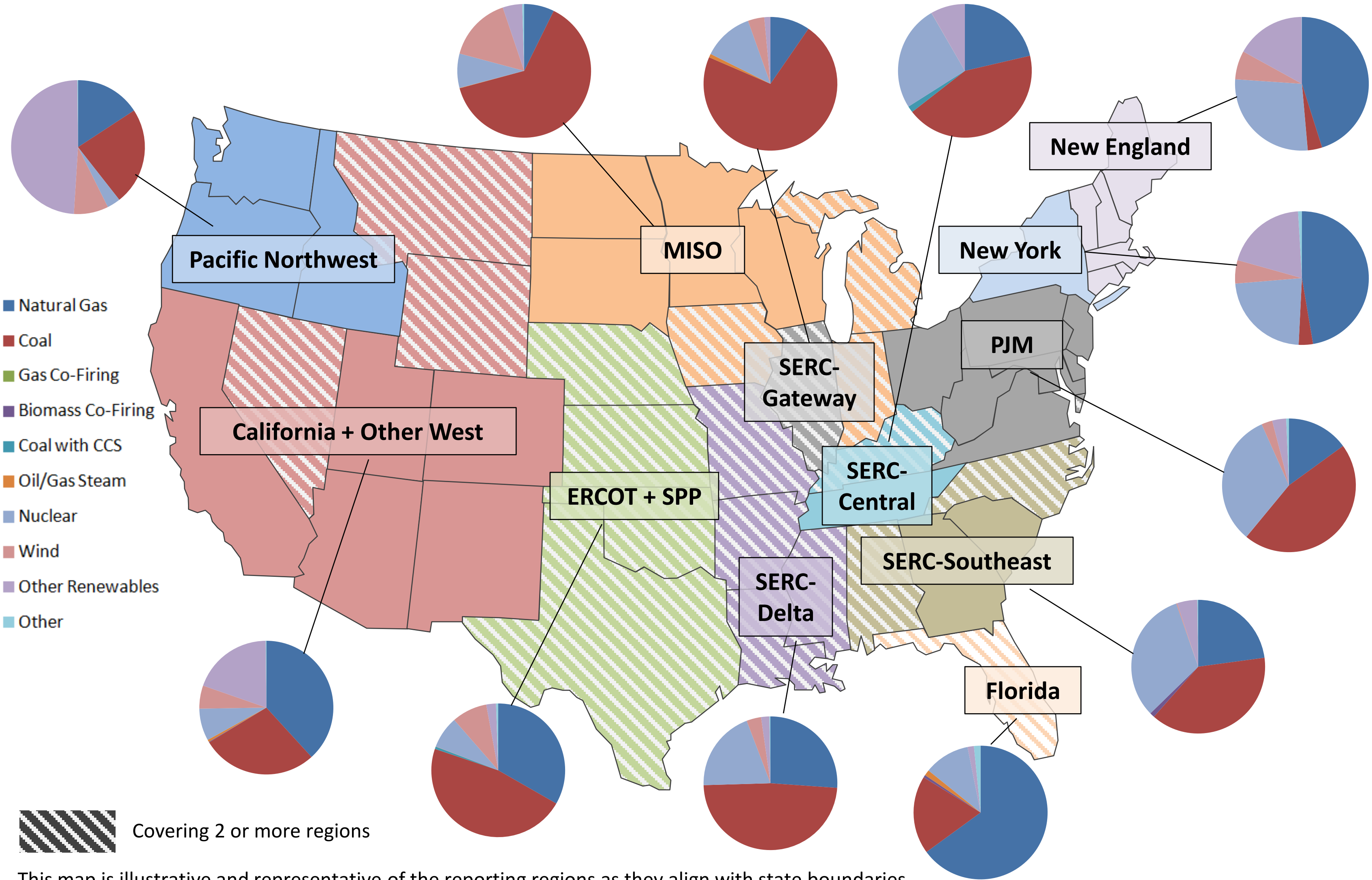
SERC-Delta reporting region includes part of Arkansas and LA, all of KS, & small parts of MO, OK, TX

CUMULATIVE CO_2 EMISSIONS IN REFERENCE, UNIT RETROFIT, AND $12/TON CASES (2016-2030)



This map is illustrative and representative of the reporting regions as they align with state boundaries. SERC-Gateway covers a portion of Illinois, Iowa, and Missouri.

Technical Appendix



This map is illustrative and representative of the reporting regions as they align with state boundaries. SERC-Gateway covers a portion of Illinois, Iowa, and Missouri.

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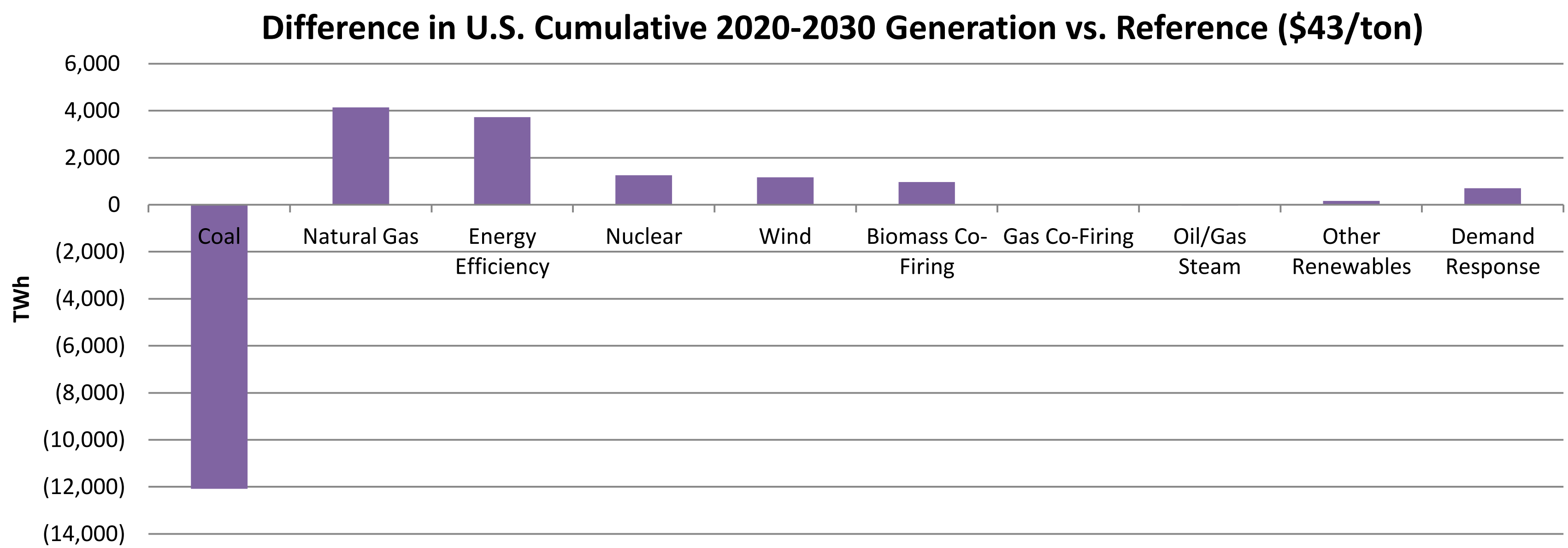
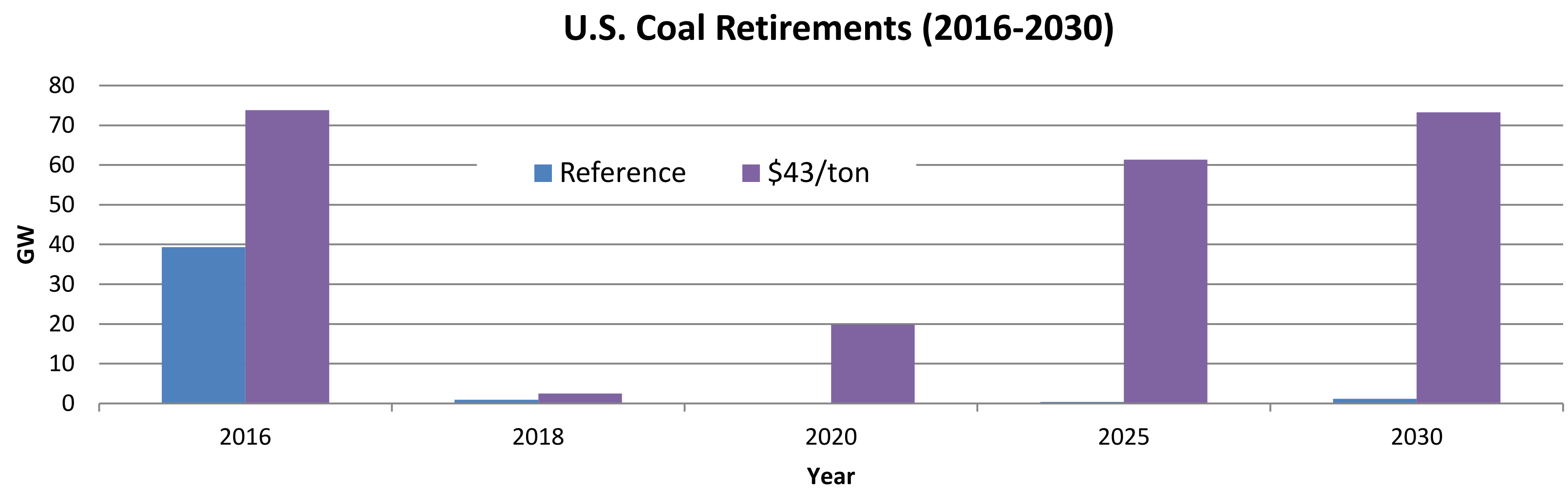
$43/ton: Major impacts on coal

