2019 ENERGY BAR ASSOCIATION MIDWEST CHAPTER ANNUAL MEETING

OMNI CHICAGO HOTEL, 676 North Michigan Avenue, Chicago, IL 60611

March 4-5, 2019  Chicago, IL
Summary

The 2019 Midwest Chapter Annual Meeting will be held at the Omni Chicago Hotel in Chicago, IL on March 4-5, 2019. The Midwest Chapter is presenting a one day CLE program and will offer numerous networking opportunities, including a pre-conference hosted cocktail reception and scheduled breaks during the program for attendees to connect.

Agenda

MONDAY, MARCH 4, 2019

5:30 pm – 7:00 pm  Welcome Reception
Raffle to benefit the Charitable Foundation of the Energy Bar Association

TUESDAY, MARCH 5, 2019

8:00 am to 9:00 am  Registration

9:00 am to 9:10 am  Welcome and Introduction
Matthew Rudolphi, President, Energy Bar Association, Duncan, Weinberg, Genzer & Pembroke
David Streicker, President, Midwest Chapter of the Energy Bar Association, Polsinelli PC

9:15 am to 10:30 am  Virtual PPAs – Are These Going to Become the Norm
Historically, the output of a generation asset was sold pursuant to a traditional power purchase agreement entered into between a developer and a utility or other purchaser. With increasing frequency, non-traditional off-take agreements such as financial hedges and virtual power purchase agreements are becoming the norm rather than the exception. This panel will explore the reasons for the rising use of such non-traditional power off-take agreements and whether such arrangements will supplant traditional PPAs. The panel will outline the basic terms and conditions of these agreements and dive into the complexities encountered when negotiating such instruments. Finally, this session will explore the market to explain why an increasing number of large commercial users are seeking PPA opportunities.

Moderator: David Streicker, President, Midwest Chapter of the Energy Bar Association, Polsinelli PC
Panelists: Maddie Knowland, Senior Director, Head of Energy Marketing, E.ON Climate & Renewables North America
Joe Condo, General Counsel, Lincoln Clean Energy, LLC
Craig P. Aubuchon, Asset Manager, Renewable Energy, U.S. Bancorp Community Development Corporation

10:30am to 10:45 am  Networking Break

10:45 am to 11:15 am  Morning Keynote Address
Speaker: Aakash Chandarana, Regional Vice President of Rates and Regulatory Affairs, XCEL ENERGY
11:15 am to 12:15 pm  **Impacts of State Policies on the Penetration of Low or Zero Cost Marginal Resources (and What this Means for the Markets)**

Practitioners are generally aware of the effect federal tax credits have had on the construction, and proposed construction, of renewable resources like wind and solar. But what effect have state policies and initiatives had on the development of these assets and the retention of other low marginal cost generation sources? And how are these policies, and the pending boom of renewable integration, affecting RTOs from both a market and operational standpoint? This panel will explore these issues and provide perspectives on the intended (and perhaps unintended) consequences of “going green.”

**Moderator:** Eric Dearmont, Director – Regulatory Affairs & Interconnection Policy, Ameren Services Company

**Panelists:**
- Michael Kessler, Assistant General Counsel – Legal, Midcontinent Independent System Operator, Inc.
- Emma Nicholson, Ph.D., Senior Project Manager, Concentric Energy Advisors, Inc.
- Timothy Burdis, Manager, State Policy Analysis & Strategy, PJM Interconnection

12:15 pm to 1:30 pm  **Networking Lunch & Luncheon Keynote Address**

*The Honorable Richard Glick, Commissioner, Federal Energy Regulatory Commission*

1:30 pm to 1:45 pm  **Networking Break**

1:45 pm to 2:45 pm  **Non-wire Alternatives to Distribution and Transmission Planning**

Utilities traditionally construct new transmission and distribution facilities, in order to resolve constraints or meet changing needs. As technology evolves, however, utilities have begun to explore using distributed energy resources, energy storage, energy efficiency, and demand response to solve the same or related problems. The application of these technologies in the context of transmission and distribution planning has become known as non-wires alternatives (“NWAs”). The regulatory landscape is still developing, and the panelists will address the many questions that remain. For example, should utilities be required to consider NWAs when developing transmission or distribution construction plans? Should utilities, particularly in deregulated markets, be permitted to own NWA infrastructure, and how should such infrastructure be functionalized? If third parties are permitted to develop NWAs, what should the data sharing and procurement processes look like?

**Moderator:** Hanna M. Conger, Associate, Rooney Rippie & Ratnaswamy LLP

**Panelists:**
- Jim Taylor, Vice President, Energy Solutions - Siemens
- Michael Strong, Member, Funkhouser Vegosen Liebman & Dunn, Ltd.

2:45 pm to 3:00 pm  **Networking Break**

3:00 pm to 4:00 pm  **Regulatory Hurdles For Siting Pipelines**

Growth in U.S. shale gas production is driving the expansion of pipeline infrastructure to transfer gas from producing regions to consuming markets, typically in other states. The regulatory processes for siting and developing this infrastructure is extensive and the scrutiny of regulatory approvals has increased. The fact that most pipeline infrastructure projects occur in multiple states creates a regulatory patchwork for siting that creates additional regulatory burden and uncertainty. This panel will discuss the regulatory hurdles that are a part of the siting process. The discussion will include state permitting and certificate of need processes and the additional complexities of siting on Tribal and ceded lands. The panel will also discuss how safety and environmental permitting and permissions (such as PMSHA and NEPA) affect the siting process and also create additional scrutiny by third-parties.

**Moderator:** Stacy Stotts, Partner, Polsinelli LLC

**Panelists:**
- Arshia Javaheerian, Senior Legal Counsel, Law Department, ENBRIDGE
- Darren J. Hunter, Partner, Hunter Masalski LLC
Sponsors:

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About the Energy Bar Association:

The Energy Bar Association is an international, non-profit association of attorneys, non-attorney professionals, and students active in all areas of energy law. The EBA promotes the professional excellence and ethical integrity of its members in the practice, administration, and development of energy laws, regulations and policies. The EBA provides superior educational programming, networking opportunities, and information resources. Find more information at www.eba-net.org.
E.ON Climate & Renewables

Energy Bar Association

March 5, 2019
Agenda

- E.ON Overview
- Corporate Buyer Experience
- Evolution of Corporate Buying
- Innovative Deal Structures
E.ON SE: Global, investor-owned energy company

- Leading owner and operator of Renewable Energy projects and Energy Networks across Europe and North America
- Market cap of $26.6B
- Strong financials with $45.6B¹ revenue and $5.9B¹ EBITDA
- Over 43,000 employees across Europe and USA¹
- Rated Investment Grade by Moody’s (Baa2) and S&P (BBB)

¹ For 2017
E.ON Climate & Renewables successfully delivered 3.9 GW across wind, solar and storage.
E.ON’s Capabilities spans across the Renewables value chain

Development Expertise

- Global presence
- Product flexibility:
  - VPPA / PPA / RECs
  - Wind / Solar / Energy Storage
- Qualified Scheduling Entity in ERCOT, a Market Participant in NYISO, ISO-NE, and MISO, and a participant in PJM
- Commitment to Safety and Sustainability

Financing

- E.ON has the financial strength and ability to balance sheet finance the project(s) until the commercial operations date
- Investment Grade:
  - Standard and Poor’s - BBB
  - Moody’s - Baa2
- Parental Guarantee / Letter of Credit
- Open to discussing Partnering / Tax Equity

E.ON Energy Services

- Full-service provider of operations & maintenance, balance of plant and asset management services in North America
- E.ON operates a 24/7 fully manned dispatch and scheduling desk
- Manage 3.0 GWs of third party customers and 3.7 GWs of E.ON owned assets in North America
Agenda

E.ON Overview

Corporate Buyer Experience

Evolution of Corporate Buying

Innovative Deal Structures
Select customers we serve
A Closer Look: SK E&S, Committed to Global Sustainability

‘SK E&S is focused on the development of new and renewable energy to expand sustainable future business opportunities and meet the government’s RPS requirements.’

