Locking In the Benefits to Fuel Switching

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Outline

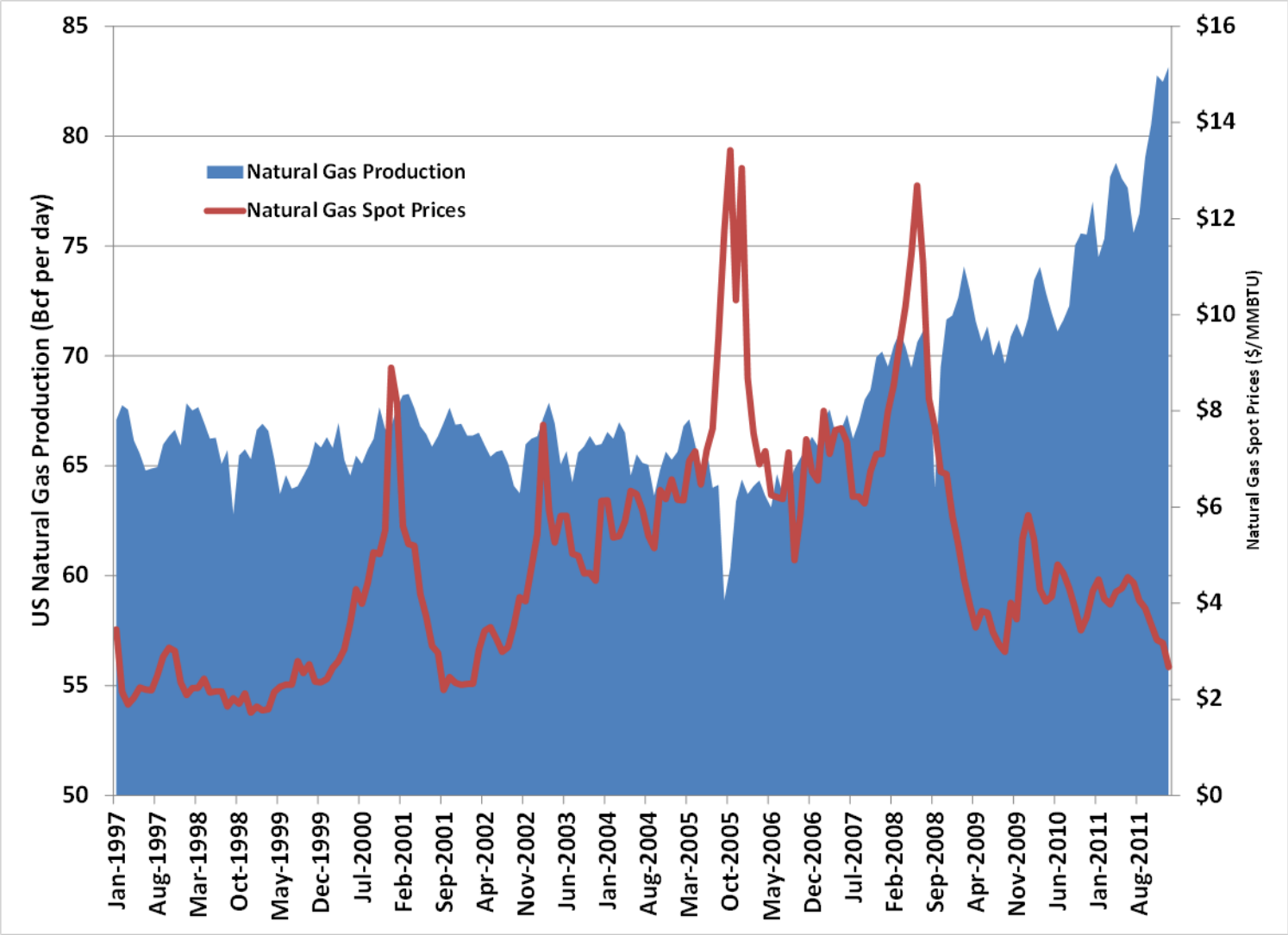
- Project purpose
- The Power Shift
  - Fuel market update
  - Changing power plant dispatch
  - Coal unit environmental Regulations
- The Generation Planning Predicament
- A No-Regrets Transition?

Project Purpose

To formulate a no-regrets approach for transitioning to a lower carbon electric sector by taking advantage of changing market dynamics.