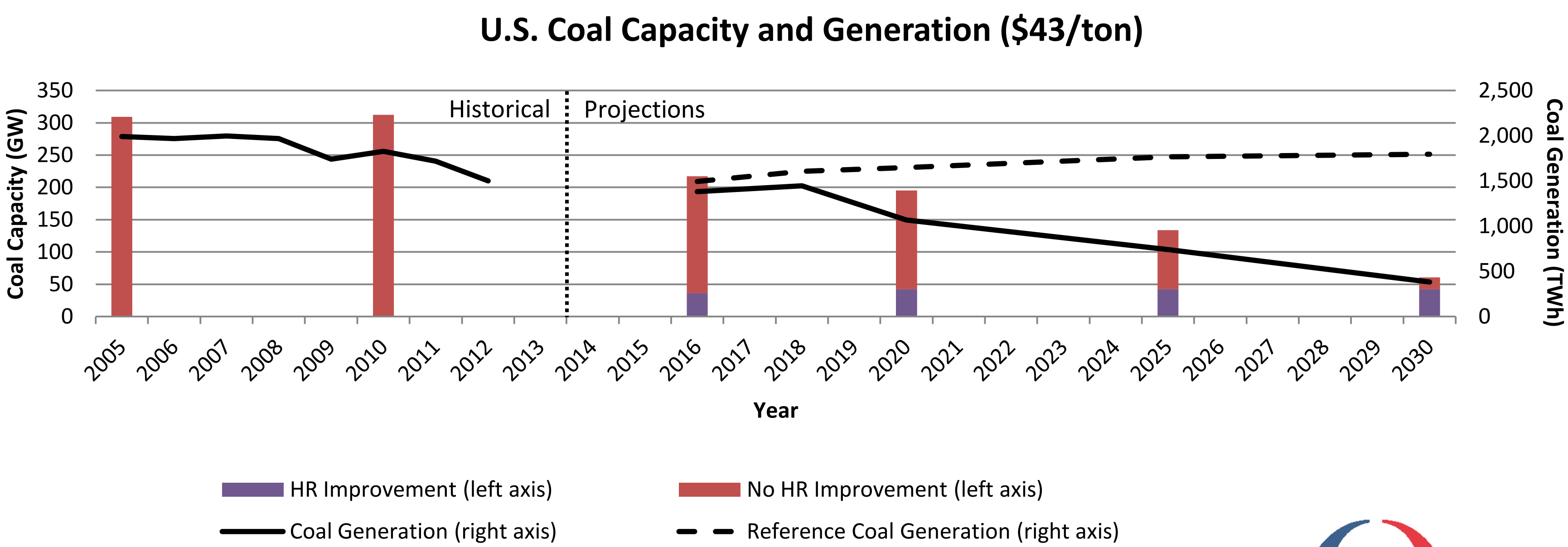
$43/ton scenario: major impacts

❖ Between 2020-2030:

- 64% decrease in cumulative generation from coal
- 33% increase in gas generation
- Significant demand side energy efficiency nearly maxes out the assumed supply
- Some additional demand reduction in response to higher electricity price
- Wholesale electricity price increases by 83% in 2025
- Additional 189 GW of coal retirement through 2015-2030




U.S. Coal Retirements (2016-2030)
Reference
$43/ton
GW
0
10
20
30
40
50
60
70
80
2016
2018
2020
2025
2030
Year


U.S. Coal Capacity and Generation ($43/ton)
Historical
Projections
Coal Capacity (GW)
Coal Generation (TWh)
0
50
100
150
200
250
300
350
0
500
1,000
1,500
2,000
2,500
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
Year
HR Improvement (left axis)
No HR Improvement (left axis)
Coal Generation (right axis)
Reference Coal Generation (right axis)

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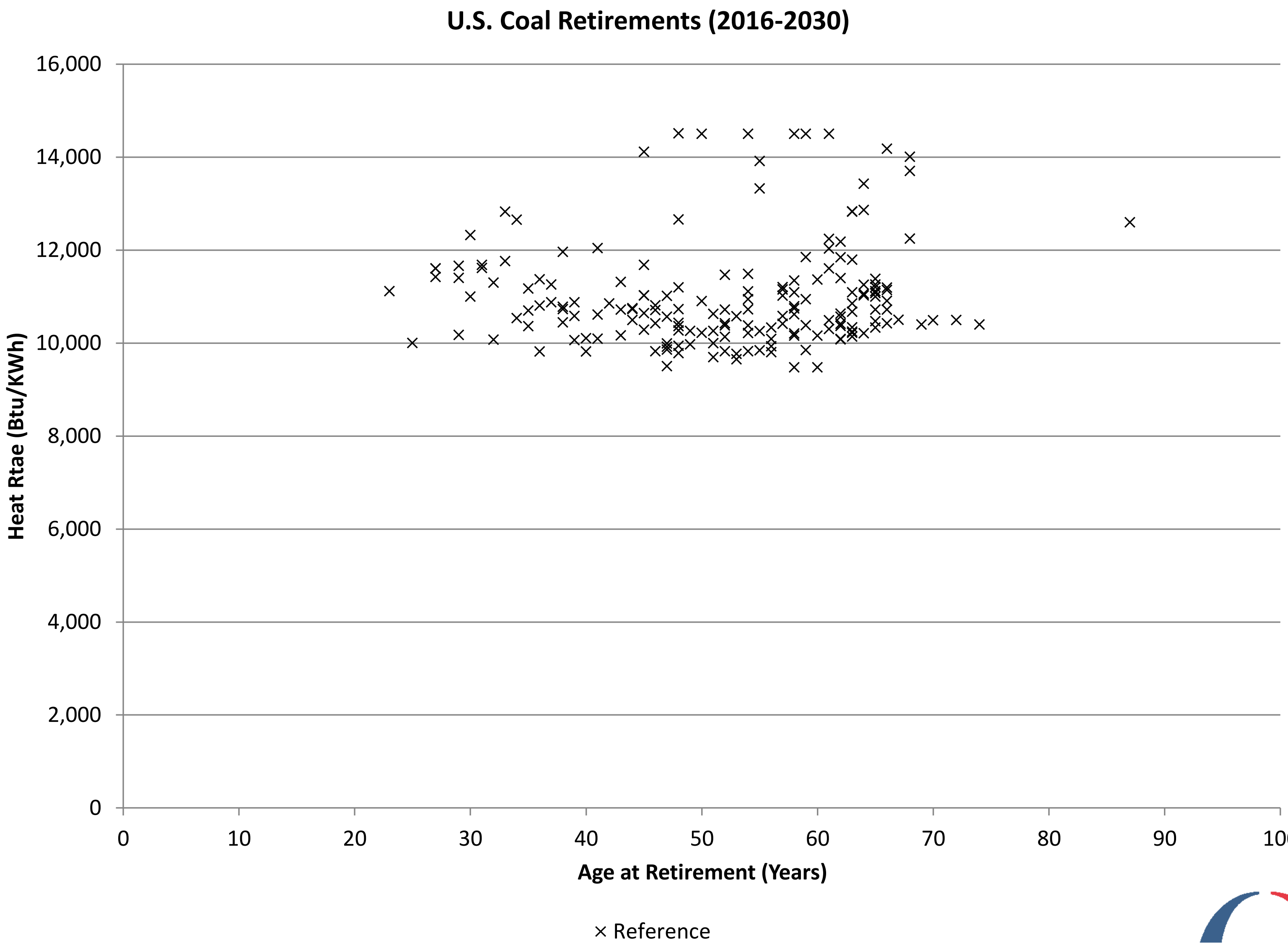
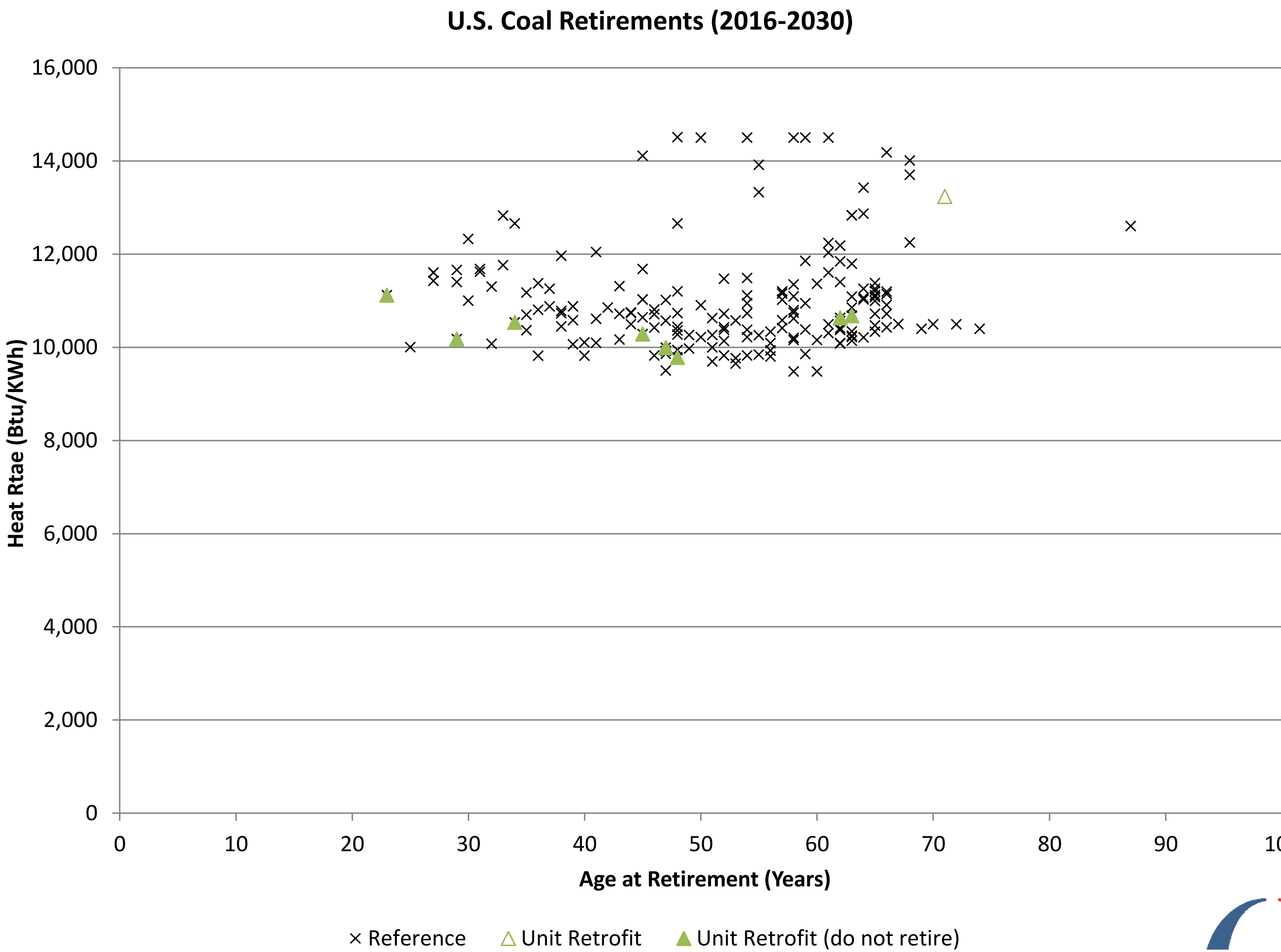
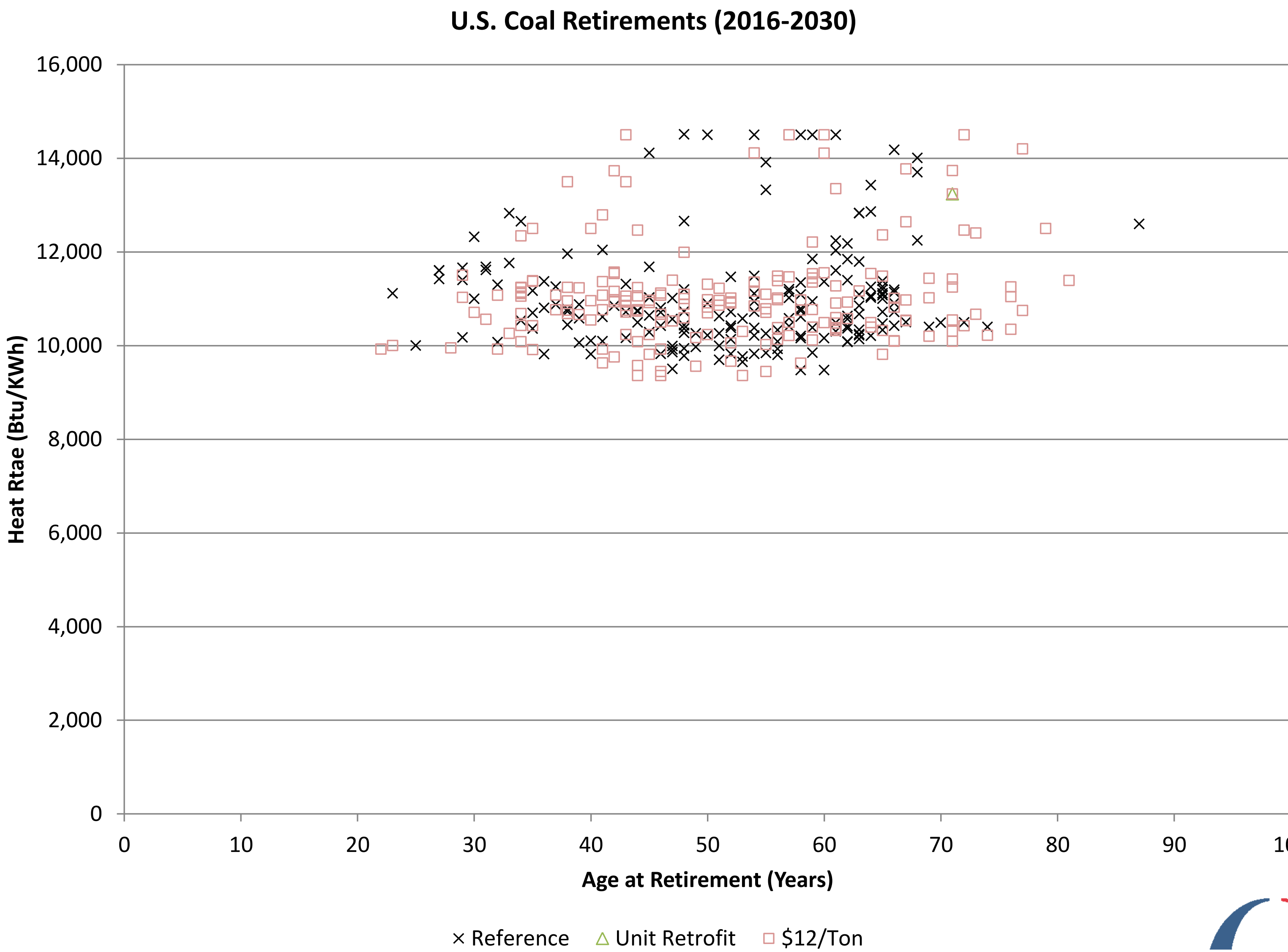
Comparison of Coal Retirement Impacts

