

The Brattle Group

Electricity Market Overview for Manitoba Hydro's Export Market in MISO

Prepared for
Manitoba Hydro

The Brattle Group

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Context and Assignment

As part of its upcoming NFAT regulatory hearing, Manitoba Hydro engaged *The Brattle Group* to prepare a market overview of its U.S. export market for the next 20 years and beyond

- ◆ The U.S. Midwest, specifically MISO (Midcontinent ISO), is expected to be the primary market for surplus electric energy and capacity from Manitoba Hydro's new hydroelectric facilities, and is thus central to the NFAT hearing
- ◆ Brattle was asked to provide an independent perspective on US electricity markets, with focus on MISO, identifying and characterizing key drivers and risks that will shape the future directions of MISO power markets

This report is developed specifically for use in Manitoba Hydro's Needs For and Alternatives To (NFAT) regulatory hearing, and should not be used for other purposes

Brattle's Qualifications

The Brattle Group is recognized as one of the leading energy consulting firms in the U.S. and the world. Our broad experience in power markets across the U.S. helps us to assist electric utilities, deregulated power producers, customers, regulators, and policy makers with planning, forecasting and the development of regulatory and market frameworks. We are able to simulate and forecast the structure and performance of power markets utilizing a range of operational and financial tools and models. We provide economic and regulatory consulting, business strategy, and expert testimony for our clients, before regulatory agencies, courts, and arbitration panels.

Dr. Dean Murphy is an engineer and economist with expertise in energy economics, competitive and regulatory economics and finance, and a background in quantitative modeling and risk analysis. His work centers on the electric industry, encompassing issues such as resource and investment planning (including power and fuel price forecasting), valuation for contract disputes and asset transactions, climate change policy and analysis, and market rules and mechanics. He has addressed these issues in the context of business planning and strategy, regulatory hearings and compliance filings, litigation and arbitration, for investor-owned and public electric utilities, independent producers and investors, industry groups, system operators, and consumers. Dr. Murphy holds a Ph.D. in Industrial Engineering and Engineering Management and an M.S. in Engineering-Economic Systems, both from Stanford University, as well as a B.E.S. in Materials Science and Engineering from the Johns Hopkins University.

1. Overview of Power Markets

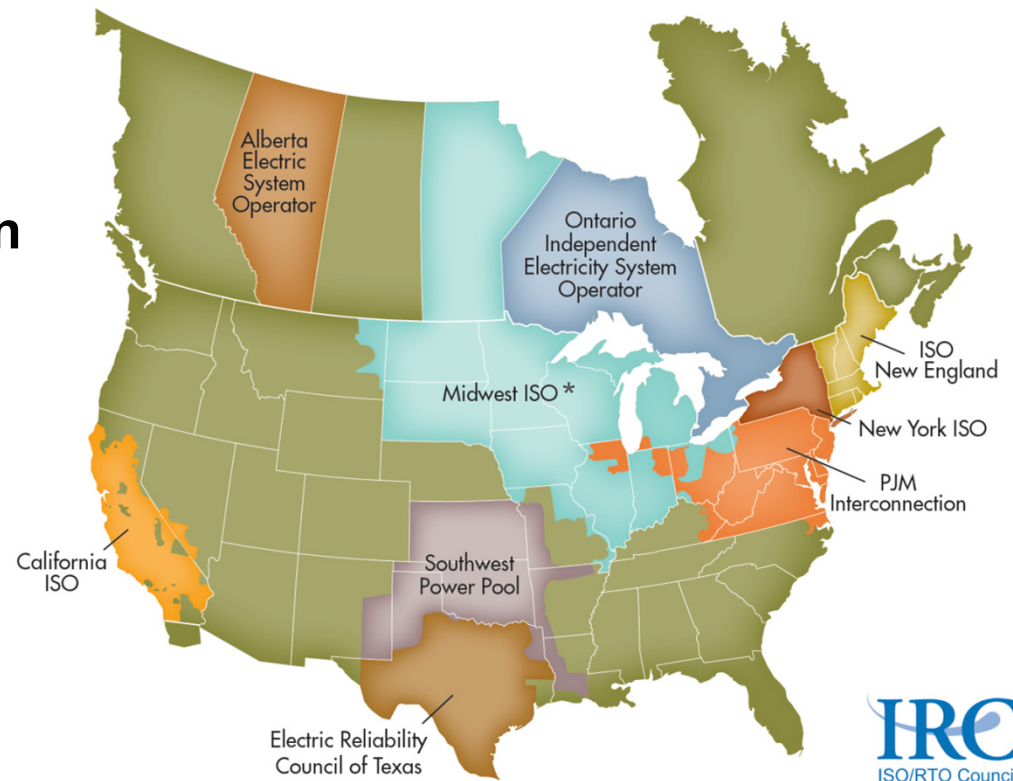
North American RTOs with Organized Wholesale Electricity Markets

Electricity markets across the US are deregulated at a wholesale level

- ◆ Transactions for electric energy, capacity, and other products may occur at prices determined by the market, rather than traditional cost-based regulation

In much of North America, Regional Transmission Organizations (RTOs) have been developed

- ◆ RTOs operate the transmission grid, run competitive wholesale markets, coordinate regional planning activities, and enforce reliability
- ◆ Bilateral markets still exist alongside RTO markets



*Effective April 26 2013, MISO changed its legal name to "Midcontinent Independent System Operator"

Types of Wholesale Electricity Markets

Electricity markets involve a number of different types of products

Product	Description
Energy	Electric energy that is actually produced and consumed.
Capacity	The ability to produce energy on demand. Capacity is important because energy is not storable; it must be produced instantaneously to meet peak load.
Ancillary Services	Physical services necessary to ensure reliable operation of the grid (such as load following, operating reserves, regulation)
Financial	Financial, non-physical instruments related to electricity (futures, options, virtual bidding, financial transmission rights); often provide market liquidity, allow hedging, etc.

Regional Markets Have Different Cost Drivers

Regional differences in fuel and resource availability affect market dynamics

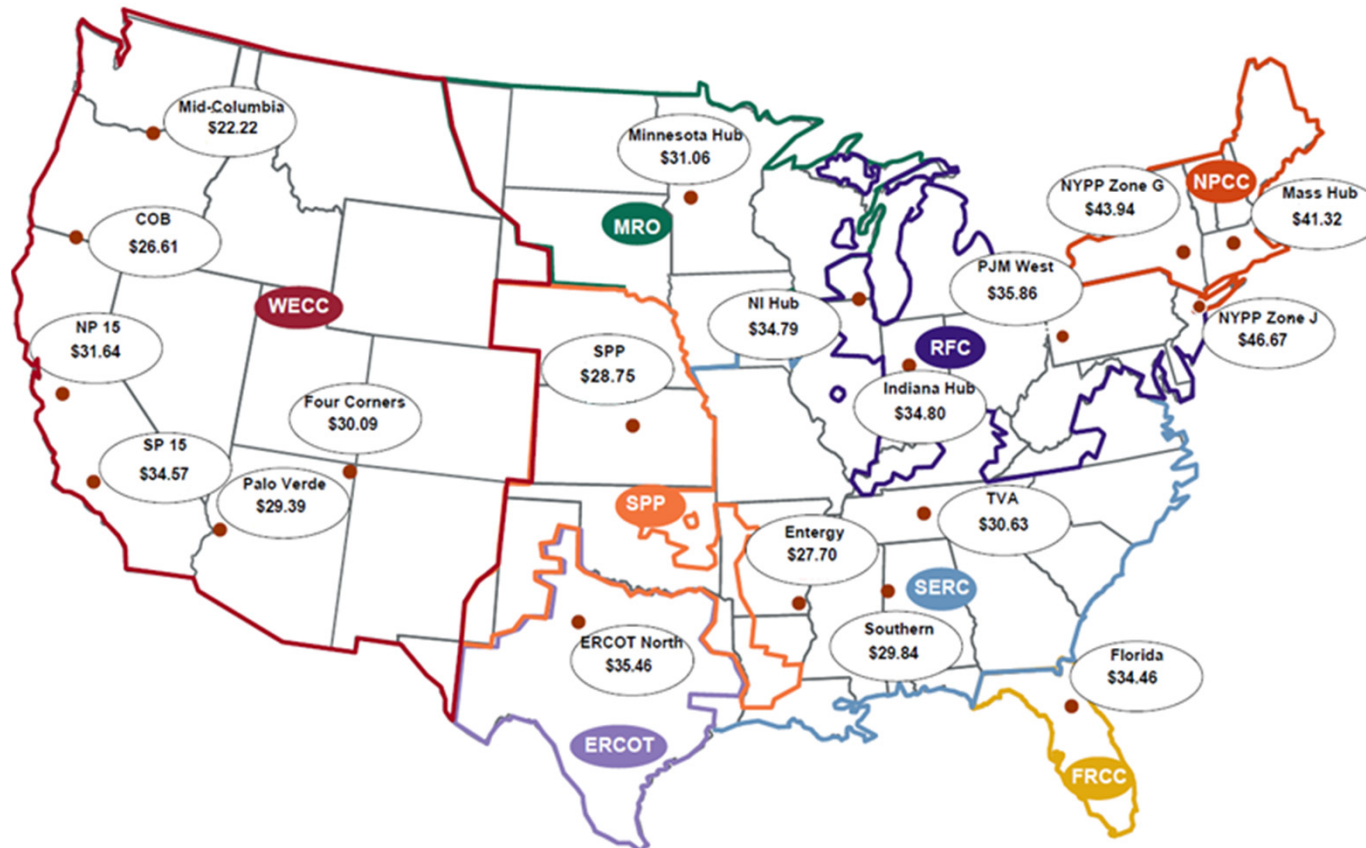
- ◆ MISO and PJM have historically depended far more on coal-fired generation
- ◆ California and Northeast markets dominated by natural gas
- ◆ Pacific Northwest has large hydro resources

Infrastructure development also plays a key role

- ◆ Major generation and transmission assets have very long lives, and can influence power markets for decades once developed
- ◆ Changing fuel availability and cost – e.g., shale gas – can thus affect future markets
 - Via fuel prices directly, and also through infrastructure buildout

Regional Electricity Prices Differ

Average On-Peak Spot Electric Prices in 2012 (\$/MWh)*



...thus transmission capability (the ability to move electricity products between locations) can be an important market component as well

Source: FERC Electricity Power Markets, National Overview (January 2013)

* U.S. power prices were unusually low in 2012 in many regions, due largely to very low 2012 natural gas prices. Gas and power prices have since recovered somewhat in most markets.

MISO is the Key RTO for Manitoba Hydro

Midcontinent Independent System Operator (MISO)



Covers much of the U.S. Midwest, including:

- ◆ All or most of North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Illinois, Indiana, Michigan; parts of Montana, Missouri, Kentucky, and Ohio

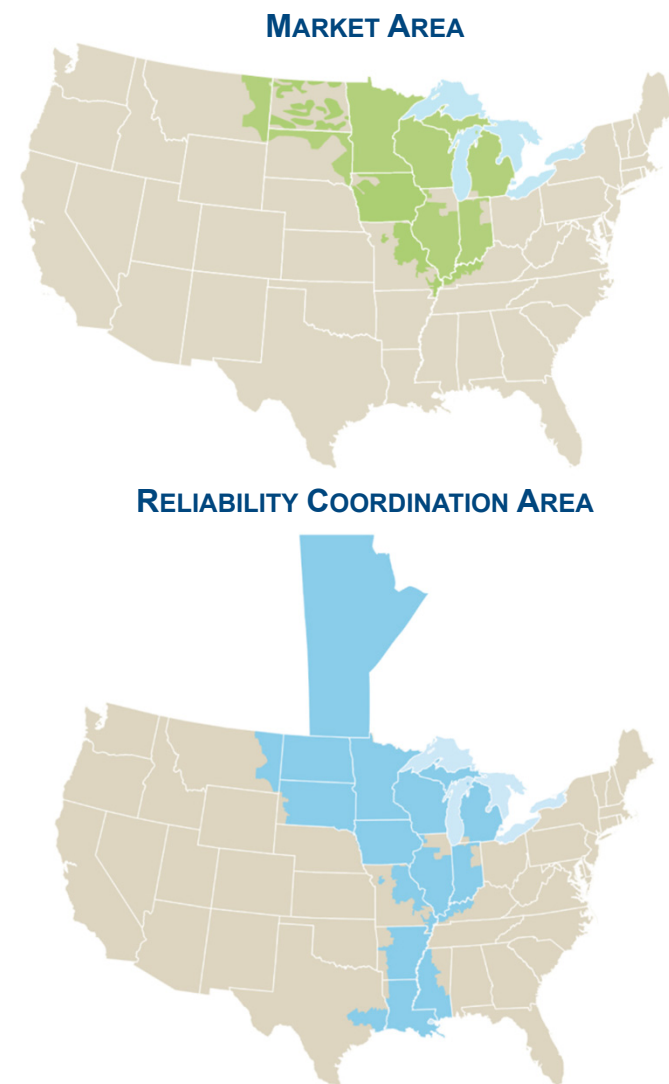
Major power trading hubs in MISO

- ◆ Indiana Hub
- ◆ Illinois Hub
- ◆ Michigan Hub
- ◆ Minnesota Hub

Source: 2012 State of the Market Report for the MISO Electricity Markets, Potomac Economics, June 2013

Overview of MISO

- ◆ All or parts of 11 states in the Midwest U.S. (plus Manitoba and Entergy for reliability coordination)
 - Entergy expected to join market area by the end of 2013
- ◆ MISO's primary roles include:
 - Provide independent transmission system access
 - Deliver improved reliability coordination
 - Perform efficient market operations
 - Coordinate regional planning
 - Foster platform for wholesale energy markets
- ◆ RTO in 2001
 - 2005: Nodal energy markets, financial transmission rights
 - 2009: Ancillary services; voluntary capacity auction
 - 2012: Independent coordinator of transmission services for Entergy
- ◆ Scope of operations
 - 131,000 MW of generation capacity in market area (206,000 MW reliability area)
 - 98,000 MW of peak load in market area (133,000 MW reliability area)
 - 362 market participants to serve population of 42 million
 - 526 million MWh of annual billings
 - Installed generation capacity includes 48% coal, 32% gas+oil, 8% nuclear, 14% renewables
 - 65,250 miles of transmission
 - 46 Transmission Owners with ~\$20 billion assets under MISO control



Sources: [1] MISO Corporate Fact Sheet (as of June 2013), [2] MISO Training Materials: Market Overview (as of June 2013)

MISO Electricity Markets

MISO operates the following markets:

- ◆ “Day-Ahead” forward energy and operating reserves (to commit generation for the next day)
- ◆ “Real-Time” spot energy and operating reserves (under 5-minute dispatch)
- ◆ Financial Transmission Rights (“FTRs”) to hedge risk of congestion costs
- ◆ Voluntary Capacity Auction (“VCA”) to help LSEs acquire resources to meet mandatory resource adequacy requirements
 - VCA acts as a balancing market
 - Resource adequacy requirements are mostly met through owned capacity and bilateral purchases, outside VCA