- What is causing the transition and how can it be sustained?
- What are the opportunities and challenges?
- The transition will require cooperation between various groups and needs to preserve electricity's affordability and reliability to be successful.

The Power Shift: Natural Gas Market



Source: EIA production and price data

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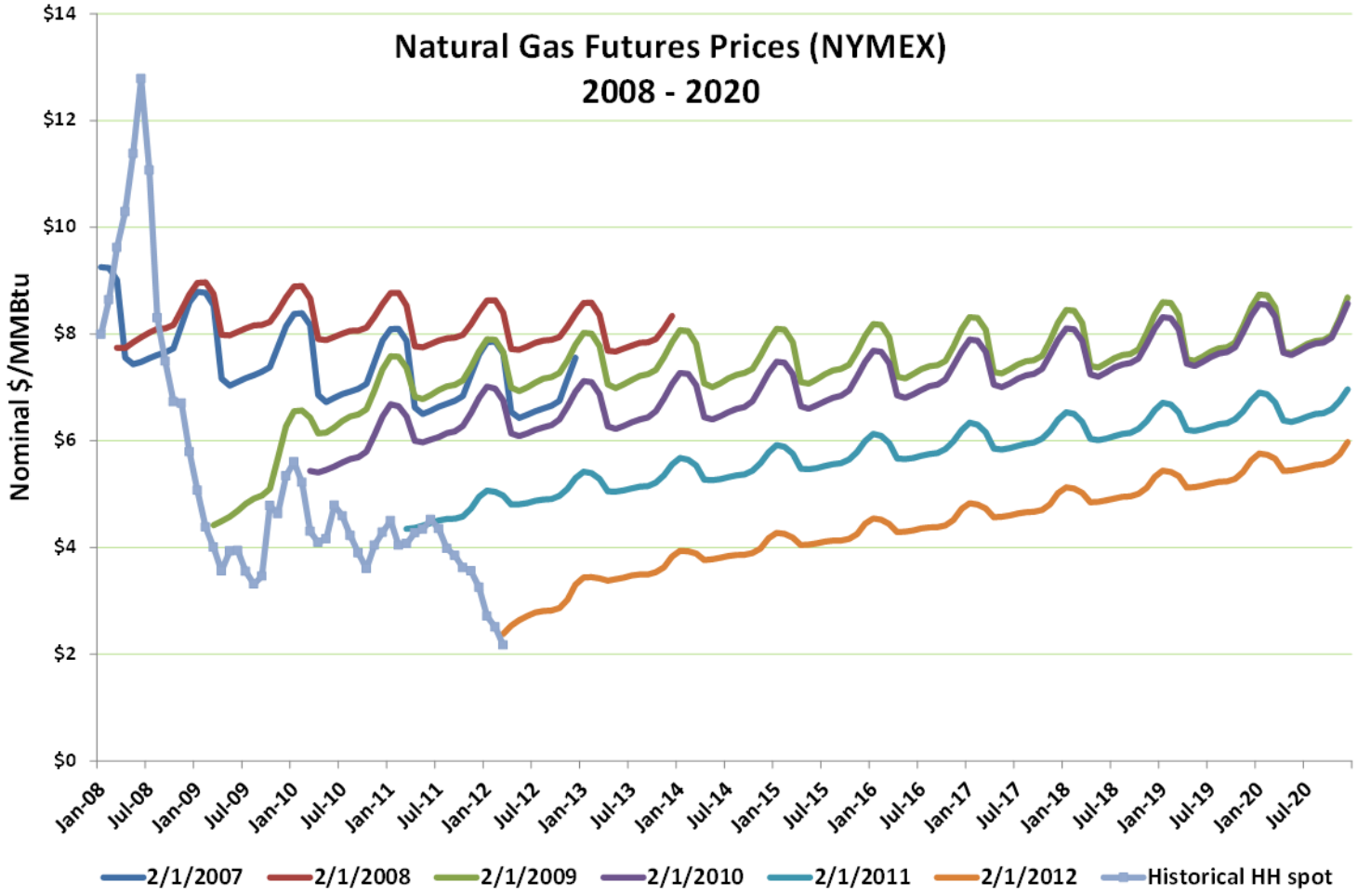
The Power Shift: Natural Gas Market