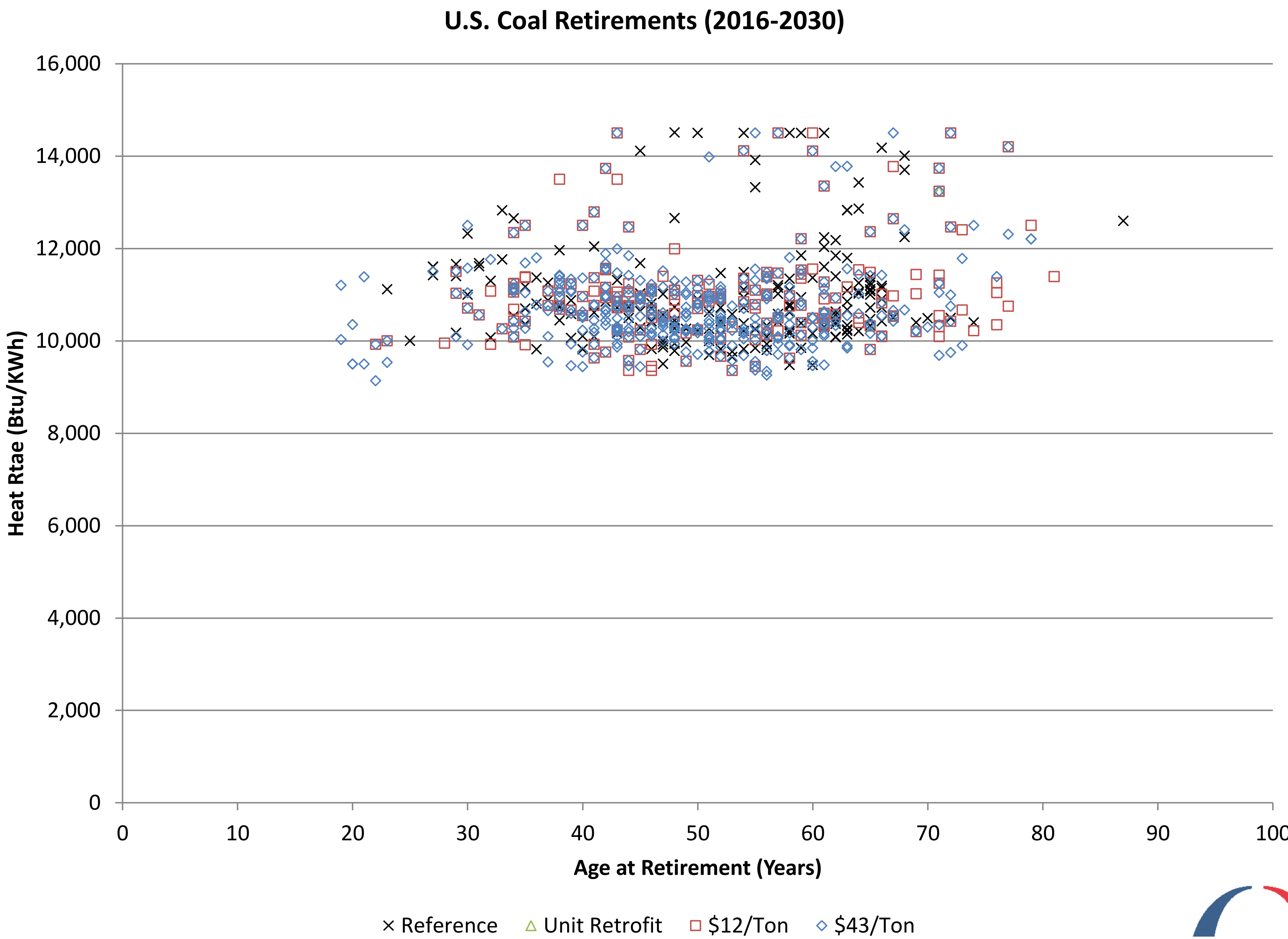
For various scenarios
By heat rate and age at retirement


U.S. Coal Retirements (2016-2030)
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
Heat Rtae (Btu/KWh)
0
10
20
30
40
50
60
70
80
90
100
Age at Retirement (Years)
Reference



*Fewer retirements in Unit Retrofit compared with Reference


U.S. Coal Retirements (2016-2030)
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
Heat Rtae (Btu/KWh)
0
10
20
30
40
50
60
70
80
90
100
Age at Retirement (Years)
× Reference
△ Unit Retrofit
□ $12/Ton


U.S. Coal Retirements (2016-2030)
Heat Rtae (Btu/KWh)
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
0
10
20
30
40
50
60
70
80
90
100
Age at Retirement (Years)
Reference
Unit Retrofit
$12/Ton
$43/Ton