- Currently operating and developing renewable energy assets in S. Korea
  - 24MW wind
  - 63MW wind
- Multinational corporation with expanding footprint
- U.S. operations include LNG liquefaction facility in TX
- Ambition to extend sustainability commitments
SK E&S Wanted to Partner with E.ON in the U.S.

**The SK Need**

- Hedge exposure to market volatility associated with the liquefaction facility in TX
- Maintain commitment to sustainability outside of S. Korea
- Partner with an experienced and credentialed developer

**The E.ON Solution**

- E.ON & SK executed a long-term, 20 year PPA for 50MW solar
- West of the Pecos Solar Project – 100MW
- Reeves County, TX – 75 miles southwest of Midland-Odessa
- 2020 COD
Agenda

E.ON Overview

Corporate Buyer Experience

Evolution of Corporate Buying

Innovative Deal Structures
U.S. Annual Renewables Growth


Source: AWEA and SEIA

*2018 4th Quarter Wind Data not yet available
The growth of C&I as a major renewable buyer—nearly 7 GW in 2018

Corporate Renewable Deals
2014 – 2018

As of December 31, 2018. Publicly announced contracted capacity of corporate Power Purchase Agreements, Green Power Purchases, Green Tariffs, and Outright Project Ownership in the US, 2014 – 2018. Excludes on-site generation (e.g., rooftop solar PV) and deals with operating plants. (d) indicates number of deals each year by individual companies.

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Outreach to potential buyers

- Direct relationships with key buyers
- Approach C&I with public renewable energy or greenhouse gas reduction targets – RE 100, Science-Based Targets
- Approach C&I with large energy consumption looking to hedge exposure to future power prices
- Work with retail suppliers who serve numerous C&I customers
- Effectively liaise with intermediaries in the market who consult C&I on renewable procurement process
Buyer agrees to pay E.ON an agreed upon PPA price for renewable energy.

- Floating Price > PPA Price, E.ON pays Buyer the difference.
- Float Price < PPA Price, Buyer pays E.ON the difference.

For Settlement the Minimum Floating Hub Price shall be $0/MWh.

- The settlement price would be the PPA price if the Market Price < $0.

No settlement at negative Floating Price.

- E.ON may opt to sell the energy into the grid or not produce but Buyer will not settle with E.ON during these periods.
Increased use of risk mitigation instruments to reduce downside price risk, volume risk, and revenue uncertainty have evolved with more experienced C&I buyers.

- Hub Settled
- $0 price floor or non settlement below $0
- Collars
- Proxy Revenue Swaps
- Volume Firming PPA
- Proxy Generation

VPPA emerged over 5 years ago as a way for C&I to use the environmental attributes from one renewable energy project to cover their national load.

C&I are pushing for PPAs /Green Tariffs through their retail suppliers and utilities in order to have more direct/physical impact on the grids in which they are located.

Aggregation is also emerging as a new structure for smaller buyers to enter the VPPA space, often anchored by a larger buyer.
Process of Negotiation

Agreement on Commercial Terms – project, price, tenor, product (unit contingent + RECs or fixed shape), settlement location

Term sheet - cover key terms that will be fundamental to the VPPA/PPA – Commercial terms, scheduling and third party charges, delay damages, guaranteed availability, environmental attributes, credit support, and termination

Exclusivity period

PPA negotiations, redlines, and agreement on language

PPA signature
Agenda

E.ON Overview

Corporate Buyer Experience

Evolution of Corporate Buying

Innovative Deal Structures
Differential Volumes – One Size Does Not Fit All Buyers

- Agreed to partial volume PPA from WOTP project
- Balance sheet financed - no execution risk
- Merchant risk managed by E.ON

- SK PPA 20 year – configurable volume for C&I Buyer
- Execute additional PPA with C&I Buyer; or
- Hedge remaining volume using financial contracts with bank or power marketer; or
- Manage remaining merchant risk internally

West of the Pecos Solar
100MW

50MW PPA
PPA/Hedge/Merchant

50MW
Hybrid Structures - Diversification

- Potential to stagger COD
- Mitigates execution risk
- Configurable volumes

- Diversification across technology, geography, settlement Hub, seasons, time of use
- Potential to merge profiles to better match usage – hedge effectiveness
- Portfolio approach mitigates settlement risk

ERCOT North Hub Solar 30MW
ERCOT South Hub Wind 120MW

C&I Buyer

30MW PPA
120MW PPA
Rise of Virtual PPAs

Prepared for: Midwest Energy Bar Association Annual meeting

March 2019
Agenda

• Overview of USB and Tax Equity
• Underwriting Considerations
• Market Perspective

Disclaimer: Opinions and Views are my own, and do not necessarily represent U.S. Bank or U.S. Bancorp Community Development Corporation
Renewable energy
Powering our nation’s communities

As of 2018

$10 billion invested

~700 projects

~10 GW

Bishop Hill Wind, Henry County, IL

Coronal Gulf Coast, Pensacola FL

Scottsdale Unified School District, Phoenix, AZ
Renewable Investments at a Glance, contd.

658 Projects Closed 2011-2017

- Excludes residential
- HI investment not shown
Tax Credit Investments

- Multiple partnership structures used for duration of ITC/PTC compliance period

- Financial benefits of tax credit investments include:
  - Tax Credits, project cash flows, and payment if exit exercised
  - Plus, allocation of income/(loss) (percentage varies by partnership structure)

- U.S. Bank is one of the nation’s largest tax credit investors
  - Primarily in solar (ITC), throughout the nation in both wholesale and regulated markets
  - (note: VPPA are limited to retail choice states in wholesale markets)
What is a VPPA? (review)

• Under a (V)PPA:
  – Customer/Off-taker pays project developer a fixed price for power (“strike price’’); contracted revenues provide certainty, potentially lower cost of capital for developer
  – Project sells energy into wholesale market
  – Project settles the net difference between strike price and market revenues with the customer

• Virtual PPA is first and foremost a financial product that provides exposure to the energy market through renewable energy
  – Energy project (developer) and contract partner do not need to be geographically connected
  – Contract partner does not take physical delivery of energy – but may take possession of RECs to satisfy environmental or corporate goals
Underwriting - Considerations

• Asset life is typically 25+ years
  – May include contracted (PPA) and uncontracted cashflows (merchant)
  – Tax credit compliance period (5 years for ITC)