Note: Henry Hub (HH), Louisiana, is a major production area delivery point in the gas industry. The NYMEX Natural Gas Futures contract uses the Henry Hub price as the reference point.
Source: New York Mercantile Exchange, American Clean Skies Foundation analysis

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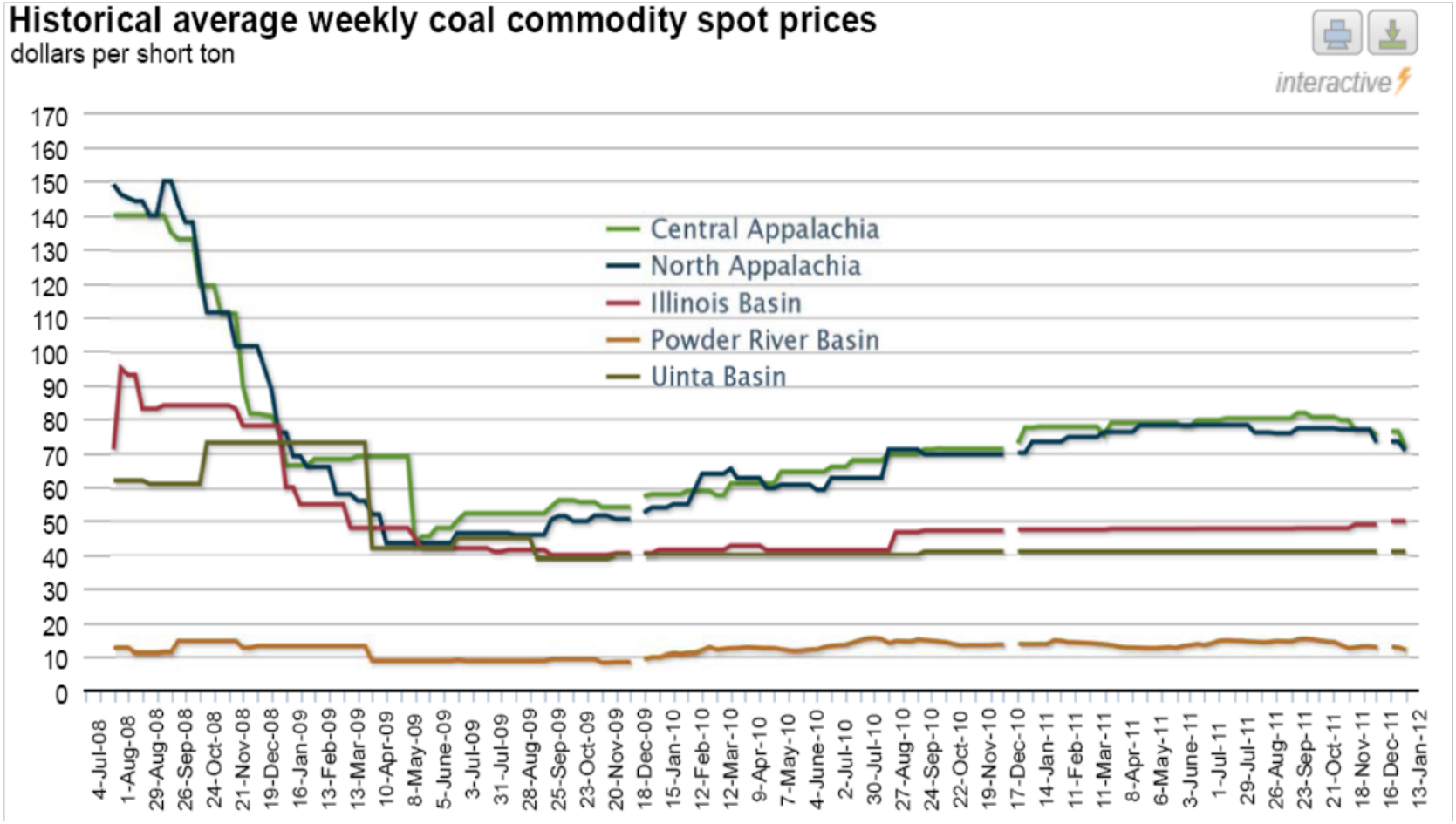
The Power Shift: Coal Market



Source: EIA. Coal News and Markets Report. January 17, 2012. Available: ftp://ftp.eia.doe.gov/coal/newsmarket/coalmar120113.pdf