Bilateral markets exist alongside formal MISO markets

- ◆ Particularly important for longer-term transactions not covered by formal markets

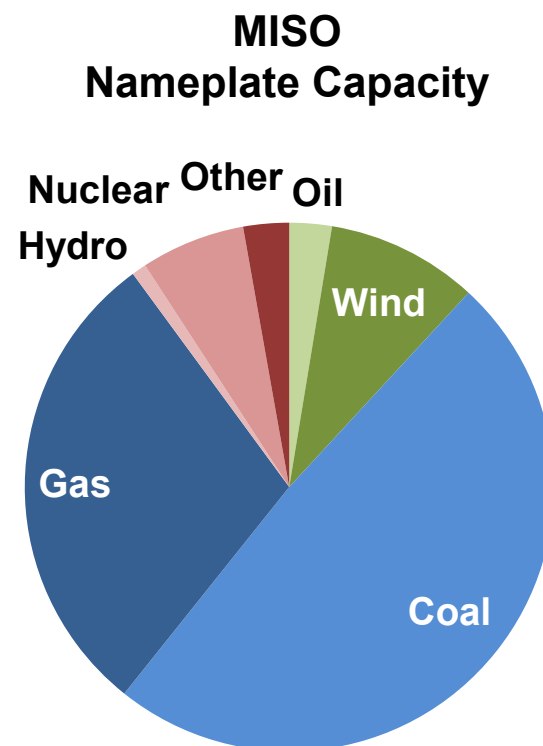
MISO’s market monitor finds its formal markets are “workably competitive”

- ◆ Thus bilateral markets are also presumed competitive

MISO's Generation Mix

MISO has been dominated historically by coal

- ◆ Drop in gas price since 2008 make gas more competitive with coal
 - 2012's extreme low gas price meant gas set price in almost all peak periods (that is anomalous)
 - Gas will not be quite so important in the near future (gas price has rebounded since 2012), but as more coal retires, and with modest load growth and continued moderate gas prices, gas will be more important than it has been historically
- ◆ Unexpectedly low load (and low growth) in recent years has led to a modest capacity surplus
 - Low capacity prices, especially near-term
 - Low energy prices off-peak when wind blows
 - Surplus likely to disappear in a few years, due largely to significant coal retirements

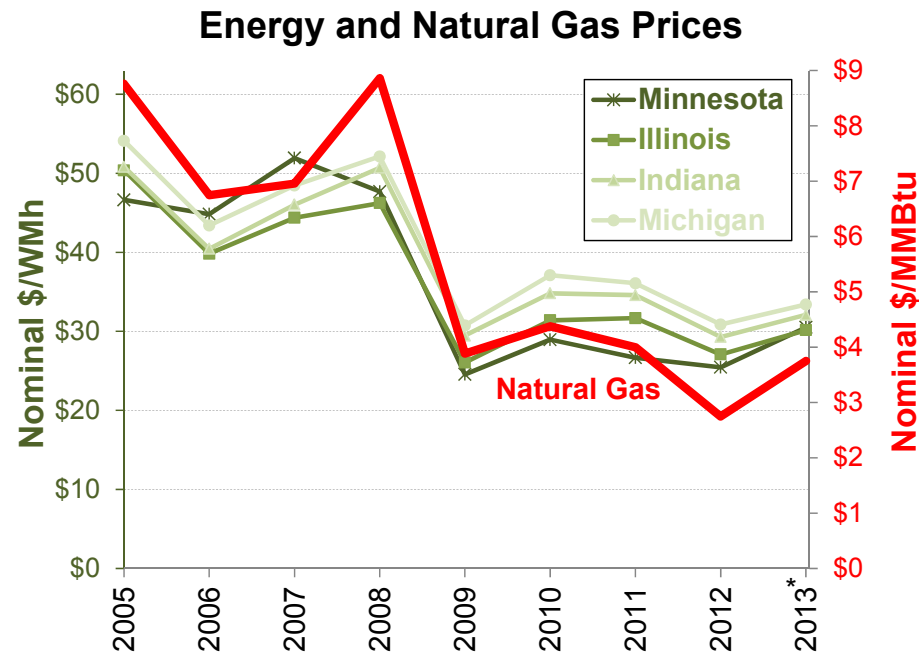


Source: 2012 State of the Market Report for MISO, Potomac Economics, June 2013

Energy Prices

Energy prices, typically set by short-run variable cost of marginal generation, have continued to be closely related to gas prices

- ◆ Falling gas price has driven down power prices, especially on-peak
 - Recent Minn Hub power prices are ~\$25-30/MWh, well below mid-2000s prices
 - Minnesota has slightly lower prices than nearby pricing points



Source & Notes:

Data compiled by Ventyx, The Velocity Suite (as of June 2013)

* 2013 is part-year data through June; it may not be representative of full-year, in part due to seasonality of gas and power prices

Peak / Off-peak Price Differential

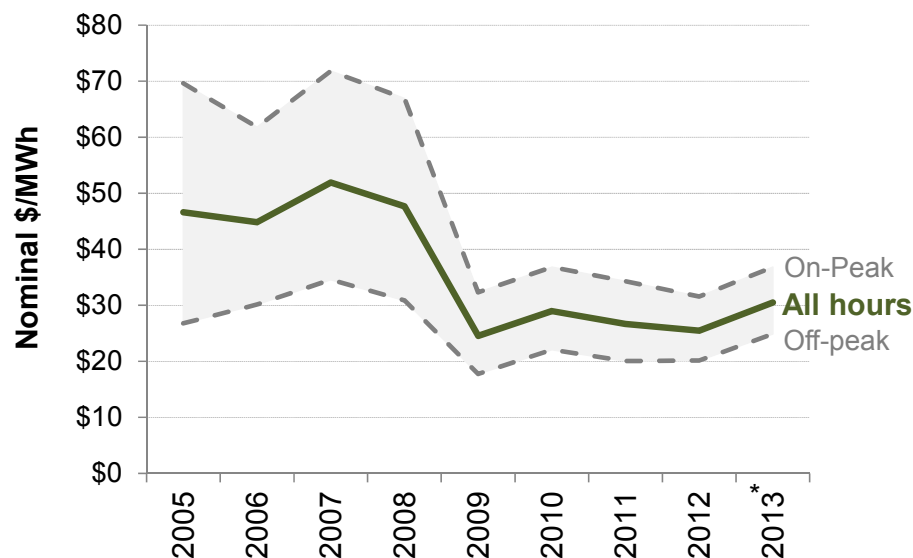
Over past 5-10 years, peak/off peak differential has fallen to ~\$10/MWh

- ◆ Similar dispatch costs for coal and gas generation at low gas prices
- ◆ Capacity glut keeps peak price low

That could reverse in future:

- ◆ More wind additions will depress off-peak prices
- ◆ More gas on the margin on peak (and rising gas price) raises peak price
 - Coal retirements, exacerbated by depressed off-peak margins, put gas on the margin still more
- ◆ But CO₂ price could have the opposite effect
 - Increasing off-peak price more than on-peak price, squeezing differential

On-Peak and Off-Peak Prices
(Minnesota Hub)



Source and notes:

Data compiled by Ventyx, The Velocity Suite (as of June 2013)

* 2013 is part-year data through June; it may not be representative of full-year, in part due to seasonality of power prices

Recent Developments in MISO Market

Integration of Entergy

- ◆ Adding Entergy will create Southern Region in MISO, including most of Arkansas, Louisiana, Mississippi, and part of Texas
- ◆ Transfer of operational control of transmission system planned for December 2013

Locational Capacity Market Reforms

- ◆ Reforms became effective October 1, 2012 for the planning year beginning on June 1, 2013
- ◆ New resource adequacy procedures set locational (zonal) capacity requirements. Unlike the previous mechanism, it is now mandatory and delivers an annual capacity product (previously monthly)

Capacity Markets

- ◆ Low load growth has contributed to a capacity surplus
- ◆ No immediate need for new capacity resources, but that could change by ~2016, depending on how much coal capacity is retired

Manitoba Hydro's Coordination with MISO

Canadian legal (sovereign) considerations prevent Manitoba Hydro from being a Transmission Owner in MISO and fully participating in MISO markets

- ◆ But Manitoba Hydro and MISO coordinate on tariff administration services, congestion management, transmission planning activities, and reserve sharing
- ◆ MISO is responsible for reliability coordination and transmission settlements, and administers the contingency reserve sharing group
- ◆ MISO has undertaken a comprehensive study to estimate the costs and benefits of increasing transmission interconnection between MISO and Manitoba Hydro
 - Started in mid-2011, the study report is due in October 2013
 - The focus is to utilize Manitoba Hydro's flexible system and storage capabilities to address the integration challenges created by variable and non-peak nature of wind generation in MISO
 - Hydro can provide ancillary services (load following, reserves) to MISO
 - Increasingly important as non-dispatchable renewable capacity is added

MISO Transmission Expansion Plan

MISO develops an annual comprehensive plan through the MTEP process to meet reliability, policy, and economic needs of the region

Main project categories, identification, and cost allocation

- ◆ Baseline reliability projects needed to ensure compliance with applicable reliability standards
 - Identified through power flow and voltage stability analysis for various system conditions
 - Costs primarily shared locally through Line Outage Distribution Factor (LODF) methodology; 20% paid by regional load if 345kV or above
- ◆ Market efficiency projects primarily relieves congestion
 - MISO performs nodal market simulations to calculate production savings, and applies a benefit-cost ratio threshold of 1.2-3.0 depending on project in-service date
 - Costs allocated to three planning sub-regions (West, East, and Central) commensurate with expected benefits; 20% paid by regional load if 345kV or above
- ◆ Multi value projects needed to address energy policy laws and/or provide widespread benefits across footprint
 - MISO uses a portfolio approach to identify projects providing reliability, public policy, and economic benefits (based on studies performed in several MTEP cycles since 2003)
 - Costs paid uniformly by load (*i.e.*, 100% postage stamp)

Primary Drivers of Long-Term MISO Power Prices

Many factors can influence long-term power prices, but a few key factors are the primary drivers

- ◆ **Fuel price** – primarily natural gas; coal prices can also be important
- ◆ **Climate policy** – stringency and form both have an effect
 - CO2 price (cap, tax) vs. non-price (promote renewables, retire coal, efficiency...)
- ◆ **Coal retirements**
 - Driven partly by new EPA environmental requirements, and in large part by relatively low gas prices, many coal units are retiring
 - Strict climate policy, if enacted, could trigger many additional retirements
- ◆ **Renewable additions (and transmission expansion)**
 - Driven by state Renewable Portfolio Standard (RPS) requirements and subsidies, but cost reductions could potentially eliminate the need for additional incentives
 - Large additions require significant regional transmission expansion
- ◆ **Load growth**
 - Tied to economic growth, but demand-side management programs (energy efficiency, load shifting) also plays a key role
 - Has been very low in the past 5-10 years (compared to a few decades ago)

Uncertainty and Feedback Effects

Many (most) of the drivers of power prices are uncertain, especially over several decades

- ◆ This leads to unavoidable uncertainty in power markets and power prices, with greater uncertainty for more distant projections

Strong negative feedback tends to restrain the extremes in the long-term (though still allowing short-term volatility)

- ◆ High prices curb demand, encourage efficiency and substitution, and encourage new supply
- ◆ Low prices boost demand, reduce efficiency incentives, encourage fuel switching to electricity, discourage new entry, and hasten retirements

Very long-term, market structure may be uncertain

- ◆ Large additions of non-dispatchable renewables could give capacity a bigger role, while depressing energy price

2. Fuel Prices

Electricity Fuels in the Midwest

Midwest power markets have historically been dominated by coal-fired power, but this is changing

- ◆ Natural gas prices have fallen dramatically since early to mid-2000s
 - Efficient gas-fired plants now compete with inefficient coal-fired plants for dispatch (though not to the extent they did in 2012, where extremely low gas price meant gas was able to compete directly with relatively efficient coal plants)
- ◆ Coal plants face new environmental requirements that could be very costly
 - Some have already retired and more are expected to retire after 2015; some are switching to gas or co-firing with gas
- ◆ The low capital cost of gas plants, along with relatively cheap gas, makes gas more economical than coal for new capacity
 - Coal capital costs are very high, in part due to the need to comply with environmental regulations
- ◆ Oil is much less important as a price-setting fuel (though some oil-fired units are used for reliability)

Over time, gas will progressively displace coal as the price-setting fuel

- ◆ Its importance in setting prices will exceed its overall energy share

Natural Gas

In the mid-2000s, gas prices were headed upward as domestic conventional gas supplies dwindled

- ◆ Gas prices were expected to increase significantly – from \$4-5/MMBtu to \$8/MMBtu or more, and stay high
- ◆ Imported LNG (liquefied natural gas) would be needed to supplement domestic supplies
 - A number of new LNG import terminals began development

The shale gas revolution changed all that

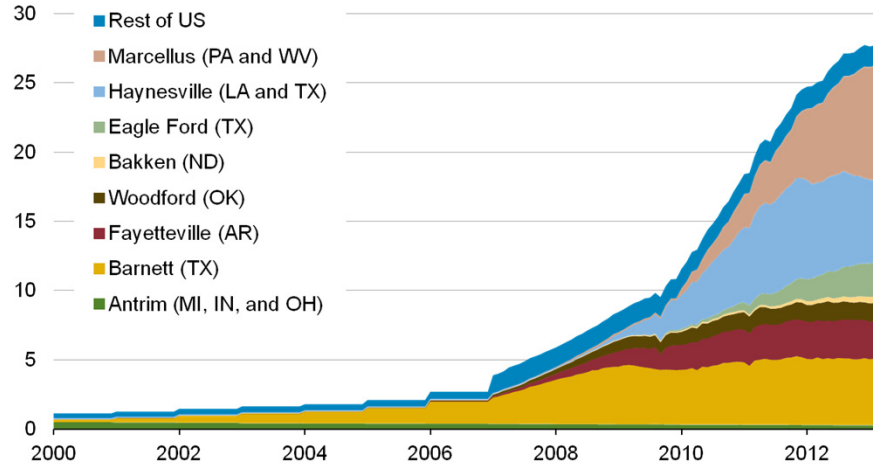
- ◆ Huge deposits of previously inaccessible shale gas have been made available and economical by new horizontal drilling and hydraulic fracturing (fracking) techniques
- ◆ Gas prices have collapsed relative to previous high prices and even higher expectations for the future