• Position in cash waterfall informs underwriting perspective
  – **First**: Credit worthiness and renewable energy experience of customer/off-taker?
  – **Second**: Do contracted revenues provide sufficient cash flows to meet debt service and cash flow obligations?
    • Can the project meet debt service and cash flow obligations in a downside analysis? (e.g., lower than expected production? merchant revenues instead of contracted revenues?)
  – **Third**: How do long-term cash flows vary by contract structure and affect the potential FMV in the event of an exit after compliance period?
*ILLUSTRATIVE* Project Costs and Revenues

- **Sponsor Equity**
- **Tax Equity**
- **Debt**
- **OpEx - Fixed**
- **OpEx - Variable**
- **PPA Price/"Strike Price" and Market Hedge**
Underwriting (other considerations)

• Some or all parties will also need to consider:
  – Power Price Risk
    • Trends in Heat Rates (penetration of renewables and gas; retirements)
    • Trends in Load and Demand
    • Trends Fuel prices
  – Generation Risk
    • Correlation with load curve; on- and off-peak pricing
  – Basis Risk at chosen settlement point (node v. hub)
  – Regulatory Risk
    • PTC/ITC expiration; RPS standards and other clean energy policies
  – Customer Preference and going forward Sustainability Goals
    • What does it mean to be “Powered By”?
    • Emerging commitments to move beyond REC compliance and achieve 24x7 carbon free generation (Terrell, M. “The Internet is 24x7. Carbon-free energy should be too” October 2018)

Disclaimer: Opinions and Views are my own, and do not necessarily represent U.S. Bank or U.S. Bancorp Community Development Corporation
Example: Power Price Risk

Inflation Adjusted Wholesale Price of Power ($/MWh) in PJM, 1999-2017

Financial Products in Renewable Energy

• VPPA is only one of many financial products – and there are multiple ways to hedge the future price of power
  – E.g., ICE/NYMEX electric futures; gas futures; in or out of market of interest (correlation)

• Tax Credit Syndication offers another avenue to participate in, and gain financial exposure to, renewable energy investment
  – Partner with Tax Credit investor to take direct ownership in renewable project
  – Provides different exposure to cash waterfall, project economics; requires ability to monetize tax credits

Bundled VPPA < ? > Syndication + Voluntary RECs
Contact and Questions?

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Tax Credit Syndications
Generating new sources of capital

As of September 30, 2018

$7.5 billion
total federal and state
tax credits syndicated

128
transactions

122
federal funds

53
investors

Olga Village, Milwaukee, WI

Macaroni Flats, Salt Lake City, Utah

Utility scale solar, Robeson Cty., North Carolina
Renewable Energy Syndication Activity

October 2014
Residential & Commercial Solar Fund

May 2015
Utility Scale Solar & Wind Project

April 2017
Utility Scale Solar Project

$1.3 billion
third party equity raised

37 total transactions

$35 million
avg. investment size

18 separate investors

$35 million
37 separate investors

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Top Renewable Energy Developer Relationships

- Sunrun
- SunPower
- PINEGATE Renewables
- Tesla
- SolarCity
- DE Shaw & Co
- Capital Dynamics
- Vivint
- nrg
- Cypress Creek Renewables

U.S. BANK | 15
U.S. Bancorp Syndication Offering

- **Alignment of Interests:**
  - USB invests alongside co-investor
  - 25% first loss guaranty from U.S. Bancorp against the risk of tax credit recapture and/or disallowance
  - Co-Investor leverages USB’s 10+ years of experience investing in the renewable energy asset class

- **Sponsor Selection**
- Risk mitigation, tax structuring and underwriting of investments on the front end
- Ongoing asset management and compliance monitoring
  - Capital contribution review and support
  - Tax return filing
  - Financial statement preparation
Financial Considerations

- Quick payback and short duration cash flows
  - 80-90% of value is earned through ITC and depreciation recognition
- Effective Tax Rate Management
- Recurring/Ongoing Investments
- Fiscal Year End Considerations and Placement in Service

Accounting Considerations

- Two Methods to Choose From
  - Effective Tax Rate Management: Flow Through Method with Equity Method for Impairment – HLBV
  - Pre-Tax Income Management: Deferral Method (USB Methodology)
- Resources
  - KPMG Accounting for Income Taxes Guide
Future Investment Opportunities

• **Large Utility Scale:**
  – $5B - $10B annual investment opportunity
  – Projects are competitively bid among all of the large financial institutions
  – Lower yields with very stable operating profile
  – Facing some tariff related headwinds currently
  – ITC safe harbor guidance should help provide certainty and runway for developers

• **Small Utility Scale, C&I, and Community Solar:**
  – ~ $3B - $5B annual investment
  – Projects are bundled into funds according to similar attributes (geography, offtake, etc)
  – More complex underwriting makes for slightly less competitive pricing environment
  – USB has expertise and resources to take on these types of projects and earn higher yields

• **Residential:**
  – ~$2B - $4B annual investment opportunity
  – Continual investment flow allows investors to programmatically invest on their own timeline
  – Highest yield potential for tax equity investors
  – USB is the largest investor in residential solar funds dating back to 2008
Contacts

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Virtual PPAs – Are These Going to Become the Norm?
Midwest Energy Bar Association
Virtual PPAs

- A virtual PPA is a financial transaction – a “contract for differences”
- The customer “buys” the project output and takes title to the RECs at a fixed PPA price in the contract (customer still)
- The seller sells the brown power (not the RECs) in the energy market and receives the market price
- Each month, we reconcile the difference between the fixed PPA price and what the seller received in the market – the difference between the two prices is then settled between the customer and seller
- If the market price received by the seller is lower than the contract price, the customer pays the difference – if higher, the customer gets the amount above the contract price
- Most virtual PPAs settle at a market hub, which can create additional risk for the seller, known as “Basis Risk”
What is “Basis Risk”?

- Utilities typically take power at the busbar, where a project sells its energy (e.g. the project point of interconnection)

- Alternatively, C&I customers typically want to settle a VPPA at the market trading hub, which creates risk for the seller that they will receive one price at the busbar where the energy is sold into the market and then settle at a different price from a market trading hub. This risk is typically known as “Basis Risk”

- So, a developer must manage the basis risk and price the VPPA accordingly to account for any losses due to “Basis Risk”

- One example:
  - Fixed price under PPA is $22/MWhr
  - Project sells a MWhr for $20 at busbar (+$20)
  - Project buys the MWhr at hub for $24 (-$24)
  - Project sells the MWhr per PPA for $22 (+$22)

- So, the end result is the project gets $18 instead of fixed $22, because of the $4 difference between busbar price and hub price – that’s basis risk
A New Idea – Proxy Revenue Swap

- A proxy revenue swap provides the project a fixed annual payment – regardless of actual production.
- The swap provider takes market price risk and wind risk, while the project still takes operational risks such as availability.
- Proxy Revenue Swaps are settled at market trading hubs, to a project will still hold basis risk.
- The swap is settled as a contract for differences where the fixed payment is compared to the proxy revenue calculated over the settlement period (typically monthly or quarterly).
  - If prices are high and/or winds are high, would result in a payment from the project to the swap provider as the proxy revenue is higher than the fixed payment.
  - If prices are low and/or winds are low, would result in a payment from swap provider to the project as the proxy revenue is lower than the fixed payment.
- Example:
  - Fixed payment is $1,000 for a given time interval (based on projected revenue – e.g. production x price).
  - Project sells to market.
  - Because of high price and/or high wind, project receives $1,100.
  - So project pays $100 to bank.
  - If project gets $900 because of low price and/or low wind, then bank pays $100 to project.
EBA Midwest Chapter – Electricity Markets and State Challenges

March 5, 2019
MISO & neighboring U.S. electric grid operators

**MISO**

- 15 states + Manitoba
  - Primarily vertically integrated, regulated states
  - OMS relationship
- 42 million customers
- $30 billion market
- > 6,600 generation units with 175,000 MW capacity*
- 68,500 miles of high voltage transmission lines
- > 180 member utilities
- > 460 market participants

*M Generation capacity in “market” footprint; “Reliability” footprint is approximately 191,000 MW

MISO Control Centers: Eagan, Indianapolis (HQ), Little Rock
What Does MISO Do?

