E&AS Revenue Offset Update

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MIC Special Session – Reserve Price Formation Order

July 21, 2020

Updates

- FERC filing extension to August 5 approved
- Updated resource parameters
- Completed historical dispatch on reference resources
- Completed initial forward price development and dispatch
  - Updating forward price methodology and dispatch parameters
- Engaged Brattle to assist in methodology development
  - Conducting review of forward price development
  - Conducting review of resource parameters

Dispatch Methods

Optimal-based Dispatch at Forward LMPs

- CT
- CC
- Coal
- Storage

Assumed Output Model Applied to Forward LMPs

- Nuclear
- Solar (Fixed and Tracking)
- Wind (Onshore)
- Wind (Offshore)

Combustion Turbine

The net energy and ancillary services revenue estimate shall be determined by a simulated energy dispatch of a 367 MW combustion turbine (with heat rate of 9,134 BTU/kWh, 20 MW/min ramp rate, variable operations and maintenance expenses of $1.10/MWh, plus major maintenance costs of $20,840/start and a 2 hour minimum run time) using an hourly zonal day-ahead forecasted LMP, developed from forward prices, forward gas prices, plus an ancillary services revenue to be determined.

Reference Resource (CT) Parameters

Parameter	Value	Notes
Max Capacity	367 MW	Average capacity of CONE Area units at ISO conditions (59°F, 14.7 psia)
Min Stable Level	244 MW	Turn down ratio = 1.5, Minimum Unit-Specific Operating Parameters for Generation Capacity Resources
Ramp Rate	20 MW/min	PJM
Heat Rate	9134 Btu/kWh	Average heat rate of CONE Area units at ISO conditions (59°F, 14.7 psia)
Min Run	2 hr	Minimum Unit-Specific Operating Parameters for Generation Capacity Resources
Min Down	1 hr	
Time to Start	21 min	Sargent & Lundy
VO&M	$1.10/MWh	Consumables
	$20,840/start	Major maintenance ($5.83/MWh)
Start Fuel	491 MMBtu/start	Average fuel use of CONE Area units
Fuel Pricing Points	Zonal fuel mapping from 2018 CONE Study, See Manual 18, Section 3.3.2	
NOx	0.0093 lb/MMBtu	2018 CONE Study; historical allowance prices escalated for forward
	55 lb/start	
SO2	0.0006 lb/MMBtu	EPA; historical allowance prices escalated for forward
CO2	117 lb/MMBtu	EPA; RGGI ECR trigger price applied to RGGI units
Forced Outages (EFORd)	6.331%	PJM 2015 - 2019 Weighted Average EFORd by Fuel Type, Class Average Values Effective June 1, 2020
Maintenance Outages	First two weeks in October	

The net energy and ancillary services revenue estimate shall be determined by a simulated energy dispatch of a 1,188 MW combustion turbine employing duct-firing (with heat rate of 6,501 BTU/kWh, 20 MW/min ramp rate, variable operations and maintenance expenses, inclusive of major maintenance costs, of $2.11/MWh and a 4 hour minimum run time) using an hourly zonal day-ahead forecasted LMP, developed from forward prices, applicable forward gas prices, plus an ancillary services revenue to be determined.

Combined Cycle

Parameter	Value	Notes
Max Capacity	1,188 MW w/ Duct Burner; 1,060 MW w/o Duct Burner	Average capacity of CONE Area units at ISO conditions (59°F, 14.7 psia)
Min Stable Level	460 MW	
Ramp Rate	20 MW/min	PJM
Heat Rate	6,501 Btu/kWh w/ Duct Firing; 6,269 Btu/KWh w/o Duct Firing	Average heat rate of CONE Area units at ISO conditions (59oF, 14.7 psia)
Min Run	4 hr	Minimum Unit-Specific Operating Parameters for Generation Capacity Resources
Min Down	3.5 hr	
Time to Start	135 min	Sargent & Lundy
VO&M	$2.11/MWh	Sargent & Lundy
Start Fuel	8242 MMBtu/start	Average fuel use of CONE Area units
Fuel Pricing Points	Zonal fuel mapping from 2018 CONE Study, See Manual 18, Section 3.3.2	
NOx	0.0074 lb/MMBtu	2018 CONE Study; historical allowance prices escalated for forward
	160 lb/start	
SO2	0.0006 lb/MMBtu	EPA; historical allowance prices escalated for forward
CO2	117 lb/MMBtu	EPA; RGGI ECR trigger price applied to RGGI units
Forced Outages (EFORd)	3.045%	PJM 2015 - 2019 Weighted Average EFORd by Fuel Type, Class Average Values Effective June 1, 2020
Maintenance Outages	First two weeks in October	

Coal

The net energy and ancillary services revenue estimate shall be determined by a simulated energy dispatch of a 650 MW coal unit (with heat rate of 8,638 BTU/kWh and variable operations and maintenance expenses, inclusive of major maintenance costs, of $9.50/MWh) using an hourly zonal day-ahead forecasted LMP, developed from forward prices, Central Appalachian coal forward prices, plus an ancillary services revenue to be determined. Modeled as an economic unit with an eco max/eco min of 650/433 MW. The time to start is 5 hours and the minimum runtime and minimum downtime are 6 hours.