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The Power Shift: Power Plant Dispatch

Power Plant Production Cost Calculations ($/MWH)

	CAPP Coal	*NAPP Coal*	*PRB Coal*	*Natural Gas Combined Cycle*	*Natural Gas Combustion Turbine*
Fuel Cost ($/MWH)	$ 31.25	$ 26.92	$ 17.05	$ 21.00	$ 32.25
VOM ($/MWH)	$ 6.00	$ 6.00	$ 6.00	$ 2.75	$ 3.75
SO2 Cost ($/MWH)	$ 0.02	$ 0.03	$ 0.01	$ 0.00	$ 0.00
Annual NOX Cost ($/MWH)	$ 0.03	$ 0.03	$ 0.03	$ 0.00	$ 0.01
Seasonal NOX Cost ($/MWH) *(May - Sep)*	$ 0.03	$ 0.03	$ 0.03	$ 0.00	$ 0.01
Dispatch Cost per MWH *(Oct - Apr)*	**$ 37.29**	**$ 32.97**	**$ 23.08**	**$ 23.75**	**$ 36.01**
Dispatch Cost per MWH *(May - Sep)*	**$ 37.32**	**$ 33.00**	**$ 23.10**	**$ 23.75**	**$ 36.02**
In 2008:				***~ $70/MWH***	***~ $105/MWH***

Source: American Clean Skies Foundation analysis. – Generic production costs for different power plants shows natural gas units are cheaper than coal units with current market conditions. Assumes delivered fuel costs of $75/ton, $70/ton, $30/ton for CAPP, NAPP, and PRB, respectively, and $3.00/MMBTU for natural gas. Assumes heat rates of 10 MMBTU/MWH for coal units, 7.0 MMBTU/MWH for the combined cycle, and 10.75 MMBTU/MWH for the combustion turbine. Assumed emission allowance prices are $50/ton for both annual and seasonal NOX, along with $1.5/ton for SO2.

"I think this is the first time in my career that our gas units are dispatching after nuclear and before all our coal plants."

– Jim Rogers, CEO of Duke Energy

(April 11, 2012 NY Times Energy for Tomorrow Conference)

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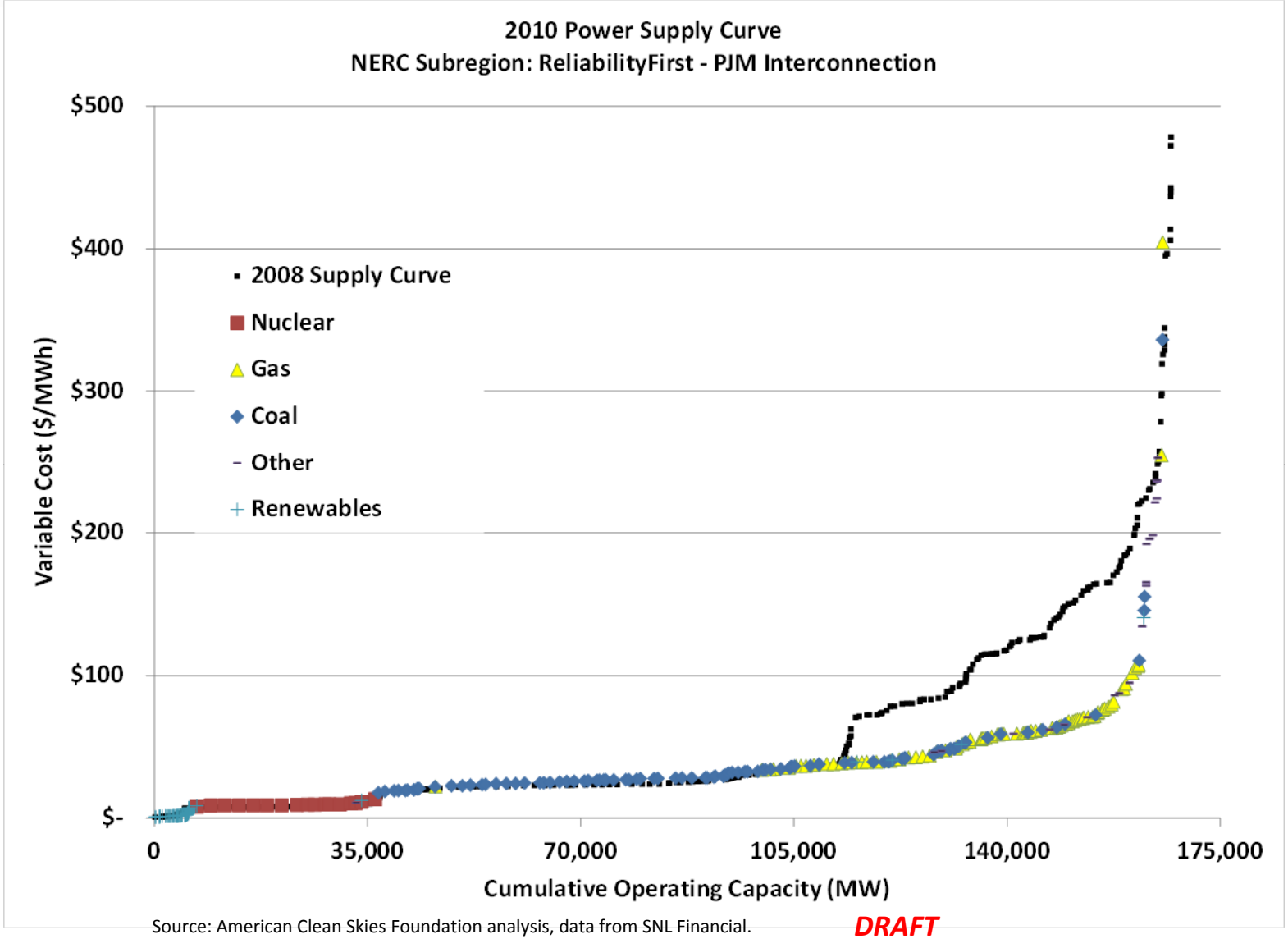
The Power Shift: Power Plant Dispatch