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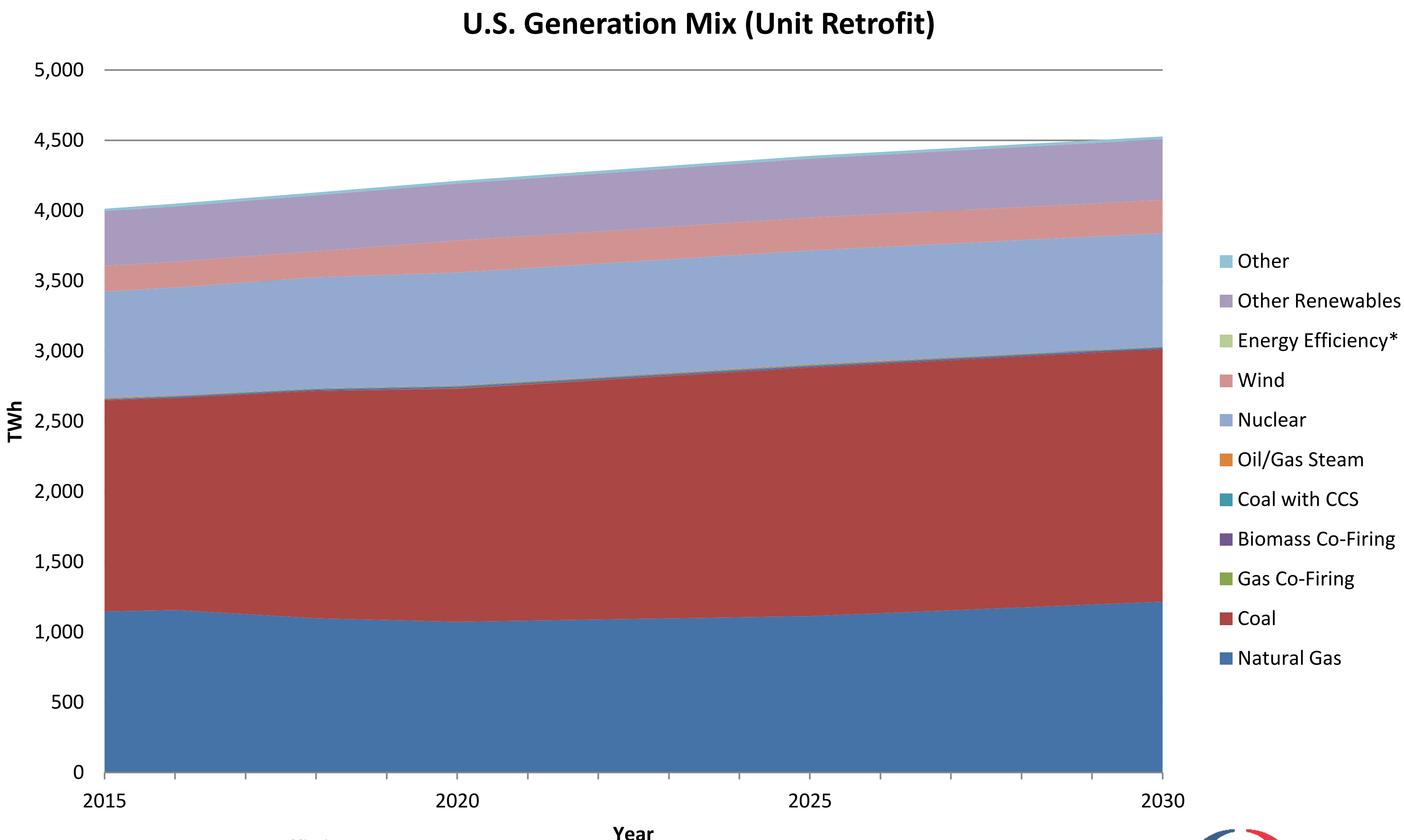
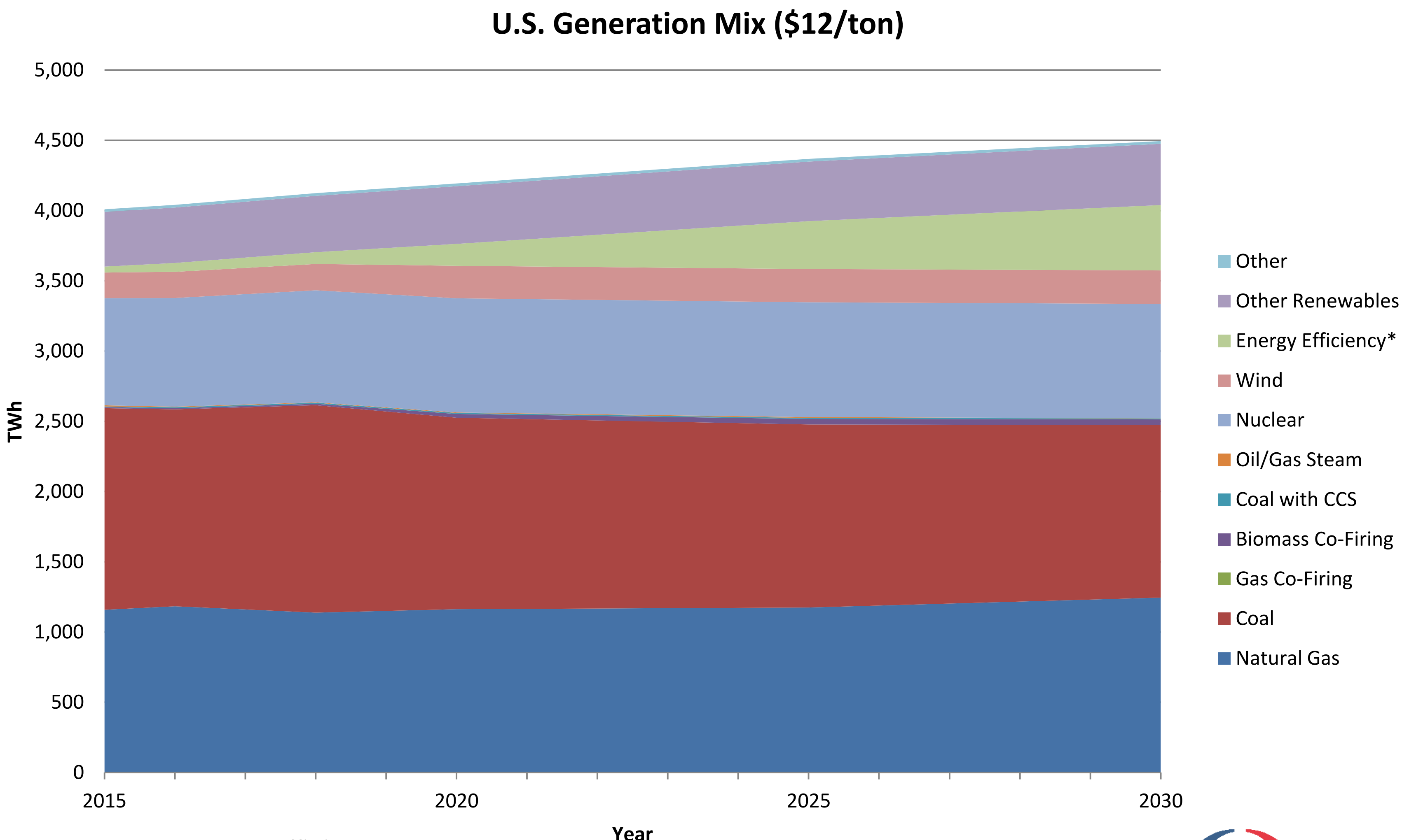
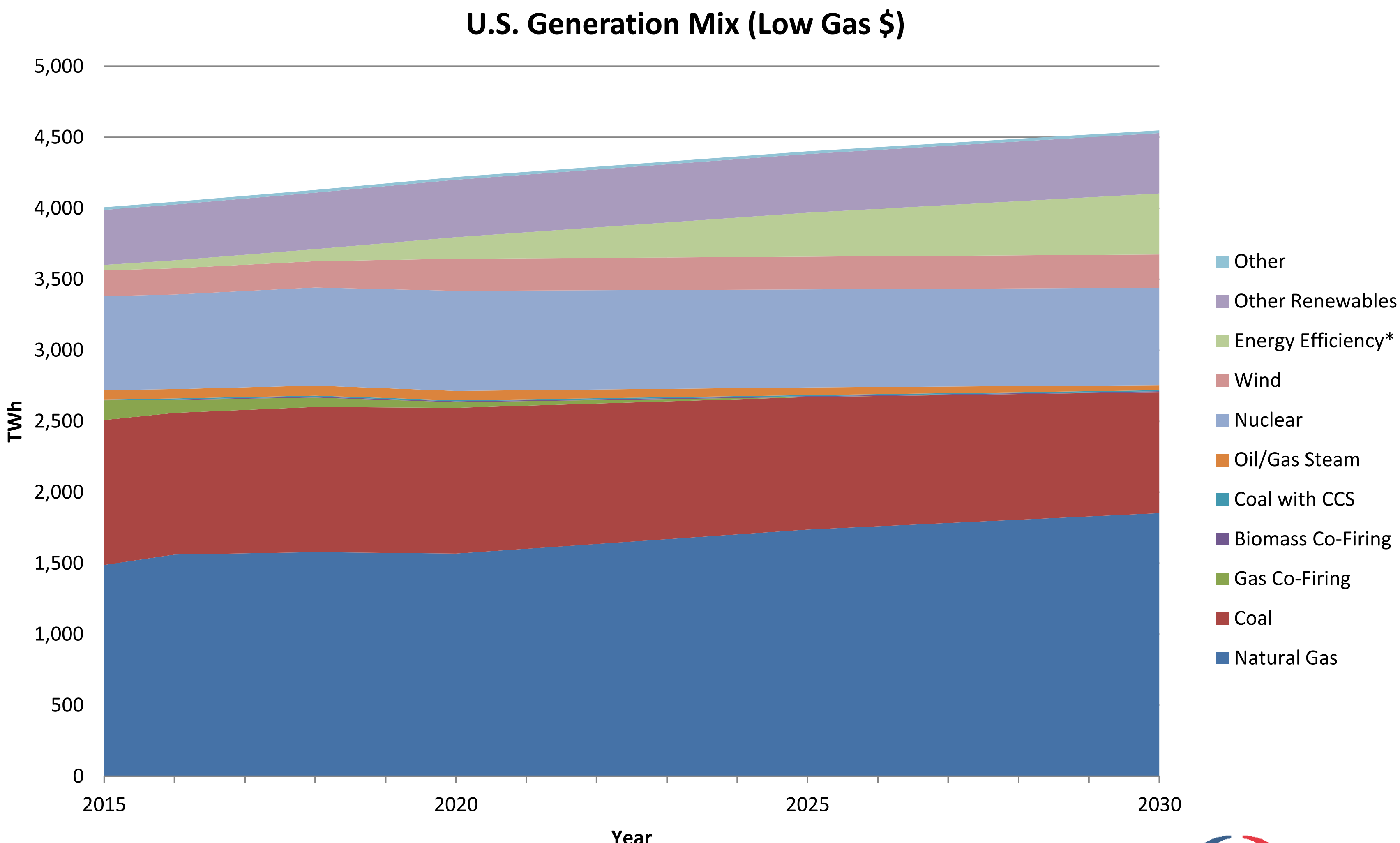
Generation Mix from Modeled Scenarios