The Shale Gas Revolution

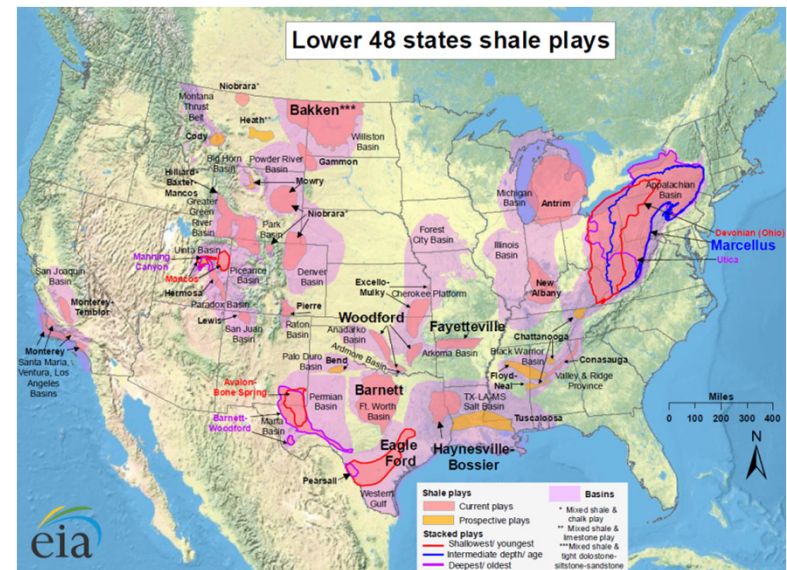
Large new unconventional, shale gas supplies began to enter production about 5 years ago, as conventional supplies were falling off

- ◆ Shale gas production has recently exceeded 25 Bcf/d, accounting for more than a third of total production in the US

Domestic Shale Gas Production (Bcf/d)

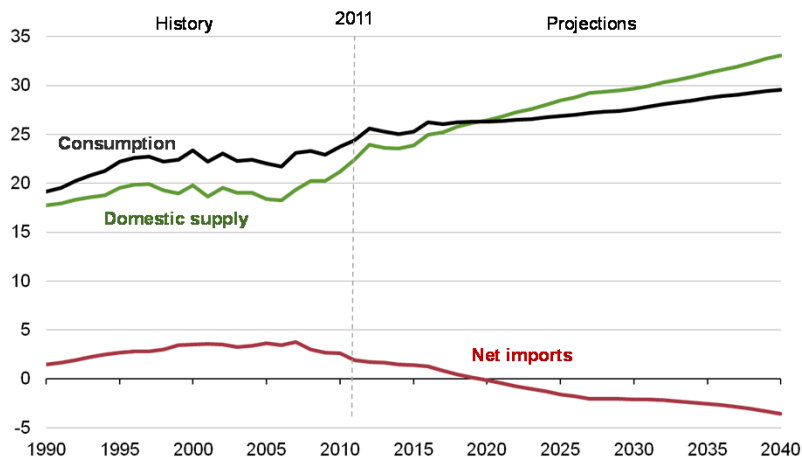
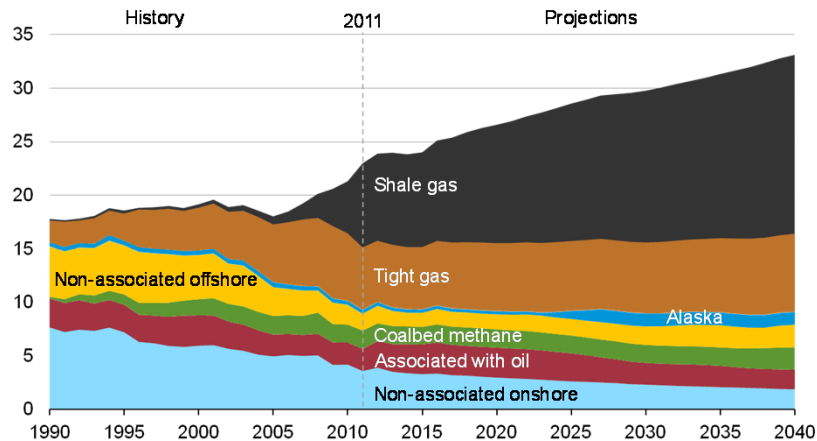


Source: EIA based on gross withdrawal estimates of LCI Energy Insight (as of March 2013)



The Shale Gas Revolution (cont'd)

Natural Gas Production and Consumption in the U.S. (Tcf/yr)



Source: EIA, 2013 Annual Energy Outlook 2013

Shale gas is expected to drive most of the growth in gas production

- ◆ The U.S. Energy Information Administration (EIA) projects that the production of shale gas will more than double by 2040, reaching about half of U.S. output
- ◆ The increase in domestic supply led by the development of shale gas resources will likely outpace consumption
 - Most of the natural gas imports from Canada could be eliminated
 - The U.S. may become a net exporter of natural gas by around 2020

Gas Prices

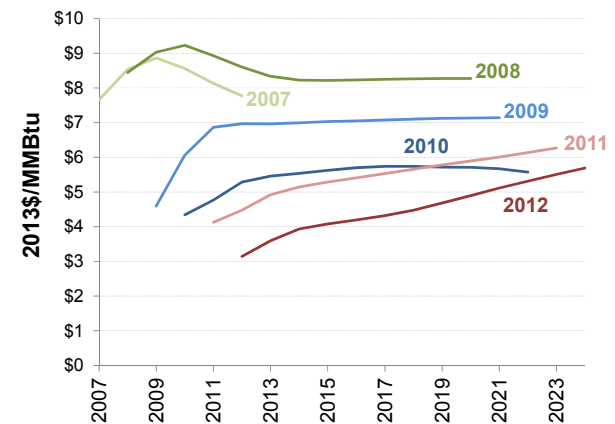
New supplies (and reduced demand) caused a gas price collapse after 2008

- ◆ Expectations of future prices also came down as the market realized the long-term potential of shale gas

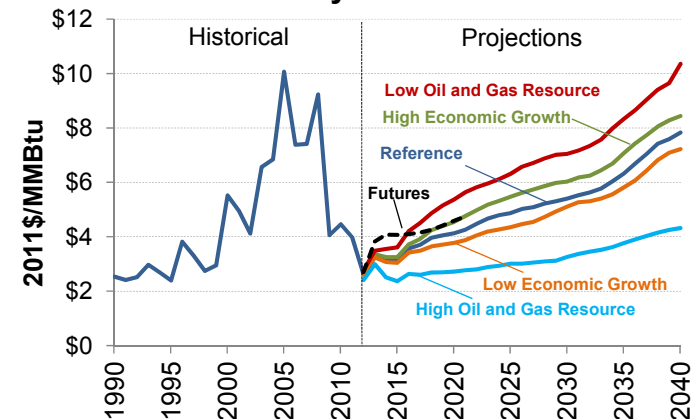
Prices are expected to remain below expectations of a few years ago (though short-term price has already rebounded from the extreme lows of 2012)

- ◆ Gas should be plentiful for decades, able to accommodate new demand (fuel switching, industrial, transport)
 - Even strict regulation of fracking would add only modestly to gas prices; around \$0.50/MMBtu
- ◆ U.S. likely to become an LNG exporter
 - LNG import terminals converting to export e.g., Dominion Cove Point (MD), Freeport (TX), Sabine Pass (LA)

NYMEX Henry Hub Futures by Vintage



Historical and Projected Henry Hub Prices



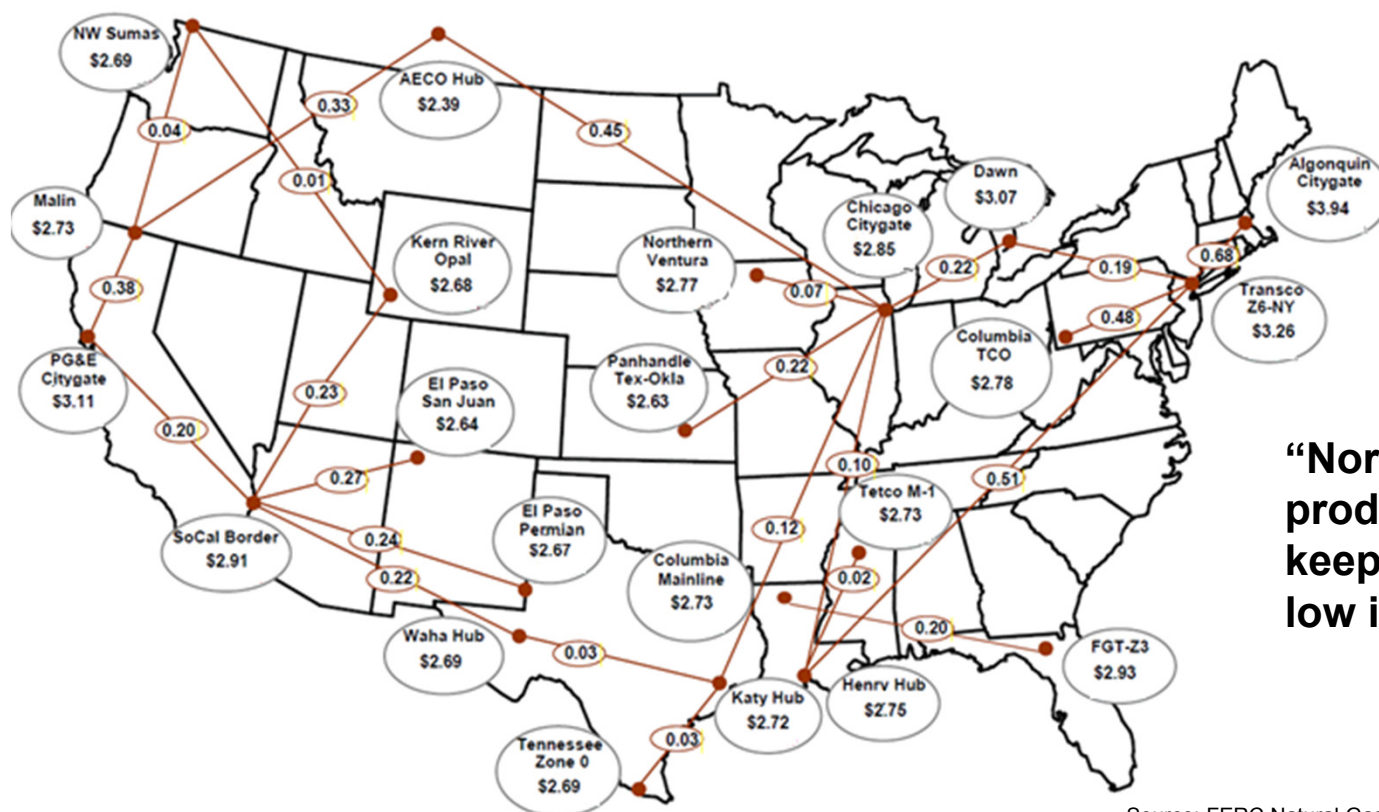
Sources:

- [1] NYMEX futures data compiled by Ventyx, The Velocity Suite; prices shown are the average of all September trading dates in given year
- [2] Henry Hub price projections from EIA, 2013 Annual Energy Outlook

Gas Prices – Basis Differentials

Basis differentials from Henry Hub to Midwest locations are relatively low

- ◆ Gas prices shown are 2012 averages, which are uncharacteristically low (gas prices have since recovered); but 2012 basis differentials are comparable to historic and likely future levels



“Northern” shale gas production will likely keep basis differentials low in the Midwest

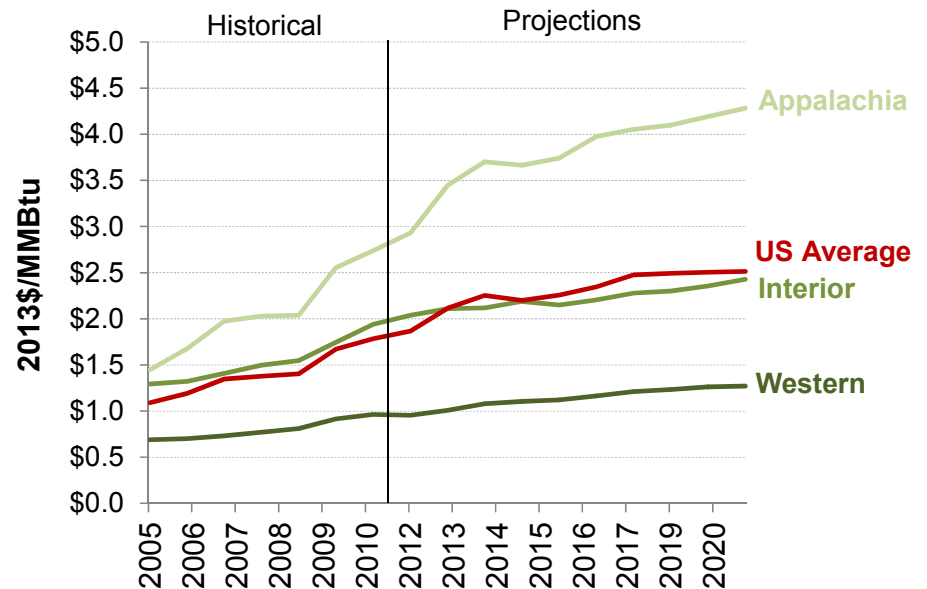
Source: FERC Natural Gas Markets, National Overview (January 2013)

Coal Prices

Coal prices are expected to increase at a modest 1-2% per year (in real dollars) due to reduced mining productivity and increased production

- ◆ Increased production is supported in part by future export opportunities
- ◆ Uncertainty in coal prices is driven by mining productivity, labor and equipment costs, and transportation rates, as well as export opportunities
- ◆ Western coal is cheaper than other regions; important in MISO
- ◆ Delivered prices also depend on transportation charges, which can be substantial

Average Minemouth Coal Prices by Region



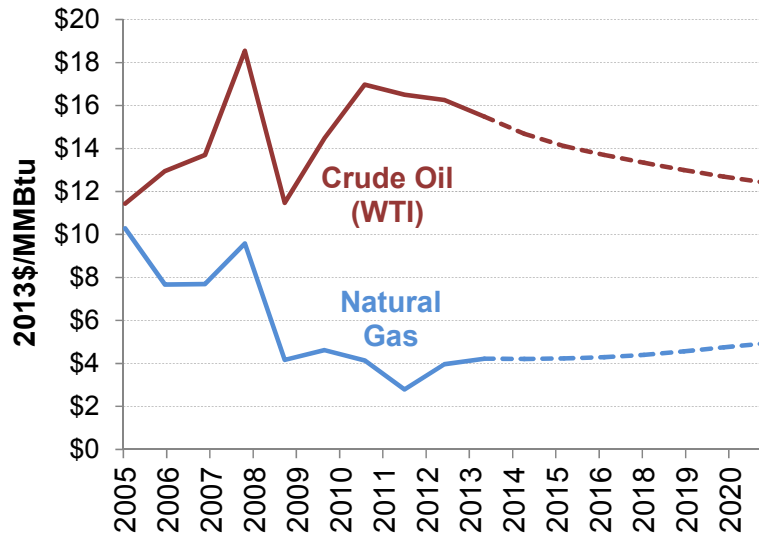
Source: EIA, 2013 Annual Energy Outlook

Oil Prices

Oil prices will not likely have a major effect on future power prices

- ◆ Over the past few years, oil prices have risen, while gas prices have fallen, making oil uneconomic for power generation going forward
- ◆ Oil will continue to serve as a backup fuel and for local reliability

Historical and Futures Prices
(Crude Oil vs. Gas)

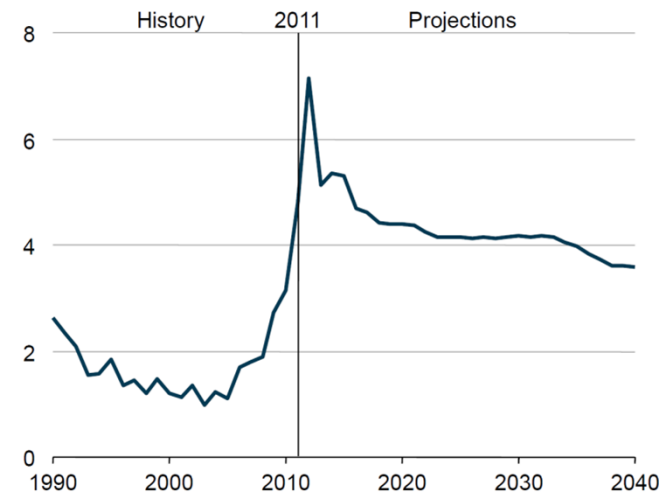


Source and Notes:

[1] Data compiled by Ventyx, The Velocity Suite (as of June 2013)

[2] Assumed heat content for crude oil to be 5.8 MMBtu/Barrel.