Source: American Clean Skies Foundation analysis, data from SNL Financial.

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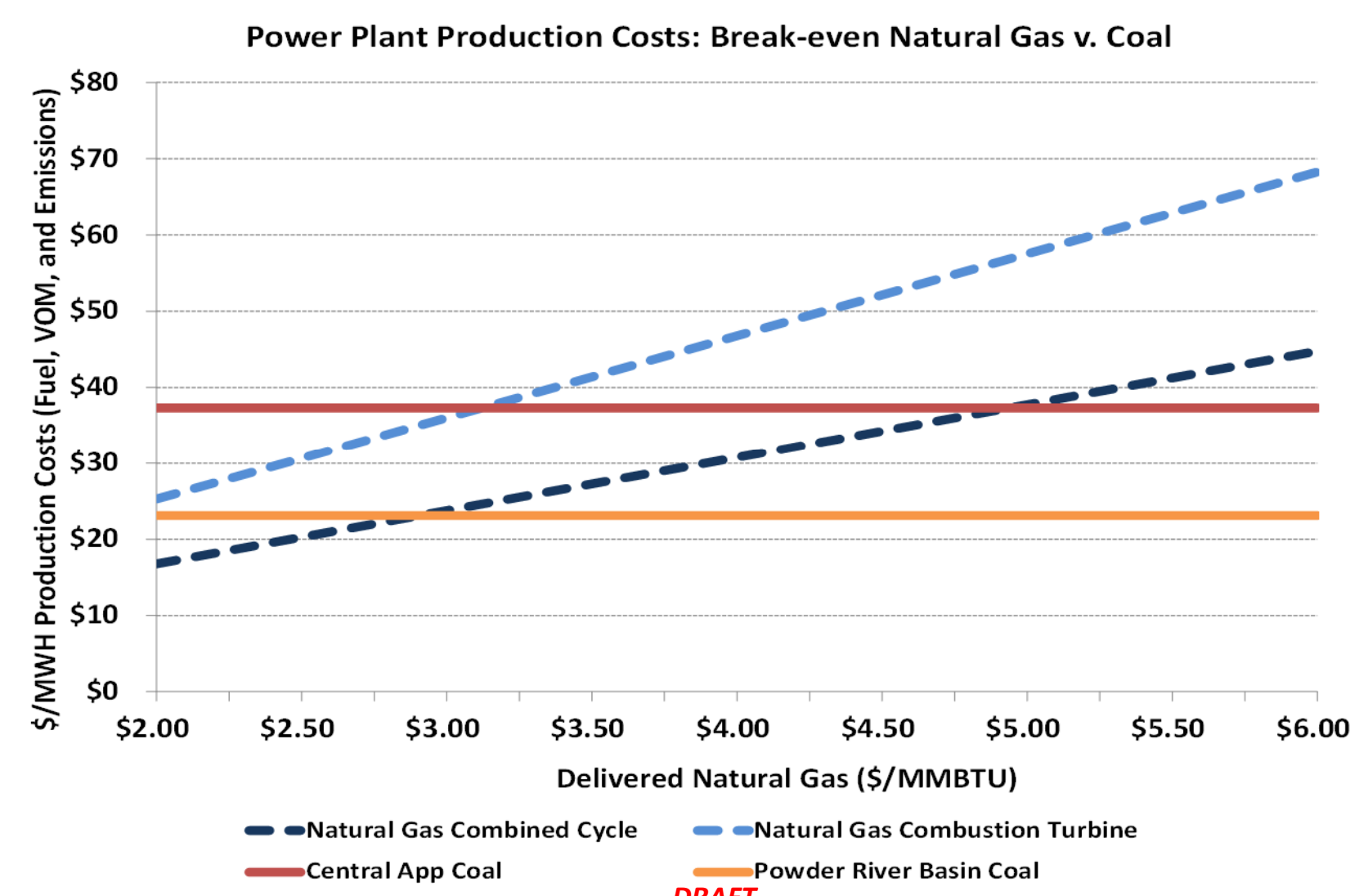
The Power Shift: Power Plant Utilization