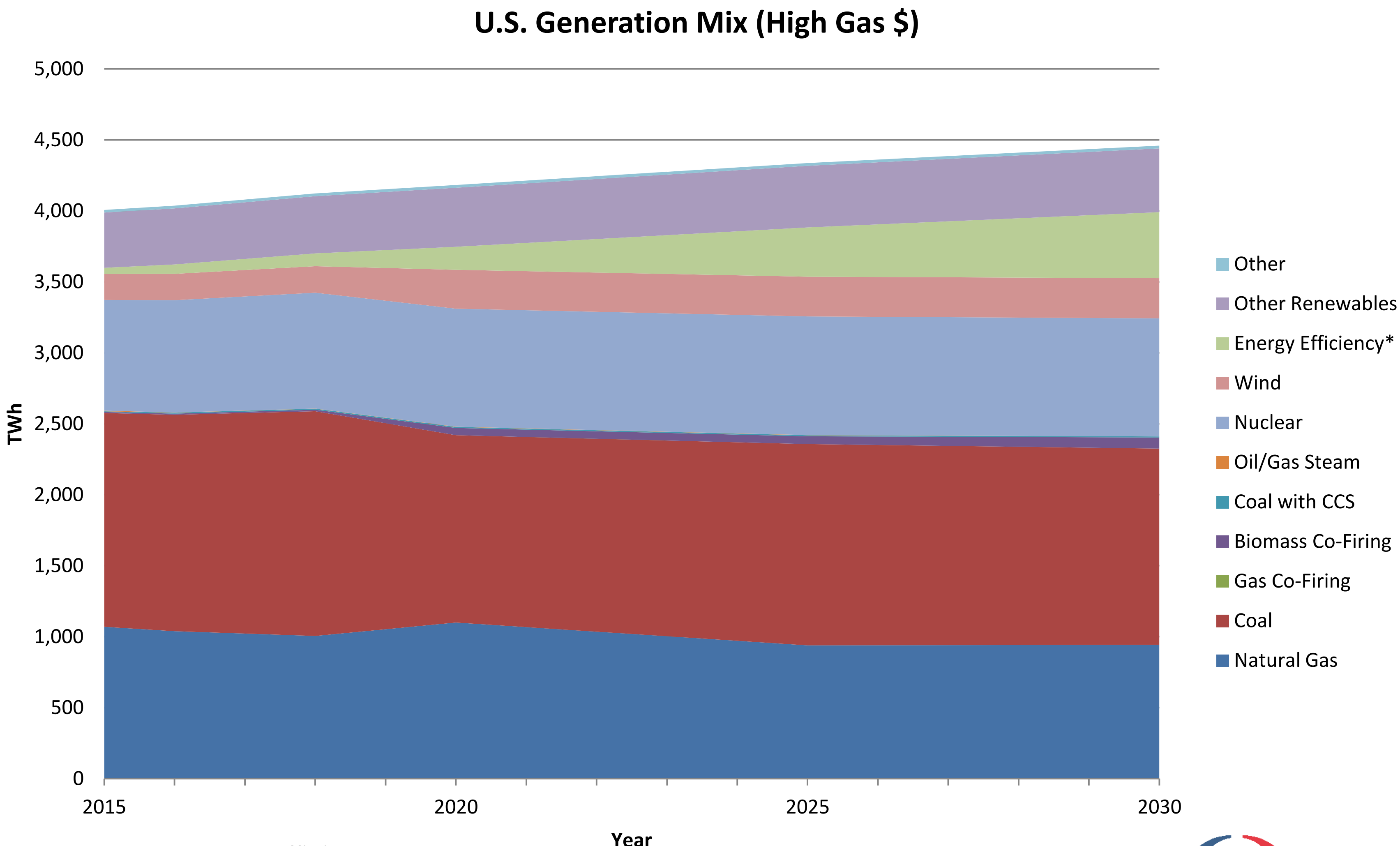
*Incremental energy efficiency



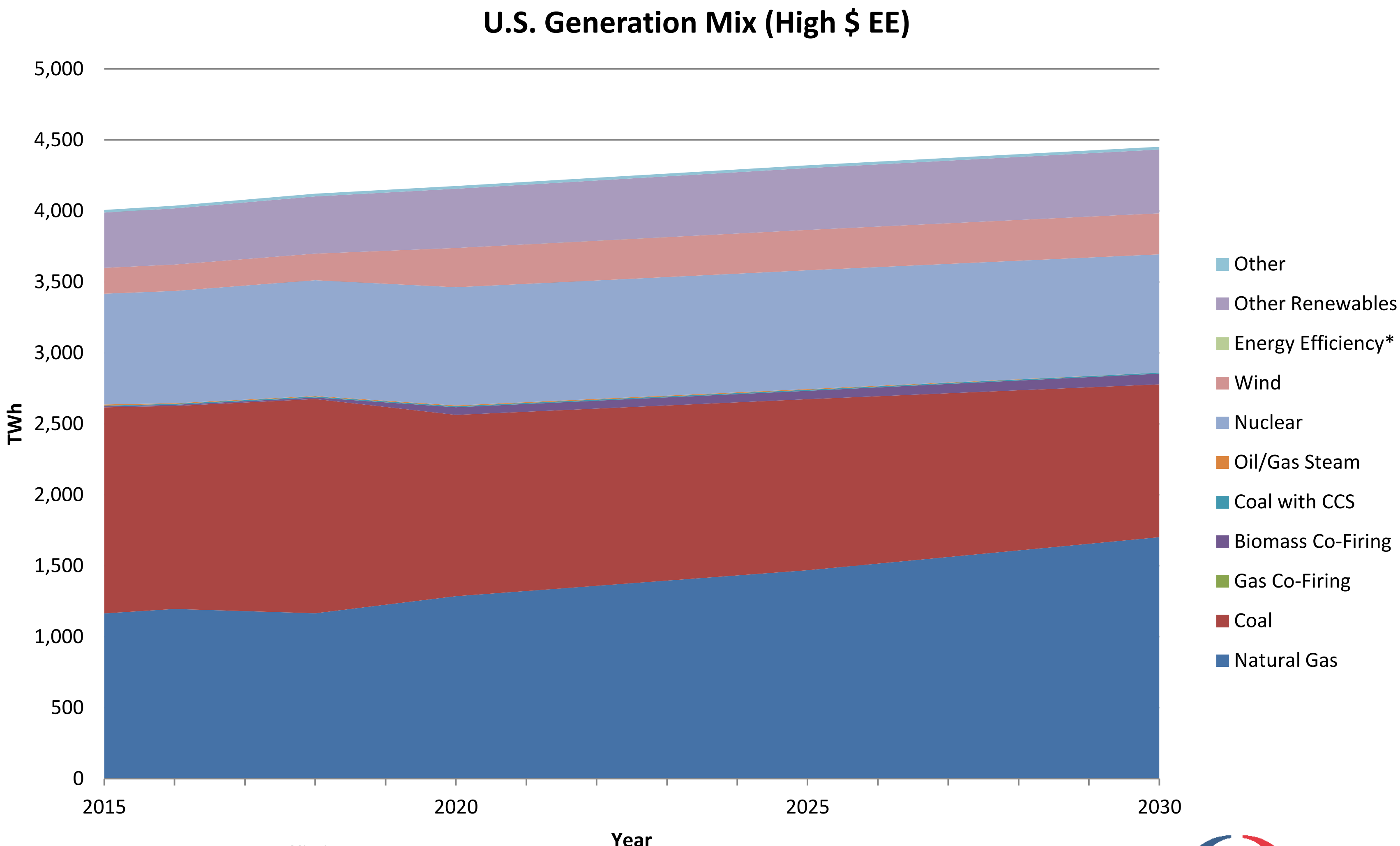
*Incremental energy efficiency



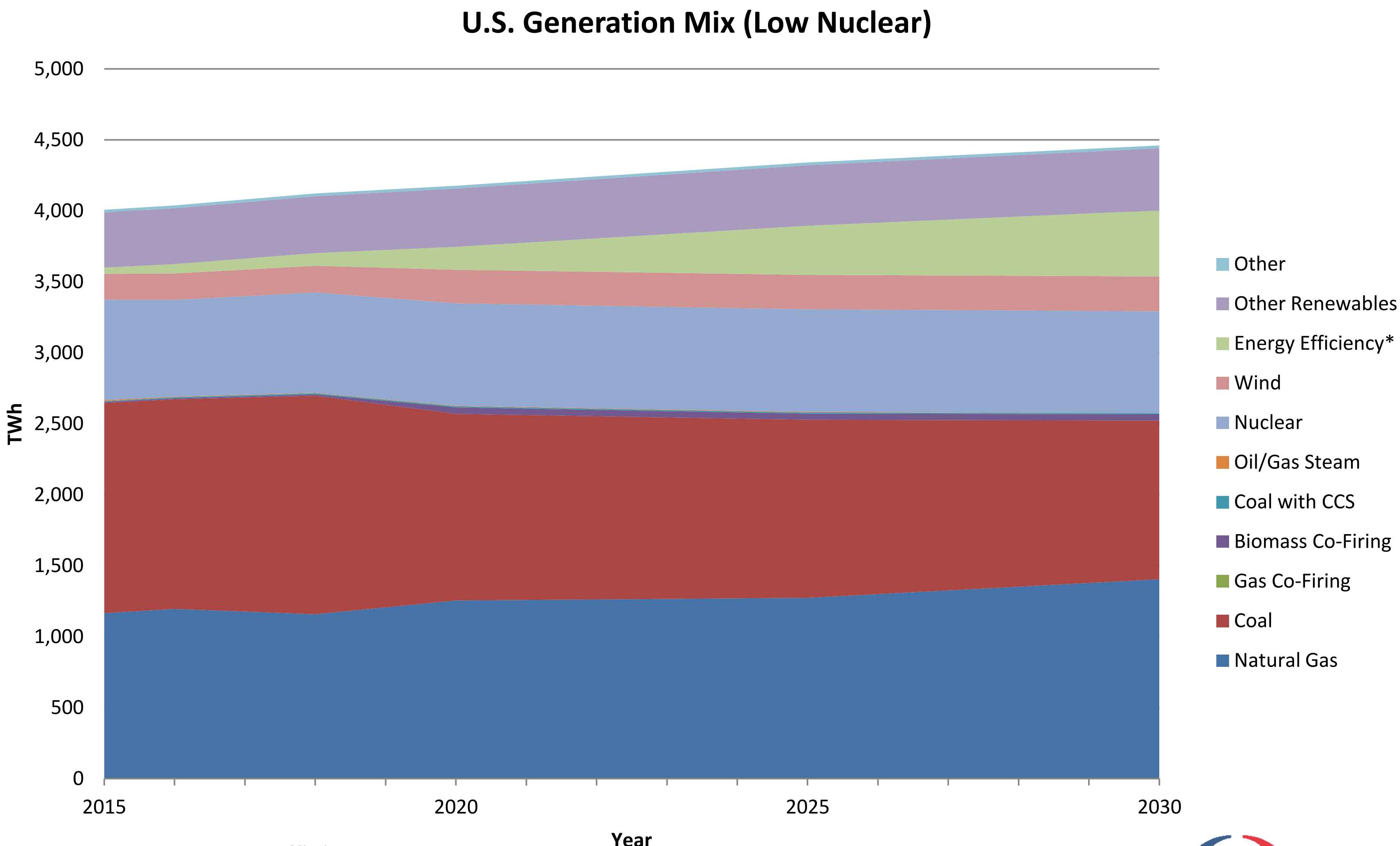
*Incremental energy efficiency



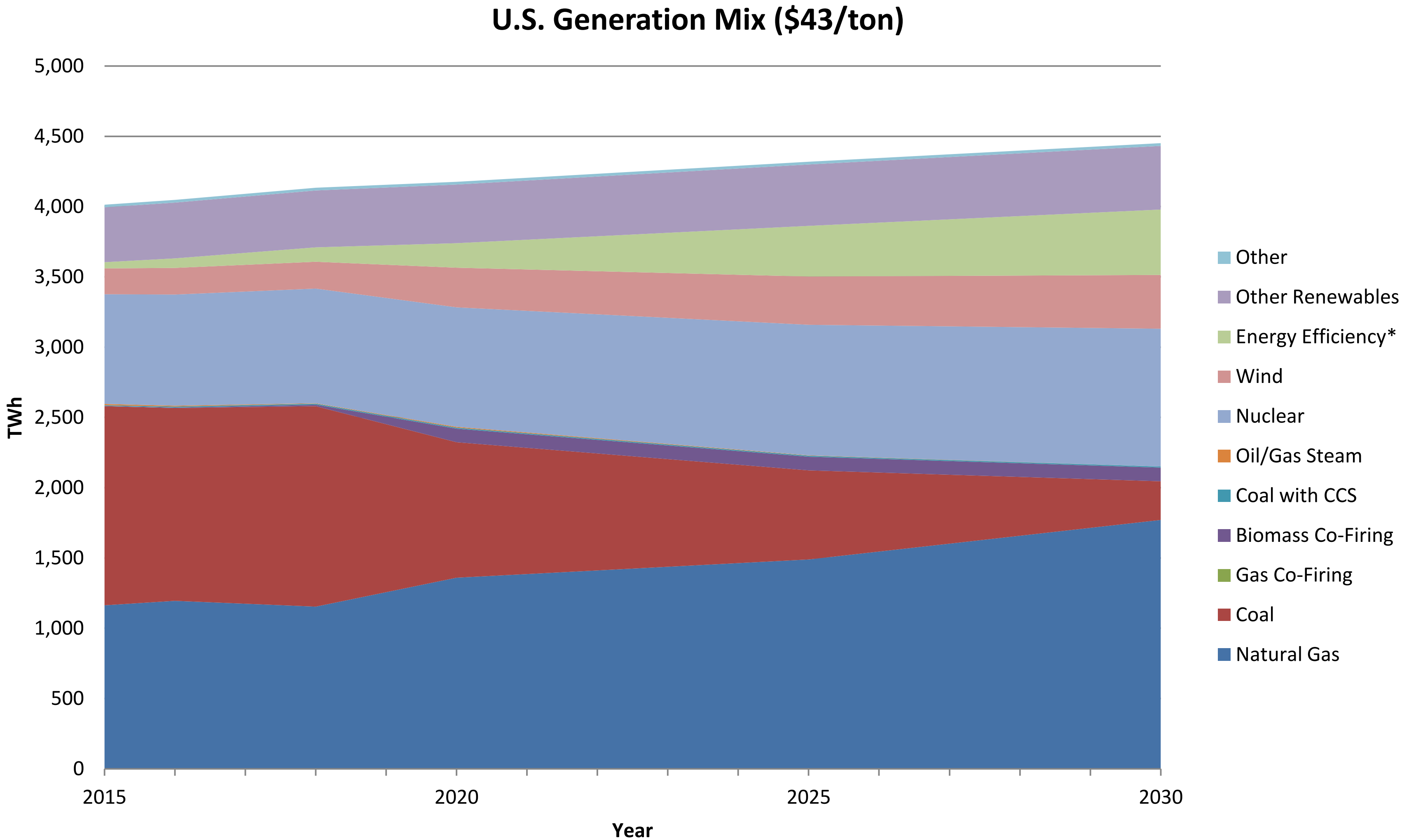
*Incremental energy efficiency



*Incremental energy efficiency

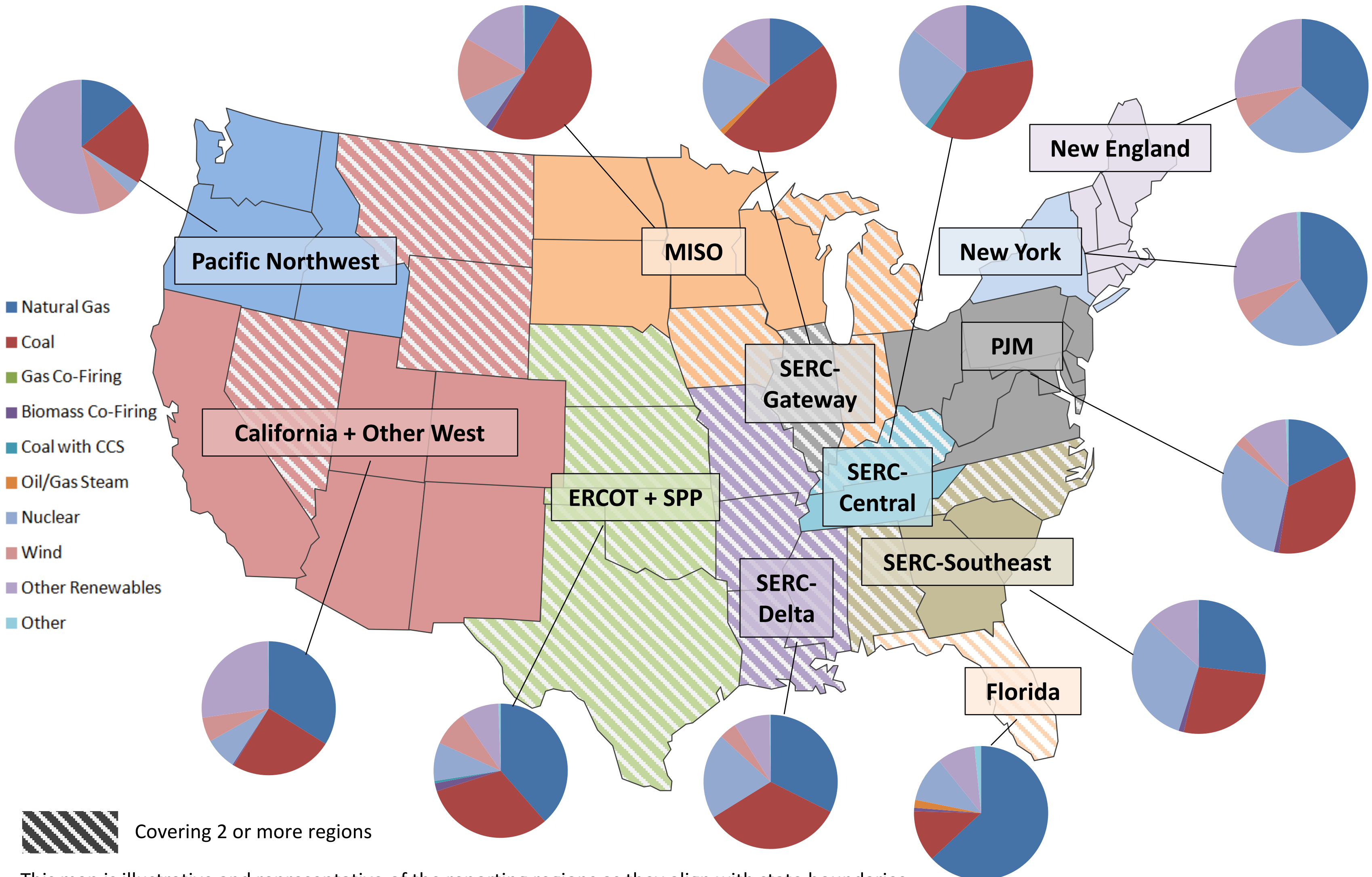


*Incremental energy efficiency