Coal

Parameter	Value	Notes
Max Capacity	650 MW	EIA (Case 1)
Min Stable Level	433 MW	Turn down ratio = 1.5, Minimum Unit-Specific Operating Parameters for Generation Capacity Resources
Ramp Rate	5 MW/min	PJM
Heat Rate	8638 Btu/kWh	EIA (Case 1)
Min Run	6 hr	Minimum Unit-Specific Operating Parameters for Generation Capacity Resources
Min Down	6 hr	
Time to Start	5 hr	
VO&M	$9.5/MWh	PJM
Start Fuel	Coal: 124 MMBtu, Oil: 8746 MMBtu	PJM
Fuel Pricing Points	Coal: Central Appalachia, Oil: New York Harbor Heating Oil	
NOx	0.06 lb/MMBtu	EIA (Case 1); historical allowance prices escalated for forward
SO2	0.09 lb/MMBtu	
CO2	Coal: 206 lb/MMBtu, Oil: 159 lb/MMBtu	EIA (Case 1), EPA; RGGI ECR trigger price applied to RGGI units
Forced Outages (EFORd)	11.776%	PJM 2015 - 2019 Weighted Average EFORd by Fuel Type, Class Average Values Effective June 1, 2020
Maintenance Outages	None modeled at this time, to be determined	

The net energy and ancillary services revenue estimate shall be estimated by a simulated dispatch of a 1 MW / 4 MWh resource with a 91% charge and discharge efficiency* against an hourly zonal day-ahead forecasted LMP, developed from forward prices, plus an ancillary services revenue to be determined. The resource is assumed to be dispatched between 90% and 10% state of charge.

** This is used to represent an 83% roundtrip efficiency in the dispatch model*

Battery Storage

Parameter	Value	Notes
Max Capacity	Modeled as 1 MW / 4MWh resource	EIA (Case 18)
Charge Efficiency*	91%	
Discharge Efficiency*	91%	
State of Charge	Between 90% and 10%	
Forced & Maintenance Outages	None at this time, to be determined	

** This is used to represent an 83% roundtrip efficiency in the dispatch model*

The net energy and ancillary services revenue estimate shall be determined by the gross energy market revenue determined by the product of [hourly zonal day-ahead forecasted LMP, developed from forward prices, times 8,760 hours, adjusted for forced & maintenance outages] minus the total annual cost to produce energy determined by the product of [8,760 hours times the annual average equivalent availability factor of all PJM nuclear resources times $9.02/MWh for a single unit plant or $7.66/MWh for a multi-unit plant] where these hourly cost rates include fuel costs and variable operation and maintenance expenses, inclusive of major maintenance costs, plus an ancillary services revenue to be determined.

Nuclear

Parameter	Value
Max Capacity	Modeled as 1 MW resource, operating 8760 hours per year
VO&M	*Multi*: $7.66/MWh
	Single: $9.02/MWh
Forced Outages (EFORd)	1.101%
Maintenance Outages	None at this time, to be determined

Solar (Fixed and Tracking)

The net energy and ancillary services revenue estimate shall be determined using a solar resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual net energy market revenues are determined by multiplying the solar output level of each hour by the hourly zonal day-ahead forecasted LMP, developed from forward prices, applicable to such hour with this product summed across all of the hours of an annual period, plus an ancillary services revenue to be determined. Two <u>separate</u> solar resource models are used, one model for a fixed panel resource and a second model for a tracking panel resource.