Ratio of Crude Oil and Henry Hub Spot Prices
in Energy-Equivalent Terms



Source: EIA, 2013 Annual Energy Outlook

3. Climate Policy

Climate Change and Climate Policy

Scientific consensus is clear – continued (accelerating) fossil fuel use is raising CO₂ levels and affecting climate

- ◆ 400 ppm threshold was passed recently (natural baseline = 280 ppm), and CO₂ concentrations will continue to rise

The U.S. administration recently updated its “official” estimate of the social cost of carbon

- ◆ At 3% discount rate, 2020 CO₂ cost is \$43/ton CO₂ (average estimate, \$2007)*
 - This value was formerly \$26/ton CO₂ (2010 report)

But no political will to address greenhouse gases (GHG) yet

- ◆ Partisan politics and concerns about weak economy create barriers
- ◆ “Natural” GHG reductions (due to economic slowdown and cheap gas) may have removed some of the urgency

Source:

Technical Support Document: - Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, United States Government, May 2013

Climate Policy Can Take Many Forms

Often thought of as broad carbon pricing policy, covering power sector and possibly economy-wide

- ◆ Cap & Trade, such as the 2007 Lieberman Warner bill
- ◆ Or Carbon Tax

But many other types of policies will advance climate goals, either as their primary purpose or as secondary effects

- ◆ Renewable requirements (RPS) and incentives
 - Production Tax Credit (PTC); Investment Tax Credit (ITC)
- ◆ Efficiency standards
- ◆ Utility demand-side programs
- ◆ EPA regulation of new and existing power plants
 - Both through direct regulation of GHG emissions, and as a side effect of regulating non-GHG emissions

Federal Carbon Pricing Policy

Carbon price (Cap & Trade, or Carbon Tax) is a natural mechanism for federal GHG policy

- ◆ Federal (nationwide) Cap & Trade is dead, for now
 - Seemed likely in 2008, but was dropped to deal with financial crisis
 - Performance of CO₂ emissions trading system in Europe (EU ETS) further discredits Cap & Trade
 - Price collapsed as a result of the natural drop in emissions that accompanied the economic downturn – this eliminated incentives to cut emissions
- ◆ Some revived interest (recently) in carbon tax approach
 - Simpler, more predictable outcomes; links to fiscal cliff and tax reform
 - Congressional proposals
 - Boxer-Sanders (2013): \$20/ton CO₂ (2014) + 5.6% per year
 - Larson, Starke, Inglis (2009): \$10 - \$15/ton CO₂ plus \$3 - \$10/year

Prospects for U.S. Carbon Pricing Legislation

Federal carbon-pricing policy (Cap & Trade, Carbon Tax) appears unlikely to be passed any time soon

- ◆ Financial crisis and increased political partisanship make it difficult to do almost anything
- ◆ National carbon pricing is less politically acceptable
 - Partly over concern for economic consequences
 - If it happens at all, a carbon price is likely to be lower and start later than expectations of a few years ago

Regional CO₂ pricing programs may now be the most likely path to a national carbon-pricing policy

- ◆ Regional Greenhouse Gas Initiative (RGGI) in the Northeast; California AB32
- ◆ If expanded to cover many populous states, a federal program might then be adopted to harmonize nationally

Background on GHG Regulation by the EPA

U.S. Supreme Court (Massachusetts v. EPA, 2007) confirmed Clean Air Act Title II includes climate change

EPA endangerment finding was issued in 2009

- ◆ Title II addresses mobile sources
 - Stringent new fuel economy standards for cars & light trucks
- ◆ Identical language in Title I for stationary sources
 - Requires performance standards for new (& modified) sources in §111(b), and existing sources §111(d)
- ◆ These standards apply for non-criteria pollutants
 - Avoids incompatibility of Title I regulations with GHG controls (*i.e.* health-based state/local air quality standards)
 - But EPA regulation via the Clean Air Act (CAA) is still generally seen as inferior to Congressional action to address GHG
 - Economically less efficient, and politically controversial (though perhaps not more controversial than GHG legislation)

Current GHG Activity under Clean Air Act

New Source Performance Standards (NSPS) under §111(b)

- ◆ Proposed April 2012 for electric generating units
 - Standard is equivalent to efficient gas combined cycle – meaning no coal without carbon capture (grace period, 30 year averaging permitted)
 - EPA claims no effect or cost since no coal would be developed in any case
- ◆ Not yet final; updated timeline of September 2013 for revised proposed rule
 - Also likely to be litigated once rule is finalized
- ◆ Not clear how EPA would handle “modified” sources
 - If an existing source deemed to be “modified” is required to meet NSPS, this might force shutdown of numerous units

Existing sources rules promised under §111(d), but have been put off

- ◆ Could require retrofits – or shut down
 - Carbon capture; switch to gas/biomass (or co-fire); possible use of offsets
- ◆ Updated timeline: proposed rule by June 2014; final by June 2015

New U.S. Climate Initiative from the White House

June 25, 2013 – Obama announced a new executive climate action plan

- ◆ Reduce GHG emissions in the U.S.
- ◆ Adapt to climate change
- ◆ Lead international efforts

Executive actions will avoid the need for Congressional approval

- ◆ Specifics are lacking, but “President Obama is directing the EPA to work closely with states, industry and other stakeholders to **establish carbon pollution standards for** both new and **existing power plants**” (emphasis added)
 - New Plants: revise proposed rule by September 2013
 - Existing plants: proposed rule by June 2014; final by June 2015; implementation date unspecified but after 2016 state implementation plans
- ◆ Policies that significantly affect existing coal plants (as they must to reduce GHGs meaningfully) could have major market effects – likely to increase prices

Source: Climate Change and President Obama's Action Plan, the White House, at www.whitehouse.gov/share/climate-action-plan

State-Level U.S. Policy: California AB32

California – AB32 Cap & Trade

- ◆ AB32 enacted 2006, first compliance period began 2013
- ◆ 3 auctions so far for 2013, 2015 and 2016 allowances
 - 2013 allowances: \$10.09 (11/12); \$13.62 (2/13); \$14.00 (5/13)
 - 2015 allowances: \$10.00 (11/12)
 - 2016 allowances: \$10.71 (2/13); \$10.71 (5/13)
- ◆ Note: 2010 CARB advisory committee estimated prices of \$8-\$214/ton CO₂
- ◆ Plan to link to Quebec, possibly Australia

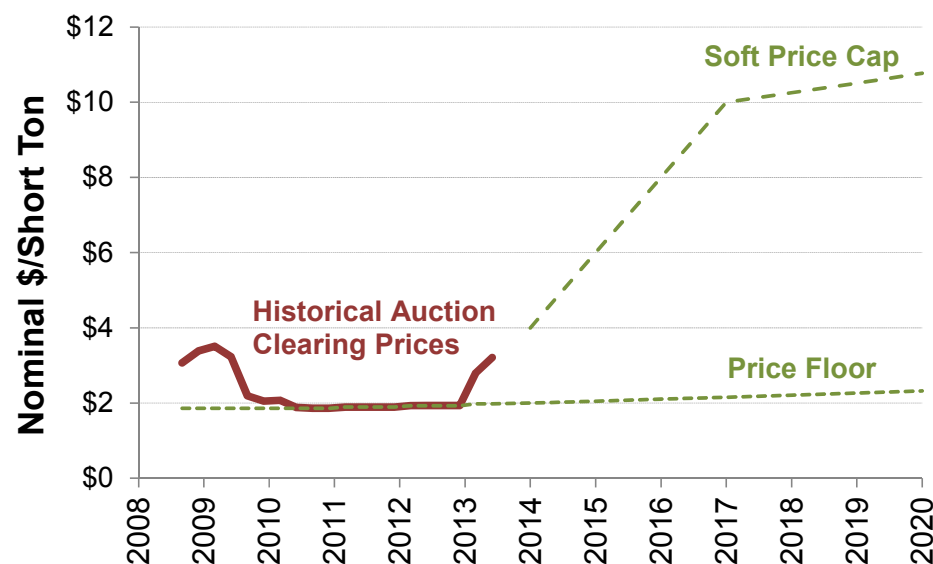
In the absence of federal policies, state/regional policies may emerge – which might then prompt federal action

State-Level U.S. Policy: RGGI

Regional Greenhouse Gas Initiative

- ◆ Now 9 states (& DC)
- ◆ Electric generators' CO₂ emissions “capped” starting 2008, and traded under the cap
- ◆ Original cap was set high, and emissions fell for unrelated reasons (recession)
 - Allowances at floor price (~\$1.90) for 2010-2013
- ◆ New agreement significantly lowers cap for 2013 forward
 - Also provides “soft cap” on price for cost-containment

RGGI CO₂ Allowance Prices



Source:

“CO₂ Allowance Auctions, Frequently Asked Questions”, RGGI.org Jan, 2013

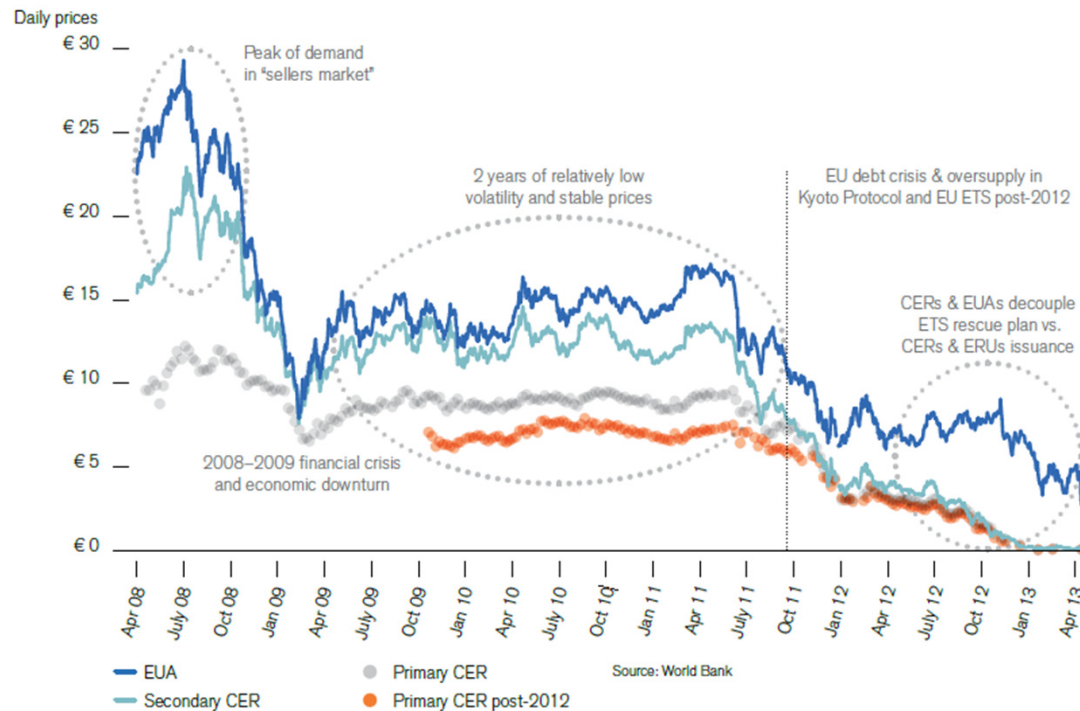
“Allowance & Bid Statistics (by Auction)” posted at www.rggi.org/component/content/article/54-co2-auctions-tracking-a-offsets/Auction-Results/205-allowance-a-bid-statistics-by-auction

European ETS Price Collapse

Problem with Cap & Trade structure:

- ◆ Price volatility (and thus inconsistent incentive to reduce GHG) caused by unrelated factors affecting GHG emissions

EU Allowances and Carbon Emission Reduction prices (2008-2013)



Source: World Bank; Mapping Carbon Pricing Initiatives, Developments and Prospects, Washington, May 2013, p.41

Effects of Other Environmental Regulations

EPA regulation of non-GHG pollutants may have significant GHG effects

- ◆ Compliance with requirements for mercury and air toxics, regional haze, cooling water, and coal ash will often necessitate large capital expenditures
- ◆ Particularly with low power prices (due to low gas prices), many coal plants may become uneconomic, and choose to retire rather than retrofit
- ◆ See Section 4: Environmental Regulation

Other Forms of “Climate Policy”

Renewables (see Section 5: Renewable Additions)

- ◆ State-level Renewable Portfolio Standards (RPS)
- ◆ Federal incentives for renewables
 - Production tax credit, investment tax credit

Demand management and conservation

- ◆ Appliance and building efficiency standards
- ◆ Utility demand-side programs

Effects of Climate Policy on Power Markets

Stringency and form of climate policy both have an effect

- ◆ Carbon price (Cap or Tax) has straightforward effects, increasing operating cost of fossil units and energy price
 - Coal dispatch cost increases ~\$1/MWh for each \$1/ton CO₂ price
 - Gas about half that
 - Power prices rise correspondingly, since fossil sets power price
 - **In the Midwest, \$1/ton CO₂ corresponds to ~\$0.75/MWh**
- ◆ Non-price policies affect power prices very differently
 - Promoting renewables (RPS, subsidy) doesn't necessarily increase energy price at all (and may decrease it)
 - Demand reductions (efficiency policies) can have similar effects
 - May also change capacity balance and affect capacity price

GHG Emissions Displacement

Additional MH exports displace energy generated in MISO

- ◆ Looking at the short-term (*i.e.*, assuming installed capacity is unaffected by Manitoba Hydro additions), emissions displaced will be those of the short-term marginal generation