**Efficient Wholesale Market Management & Operations to Ensure Reliability**

- Operate day-ahead and real-time energy and operating reserves markets
- Manage transmission system ‘congestion’ through economic dispatch of generation units
- Monitor energy transfers on the high voltage transmission system
- Schedule transmission service

**Comprehensive Regional Transmission Planning**

- Long-range transmission planning
- New generator interconnection and retirement
- Long-range studies, such as Renewable Integration Impact Assessment (RIIA)

*MISO’s Vision: Be the most reliable, value-creating RTO*
Three trends are driving the portfolio evolution and our work on several key initiatives to prepare:

**De-Marginalization**
- The significant growth of resources that can provide low or no-cost energy (shift from variable cost to fixed cost)

**Decentralization**
- The shift away from larger central-station power plants to smaller, often variable resources

**Digitalization**
- The revolution in information and communication technologies is a key enabler in the decentralization of generation and demand-management resources
State/federal developments affecting markets

**State “subsidy” Issues**
- RPS
- ZECs

**Federal Issues**
- Capacity market reforms
- Resilience initiative
- Storage/DERs

**Market/Other Impacts**
- Renewable Integration Impact Assessment
- Resource Availability & Need
- New market products (e.g., ramp, OR, ELMP, etc.)
- Transmission Planning
- Capacity crediting
MISO’s generation fleet is changing

- Conventional generation (coal) retirements
- Growth of gas, renewables and DERs

### MISO 2033 Future Scenarios

**Accelerated Fleet Change**
- Nuclear: 3%
- Coal: 7%
- Gas: 29%
- Wind: 16%
- Solar: 11%
- Other: 30%

**Distributed & Emerging Tech**
- Nuclear: 4%
- Coal: 9%
- Gas: 13%
- Wind: 8%
- Solar: 26%
- Other: 30%
MISO’s Generation Interconnection (GI) Queue

Trends in MISO GI requests
Active and Completed Projects by Year (GW)

- The queue grew by over 230 projects and ~40 GW with the addition of the April 2018 queue cycle.
Renewable Portfolio Standard Policies

www.dsireusa.org / October 2018

Renewable portfolio standard

Renewable portfolio goal

Extra credit for solar or customer-sited renewables

Includes non-renewable alternative resources

29 States + Washington DC + 3 territories have a Renewable Portfolio Standard
(8 states and 1 territories have renewable portfolio goals)
What has MISO done? What will be needed?

- Wind forecasts are implemented in operations
- The Multi-Value transmission projects (MVP) are approved by the MISO Board
- Dispatchable Intermittent Resources (DIR) are introduced
- Solar forecasts are implemented in operations
- Interconnection Queue Reform

Cumulative Renewable Additions (GW)

- MISO South renewables begin to grow
- Falling Renewable Costs

TREND OF HISTORICAL + FORECASTED ADDITIONS

- North/Central
- South
Planning and operating risks

- Risks shift and become more acute

Solar ramps down sharply at the end of the day.

Risk of losing load compresses into a smaller number of hours.

Illustrative Planning and operating risks

- Risks shift and become more acute

Net peak load shifts from 3 pm to 6 pm.

Risk of losing load compresses into a smaller number of hours.
Renewable Integration Impact Assessment (RIIA)

- Identify “inflection points” of renewable integration complexity

RIIA seeks to identify inflection points where integration complexity significantly increases.

RIIA begins by modeling the current system.

Illustrative example
Interim RIAA results

Interim results indicate integration complexity increasing sharply from 30 - 40% renewable penetration.

Potential inflection point driven by Energy Adequacy issues.
Resource Availability and Need (RAN)

- RAN effort designed to ensure that resources committed to serve MISO customers are available to provide sufficient energy and flexibility to serve load throughout the year.
- Combination of factors have resulted in a resource portfolio with changing operating and availability characteristics, with corresponding deficiency of available capacity each operating day:
  - Increase in variable and/or intermittent resources, aging fleet, and base-load unit retirements.
  - Reduced reserve margins, increased forced outage rates and changing market conditions.
  - Increased reliance on resources during emergency conditions, occurring more frequently and during traditionally “off peak”/shoulder seasons.
- Four goals:
  - Improve generator outage scheduling.
  - Link resource accreditation and requirements with initial focus on Load-Modifying Resources (LMRs).
  - Align Planning Resource Auction (PRA) commitments with energy needs all year.
  - Ensure flexible resource availability to address changing fleet character.
What’s next?

• “MISO Forward”
• Integrated Roadmap
• RIIA
• Transmission planning
• FERC and other market initiatives
  • Energy storage, RAN, DERs, resilience, ramp, ELMP, new ancillary services (e.g., 30-minute operating reserves, fast regulation), gas/electric coordination
  • R&D opportunities – see Appendix
• Continue coordination with OMS/states
  • DERs, ARCs, RPS/other renewable initiatives, ZECs, other initiatives
• Learn from others and participate in developing/establishing industry “best practices”
  • RTO/ISO Council, other RTOs/ISOs, EEI, NARUC, many others
Questions?

Michael Kessler
mkessler@misoenergy.org
Markets must be designed to enable adequate supply and incentivize efficient market outcomes

**Price Formation**
- **Out-of-market Payments**: With more renewables, traditional plants (e.g., gas turbines) would cycle more often, but their commitment costs (and dispatch costs if at operating limits) may not be eligible to set prices
- **Resource Flexibility**: Resources may have to be committed or positioned for reliability needs, but are transparent market signals in place to valuate the resource flexibility?
- **Sufficient Reserve Margins**: Sustainability of conventional power plants is impacted by low-marginal costs of Renewables

**Demand-Side Participation**
- With tightening reserve margins following the retirement of aged coal plants, demand responsiveness becomes very important
- Visibility and bid/offer formats of demand resources can be challenging and ineffective treatment may distort prices

**Modeling of Supply**
- Storage Resources
- Distributed Energy Resources
- Configuration-based Combined Cycle Modeling
- …

**Software Platform**
- Computational performance improvement to allow alignment with gas industry
- Market System Evaluation to identify runway of future market enhancements and system extension
With increasing renewables, resource flexibility becomes a valuable attribute for grid operation

- Up/down ramp requirements are enforced based on anticipated system ramping needs
- Prices are the marginal costs to meet ramp requirements
  - Opportunity cost
  - Ramp Capability Demand Curve

### Expected Benefits obtained in Production

<table>
<thead>
<tr>
<th>Expected results</th>
<th>Actual Results</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production cost savings</td>
<td>$4.2 million/year</td>
</tr>
<tr>
<td>Reduced Price volatility</td>
<td>~7%</td>
</tr>
<tr>
<td>Improved Day-Ahead/Real-Time convergence</td>
<td>~3%</td>
</tr>
<tr>
<td>Reduced short-term scarcities and price spikes</td>
<td></td>
</tr>
</tbody>
</table>