Onshore Wind

The net energy and ancillary services revenue estimate shall be determined using a wind resource model that provides the average MW output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual energy market revenues are determined by multiplying the wind output level of each hour by the hourly zonal day-ahead forecasted LMP, developed from forward prices, applicable to such hour with this product summed across all of the hours of an annual period, plus an ancillary services revenue to be determined

The net energy and ancillary services revenue estimate shall be the product of [the hourly zonal day-ahead forecasted LMP, developed from forward prices, times 8,760 hours times at an assumed 45% of rated output], plus an ancillary services revenue to be determined

Onshore Wind, Fixed Tilt Solar PV, Single-Axis Tracking Solar PV:

Parameter	Value
Output	Hourly capacity factor profiles applied to a 1MW resource
VO&M	$0/MWh
Forced & Maintenance Outages	None at this time, to be determined

Offshore Wind:

Parameter	Value
Output	1MW resource at 45% capacity factor for 8760 hours per year
VO&M	$0/MWh
Forced & Maintenance Outages	None at this time, to be determined

Dispatch Methods Applied to Historical Day-Ahead LMPs

RTO Average Results

	Resource	Net Revenue ($/MW-year)				Run Hours*			
		2017	2018	2019	Average	2017	2018	2019	Average
Optimal-Based	Reference CT (No 10% Adder)	$31,772	$44,431	$25,495	$33,899	5,406	5,367	5,203	5,325
	Reference CT (10% Adder)	$21,793	$32,881	$16,386	$23,687	3,592	4,133	3,660	3,795
	MOPR CC	$74,736	$91,781	$62,918	$76,478	8,348	8,262	8,298	8,303
	MOPR Coal	$3,653	$20,893	$817	$8,455	197	373	65	212
	MOPR Battery * Discharge Hours	$18,556	$25,370	$14,522	$19,483	1,353	1,407	1,295	1,352
Assumed Output	MOPR Nuclear (Single)	$175,720	$230,721	$143,263	$183,234	8,760	8,760	8,760	8,760
	MOPR Nuclear (Multi)	$187,502	$242,503	$155,045	$195,017	8,760	8,760	8,760	8,760
	MOPR Onshore Wind	$81,041	$100,772	$70,933	$84,249	8,760	8,760	8,760	8,760
	MOPR Offshore Wind	$117,670	$145,751	$100,934	$121,452	8,760	8,760	8,760	8,760
	MOPR Fixed-Tilt Solar PV	$38,865	$45,397	$33,149	$39,137	4,717	4,716	4,717	4,717
	MOPR Tracking Solar PV	$63,096	$73,939	$53,902	$63,645	4,749	4,748	4,749	4,749

Ancillary Services

- Considering two options:
  - Analyze the percent of historical revenues from selling energy and ancillary services across resource classes. Develop a revenue adder for reserve and regulation market revenues that can be added to the projected energy market revenues.
  - Analyze the historical correlation between energy and ancillary market prices. Develop forward-looking hourly reserve and regulation market prices based on the forward hourly energy prices. Perform a co-optimized energy, regulation and reserve dispatch against the forward prices.
- Continue to assume fixed reactive services revenues, consistent with March MOPR filing
- Account for which services each resource type is able and likely to provide

Methodology Update – Price Development

- Based on (Manual 15, Long Term Method 12.5.1 – 12.5.5)
  - RT monthly LMP forwards for delivery year (calendar year)
    - Power – West Hub, with 3-yr historical hourly basis to other hubs
    - Gas – Henry Hub, with 3-yr historical daily basis to other hubs
  - Shaped with historical DA LMPs from most recent 3 years
    - Conducted for each of 3 years individually

- Considering Brattle recommendations regarding pricing hubs and basis determination
    - *(Note: See corresponding Brattle presentation)*

Methodology Update – Dispatch

- Use of 10% adder
  - Accounts for uncertainty in the values of the costs used to determine cost-based offers in the energy market
  - Accounts for real-time gas charges, balancing fees when dispatching CT for Net CONE development
  - Is this a valid application of the 10% adder in the context of the E&AS Offset?
  - Dispatch impact: CT run hours increased 40% when 10% adder was removed from historical run

Decision Matrix – Price Development

Decision Item	Choices	Current Thinking	Reasoning
Price method	• Heat Rate Output Scalar • Forward Input Scalar	Forward Input Scalar	Use of forward prices scaled for historical shape.
Forward sample	• Single day • Multiple days	Multiple days	Provides a large sample to address anomalous data, but not too historic
Power hub	• West hub • Local hub	West, NI, AEP-Dayton	Most liquid. Historical basis provides reasonable expectation of future local price
Gas hub	• Henry hub • Local hub	DomS, Chicago, MichCon	Liquid, match to Electric hub.
Basis method	• Historical • FTR	Historical	Most liquid. Match electric and gas hubs. Use monthly differentials
Day of Week Adjustment	• Adjust • Do not adjust	Under investigation	Prevents mismatch of days of week when conducting hourly scaling
Market for scalar	• Day-Ahead/Real-Time • Day-ahead	Day-ahead, investigating	Majority of units committed in day-ahead, thus volatility shape more applicable
Scalar sample	• One-year • Three-year	Three year	Provides a large sample to address anomalous data, but not too historic