Fossil is virtually always on the margin in operation

- ◆ Either coal or gas
 - Other generation types (nuclear, wind) have lower dispatch cost and are not displaced
- ◆ A typical coal plant emits ~1 ton CO₂/MWh
 - Gas-fired combined cycle (CC) about half that, gas-fired combustion turbine (CT) between coal and CC

Emissions displaced (short-term) are in the range 0.5 - 1.0 ton CO₂/MWh

- ◆ Not at either extreme – neither coal nor CC are always marginal
 - Historically, coal was marginal almost all the time; somewhat less true in future
- ◆ Future displacement depends on how other factors play out over time
 - Gas, coal and CO₂ prices, coal retirements, renewable additions, *etc.*

GHG Emissions Displacement – Long Run

The short-run measure discussed above likely understates the actual emissions displaced, because of current market dynamics

- ◆ Much coal is at risk of retiring, but little other (lower emission) capacity is threatened
- ◆ Thus any incremental retirements are very likely to be coal
 - Adding hydro (or any other) capacity resource increases the supply excess, reducing/delaying energy and capacity prices slightly
 - May cause retirement of incremental coal that would not otherwise retire
- ◆ Even if that coal capacity would never be on the margin in the short run, it is arguably a better measure of actual displaced generation (and emissions)
 - It is difficult to model this effect explicitly; retirement decisions are more complex than short-run dispatch decisions, and are “lumpy”
 - Emissions displaced depend on how much (and which) additional coal retires in response to adding a given amount of hydro capacity
 - But the direction is clear – displacement would be closer to 1 ton CO₂/MWh

4. Environmental Regulations

Overview of EPA Regulations

EPA's environmental regulations are expected to play an important role in electricity markets – mostly by pushing significant amounts of coal capacity into retirement

Regulation	Status	Pollutant Targeted	Compliance Options	Expected Date of Compliance
MATS (Mercury and Air Toxics Standards)	Final	HAPs (mercury, acid gases, PM)	ACI, baghouse, FGD/DSI	2015/2016
Regional Haze	Final	NO _x , SO ₂ , PM	SCR/SNCR, FGD/DSI, Baghouse/ESP, combustion controls	Typically in 5 years
CSAPR	Vacated, To Be Reviewed by Supreme Court	NO _x , SO ₂	SCR/SNCR, FGD/DSI, fuel switch, allowance purchases	Potential revised rule after 2015?
316(b)	Proposed	Cooling water	<u>Impingement</u> : Mesh screens; <u>Entrainment</u> : Case-by-case, may include cooling towers	2018
Combustion by-products (ash)	Proposed	Ash, control equipment waste	Bottom ash dewatering, dry fly ash silos, etc.	2019/2020
GHG Standards (see Section 3: Climate Policy)	Potential	GHG	Unknown, potential for trading of allowances	unknown

Mercury and Air Toxics Standards (MATS)

Covers Hazardous Air Pollutants (HAPs) such as mercury, phosphoric acid, lead and selenium compounds that are associated with cancer or other serious health affects

- ◆ Requires power plants to install Maximum Achievable Control Technology (MACT) with little flexibility for sources to comply
- ◆ Compliance date: April 2015
 - 1-year extension from state permitting agencies, and another possible 1-year extension from EPA if needed to maintain grid reliability
- ◆ Compliance options include combinations of:
 - Baghouse (\$200-500/kW), scrubber (\$450-900/kW), dry sorbent injection (~\$40/kW), activated carbon injection (\$20-30/kW), switch to gas/biomass

MATS is the single most important new environmental regulation (alongside low gas prices) driving coal plant retirements in the U.S.

- ◆ Most coal plants need to either add some controls, or switch fuel to gas/biomass

Regional Haze Rule

Aims to reduce haze-forming pollution that reduces visibility in parks and wilderness areas, especially in the Western U.S.

- ◆ Primarily due to emissions of particulate matter and its precursors SO_2 and NO_x
- ◆ Each state develops State Implementation Plans to reduce haze, requiring coal plants to install Best Available Retrofit Technology (BART)
 - Certain plants built during 1962-1977 are covered

EPA may either approve (fully or partially) or disapprove the State Implementation Plan (SIP), or issue a Federal Implementation Plan (FIP)

- ◆ Compliance date: Typically five years after EPA's ruling for each plant (ongoing, most recent proposed ruling was for Wyoming in June 2013)
- ◆ Compliance options (cost range due to unit size):
 - NO_x → Selective catalytic reduction (SCR, \$200-300/kW), selective non-catalytic reduction (SNCR, ~\$50/kW), or combustion controls
 - SO_2 → Scrubber (\$450-900/kW), dry sorbent injection (~\$40/kW)
 - PM → Baghouse (\$200-\$500/kW)
- ◆ Controls to comply with MATS not sufficient to meet NO_x requirements for Haze

Cooling Water Regulations

EPA proposed a rule in March 2011 to regulate cooling water intake structures (CWITs) at large power plants to reduce injury and death of fish and aquatic life

- ◆ Applies to 670 power plants across the U.S. (those using over 2m gallons/day of cooling water)
 - NERC study projects that the rule could trigger up to 1,500 MW in capacity losses in MISO^[1]
- ◆ The proposed rule does not require closed-loop cooling (cooling tower) for existing facilities
- ◆ Requirements:
 - Impingement: Limits on mortality (through modified traveling screens) or speed of water intake
 - Entrainment: Applies to large plants (> 125 million gallons per day), decided by state permitting agencies on a case-by-case basis, may include cooling towers
- ◆ Final rule delayed until November 2013 (compliance deadlines still uncertain)

Source: NERC, 2011 Long-Term Reliability Assessment, November 2011

Combustion By-Products (Ash) Regulations

Covers the handling of combustion by-products at coal plants including bottom ash, fly ash, boiler slag and gypsum

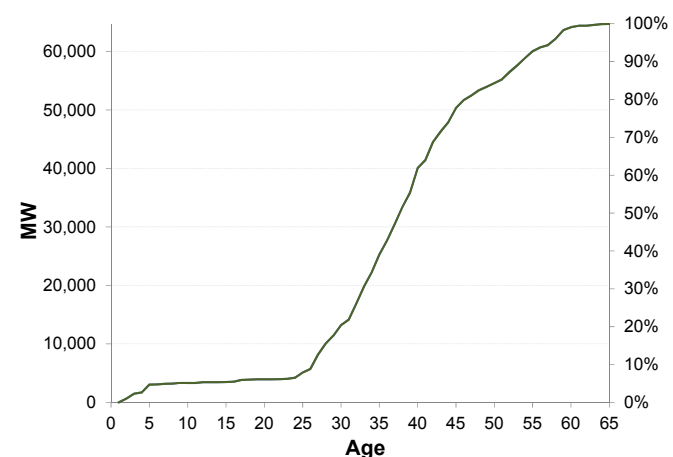
- ◆ EPA proposed two options in 2010:
 - Regulate as hazardous waste under Subtitle C of Resource Conservation and Recovery Act (RCRA)
 - Regulate under Subtitle D similar to those for municipal and non-hazardous solid waste, hence less stringent than Option 1
- ◆ In both options, it is likely that by the end of this decade:
 - Wet ash ponds will be eliminated or converted to dry landfills for most plants
 - Dry collection systems for bottom ash and fly ash will be installed
- ◆ The first option (Subtitle C) would significantly lessen the beneficial use of combustion byproducts
 - Currently, about 45% of ash is used in concrete, wallboard, roofing shingles, *etc.*

Coal Capacity and Retirements

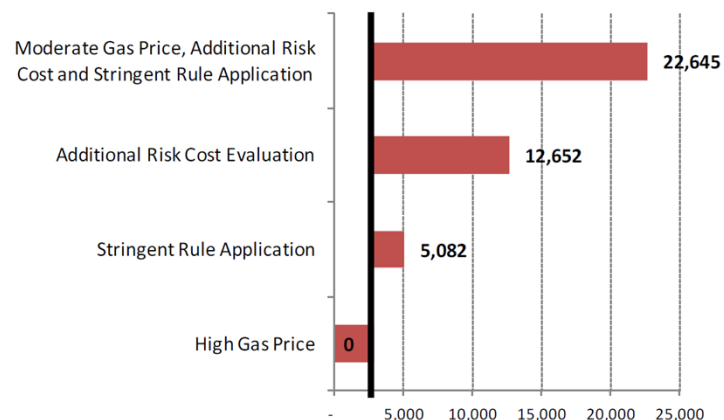
Significant coal capacity may be pushed into retirement by the new EPA environmental regulations

- ◆ Many units, especially older ones, do not have modern pollution controls, but may need to install them (or retire)
- ◆ Most coal plants in MISO are quite old
 - 92% now over 25 years; 61% over 35 years
- ◆ MISO's EPA Impact Study estimated up to 22 GW of coal capacity at risk of retirement
 - 1.3 GW already retired since October 2011; additional 4.9 GW retirements announced
 - Most MISO studies (*e.g.*, MTEP, the MISO Transmission Expansion Plan) assume 10-12 GW in their base case scenarios
 - *Brattle* recently estimated MISO retirements of 11-16 GW by the end of 2016^[3]

Cumulative MISO Coal Capacity by Unit Age^[1]



MISO Coal Capacity at Risk of Retirement^[2]



Sources:

[1] Data compiled by Ventyx, The Velocity Suite (as of June 2013)

[2] MISO, EPA Impact Study (October 2011)

[3] "Potential Coal Plant Retirements: 2012 Update," by Metin Celebi, Frank C. Graves, and Charles Russell, The Brattle Group, Inc., October 2012

Impact of Retirements & Retrofits on Power Prices

Coal retirements and retrofits would likely result in higher energy prices due to:

- ◆ Removal of low-cost resources from the regional supply curve, which would result in higher-cost (often gas) resources setting prices more often
- ◆ Increased variable O&M costs and heat rates of retrofitted coal units
- ◆ Possibility of higher gas prices in the short-run (due to feedback effects if gas demand increases sharply) would increase dispatch cost of gas units

MISO projects that retiring 12 GW of coal capacity would increase energy prices by \$1 to 5/MWh*

- ◆ Whether the price impact persists in the long-run depends partially on the amount and timing of replacement capacity
- ◆ Price effect could diminish if the retired capacity is replaced by efficient gas plants running at dispatch costs similar to coal

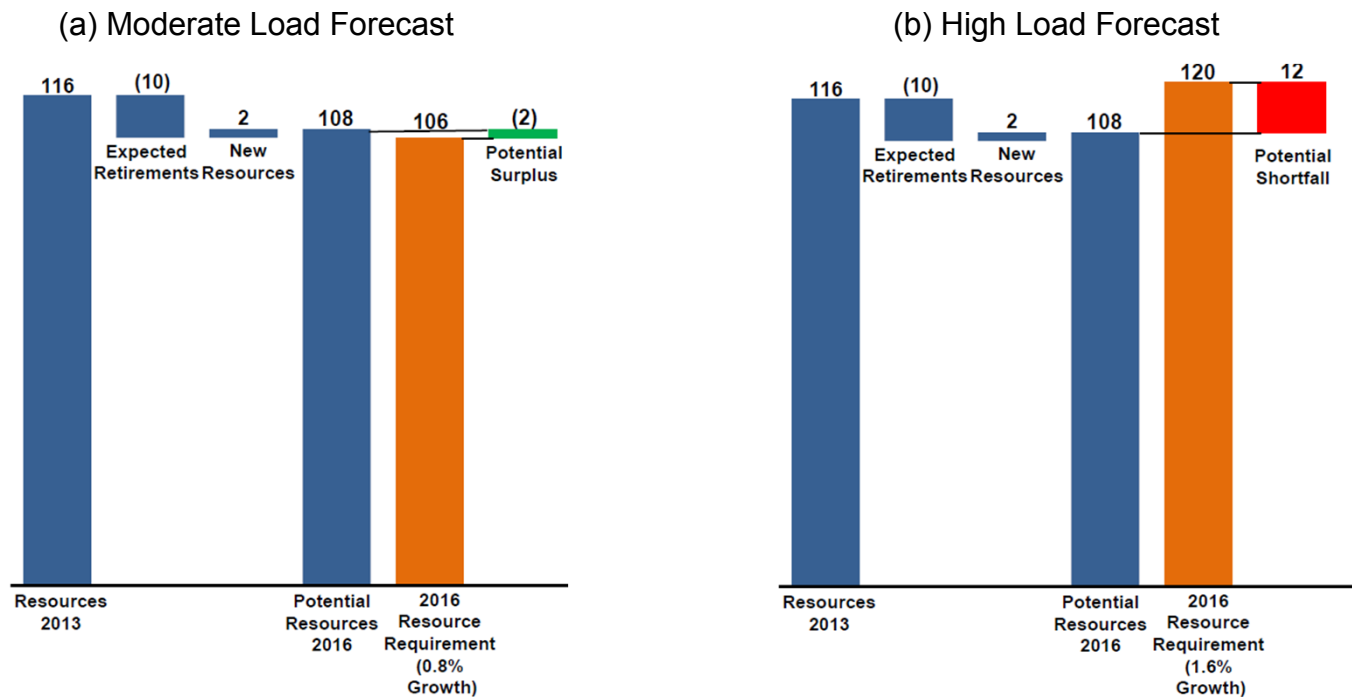
* Source: MISO, Impact of EPA Regulations on Coal-Fired Capacity (July 24, 2012)

Resource Adequacy Impacts of Retirements

Potential retirement of 10-12 GW of coal capacity would essentially eliminate the current surplus of capacity in MISO by 2016