- EIA projects a continued shift in electricity generation from 2011 to 2012:
  - Natural gas from **24.8%** to **29.2%**
  - Coal from **42.2%** to **38.3%**
- Coal consumption projected to drop below 900 million tons…the lowest level since 1995

The Power Shift: Power Plant Dispatch



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Source: American Clean Skies Foundation analysis.

Environmental Regulations Affecting Coal Units

CSAPR	MATS	316(b)	CCB	GHG

• NO_X controls
  • Low NOX burner; SCR; SNCR
• SO_2 Controls
  • Scrubber; DSI
	• Acid gas controls
	  • DSI; Scrubber
	• Mercury and air toxics controls
	  • Baghouse; ESP
		• Closed loop cooling towers
		• New water intake structures
			• Dry ash conversion
			• Waste-water treatment
			• Pond closures
				• Operating guidelines or constraints
				• Efficiency upgrades

Compliance costs include capital costs for environmental controls and/or increased operating expenses

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The Generation Planner Predicament

Is it cheaper to construct environmental retrofits and continue coal operation? Or is it cheaper to build and operate replacement capacity?

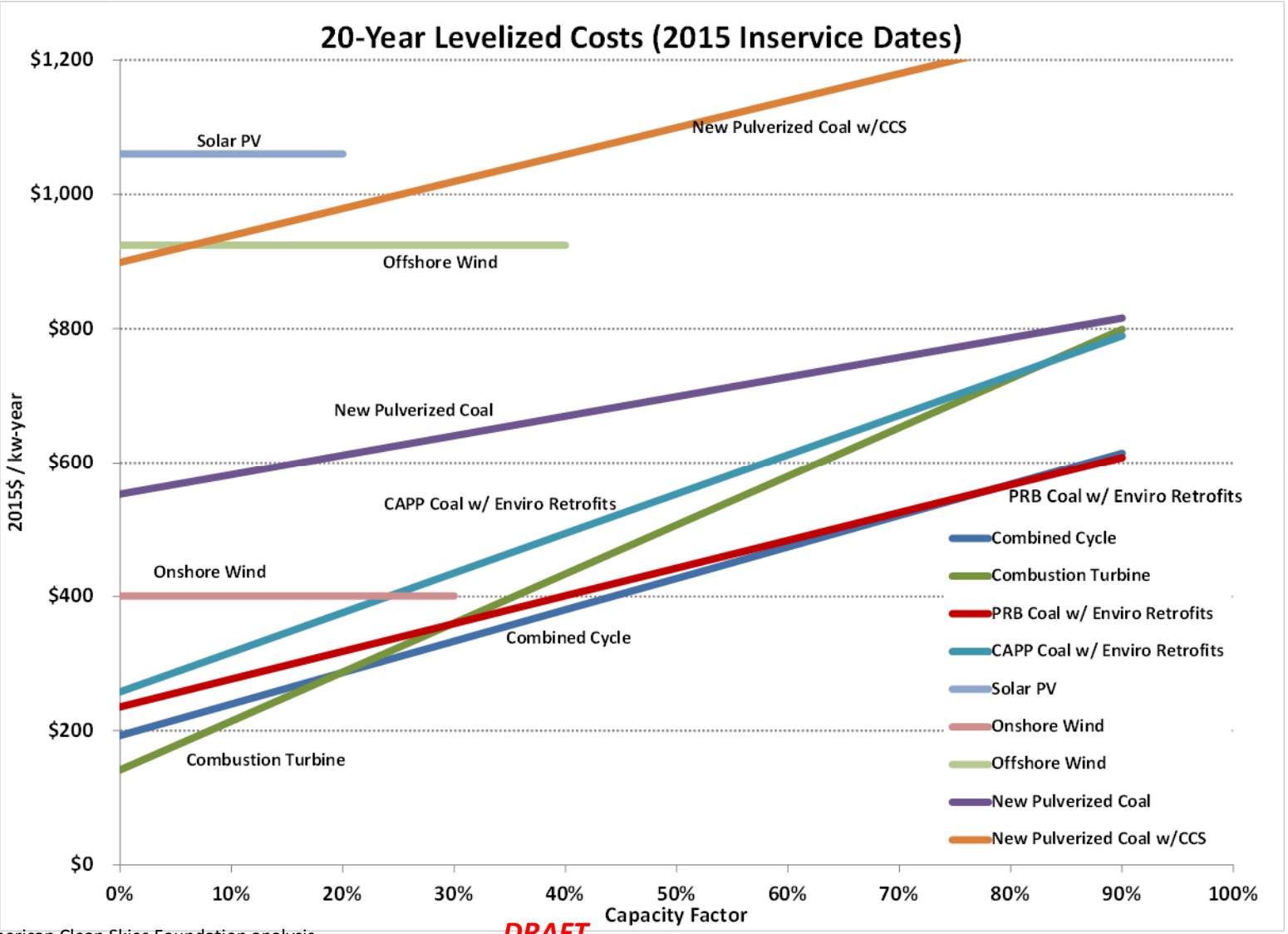
- What are the options?
  - Retrofit with environmental controls
  - Retire and replace with new units
  - Retire and replace with existing slack capacity
  - Convert coal boiler to fire biomass or natural gas

Retire and Replace with Existing Capacity

Utilization of CCGT Fleet			
Capacity Factor Category	Net Summer Megawatts, 2011 preliminary	Percent of Total CCGT Megawatts, 2011 preliminary	Percent of Total CCGT Megawatts, 2007
70% and Greater	12,582	7%	5%
Under 70% to 50%	62,111	32%	24%