Real-Time Prices with (green) and without (red) ramp capability product on a sample day of 07/17/2016
Facing tightening supply margin, Emergency pricing values demand resources and supports reliability

- The RTO progressively accesses Emergency energy & demand resources
- Prices could be depressed due to injection of Emergency supply

**Alert**
- Define boundaries/suspend maintenance

**Warning**
- Step 1 - Schedule in External Module E Capacity/Reserves
- Step 2 - Curtail Non-firm energy sales
- Step 3 - Implement reconfiguration options

- Step 1 - Emergency Generation and Emergency Dispatch Ranges
- Step 2 - Load Management
- Step 3 - Utilize Operating Reserves
- Step 4 - Reserve Call and Emergency Reserve Purchases
- Step 5 - Firm Load Shedding

**Event**
- LMR (BTMG & DR) at 2.b) & EDR at Step 2.c)

- Establish Emergency Offer Floors as the highest available economic and/or emergency offer
- Allow Emergency resources such as LMR to be “partially committed” for pricing purpose

Offer Floors ensure Emergency resources are stacked on top of the supply curve

Emergency supply that appears “free” or cheaper injected
Traditional fossil fuel plants cycling on and off more often present more pricing needs

**Pricing Needs**
- Resources may have to be dispatched at their minimum limits and cannot be turned off within min run times
  - Current ELMP effectively prices units dispatched at limits including their commitment costs, but only treats cost of a single dispatch interval at a time

**Research Questions**
- Costs incurred in one interval can be driven by the need in another interval
  - Minimum up/down time constraints
  - Ramp rate constraints etc.
- How can such inter-temporal effects be considered in setting prices?
With increased ramping constraints and uncertainty, more questions arise in pricing intertemporal costs

**Pricing Needs**
- Increasing system ramping needs and new technologies such as storage draw interests of optimization over future intervals
- Real-time dispatch is performed every five minutes on a rolling-window basis
  - Pricing incentives at an advisory interval may disappear when it becomes the binding interval

**Research Questions**
- How can the pricing incentives be appropriately retained despite changing time interval and/or system conditions?
Anticipating negative energy prices by renewables, conventional units face sustainability challenges

**Pricing Needs**
- With high penetration of low marginal cost renewables, energy price can be driven near-zero or negative
- Positive-cost fossil plants like gas turbines may need to be held online at their minimum limits to provide reliability services such as ramp product

**Research Questions**
- Whether and how can these units affect prices, or how can their reliability value be rewarded?
  - Align market requirement with reliability requirement
  - Reflect cost causation to meet the requirement
Computational advancements enable Real-Time and Day-Ahead market enhancements

Business Needs, Market Design ...

System construction & improvements...
More efficient user interface; Improvement of Market Clearing Engines (GE/IBM solver, parallel computing and HPC)

Theory & Technology advancements ...
PROCURING FLEXIBILITY IN WHOLESALE ELECTRICITY MARKETS

2019 Energy Bar Association Midwest Annual Meeting
March 5, 2019
Emma Nicholson, Concentric Energy Advisors
Implications of increased variable generation

- Independent System Operators and Regional Transmission Operators (ISOs/RTOs) must balance the system to serve net load
  - net load = load – intermittent generation
  - both load (distributed energy resources, retail demand response, and increased price responsiveness) and intermittent generation (public policies and voluntary purchases) are becoming more variable and uncertain
- ISO/RTO must respond quickly to unforecasted changes in net load
RTO/ISOs will need more flexibility

• Resources often categorized as
  • Dispatchable: resources that can respond to a dispatch signal
  • Non-dispatchable/Variable: resources that cannot respond or can only respond to dispatch signal in a limited fashion

• Several different types (or dimensions) of flexibility are valuable to the system
  • short minimum run time (minutes)
  • low or zero minimum operating level (MW)
  • fast start-up (minutes)
  • fast shut-down (minutes)
  • fast up and/or down ramp (MW/minute)

• ISOs/RTOs can only access resource flexibility if resources submit flexible energy supply offers and follow dispatch signals
RTO/ISO existential question: What is your spirit animal?

CAISO Duck Curve

MISO Alligator Curve

Source: California Independent System Operator

Source: Fresh Energy
Variable net load creates uncertainty for RTOs/ISOs

load in period $t$

baseline load forecast

load in period $t+1$

baseline + more intermittent

baseline + less intermittent

Ramp up uncertainty

Ramp down uncertainty
RTO/ISO flexible ramping products

• Procure ramp to cover uncertainties in the change of net load between the current interval \( t \) and the following interval \( t + 1 \)

• Quantity
  • dynamic tradeoff between holding back/prepositioning resources from generating energy in the current period and minimizing expected production costs in a future period(s)
  • balance the cost of experiencing a shortage in the future against the cost of procuring more reserves and a potentially sub-optimal dispatch in the current period

• Accurate tradeoffs involve truthful offers from resources, a good net load forecast, and understanding of costs of experiencing a shortage (Value of Lost Load-based)
Status of flexible ramping products in RTOs/ISOs

- CAISO and MISO have flexible ramping products in place
- ISO-NE, NYISO, and SPP staff have studied flexible ramping products and engaged with stakeholders
- ISO-NE and NYISO do not have immediate plans to implement a flexible ramping product any time soon
- To my knowledge, PJM has not formally considered a flexible ramping product but is currently considering revising its operating reserve demand curve
What is the difference between a ramping product and a standard reserve product?

- **Traditional reserves**
  - designed to ensure system has sufficient reserves to protect against the largest contingency - a fixed MW amount
  - reserves in upward direction to protect against loss of generation

- **Ramping product**
  - determine system ramp needs on a more dynamic basis
  - procures ramp in both directions
  - similar to insurance on holding sufficient traditional reserves, which becomes more difficult as net load becomes more variable

- **Similar in many ways**
  - both generally hold back resources to maintain reserves/ramp capability
  - compensated in the same manner – opportunity cost payment based on energy price
MISO ramp capability product

- MISO was first ISO to implement a flexible ramping product - Ramp Capability Product - in May 2016
- Bi-directional, co-optimized with energy and ancillary services
- Settles in both day-ahead and real-time markets
- Clearing price based on opportunity cost of not selling energy, resources do not submit separate bids
- Demand curve has a single segment representing a $5/MWh maximum willingness-to-pay for ramp
- Single clearing price (no zones), 10-minute timeframe
CAISO flexible ramping product

- Implemented in November 2016, revised in February 2018 due to implementation errors
- Bi-directional, co-optimized with energy and ancillary services
- Clearing price based on opportunity cost of not selling energy, resources do not submit separate bids
- Settles in fifteen-minute (FMM) and real-time markets
- Designed to the trade-off between the cost of procuring additional ramp and the expected costs of violating the power balance constraint (currently $1,000/MWh)
  - max willingness-to-pay for Flex-up $247/MWh
  - max willingness-to-pay for Flex-down $152MWh
CAISO flexible ramping product (cont.)

• For each FMM and RTM interval, CAISO calculates “uncertainty requirements” and the market optimization satisfies that requirement though a combination of flexible ramp procurement up to the price indicated in the demand curve
• Single clearing price (no zones), 5-minute timeframe
FRU’(t) is the expected net load forecast error within a 95% confidence interval.