- ◆ Capacity prices would increase to attract needed new capacity

Summer Resource Adequacy for 2016



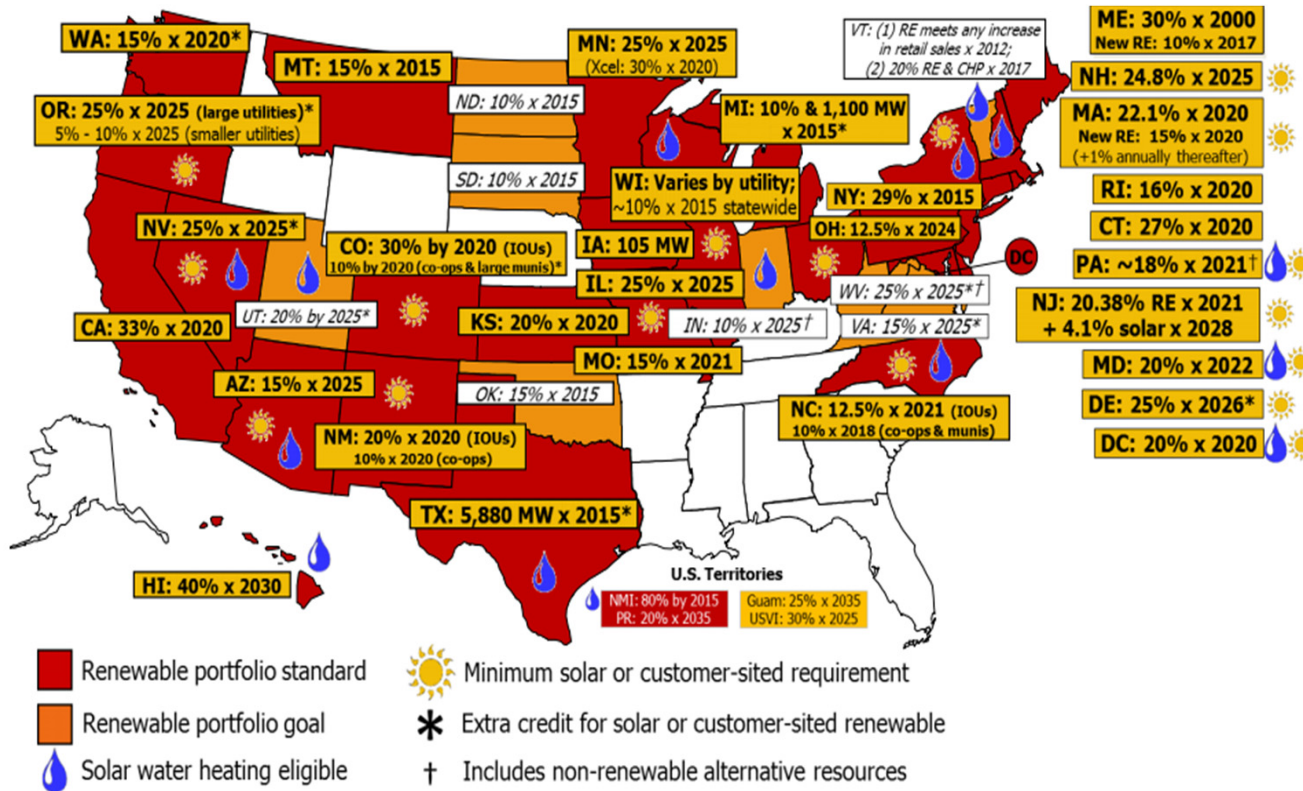
Source: MISO, Updated Resource Adequacy Impacts of EPA Implementation (March 27, 2013)

5. Renewable Additions (and Transmission)

Renewable Portfolio Standards

29 states and DC have adopted Renewable Portfolio Standards (RPS) with mostly ambitious targets; 8 others have renewable goals

- ◆ Most MISO states have targets of 10% to 25% over the next 10-15 years



Federal tax credits:

- ◆ Production tax credit (PTC) of \$22/MWh for wind, geothermal, biomass
Deadline for in-service extended through 2013
- ◆ Investment tax credit (ITC) of 30% for solar, fuel cells, and small wind, with a cash grant option
Recently allowed PTC-eligible resources

Source: Department of Energy, Database for State incentives for Renewables & Energy Efficiency (DSIRE), March 2013

Renewable Portfolio Standards

- ◆ Minnesota, Michigan, Illinois and Indiana comprise roughly 75% of the RPS demand in MISO
- ◆ Demand for renewable energy based on state-level RPS requirements for Class I-equivalent resources
- ◆ Existing demand for Class I RECs in MISO is ~20,000 GWh, about 3% of total system load
- ◆ This is estimated to increase to 35,000 GWh by 2015 (6.1% of load); over 70,000 GWh in 2025 (11.9%)
 - Actual GWh required depends on load since RPS is a percentage

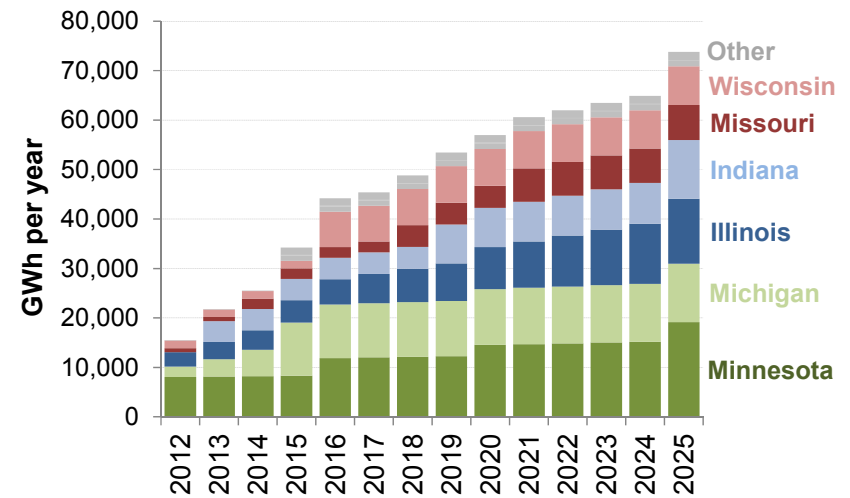
Sources and Notes:

- [1] RPS targets from DOE's Database of State Incentives for Renewables and Energy Efficiency (DSIRE)
- [2] Percentages for North Dakota, South Dakota and Indiana reflect voluntary goals.
- [3] Demand calculations based on 2012 sales data reported by EIA; assumed 1%/yr load growth
- [4] Only MISO portions of Illinois and Missouri are included.
- [5] States in Entergy's service area are not included

RPS Requirements in MISO States

State	Current	2015	2020	2025
Iowa	1.0%	1.0%	1.0%	1.0%
Illinois	6.0%	9.0%	16.0%	23.5%
Indiana ^[2]	0.0%	4.0%	7.0%	10.0%
Michigan	2.0%	10.0%	10.0%	10.0%
Minnesota	12.0%	12.0%	20.0%	25.0%
Missouri	2.0%	5.0%	10.0%	15.0%
Montana	10.0%	15.0%	15.0%	15.0%
North Dakota ^[2]	0.0%	10.0%	10.0%	10.0%
South Dakota ^[2]	0.0%	10.0%	10.0%	10.0%
Wisconsin	2.2%	2.2%	10.0%	10.0%
MISO Total	2.9%	6.1%	9.6%	11.9%

Annual Renewable Demand in MISO

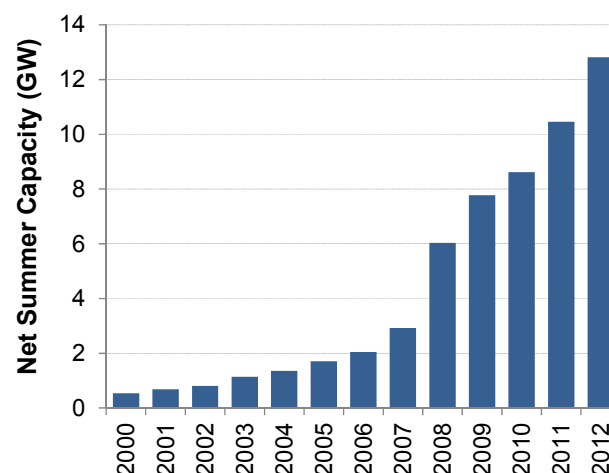


Wind Generation

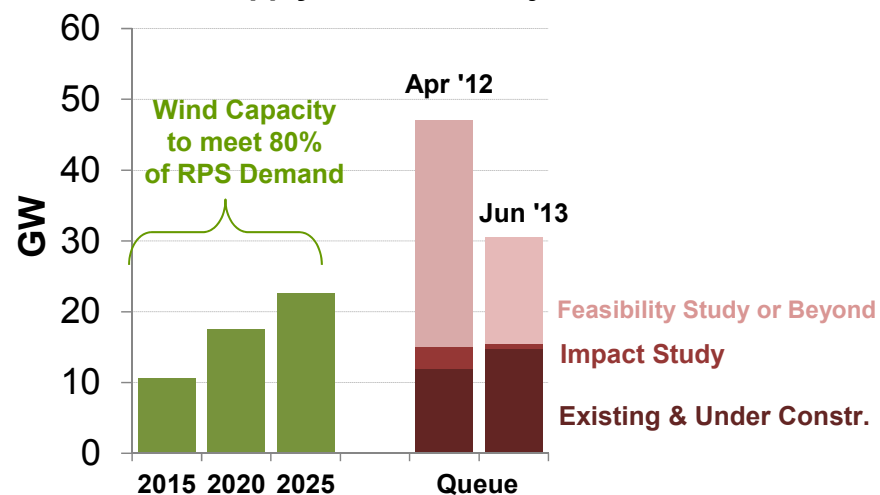
Wind has been the primary renewable technology added in recent years

- ◆ Driven by RPS requirements and financial incentives, wind capacity has grown by ~10% annually between 2009 – 2013
- ◆ MISO states need ~20 GW of wind capacity to satisfy 80% of the RPS requirements in 2025 (assuming other technologies supply ~20%)
- ◆ Uncertainty around the extension of the Production Tax Credit reduced the number of wind projects in the request for interconnection queue
 - Between April 2012 and June 2013, wind projects in MISO queue declined over 15 GW
- ◆ Growth in wind generation has caused increased transmission congestion, resulting in more wind curtailments

Installed Wind Capacity in MISO^[1]



Renewable Supply and Wind Projects in Queue^[2]



Sources and Notes:

[1] Wind Generation Capacity obtained from Ventyx, Energy Velocity on June 16, 2013
 [2] Calculated based on generation interconnection requests in the MISO queue (as of June 17, 2013). Demand calculations based on 2011 sales data reported by EIA; assumed 1%/yr load growth and 30% wind capacity factor. Assuming remaining 20% of the RPS requirement is satisfied by non-wind renewables RPS targets from DOE's Database of State Incentives for Renewables and Energy Efficiency (DSIRE).

Effect of Transmission

Transmission is complex, with widespread network effects

- ◆ Affects zonal capacity value under MISO's new locational capacity requirement
 - Though first auction suggests capacity values are unlikely to differ by zone for some time

Transmission patterns evolve slowly in a mature system, unless:

- ◆ There are rapid changes in load levels or locations
 - Very unlikely
- ◆ There are changes in generation locations
 - Quite possibly – old coal, often near load, is retiring; remote wind additions; gas development near pipelines

Potential Transmission Expansion

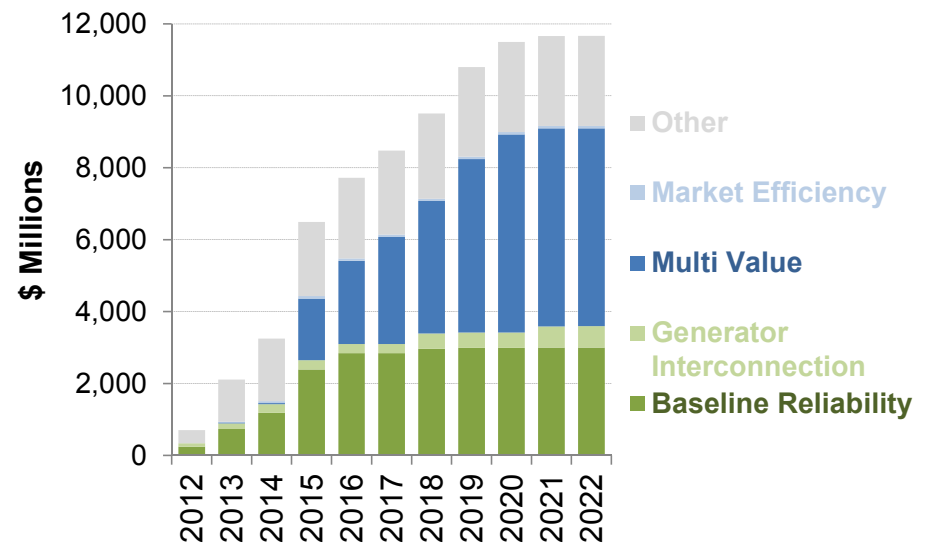
Large transmission expansion (e.g., to allow more wind development in the Dakotas to access distant loads)

- ◆ Likely would be tied to renewables development
 - If transmission lags wind development, price could be temporarily depressed in “generation pocket” until transmission expands
 - Particular location of transmission constraint may be important (and will be affected by location of generation development, transmission and load)
 - If transmission fails to keep up with wind development in the Dakotas, causing a transmission constraint and depressing energy prices near the wind resources, will Minn Hub be on the low-priced or higher-priced side of the constraint?
- ◆ Expanded transmission will level out regional energy prices
 - Reduces prices in high-priced regions, and raises them in regions like Minn Hub that have generally had lower prices
- ◆ May also smooth intertemporal price variability
 - Broader access to resources and load over a wide region

Transmission Investments

- ◆ Wind output expansion has created transmission challenges, which resulted in ~3% of potential wind output being curtailed in 2011^[1]
- ◆ Transmission investments are needed in high wind potential areas to integrate new projects - particularly in the Upper Midwest and around the Great Lakes
- ◆ Nearly \$12 billion of estimated future investments through 2022 – of which roughly \$5.5 billion represents multi value projects (MVPs)
- ◆ MVP projects will improve transfer capabilities and enable more wind energy to satisfy states' RPS requirements
 - Projects will allow lower cost generation in the West to serve load in the East

Projected cumulative transmission investments^[2]



Sources and Notes:

[1] 2011 Wind Technologies Market Report, US DOE, August 2012, p. 42

[2] MISO Transmission Expansion Plan 2012

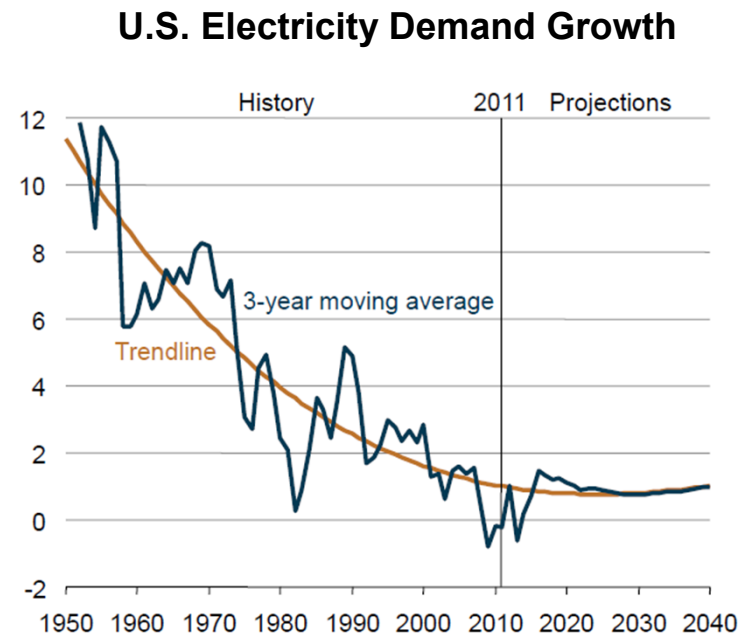
Assumed 100% of the project's investment is incurred in the in-service year, instead of spread across multiple years. Included projects in Appendix A (being or have been approved by MISO Board of Directors) and B (reviewed by MISO staff for need and effectiveness).