*Incremental energy efficiency

REGIONAL GENERATION MIX IN 2025 $12/TON POLICY SCENARIO



This map is illustrative and representative of the reporting regions as they align with state boundaries. SERC-Gateway covers a portion of Illinois, Iowa, and Missouri.

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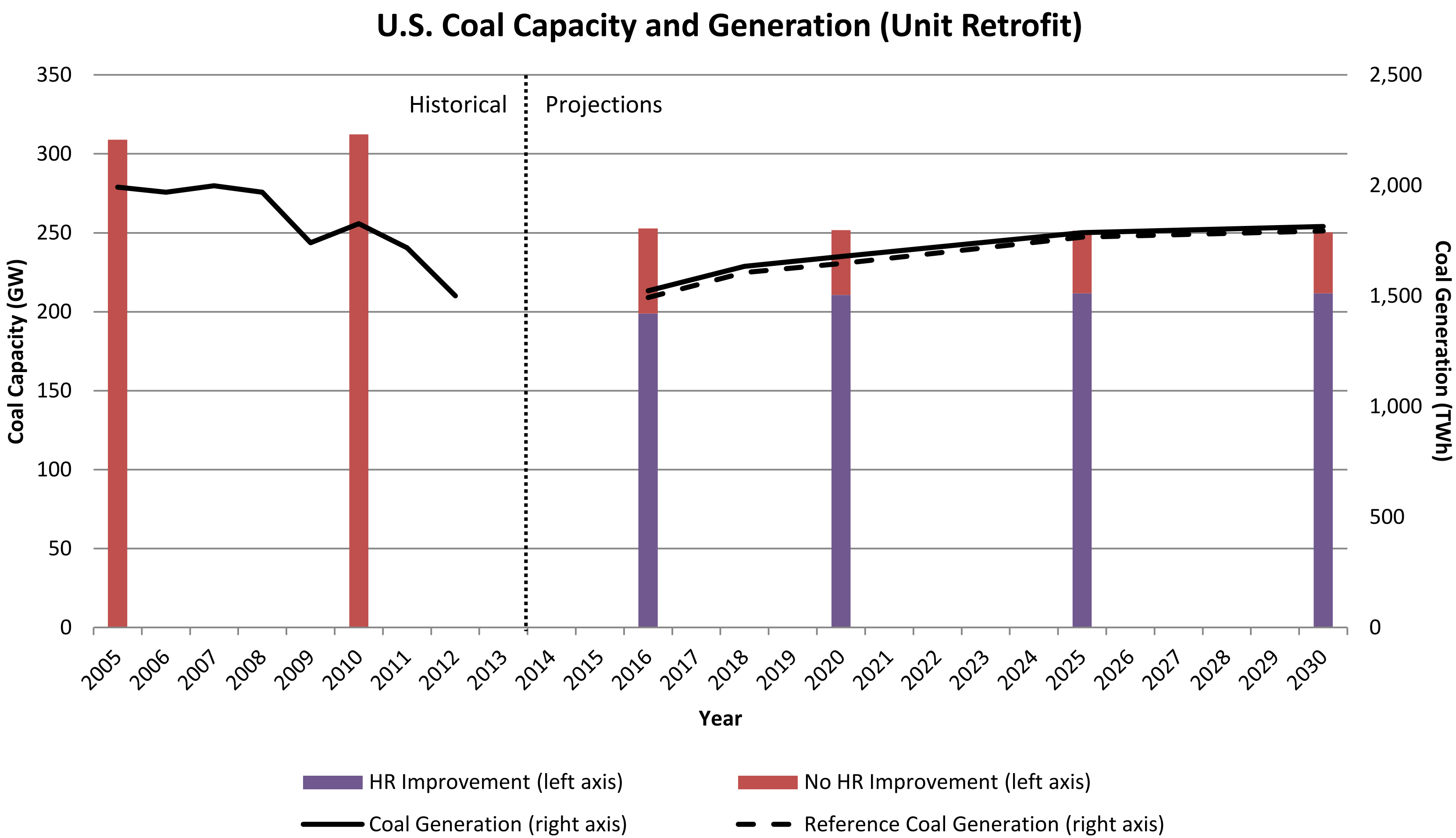
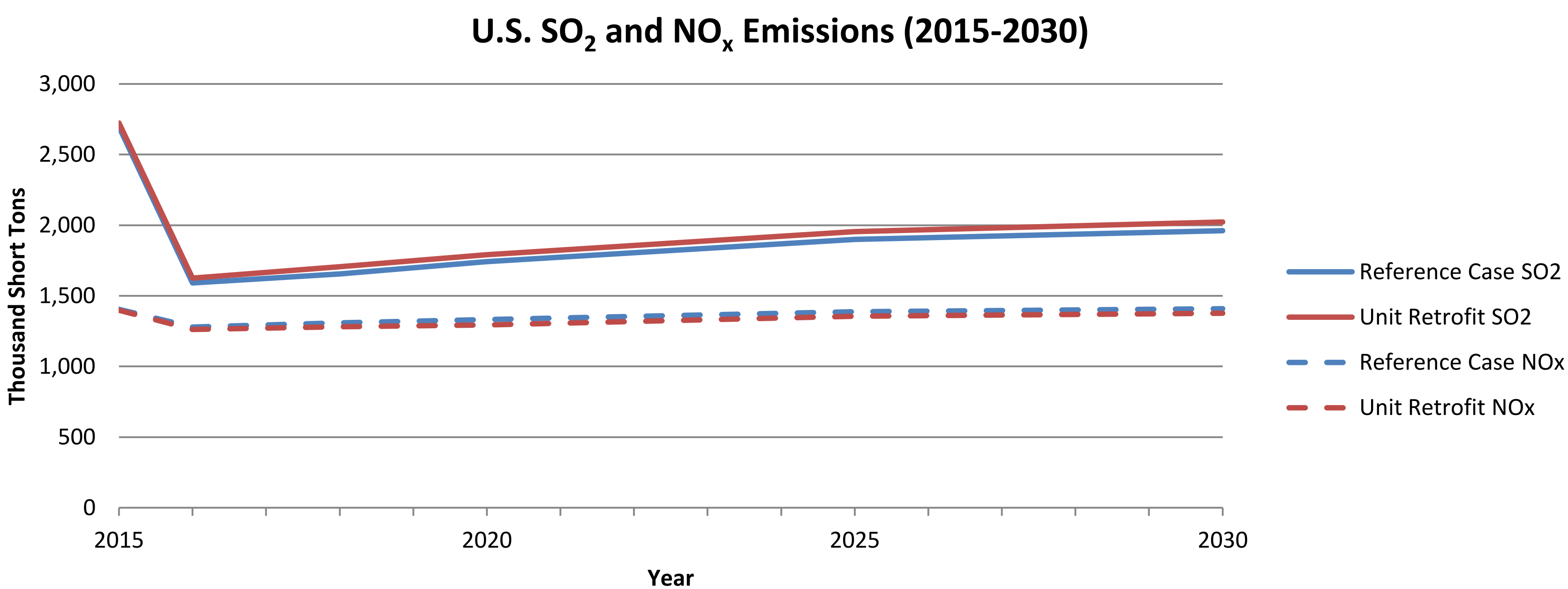
Unit Retrofit: Impact on existing coal