Net load forecast error is based on an empirical distribution (like hours in past 40 weekdays or past 20 weekends).

Flex-Up requirement is 97.5 percentile
Flex-Down requirement is 2.5% requirement
CAISO – determining system’s need for ramp

Load forecast error in HE 17 is systematically negative
actual - forecast < 0
actual < forecast

System needs more generation online quickly – CAISO needs Flex-Up ramp

Since 97.5\textsuperscript{th} percentile is negative the Flex-Down Requirement in HE 17 is zero.

Source: CAISO, Flexible ramping product performance discussion, Feb. 2, 2018
Are ramping products high enough to incent investment?

Source: MISO, May 2018 Monthly Market Report, at 48
CAISO Flexible Ramping Product drivers

CAISO Percentage of real-time intervals with system marginal cost of energy > $500/MWh
Are ramping product prices high enough to incent investment in flexible capacity?

- Not currently
- Prices mostly zero and very low if non-zero but this will not be the case as ramping constraints start to bind in the future
- To date, ramp products give flexible resources the incentive to follow dispatch (short-run behavior) but do not enable fixed-cost recovery to stimulate investment in (long-run behavior) or maintenance of (intermediate timeframe) flexible capacity
- What happens when LMPs approach zero or go negative? Reserves and ramp will cost more than energy
Reminiscent of energy-only versus energy + capacity market debate

• CAISO has a flexible capacity product that is procured on an annual basis
  • requirement designed to match CPUC Resource Adequacy program requirements
  • currently considering additional revisions
• Should capacity markets be revised (yet again)?
  • capacity performance market designs in ISO-NE and PJM do not require flexibility. Capacity obligation is 24x7 for the 12 month delivery year.
  • annual payment provides a very weak short-run signal and the annual timeframe ignores sub-annual flexibility needs that vary by season, across days, and within an operating day
Options for increasing flexibility in RTOs/ISOs

- Flexibility can come from generation resources, RTO/ISO coordinated demand-response, or non-RTO/ISO price-responsive load
- Flexible ramping products
- Procure additional reserves – RTOs/ISOs can adjust the operating reserve demand curve
  - PJM and NYISO considering this approach
- Add a short-term capability product that matches the RTO/ISO system needs
  - more granular timeframe than annual delivery period
  - procured closer to delivery period to account for fast-changing market conditions
  - better suited to reward operating performance and address bad actors
  - MISO considering such a product
Emma Nicholson
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202-836-8321
Low Marginal Cost Resources

Timothy Burdis
March 5, 2019

EBA Midwest Chapter Annual Meeting
Chicago, IL
### Key Statistics

<table>
<thead>
<tr>
<th>Category</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Member companies</td>
<td>1,018</td>
</tr>
<tr>
<td>Millions of people served</td>
<td>65</td>
</tr>
<tr>
<td>Peak load in megawatts</td>
<td>165,492</td>
</tr>
<tr>
<td>MW of generating capacity</td>
<td>180,086</td>
</tr>
<tr>
<td>Miles of transmission lines</td>
<td>84,042</td>
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<tr>
<td>2018 GWh of annual energy</td>
<td>806,546</td>
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<tr>
<td>Generation sources</td>
<td>1,379</td>
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<tr>
<td>Square miles of territory</td>
<td>369,089</td>
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<tr>
<td>States served</td>
<td>13 + DC</td>
</tr>
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</table>

**21% of U.S. GDP produced in PJM**
PJM’s Role as a Regional Transmission Organization

PLANNING

Planning for the future like...

Urban Planning

OPERATIONS

Matches supply with demand like...

Air Traffic Control

MARKETS

Energy Market Pricing like...

Stock Market

www.pjm.com
Value Proposition

- **Grid Services:** $100 million savings
- **Reliability:** $475 million savings
- **Total Annual PJM Value:** $2.8 to 3.1 billion
- **Energy Production Costs:** $525 million savings
- **Integrating More Efficient Resources:** $600 million savings

**Generation Investment:** Savings of $1.1 to $1.4 billion
PJM’s Evolving Fuel Mix
Increasing Demand Resources in the Capacity Market

- Price Responsive Demand
- Energy Efficiency
- RPM & FRR Demand Response
- Cleared & Committed Demand Response

RPM Implemented

Experienced Operational, Market & Environmental Outcomes of Evolution
Solar (Grid-Connected + Behind-the-Meter): Actual Output
During 8/21/2017 Eclipse

MW

- Low: More Conservative
- Low: Less Conservative
- High: More Conservative
- High: Less Conservative
- Estimated Actual

www.pjm.com
### Changing Market Dynamics

<table>
<thead>
<tr>
<th>Starting Point</th>
<th>Supply-Side Effects</th>
<th>Demand-Side Effects</th>
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<tbody>
<tr>
<td></td>
<td>Natural gas prices fall</td>
<td>Load growth reductions</td>
</tr>
<tr>
<td></td>
<td>Renewable build-out - merit order shift</td>
<td>Demand Response</td>
</tr>
</tbody>
</table>

#### Graphical Representation

1. **Price - $/MWh**
   - **Wholesale price**
   - **Supply Curve (merit order)**
   - **Demand Curve (load)**

2. **Quantity - MW**
   - **Supply Curve (merit order)**
   - **Demand Curve (load)**

#### Key Points
- **Falling natural gas prices** reduce the marginal cost of generation - shifting the supply curve downward.
- **Renewables with zero short-run marginal costs** place themselves at the front of the supply stack; displacing more expensive resources.
- **Energy efficiency, distributed energy resources and low load growth** contribute to reduced overall demand (MWh).
- **Demand elasticity has been injected into power markets reducing system peaks (MW)**

---

Adapted from Bloomberg New Energy Finance
PJM Wholesale Cost – 6 Years

<table>
<thead>
<tr>
<th>Year</th>
<th>Energy</th>
<th>Transmission</th>
<th>Reliability Capacity</th>
<th>Other</th>
<th>Total</th>
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<tbody>
<tr>
<td>2011</td>
<td>$45.94</td>
<td></td>
<td></td>
<td>$61.66</td>
<td>$117.60</td>
</tr>
<tr>
<td>2012</td>
<td>$35.23</td>
<td></td>
<td></td>
<td>$47.78</td>
<td>$82.99</td>
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<tr>
<td>2013</td>
<td>$38.67</td>
<td></td>
<td></td>
<td>$52.96</td>
<td>$91.64</td>
</tr>
<tr>
<td>2014</td>
<td>$53.13</td>
<td></td>
<td></td>
<td>$70.37</td>
<td>$123.50</td>
</tr>
<tr>
<td>2015</td>
<td>$36.25</td>
<td></td>
<td></td>
<td>$55.89</td>
<td>$92.14</td>
</tr>
<tr>
<td>2016</td>
<td>$29.27</td>
<td></td>
<td></td>
<td>$47.49</td>
<td>$76.76</td>
</tr>
<tr>
<td>2017</td>
<td>$31.06</td>
<td></td>
<td></td>
<td>$49.63</td>
<td>$80.69</td>
</tr>
<tr>
<td>2018</td>
<td>$37.83</td>
<td></td>
<td></td>
<td>$59.95</td>
<td>$97.78</td>
</tr>
</tbody>
</table>
Continued Evolution of Fuel Mix
Queued Generation Fuel Mix
(December 31, 2018)