6. Supply-Demand Balance

Load Growth – Historical

Many factors have combined to reduce growth rates from the 2-4% annual level that was common a few decades ago

- ◆ Declining growth trend since 1950:
 - Population growth is down
 - Fewer large new loads
 - Shift from manufacturing economy
 - Increased efficiency, due to:
 - Utility programs,
 - State/Federal end-use codes and standards
 - Higher prices suppress demand
- ◆ More recently:
 - Consumer preferences for efficiency
 - Distributed generation such as rooftop solar approaching grid parity (with subsidies)
 - Fuel switching: electric to cheap gas



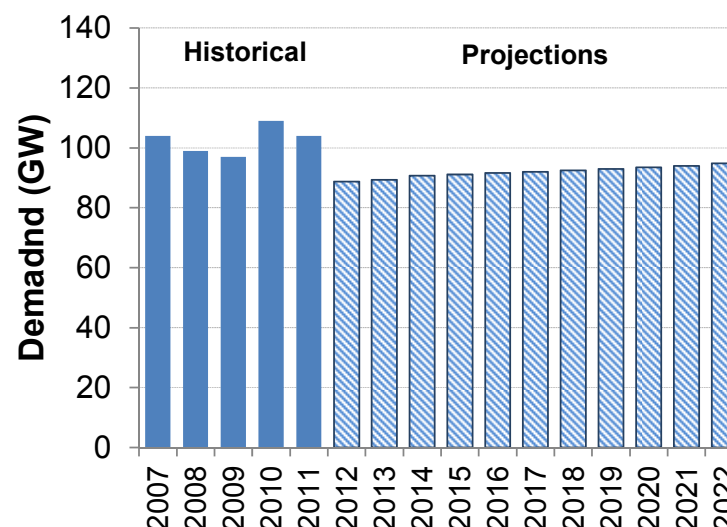
Source: EIA, 2013 Annual Energy Outlook

Load Growth – Future

Four years after the financial crisis, “normal” growth has not resumed

- ◆ Low growth rates may be the “new normal”
 - Even “industrial renaissance” (if it occurs) may not restore growth to previous levels
 - Electric vehicles could potentially drive growth in the very long run, but penetration has been disappointingly low to date
- ◆ Long-term projections show slow growth continuing
 - MISO projects ~1.4% of annual peak load growth over the next 15 years (0.9% if accounting for 0.5% of peak reduction from demand side (DSM) programs)^[2]
 - NERC’s latest long-term assessment: ~1.4% annual growth nationwide; 1.1% in MISO over next decade (excluding DSM program effects)^[3]

MISO Net Internal Demand^[1]



Sources and notes:

[1] MTEP12 Report Overview, August 29, 2012

2011 Long Term Resource Assessment, MISO

Net internal demand: peak demand reduced by load modifying resources

[2] MISO Transmission Expansion Plan 2012, MISO, Business as Usual case

[3] 2012 Long-Term Reliability Assessment, NERC, November 2012

Capacity Surplus and Capacity Markets

Low load growth (also large wind additions, which earn limited capacity credit) contribute to surplus capacity

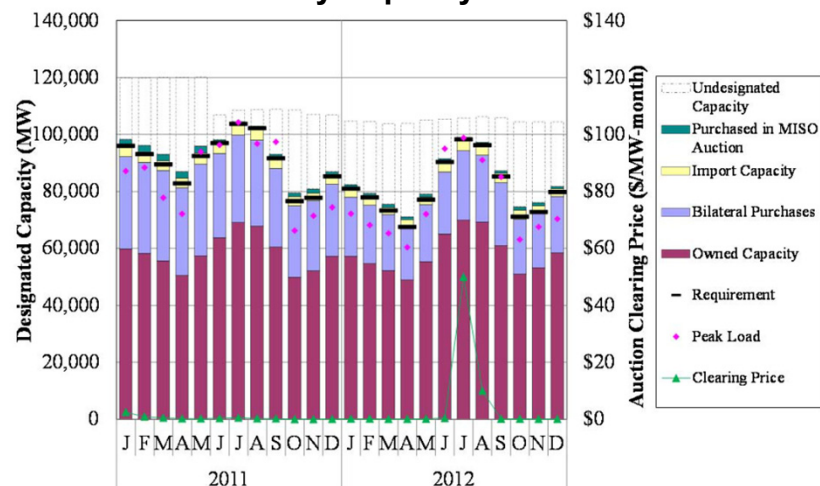
- ◆ Current reserve margin is 16.9%^[1], modestly above the 14.2% target
 - No immediate need for new capacity resources
 - That could change quickly, depending on how much coal capacity retires
- ◆ Capacity surplus drives low capacity price, especially in MISO's short-term Voluntary Capacity Auction (VCA)
 - VCA provides market signals even though most requirements are satisfied through owned capacity or bilateral purchases
 - Once the capacity surplus is eliminated, capacity prices should increase, likely to be set by the cost of gas-fired generation (CT and/or CC)

Source and Notes:

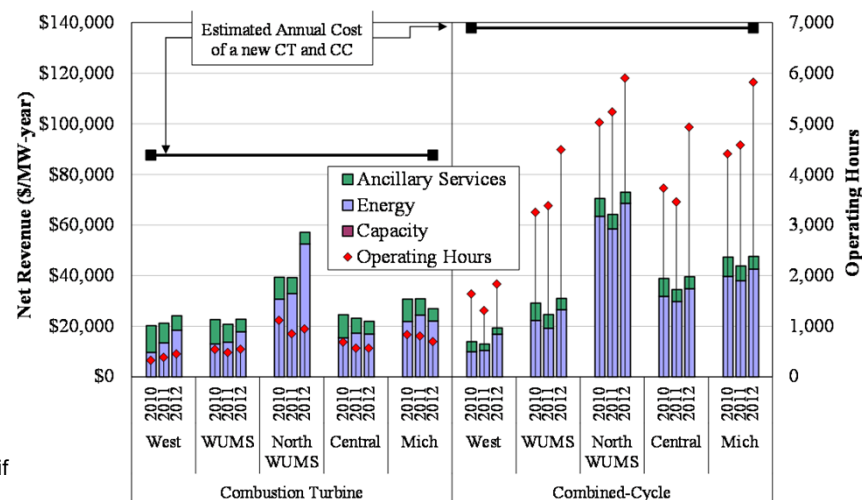
2012 State of the Market Report for MISO (Potomac Economics, June 2012)

[1] MISO forecast 28.1% of planning reserve requirement for summer 2013.. This is reduced to 16.9% if only firm imports are included and more realistic wind and demand response assumptions are used

Monthly Capacity Procurement



Net Revenues and Cost of New Entry



Recent Developments in MISO Markets

Locational Capacity Market Reforms

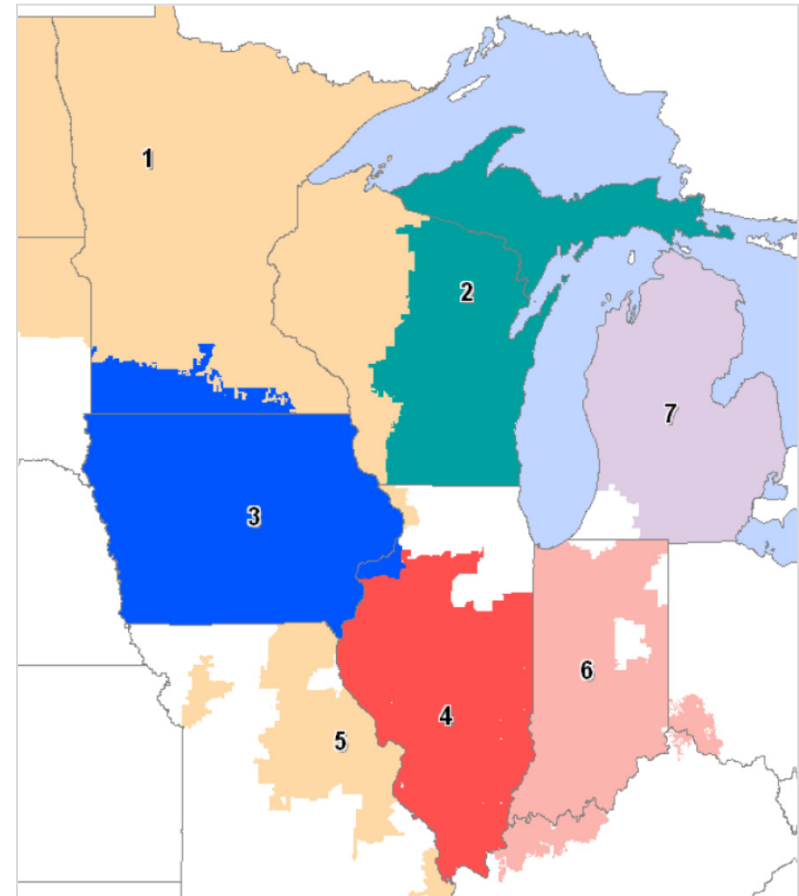
Previous mechanism

- ◆ Monthly requirement for Load Serving Entities (LSEs)
- ◆ Bilaterally tradable capacity product
- ◆ Voluntary Capacity Auction (VCA) a few days before the monthly deadline

Recently implemented mechanism

- ◆ Mechanism became effective October 1, 2012 for the planning year beginning on June 1, 2013
- ◆ Locational (zonal) capacity requirements
 - Initial auction results indicate zonal limits unlikely to bind in the near term
- ◆ Annual product, not monthly; diversity contracts allow exchange between summer/winter peak entities (MH)
- ◆ Capacity requirement is mandatory
 - Auction “voluntary,” but severe deficiency penalty
- ◆ Opt-out provisions:
 - Self-supply may opt out of the auction
 - LSEs may face Zonal Deliverability Charge if capacity is in a lower-priced zone than their load

MISO's Capacity Zones



Sources:

[1] MISO FERC RA Enhancements Filing. July 20, 2011

[2] <https://www.midwestiso.org/Events/Pages/SAWG20110317.aspx>

Supply-Demand Balance

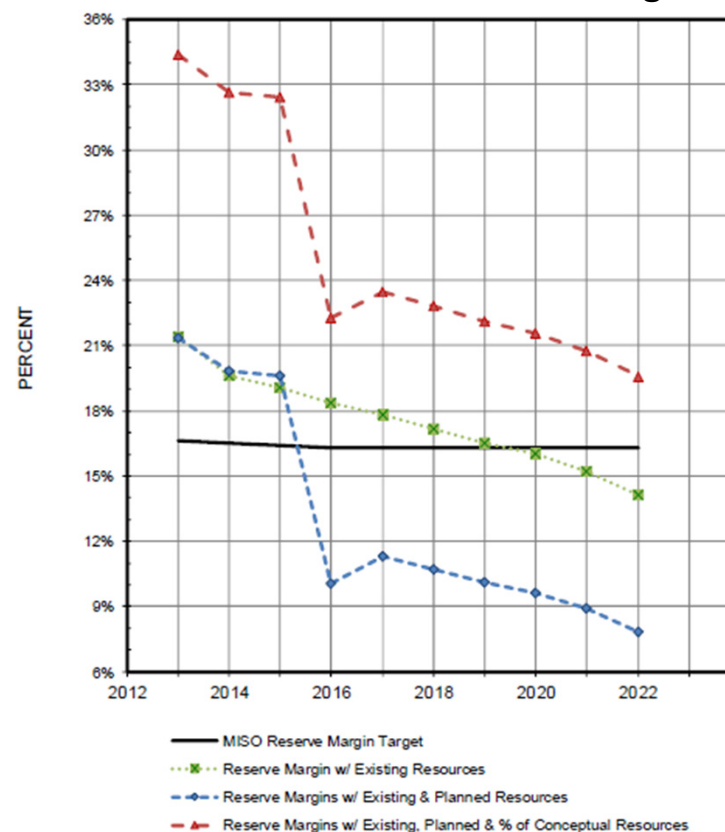
Near term, capacity additions and retirements (especially coal) may be as or more important for capacity balance than load growth rates

- ◆ Despite current capacity surplus and projections of low load growth, large coal retirements may bring MISO into approximate supply-demand balance within a few years
 - MISO projects a need for capacity by 2016, based on expectations of large coal retirements

In the long run, supply adjusts to growth

- ◆ Long-term load level may have little effect on energy prices if it leaves similar types of generation on the margin setting price

MISO Summer Reserve Margin



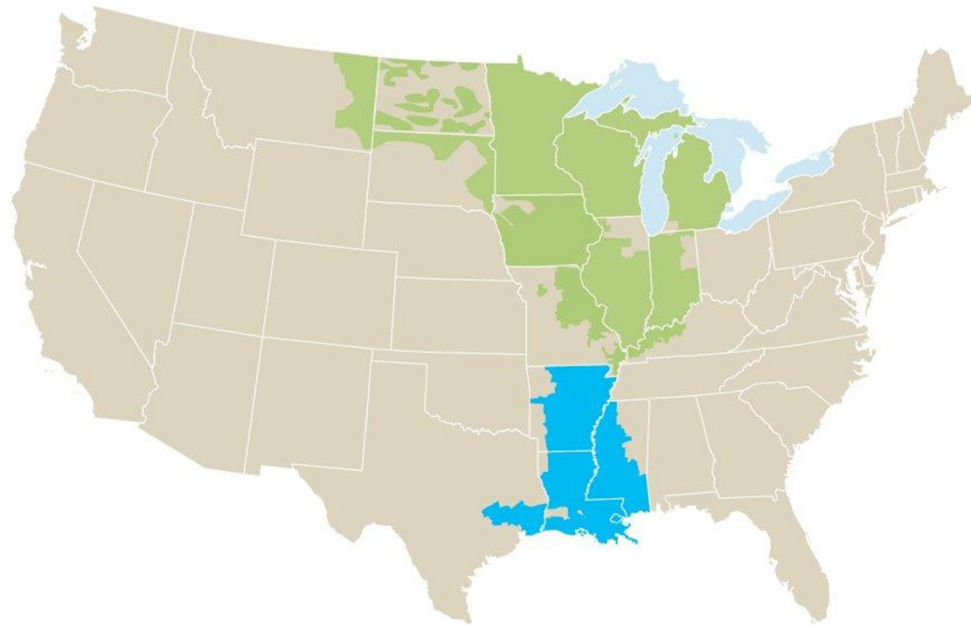
Source and Notes:

- [1] Reliability First Corporation, Long Term Resource Assessment 2013-2022 , Nov 2012
- [2] Demand is based on weather-normalized 50/50 forecasts (~1% annual growth rate)
- [3] Planned additions is net of 8,700 MW of potential coal retirements by 2016
- [4] Conceptual additions include existing energy resources that currently are not used to meet reserve requirements.