U.S. Coal Capacity and Generation (Unit Retrofit)
Historical
Projections
Coal Capacity (GW)
Coal Generation (TWh)
350
300
250
200
150
100
50
0
2,500
2,000
1,500
1,000
500
0
2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030
Year
HR Improvement (left axis)
No HR Improvement (left axis)
Coal Generation (right axis)
Reference Coal Generation (right axis)

Unit Retrofit: could increase SO_2 emissions above Reference case

❖ Modest increase in national SO_2 emissions projected

- Significant increases in some regions
- Due to changes in dispatch of coal generators after plant upgrades
- EPA determinations on New Source Review could limit SO_2 increases
- CO_2 and NO_X emissions are lower than Reference



SO_2: Sulfur Dioxide
CO_2: Carbon Dioxide
NO_x: Nitrogen Dioxide

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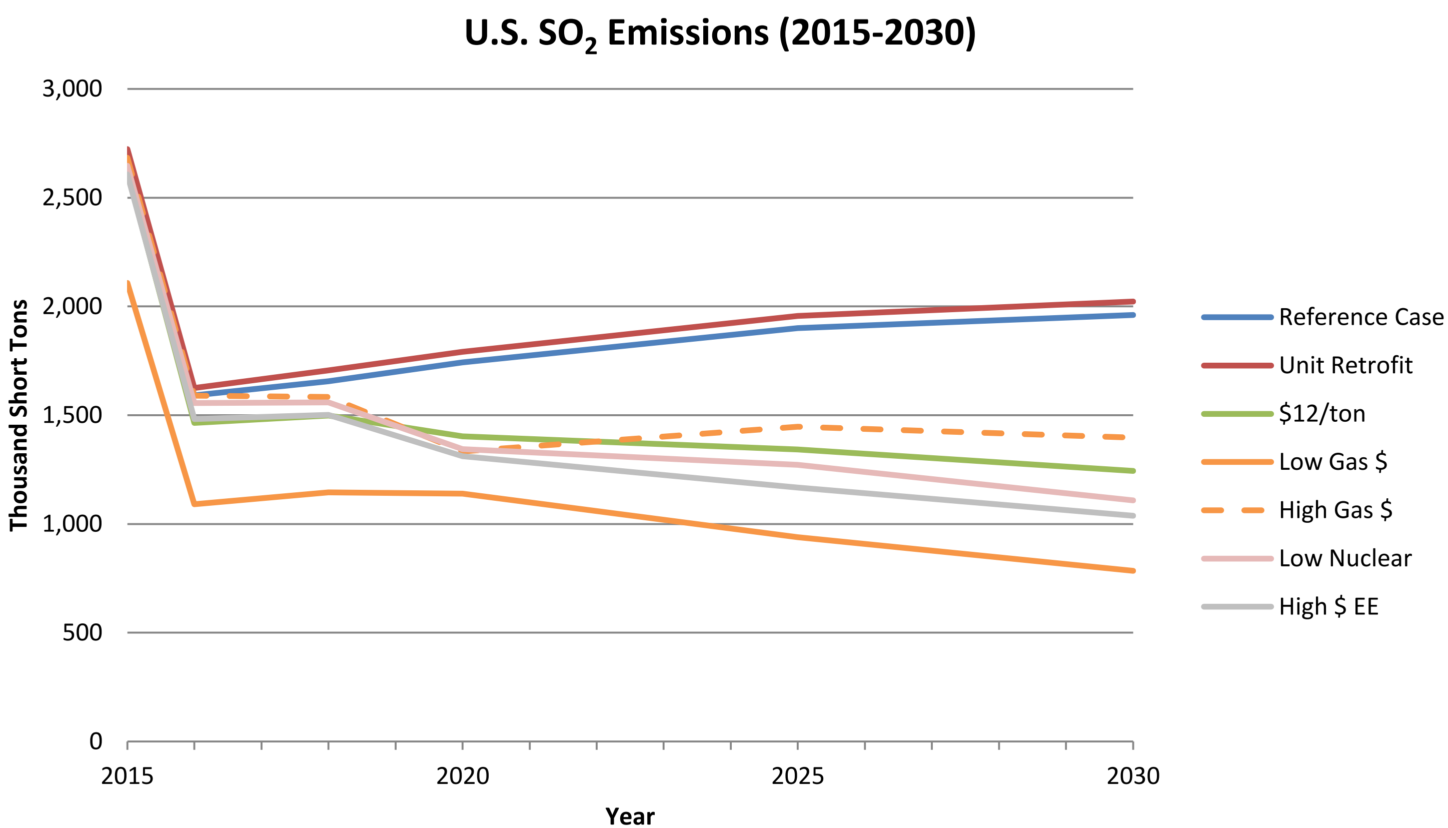
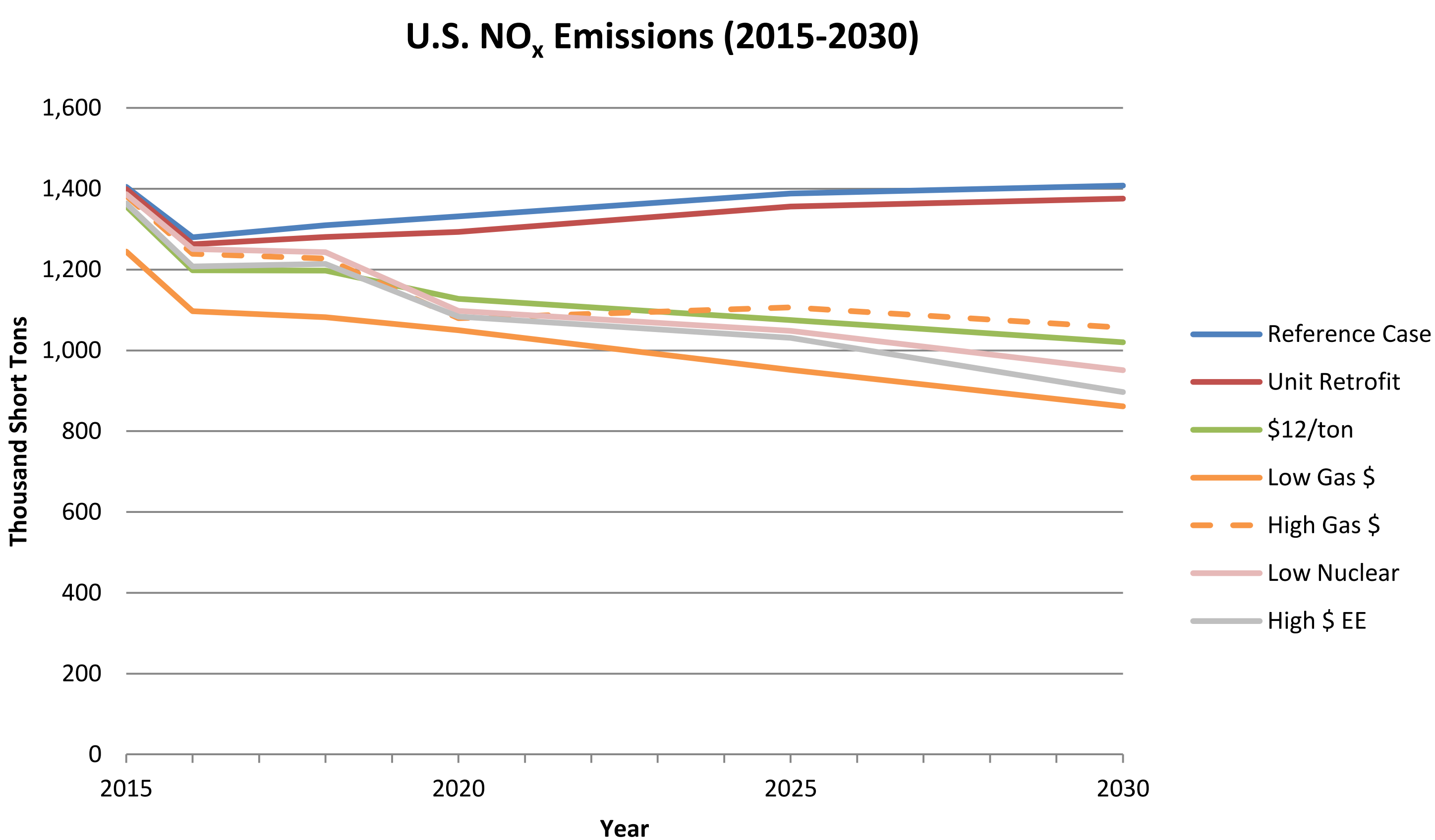
SO_2 and NO_x Emissions