Under 50% to 30%	56,915	30%	35%
Under 30%	60,873	32%	37%
Total	192,481	100%	100%

Source: Data from SNL Financial. To replicate the CRS Study, the group of combined cycle plants included those meeting the following characteristics: minimum net summer capacity of 100 MW; the plant operated at some point in time during 2011/2007 respectively and was in operational condition at the end of 2011; the plant's primary fuel was natural gas; and the plant's primary purpose was to sell power to the public [excludes industrial and commercial cogenerators who operate primarily to provide electricity and steam to a single business establishment].

“Busbar” Analysis



Source: American Clean Skies Foundation analysis.

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Detailed Analysis Example

Dayton Power & Light's O.H. Hutchings Plant

Option 1 - Install wet scrubbers & baghouses in 2015, costs for 316(b) and CCB in 2019-20

Option 2 – Retire and replace with combined cycle

Option 3 – Retire and replace with combustion turbine

Option 4 – Convert units to natural gas

Benefits – Costs = Net Value

Net Value of Option 1 is compared relative to other options

O.H. Hutchings 1-6 Net Present Value through 2025 (in $ millions)	Low Price Scenario	Base Case	High Price Scenario
Retrofit value relative to combined cycle value	$ (277)	$ (273)	$ (233)
Retrofit value relative to combustion turbine value	$ (244)	$ (236)	$ (207)
Retrofit value relative to natural gas conversion	$ (403)	$ (396)	$ (374)

Lowest Cost option →

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The Generation Planner Predicament

Electric sector assets are long-lived (20-60+ years). In the future, will we regret the decisions we make today?