Recent Developments in the MISO Markets

Integration of Entergy

Adding Entergy will create Southern Region in MISO, including most of Arkansas, Louisiana, Mississippi, and part of Texas



- ◆ Transfer of operational control of transmission system will occur in December 2013
- ◆ Nearly 40 GW of generating capacity and 40 GW of additional load added to MISO
- ◆ Apart from a 1,000 MW contract tie, no physical ties currently exist between MISO and Entergy
 - Entergy integration is likely to have little effect on energy and capacity markets at Minn Hub

Source: MISO, Southern Region Integration

7. New Generation Costs

Costs of New Gas Plants

Capital cost of gas-fired generation is relatively low

- ◆ Efficient gas-fired combined cycle (CC), or combustion turbine (CT) for a capacity resource, are typically the generation types of choice for new plants
 - Inexpensive fuel, modest capital cost (and thus less risk), flexible operation
 - In contrast, coal has very high capital cost, plus climate risk, and fuel cost not much below that of gas
 - Nuclear: extremely high capital cost, construction risk, high operating cost
- ◆ As gas increases its share of total generating capacity, gas will be on the margin setting energy price more often
 - This trend is likely to continue in the future and intensify as more coal capacity retires
- ◆ Gas-fired generation is a mature technology
 - Continuing incremental performance improvement (such as lower heat rates, increased operational flexibility) is likely, but not expected to be large
 - Capital costs are likely to remain stable (could rise temporarily, if large and fast coal retirements create a sudden demand for new gas capacity)

Cost of New Coal and Nuclear Plants

Coal is very capital intensive – not justified at low gas prices (especially if there is a CO₂ price, or a threat of one)

- ◆ High cost of pollution control equipment to comply with MATS and New Source Performance Standards
- ◆ Coal also faces climate risk
 - Must comply with potential climate policy – pay CO₂ price (if there is one), or add carbon capture and sequestration (CCS) to meet GHG limits
 - CCS is very costly and unproven at full scale – uneconomic except possibly at high gas price and/or high CO₂ price

Nuclear is even higher capital cost – also not justified at low gas prices (unless CO₂ price is very high)

- ◆ Long construction time, regulatory uncertainty also create barriers to the extremely large investment required
- ◆ Social acceptability still an issue

Nuclear Power

The “Nuclear Renaissance” that was expected as of about 5 years ago has been cancelled, due largely to low gas prices

- ◆ New nuclear plants (beyond the few already started) are unlikely in this environment

Existing plants may be at risk

- ◆ Kewaunee (WI); Crystal River 3 (FL); San Onofre 2&3 (CA) all retired in 2013; maybe others in future
 - Operating problems or costly upgrades/repairs can threaten viability of nuclear plants whose economics are weak due to low power prices
 - Single-unit plants may be at greatest risk; they often have higher costs

Mini-nukes and other new nuclear technologies are touted in principle, but it is likely to be many years before a radically new nuclear design becomes viable

- ◆ Wild card is very strict climate policy, which could make nuclear look attractive compared to the lack of alternatives

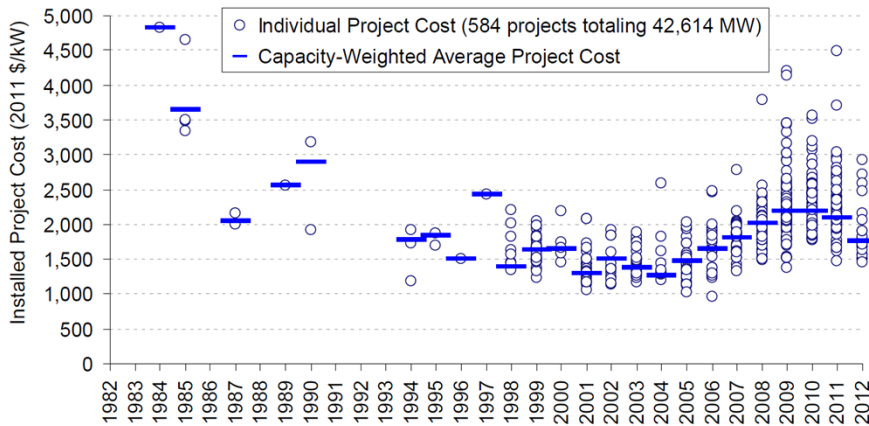
Costs of Renewables

Capital costs of renewables have dropped rapidly and are projected to continue falling

- ◆ Renewables are still mostly uneconomic compared to gas plants (at current relatively low gas prices, absent subsidies or incentives)
- ◆ But renewable capital costs are falling
 - Capital costs of wind and solar generation have fallen considerably in recent years, and are likely to continue to fall (particularly solar)
 - If gas price increases and/or CO₂ price is implemented, renewables could become economic – maybe even without subsidy
- ◆ This could cause large new additions of renewable capacity, based mostly on energy value
 - In the extreme, this could change market dynamics – driving very low (even negative) prices in many hours, threatening even more coal capacity
 - Non-dispatchable renewables offer relatively little capacity value
 - Capacity may get tight and command a premium

Downward Trending Renewables Cost – Wind

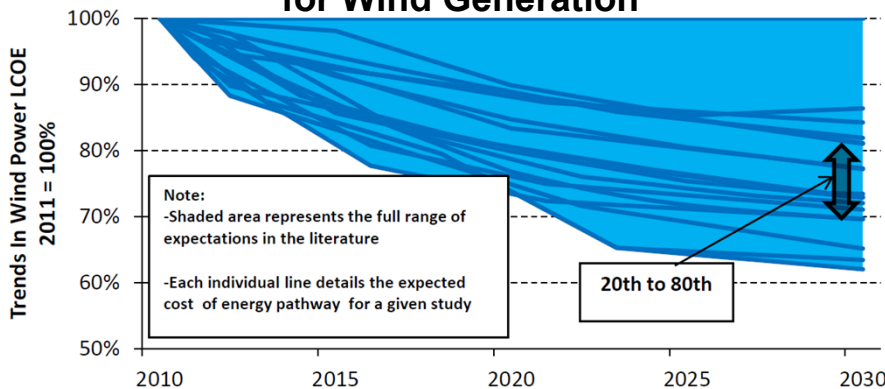
Historical Installed Costs for Wind Resources^[1]



Wind costs fell sharply through the early 2000s

- ◆ Installed costs increased between 2004 and 2010 – high demand for new wind capacity; limited turbine production/installation capability
- ◆ Costs resumed downward trend after 2010, expected to continue

Projections of Levelized Costs for Wind Generation^[2]



Midwest is among the lowest price areas for wind power contracts

- ◆ Driven by higher wind speeds and better capacity factors
- ◆ Some recent contracts have been below \$40/MWh (close to competitive with gas, depending on gas price)

Sources:

[1] DOE, 2011 Wind Technologies Market Report (August 2012)

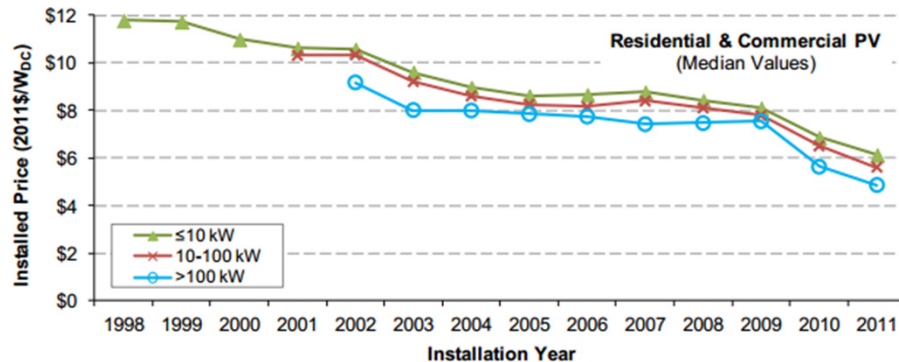
[2] NREL, EIA Wind Task 26: The Past and Future Cost of Wind Energy (May 2012)

Downward Trending Renewables Cost – Solar

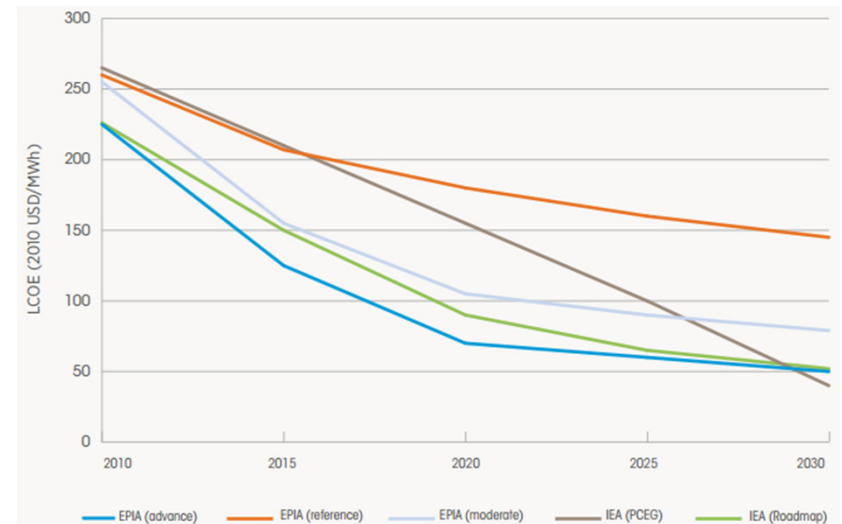
Solar costs have also declined dramatically in the past decade, and continued large cost reductions are expected

- ◆ Distributed solar also can avoid some transmission and distribution costs
- ◆ But solar is still well above the cost of wind (and gas)

Installed Price of Residential and Commercial PV^[1]



Range of Solar PV LCOE Projections^[2]



Sources:

[1] Galen Barbose, Naïm Darghouth, Ryan Wiser, Joaquim Seel, "Tracking the Sun V", Lawrence Berkeley National Laboratory, 2011, P.14.

[2] "Solar Photovoltaics," Renewable Energy Technologies, Cost Analysis Series, Volume 1, The International Renewable Energy Agency (IRENA), p.39.

8. MISO Market Outlook

How Factors Combine to Affect Power Price

Primary determinant of energy price is the short-run variable cost of marginal generation

- ◆ Coal units are often on the margin, but increasingly it will be gas units, particularly on peak
- ◆ Fuel and emissions prices are key
 - Variable cost is driven by fuel price
 - Also CO₂ (if priced), which affects coal disproportionately, but also affects gas
- ◆ Factors affecting what capacity is on the margin have some effect
 - Coal retirements, renewable additions, demand levels
 - Midwest supply curve is flat when gas is relatively cheap, so this effect is modest

Capacity price is influenced by capacity balance

- ◆ Surplus drives very low near term capacity prices
- ◆ But large coal retirements are expected to bring capacity into balance in the next few years, leading to better capacity prices

How Factors Combine to Affect Power Price

Among key input factors, accounting for their likely ranges, CO₂ price has largest impact, then gas price

- ◆ Each \$1/ton CO₂ price = ~\$0.75/MWh
CO₂ price could be up to \$30/ton, or more
 - Thus CO₂ price could add \$20-25/MWh (upside only)
- ◆ Each \$1/MMBtu in gas price = ~\$7/MWh (if gas on margin, less when not)
 - Likely gas price range is \pm \$1-2/MMBtu (estimate based on implied volatility of financial options, historical variance and historical forecast error)
 - Thus gas price could cause \pm \$10/MWh, either direction
 - Coal price likely to have less effect than gas price; it is lower and less variable
- ◆ Coal retirements could increase prices by ~\$1-5/MWh (MISO study)

These are rough rules of thumb only; moderated by system responses

Power Prices are Likely to Rise

Relative to recent depressed power prices, long-term power prices are likely to increase, perhaps substantially

For prices to remain at recent low levels, would need

- ◆ Continued lack of CO₂ price
 - CO₂ price is by no means assured, but several mechanisms are possible, and it cannot go down
- ◆ Gas remaining at depressed levels
 - It has already rebounded from 2012 lows, and further (modest) increase is expected
- ◆ No (or very little) coal retirements in MISO
 - 6 GW have already retired or announced retirement

This is not a guarantee, but a likelihood

- ◆ Of the primary factors that affect power prices, most appear to be heading in a direction that would lead to higher power prices

Summary of Factors Affecting Power Price

Factor	Effect on Power Price	Likely Change in Factor
CO ₂ price	CO ₂ price increases power price directly	Large effect; upside potential only
Gas price	Gas price rise increases power price directly	Up from 2012 lows; expected to increase further (though slowly)
Coal Retirements	Retirements increase power price modestly	Large announced retirements, with additional retirements likely
Load Growth	Growth increases power price modestly, all else equal	Likely low load growth
Renewable Additions	More renewables lowers power price modestly	Continued renewable additions likely (coal retirements mitigate)
Transmission (w/ Renewables)	Large transmission additions could raise Minn Hub price slightly	Some additions likely, especially if there are large renewable additions

5 Year MISO Market Outlook (2018)

Likely future:

- ◆ Large coal retirements: 10-12GW or more
- ◆ Gas price stable, up modestly from now: ~\$4.75/MMBtu
- ◆ Continuing renewable additions; mostly wind
 - Only ~2 GW more needed to meet 2018 RPS, but likely to stay ahead of requirement
- ◆ No CO₂ price implemented (but possibly on the horizon)
- ◆ Possible additional nuclear retirement (modest)
- ◆ System in approximate supply-demand balance
- ◆ Emissions displaced: marginal generation accounts for ~0.75 tons CO₂/MWh; larger displacement if coal retirements increase in response to hydro additions

Primary uncertainties:

- ◆ Extent of coal retirements: could be much more
- ◆ Gas price: will it remain relatively stable, as recent experience suggests?

20 Year MISO Market Outlook (2033)

Likely future:

- ◆ CO₂ price likely, and probably significant, but level is uncertain
- ◆ More coal retirements: possibly not much left (almost all >45 years by 2033)
- ◆ Gas prices significantly higher
- ◆ Large installed renewable base – but uncertain
 - Possible very low off-peak prices if system dominated by wind
- ◆ Existing nuclear plants retiring – will new technology be available to replace?
- ◆ System in approximate supply-demand balance
- ◆ Emissions displaced: likely at least that of gas CC (0.5 ton CO₂/MWh); more if coal remains and is sometimes marginal

Primary uncertainties (large uncertainties drive broad range):

- ◆ Climate policies: uncertain CO₂ price; stringency and form drive other factors
 - Likely to drive coal retirements, renewables, gas prices, new nuclear
- ◆ Gas dominated system, or weaning off gas by then?
- ◆ Potential premium for grid services from flexible hydro?

Potential for Disruptive Change in Very Long Run

The fundamental structure of power markets may change

- ◆ Massive renewable additions, driven by falling costs
 - But still non-dispatchable
- ◆ Bulk storage to augment renewables in system operation
- ◆ Fossil use heavily curtailed (even gas)
- ◆ Dispatchable demand on very large scale
- ◆ Marginal cost of production may often be zero, and/or the marginal “resource” may be demand, via price-rationing
- ◆ Market paradigm may shift from short-run variable cost pricing to a market based primarily on capacity value
 - Telecoms experienced changes of this sort starting in the 1980s
- ◆ It is not clear how such a new market structure might work
 - But hydro’s flexibility and storage capability would probably continue to be valued, perhaps even more highly

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