Decision Matrix – Dispatch

Decision Item	Choices	Current Thinking	Reasoning
Dispatch method	• Peak-hour based • Optimal based	Optimal based	Removes peak hour limitations. More applicable to dispatchable unit operations
Offers modeled	• Cost • Cost-based plus 10% • Price-based	Cost-based plus 10%?	Simple, transparent and reasonable. Use of 10% adder approved as part of quadrennial review. Is 10% adder applicable here?
Maintenance Outages	• Two-weeks in October	Two-weeks	
Forced Outages	• Account for in EFORd	EFORd	
Optimization	• 24-hour look ahead • None	24-hour look ahead	Closer to Day-ahead optimization
Daily start limitations	• Yes • No	No	Allows for economic operation
Emissions adders	• Yes • No	Yes	Included for units in allowance trading programs (NOx, SO2, CO2)
Gas mapping	• PJM • IMM	PJM	Matches decisions agreed to in Quadrennial Review

Unit-Specific Exceptions

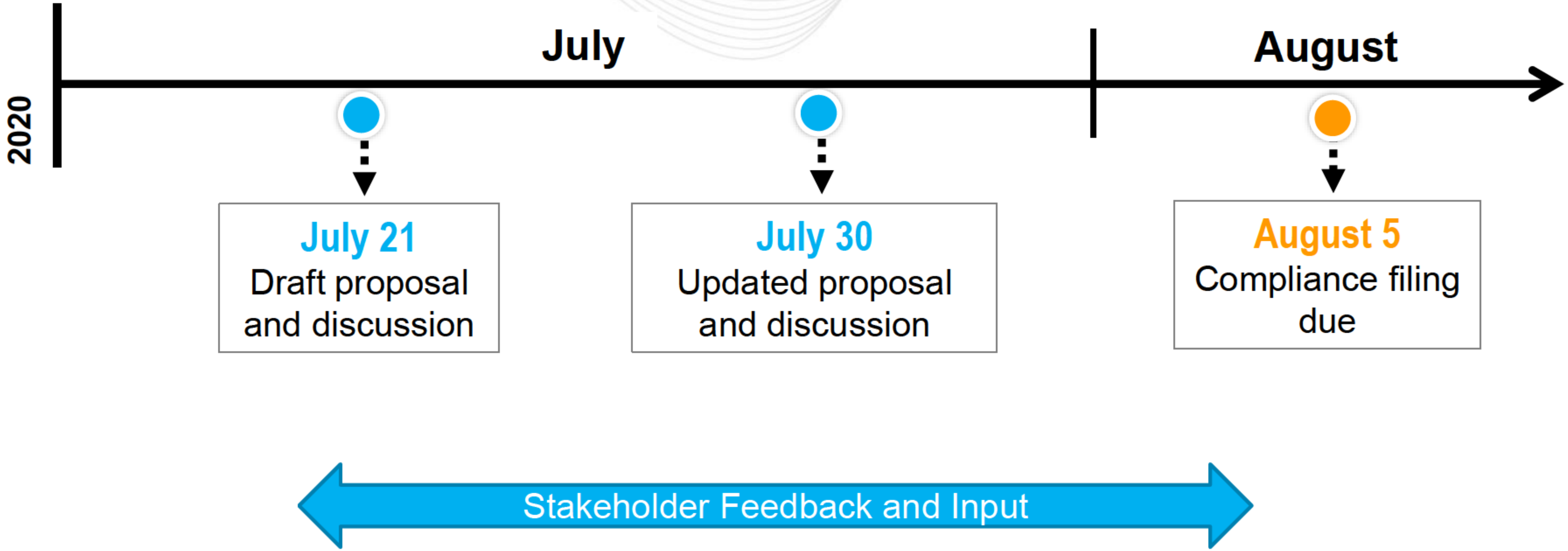
PJM intends to outline acceptable deviations from the default methodology for developing the forward E&AS offset through the unit-specific exception process.

- What deviations from the default methodology do participants feel are necessary?
- What evidence should be shown to demonstrate that such deviations match commercial expectations?

Next Steps

- Test forward price development with updated methodology
- Run dispatch with updated forward prices and parameters
- Develop acceptable ranges for unit specific process

Stakeholder Process



July 30 Meeting

- Brattle recommendations
- Forward prices
- Dispatch parameters and methods
- Present indicative values

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