- **Solar**, 18,751 MW
  - Nameplate Capacity, 33,281 MW
- **Methane**, 8 MW
- **Other**, 240 MW
- **Storage**, 515 MW
- **Oil**, 14 MW
- **Diesel**, 4 MW
- **Biomass**, 4 MW
- **Coal**, 146 MW
- **Wind**, 4,845 MW
  - Nameplate Capacity, 25,793 MW
- **Wood**, 66 MW
- **Hydro**, 580 MW
  - Nameplate Capacity, 1,077 MW

**Natural Gas**, 50,602 MW

**NOTE:** Nameplate Capacity represents a generator’s rated full power output capability.
Continued Growth in Renewable Energy Necessitates

The significant expected increase in wind resource in PJM will increase system uncertainty.
Market & Operational Reform to Address Evolution: Fuel Security & Reserve Enhancements
2017/18 PJM Winter Peak

Feb. 20, 2015 – All Time Winter Peak (DR Included)

Aug. 2, 2006 – All Time Summer Peak (DR Included)

Jan. 5, 2018 (DR Included)

* Includes coincident not-yet-integrated zones
Top Ten Winter Peaks

As of Feb. 28, 2019. This data should not be used as the basis for decision-making.

Total RTO Load with coincident peaks and demand response, 2018 info. is preliminary
There is NO immediate threat to the reliability of the PJM RTO.

- PJM is reliable in the announced retirements and escalated retirements cases under all typical winter load scenarios.
- PJM is reliable in the announced retirements cases under all extreme winter load scenarios.

Scenarios to identify points at which an assumption or combination of assumptions begin to impact the ability to reliably serve customers.
- The stressed scenarios resulted in a loss of load under extreme but plausible conditions.

Contributing factors:
- The level of retirements and replacements
- The level of non-firm gas availability
- The ability to replenish oil supplies
- The location, magnitude and duration of pipeline disruption
- Pipeline configuration
Jan. 30 - 31, Synchronized Reserve Prices

Jan. 30 - 31
Synchronized Reserve Prices

Notes:
- Hours less than $10 included two at $0.08, one at $0.63, one at $0.69 and one at $1.88
- 10-minute, non-synchronized reserve prices were $0 for 46 of the 48 hours
Uplift (Balancing Operating Reserve) Results

Average Uplift Costs
(Average Balancing Operating Reserves) from week of Jan. 13 & Jan. 24

Balancing Operating Reserve Costs

- Jan. 21
- Jan. 22
- Jan. 23
- Jan. 30
- Jan. 31

COLD SNAP 1
COLD SNAP 2
Downward-Sloping Demand Curves and Increased Penalty Factors

Synchronized Reserves

- $2,000/MWh, Penalty Factor
- $850/MWh, Current Penalty Factor
- $300/MWh, Current Penalty Factor Curve

Synchronized Reserve (MW)
Basis for value is the cost of a reserve shortage and the uncertainty on the system that could result in falling below the reserve requirement despite procuring sufficient reserves in advance

- Cost of a reserve shortage is based on the penalty factor
- Uncertainty is measured from historical data:
Non-Wire Alternatives to Distribution and Transmission Planning

EBA 2019 Midwest Chapter Annual Meeting
March 5, 2019

Michael R. Strong
Member, Funkhouser Vegosen Liebman & Dunn, Ltd.
Key Players and Interests

- Utility
  - Accountability
  - Performance
  - Least cost
- Customer
- Regulator
  - Balance interests
  - Innovation
- Key Players
  - Utility
  - Customer
  - Regulator

Interests
- Accountability
- Performance
- Least cost
- Payment
- Comfort
- Balance interests
- Innovation
- Key Players
  - Utility
  - Customer
  - Regulator

Balance interests
- Innovation
- Payment
- Comfort
- Accountability
- Performance
- Least cost
Key Players and Interests (cont’d)

- Utility
  - Accountability
  - Performance
  - Cost Recovery

- Customer
  - Payment
  - Comfort

- Developer
  - Revenue
  - Performance

- Regulator
  - Balance interests
  - Innovation
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Regulatory Hurdles for Siting Pipelines
2019 Energy Bar Association Midwest Annual Meeting

Darren J. Hunter

March 4 - 5, 2019
Focus on Pipeline Safety and Environmental Impact of Proposed Pipeline Projects
Pipeline Safety

• The Department of Transportation (“DOT”), through the Pipeline and Hazardous Materials Safety Administration (“PHMSA”), has exclusive authority to promulgate federal safety standards used in the transportation of natural gas.

• The FERC’s rules require that applicants certify that they will meet these standards.

• If applicants so certify, the FERC does not impose additional safety standards.
Pipeline Safety – PHMSA’s Design and Construction Standards

- **Natural Gas (49 CFR Part 192)**
  - Materials – Subpart B
  - Pipe Design – Subpart C
  - Design of Pipeline Components – Subpart D
  - Welding of Steel – Subpart E
  - Joining of Materials Other than Welding – Subpart F
  - General Construction Requirements – Subpart G
  - Operator’s Procedures

- **Oil (49 CFR Part 195)**
  - Design Requirements – Subpart C
  - Construction Requirements – Subpart D
  - Operator’s Procedures
Pipeline Safety – Impact on the Environment

• Notwithstanding an Operator’s certification that it will meet or exceed PHMSA’s standards, the FERC analyzes the environmental consequences of potential safety incidents.

• Typically, the FERC will assess the potential risks of a pipeline failure, and determine whether the identified risks are acceptable (as those risks may be modified and mitigated).
National Environmental Policy Act of 1969

• National Environmental Policy Act of 1969 (“NEPA”)
  • Effective: January 1, 1970
  • Purpose: “To declare a national policy which will encourage productive and enjoyable harmony between man and his environment; to promote efforts which will prevent or eliminate damage to the environment and biosphere and stimulate the health and welfare of man; to enrich the understanding of the ecological systems and natural resources important to the Nation; and to establish a Council on Environmental Quality.”
National Environmental Policy Act of 1969 – Pipeline Projects

• The Energy Policy Act of 2005 designates the FERC as the lead agency for coordinating all applicable federal authorizations and for NEPA compliance in reviewing natural gas pipeline certificate applications. The FERC does not oversee the construction of oil pipelines.

• Cooperating agencies include PHMSA, Environmental Protection Agency, Bureau of Land Management, Fish and Wildlife Service, National Park Service, Army Corps of Engineers, among others.

• The FERC must analyze the environmental impacts of the proposed project and consider alternatives and appropriate mitigation measures.

• However, the FERC also has to consider and balance the energy needs where the natural gas pipeline is being planned.

• Upon completion of the process, if the FERC approves the application and grants a Certificate of Public Convenience and Necessity, the applicant still must take a number of separate actions, including, but not limited to, obtaining necessary environmental permits under the Clean Air Act and Clean Water Act.
National Environmental Policy Act of 1969 – Environmental Assessment (EA)

- An Environmental Assessment (EA) is “a concise public document” intended to “briefly provide sufficient evidence and analysis” to determine whether a finding of no significant impact can be issued.
  - Land, water, air, structures, living organisms, environmental values at the site, and the social, cultural, and economic aspects are considered.
  - If the EA determines impacts are significant, a more extensive and detailed Environmental Impact Statement must be prepared.
An Environmental Impact Statement (EIS) is a comprehensive document to describe the effects of proposed activities on the environment.