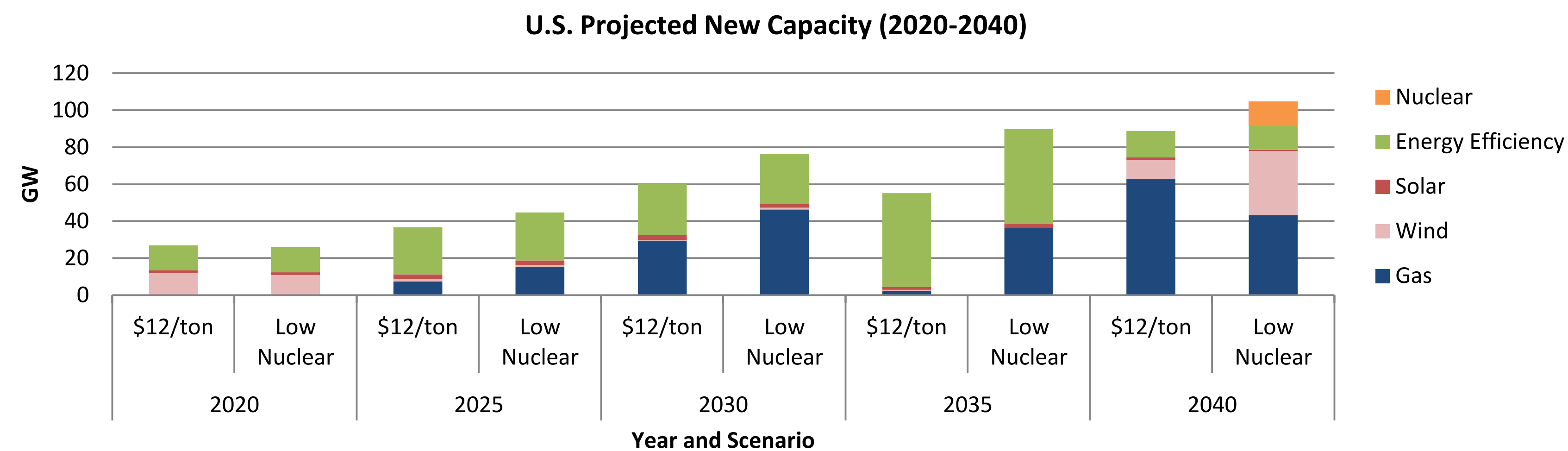


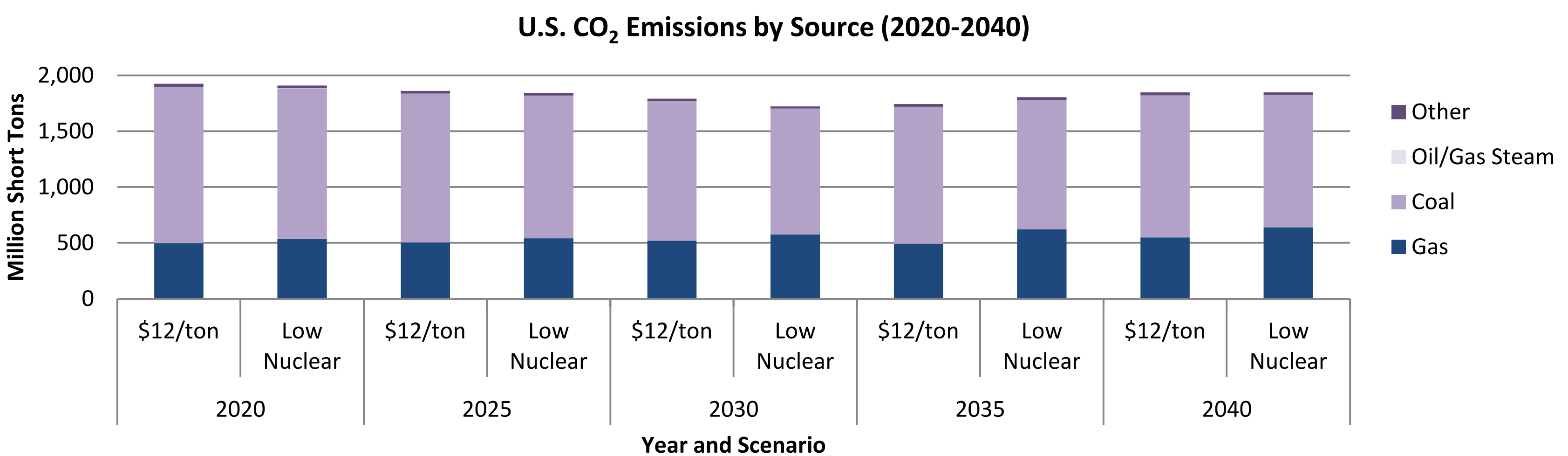
SO_2: Sulfur Dioxide



NO_x: Nitrogen Dioxide

Comparison of $12/ton and Low Nuclear


U.S. Projected New Capacity (2020-2040)
GW
120
100
80
60
40
20
0
$12/ton
Low Nuclear
2020
2025
2030
2035
2040
Year and Scenario
Nuclear
Energy Efficiency
Solar
Wind
Gas


U.S. CO2 Emissions by Source (2020-2040)
Million Short Tons
2,000
1,500
1,000
500
0
$12/ton
Low Nuclear
2020
2025
2030
2035
2040
Year and Scenario
Other
Oil/Gas Steam
Coal
Gas

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Assumptions

Unit Retrofit: On-Site Modest Unit Retrofits

❖ **Policy: requires coal plants to invest in on-site reductions by 2020**

- On-site efficiency (heat rate) retrofits and/or co-fire natural gas/biomass
- Unit-specific heat rate improvement & cost based on analysis of available data
- Coal units with on-site gas or nearby pipeline can co-fire 15% natural gas
- Coal units can co-fire up to 15% biomass (EIA biomass supply and cost)

$12/ton: System-Wide Reductions up to $12/ton

❖ **Policy: requires electric sector CO_2 reductions up to $12/ton in 2020**

- Modeled as a national tax that rises at the rate of the social cost of carbon
- Representative of program with national trading

$43/ton: System-Wide Reductions up to $43/ton

❖ **Policy: requires electric sector CO_2 reductions up to $43/ton in 2020**

- Same as $12/ton scenario, except at $43/ton

➢ **All policy scenarios require §111(b) CCS for new coal capacity**

CO_2: Carbon Dioxide
§111(b): Section 111(b) of Clean Air Act
CCS: Carbon Capture and Storage
EIA: Energy Information Administration

Matrix of Policy Scenario Features

	111(b) Policy	111(d) Compliance Options				Basis for CO_2 Limit
		Heat Rate Upgrades	Co-Fire Gas or Biomass	Shift to Cleaner Generation	Demand-Side Energy Efficiency	
Reference						None
Unit Retrofit	X	X	X			Modest Plant Upgrade
$12/ton	X	X	X	X	X	Price on CO_2 Emissions
$43/ton	X	X	X	X	X	Price on CO_2 Emissions

111(b): Section 111(b) of the Clean Air Act
111(d): Section 111(d) of the Clean Air Act
CO_2: Carbon Dioxide

Assumption	Sources	Description
Electric and Peak Demand Growth	AEO 2013	
Capacity Build Costs	AEO 2013 & LBNL	Costs for all technologies come from AEO 2013, except on-shore wind capacity costs come from Lawrence Berkeley National Laboratory's (LBNL) 2012 Wind Technologies Market Report.
Gas Supply/Prices	AEO 2013	Gas supply curves by year are based on AEO 2013 scenarios.
Coal Supply/Prices	AEO 2013	ICF coal supply is calibrated to AEO 2013 average minemouth prices.
Air Pollution Control Costs	EPA, EIA, AEO 2013, & AEO 2013 Early Release	Retrofit costs for most pollution control technologies come from EPA. DSI costs come from EIA. CCS retrofit costs for coal and gas come from AEO 2013 & AEO 2013 Early Release.
Nuclear Power Licensing/Operation	AEO 2013 & BPC	Reference case retirements come from AEO 2013. In addition, Vermont Yankee nuclear power plant retires. Plants are able to relicense at 60 years. In the nuclear sensitivity case, all nuclear power plants must retire at 60 years, along with an additional 7 GW, which retires in 2016.
Biomass Co-firing	EIA, AEO 2013, & BPC	Costs are based on EIA biomass cost curves and AEO 2013 co-firing cost assumptions. Coal units can co-fire up to 15%. Existing subcritical coal units that are 300MW or smaller can repower/retrofit to burn 100% biomass.
Natural Gas Co-firing	EPA & BPC	Coal units that use gas on site can co-fire up to 15% without additional pipeline costs or efficiency degradation penalties. Units that are within 10 miles of a gas pipeline can fully convert to gas. These units incur a pipeline cost and a 5% heat rate penalty.
Demand Side Energy Efficiency	BPC, NRDC, & ACCCE	In policy runs only, energy efficiency is available up to one half of the supply assumed by NRDC in the core case of its March 2014 111(d) analysis. Depending on the scenario, costs are either based on NRDC's March 2014 or ACCCE's March 2014 111(d) analyses.
Heat Rate Improvement	BPC	In policy runs only, coal units can select between two levels of efficiency upgrades based on the unit's capacity, fuel type, steam cycle, and boiler type to close 25% or 40% of the gap between the unit heat rate and the "best in class" heat rate.
Coal with CCS	BPC	BPC assumes both the Kemper plant and the Texas Clean Energy Project will be built as coal-fired generation with CCS. Other CCS generation can come online if it is deemed economical.

EIA: Energy Information Administration
AEO: Annual Energy Outlook
CCS: Carbon Capture and Storage
NRDC: Natural Resources Defense Council
ACCCE: American Coalition of Clean Coal Electricity
DSI: Dry Sorbent Injection

Scenario	Description
Reference	Includes existing state and federal regulations.
Unit Retrofit	Identical to the Reference case, with the addition of a GHG emission rate standard modeled as a requirement for coal plants to either 1) invest in on-site efficiency improvements or 2) co-fire gas or biomass so CO_2 emissions are equivalent to the unit-specific rate achieved by requiring each coal unit to close 40% of the gap between its heat rate and the "best in class" heat rate based on the unit's capacity, fuel type, steam cycle, and boiler type. Any new coal capacity must include CCS.
$12/ton	Identical to the Reference case except for the addition of a GHG policy that requires power sector emission reductions up to $12 per metric ton of CO_2 in 2020 (rising at the rate of the social cost of carbon). The case is representative of national emissions trading under a 111(d)-like policy that allows for investment in demand side energy efficiency at a cost of 2.3-3.2 cents/kWh. Any new coal capacity must include CCS.
$43/ton	Identical to the $12/ton case except the GHG policy requires power sector emission reductions up to $43 per metric ton of CO_2 in 2020 (rising at the rate of the social cost of carbon). Any new coal capacity must include CCS.
Low Gas $	CO_2 emissions are capped at the level from the $12/ton case with banking of allowances permitted. Gas prices from AEO 2013's low gas price sensitivity are imposed. Any new coal capacity must include CCS.
High Gas $	CO_2 emissions are capped at the level from the $12/ton case with banking of allowances permitted. Gas prices from AEO 2013's high gas price sensitivity are imposed. Any new coal capacity must include CCS.
Low Nuclear	CO_2 emissions are capped at the level from the $12/ton case with banking of allowances permitted. In addition to Reference case nuclear retirements, 7 GW of nuclear power is retired in 2016 and no 60-year relicensing agreements are allowed. Any new coal capacity must include CCS.
High $ EE	CO_2 emissions are capped at the level from the $12/ton case with banking of allowances permitted. Demand side energy efficiency is priced at 11 cents/kWh. Any new coal capacity must include CCS.

GHG: Greenhouse Gas
CO_2: Carbon Dioxide
AEO: Annual Energy Outlook
CCS: Carbon Capture and Storage

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For additional detail about modeling assumptions as well as additional results see the Technical Appendix