"While gas looks cheap today it's looked cheap in the past, only to disappoint."
– Tom Fanning, CEO of Southern Company

"Over the many the many decades, there have been boom and bust cycles in the natural gas business… Utilities are very reluctant to enter into long-term contracts for any source, because of the volatility, and the situation we're in is we have a regulator looking over our shoulder, asking why we [signed a long-term deal]"
– Thomas Farrell, CEO of Dominion Resources

Concerns: *Uncertainty, cost recovery, financing ability, maintaining reliability and competitive rates.*

Project Next Steps: Is there a “No-Regrets” Approach to Sustaining the Low-carbon Transition?

- What’s at stake for customers? What are the opportunities?
- Further investigate hurdles for transitioning to a low-carbon electric sector
- Develop mechanisms to promote the a “no-regrets” transition that preserves affordable and reliable electric service while reducing environmental impacts.

Questions?

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Appendix

Utilization of CCGT Fleet

Capacity Factor Category	Net Summer Megawatts, 2011 preliminary	Number of CCGT Plants, 2011 preliminary	Percent of Total CCGT Megawatts, 2011 preliminary	Percent of Total CCGT Megawatts, 2010	Percent of Total CCGT Megawatts, 2009	Percent of Total CCGT Megawatts, 2008	Percent of Total CCGT Megawatts, 2007
70% and Greater	12,582	25	7%	5%	5%	5%	5%
Under 70% to 50%	62,111	84	32%	32%	29%	27%	24%
Under 50% to 30%	56,915	88	30%	31%	31%	30%	35%
Under 30%	60,873	118	32%	32%	35%	38%	37%
Total	192,481	315	100%	100%	100%	100%	100%

Utilization of CCGT Fleet in the PJM Interconnection

Capacity Factor Category	Net Summer Megawatts, 2011 preliminary	Number of CCGT Plants, 2011 preliminary	Percent of Total CCGT Megawatts, 2011 preliminary	Percent of Total CCGT Megawatts, 2010	Percent of Total CCGT Megawatts, 2009	Percent of Total CCGT Megawatts, 2008	Percent of Total CCGT Megawatts, 2007
70% and Greater	669	1	3%	0%	0%	0%	0%
Under 70% to 50%	10,159	13	46%	24%	19%	0%	0%
Under 50% to 30%	7,290	10	33%	30%	24%	34%	28%
Under 30%	4,080	11	18%	46%	56%	66%	72%
Total	22,198	35	100%	100%	100%	100%	100%

Utilization of CCGT Fleet in the Midwest ISO

Capacity Factor Category	Net Summer Megawatts, 2011 preliminary	Number of CCGT Plants, 2011 preliminary	Percent of Total CCGT Megawatts, 2011 preliminary	Percent of Total CCGT Megawatts, 2010	Percent of Total CCGT Megawatts, 2009	Percent of Total CCGT Megawatts, 2008	Percent of Total CCGT Megawatts, 2007
70% and Greater	0	0	0%	1%	1%	0%	0%
Under 70% to 50%	0	0	0%	0%	0%	1%	1%
Under 50% to 30%	1,606	3	13%	13%	2%	2%	30%
Under 30%	10,805	19	87%	86%	97%	97%	68%
Total	12,411	22	100%	100%	100%	100%	100%

Utilization of CCGT Fleet in the Southwest Power Pool

Capacity Factor Category	Net Summer Megawatts, 2011 preliminary	Number of CCGT Plants, 2011 preliminary	Percent of Total CCGT Megawatts, 2011 preliminary	Percent of Total CCGT Megawatts, 2010	Percent of Total CCGT Megawatts, 2009	Percent of Total CCGT Megawatts, 2008	Percent of Total CCGT Megawatts, 2007
70% and Greater	450	1	4%	4%	4%	0%	0%
Under 70% to 50%	2,350	5	19%	12%	23%	12%	19%
Under 50% to 30%	2,969	5	24%	35%	30%	25%	20%
Under 30%	6,381	11	53%	50%	43%	63%	61%
Total	12,150	22	100%	100%	100%	100%	100%