- The EIS must include a statement of:
  - The purpose and need for the proposed project;
  - A description of all reasonable alternatives to meet that purpose and need;
  - A description of the environment that would be affected by the project and the alternatives; and
  - An analysis of the direct and indirect effects of the project and the alternatives, including cumulative impacts.

- Direct effects “are caused by the action and occur at the same time and place.”
- Indirect effects “are caused by the [project] and are later in time or farther removed in distance, but are still reasonably foreseeable.”
- Cumulative impacts “result from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions.”
- The FERC will issue a draft EIS, which goes through Notice and Comment, and then a final EIS.
  - The draft and final EIS will address the direct, indirect, and cumulative impacts of the project.
  - The draft and final EIS will include recommendations to approve or deny the application for the project.
National Environmental Policy Act of 1969 – Sierra Club v. FERC

- In *Sierra Club v. FERC*, No. 16-1329 (D.C. Cir. August 22, 2017, the FERC had approved a Certificate of Public Convenience and Necessity for a natural gas pipeline project that includes a five hundred mile pipeline, known as the Sabal Trail Pipeline, stretching from Alabama, through Georgia, to Florida, to deliver natural gas to gas-fired power plants in Florida.
- The Sierra Club challenged the FERC’s environmental review process under NEPA.
- On appeal, the D.C. Circuit held that the FERC failed to fully examine greenhouse gas impacts related to a pipeline project because the EIS for the project failed to consider the impacts from greenhouse gas emissions from the power plants to be served by the proposed pipeline.
- The D.C. Circuit also held that the FERC should have either considered the Social Cost of Carbon (a scientifically-derived tool to translate tonnage of carbon dioxide or other GHGs to the cost of long-term climate harm), or explained why the Social Cost of Carbon tool is not useful for the FERC’s NEPA evaluation.
National Environmental Policy Act of 1969 – Sierra Club v. FERC

• On remand, the FERC issued a supplemental EIS ("SEIS"), stating that it could not determine whether downstream GHG emissions are significant.

• The SEIS also declined to use the Social Cost of Carbon tool, reiterating the FERC’s explanation from other proceedings why the Social Cost of Carbon tool is not appropriate in project-level environmental review under NEPA.

• The SEIS concluded that its additional analysis does not alter its conclusion in the prior final EIS that the Sabal Trail project is an environmentally acceptable action.

• Therefore, the FERC reinstated the Certificate, approving the Sabal Trail project.
In *Appalachian Voices v. FERC*, No. 17-1271 (D.C. Cir. February 19, 2019), the D.C. Circuit assessed the FERC’s approval of a Certificate of Public Convenience and Necessity for the Mountain Valley Pipeline, a 303-mile pipeline from West Virginia to Virginia. The D.C. Circuit issued an unpublished, five-page opinion, upholding the FERC’s Order. The D.C. Circuit rejected each of the arguments on appeal in summary fashion.
National Environmental Policy Act of 1969 – Appalachian Voices v. FERC

• The D.C. Circuit held that the FERC’s NEPA analysis was sufficient because:
  • FERC provided an estimate of the upper bound of GHG emissions resulting from end use combustion.
  • FERC concluded that the Social Cost of Carbon tool is not an appropriate measure of project-level climate change impacts and their significance under NEPA or the Natural Gas Act.

• While not stated in the decision, the *Appalachian Voices* case can be distinguished from the *Sierra Club* case because:
  • In *Sierra Club*, the end use combustion is arguably more reasonably foreseeable because the almost all of the gas would be delivered for use at gas-fired power plants.
  • In *Appalachian Voices*, the end use combustion is not as foreseeable because the gas would be delivered to other pipelines and LDCs, so the end use is not known.
Questions
As a pipeline safety, occupational safety, environmental attorney for over 30 years, Darren has been involved in too many emergency response and crisis management situations to count. Darren has represented the interests of energy sector since he was a first-year associate.

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Regulatory Hurdles for Siting Pipelines

2019 EBA Midwest Chapter Annual Meeting

Arshia Javaherian
Senior Legal Counsel
March 5, 2019
Overview:

- Enbridge
- Need for new and replacement energy infrastructure
- Regulatory hurdles to new and replacement infrastructure
- Successful Projects
Enbridge Story

The leading energy delivery company in North America
The Need for Pipelines

1 Safety
The Need for Pipelines

- Safety
- Reliability
New England Energy Prices

**Electricity Prices** ($/MWh)

**Natural Gas Prices** ($/MMBtu)

- Henry Hub
- Algonquin City Gate
New England Energy Prices

Algonquin Citygate
Northeast Natural Gas Prices

Appalachia Regional Avg.
Appalachia Natural Gas Prices

Chicago Citygate
Midwest Natural Gas Prices

Published 03/04/2019 naturalgasintel.com
The Need for Pipelines

- Safety
- Reliability
- Energy Interdependence
No State is an Island
Enbridge meets:

~70% Refining demand in broader Midwest

Husky
Flint Hills Resources
Marathon
BP Whiting
PBF
CITGO
ExxonMobil
BP-Husky
Marathon
The Need for Pipelines

- Safety
- Reliability
- Energy Interdependence
Hurdles to New and Replacement Infrastructure

1. Disparate Regulatory Treatment
Midwest State Regulatory Schemes
Hurdles to New and Replacement Infrastructure

- Disparate Regulatory Frameworks
- Unknown Regulatory Timelines
## Enbridge Line 3

### Minnesota PUC Permitting Timeframes

<table>
<thead>
<tr>
<th>Permit Type</th>
<th>Required Timeframes</th>
<th>Approval Dates</th>
</tr>
</thead>
<tbody>
<tr>
<td>Legal Statutory Time</td>
<td>Certificate of Need (CN)</td>
<td>12 MONTHS/CN</td>
</tr>
<tr>
<td></td>
<td>Pipeline Route Permit (RP)</td>
<td>9 MONTHS/RP</td>
</tr>
<tr>
<td><strong>MinnCann Project</strong></td>
<td></td>
<td><strong>17 MO. CN / RP</strong></td>
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<tr>
<td>(Minnesota Pipe Line)</td>
<td></td>
<td><strong>APPROVED April 2007</strong></td>
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<tr>
<td><strong>Alberta Clipper</strong></td>
<td></td>
<td><strong>20 MONTHS CN / RP</strong></td>
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<tr>
<td>(Enbridge)</td>
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<td><strong>APPROVED Dec 2008</strong></td>
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<tr>
<td><strong>Line 3 Replacement</strong></td>
<td></td>
<td><strong>43 MONTHS - CN / RP</strong></td>
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<tr>
<td>(Enbridge)</td>
<td></td>
<td><strong>16 MON = EIS Mar 2018</strong></td>
</tr>
</tbody>
</table>

As of Jan 2019
Hurdles to New and Replacement Infrastructure

- Various Regulatory Frameworks
- Unknown Regulatory Timelines
- Tribal Sovereignty
Hurdles to New and Replacement Infrastructure

- Various Regulatory Frameworks
- Unknown Regulatory Timelines
- Tribal Sovereignty
How Enbridge Succeeds

Safety

Integrity

Respect
thank you.