

Introduction

This Assumptions Book document is for MISO stakeholders to reference when questions arise related to assumptions used in the Futures Refresh/Series 1A Futures. It describes components that are requested in more detail from the [stakeholder feedback](#).

Throughout this document the terms “Series 1A” or “Futures Refresh” are used interchangeably and refer to the same set of Futures: 1A, 2A, and 3A. Similarly, the terms “original Futures” or “Series 1” are used interchangeably, referring to the MISO Futures developed in 2019-20.

For more information, or if a question is not answered here, please refer to the following sources.

- The [Future Planning Scenarios webpage](#) on the MISO website.
 - The Series 1 [MISO Futures Report](#).
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General Assumptions

Study Period

The study period of the EGEAS resource expansion analysis is 20 years, beginning on 1/1/2023 and ending on 12/31/2042. An extension period of 40 years is added to the end of the simulation, with no new units forecasted during this time. This extension ensures that the generation selected in the last few years of the forecasting period (i.e., Years 15-20) is based on cost of generation spread out over the total tax/book life of the new resources (i.e., beyond Year 20) and does not bias to the cheapest generation in those final years.

Discount Rate

The discount rate of 6.93% is based on the after-tax weighted average cost of capital of the Transmission Owners that make up the Transmission Provider Transmission System.

MISO Footprint Study Area

The study area for the updated MISO Futures continued to be the entire MISO footprint. However, the Local Clearing Requirement (LCR) for each zone was evaluated during the siting process to ensure each LRZ met their respective LCR as defined in the 2020/2021 Planning Resource Auction (PRA).

1.) Planning Reserve Margin

Because the EGEAS model only allows for a single annual Planning Reserve Margin (PRM) value, an updated approach reflects MISO’s shift to a seasonal Resource Adequacy construct. For the Futures Refresh, MISO used data from the 2023-24 Planning Year PRM and Local Reliability Requirements (LRRs) under seasonal construct.

MISO divided the highest seasonal installed capacity (ICAP) PRM requirement (Winter 2023-2024) by the highest seasonal System Peak Demand (Summer 2023), which yielded an 18.05% Planning Reserve Margin. For reference, the LRTP Tranche 1 Futures used a PRM of 18%.

2.) Why EGEAS may favor Wind over PV load shape

In F2A, we see the load shape shifting which impacts the effectiveness of solar to meet energy demand.

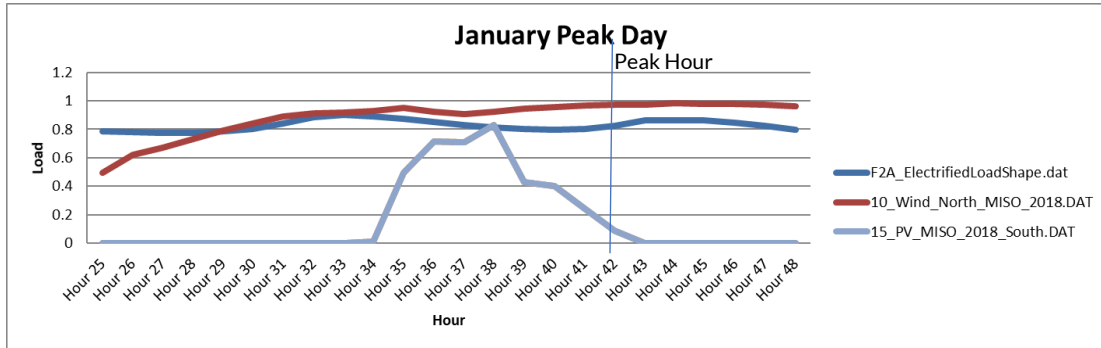


Figure 1. January 2026 - Winter Peaks Occurring Outside Solar Hours

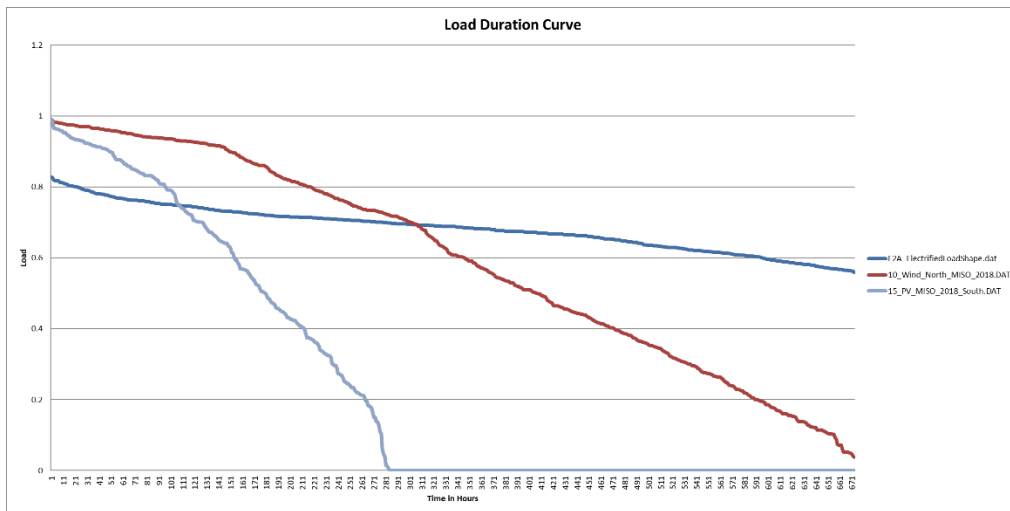


Figure 2. 2023, Segment 2

The timing and amount of energy generated by solar photovoltaic (PV) and wind is quite different. PV can only produce energy during the daylight hours, while wind tends to produce energy throughout the day and night. Additionally, the annual capacity factor of PV is only in the low 20% range, while for wind, it exceeds 40% within the MISO footprint and reaches 61% in external areas.

Another important factor is the cost difference between wind and PV options. The primary reason for lower wind costs is the production tax credit (PTC), modeled as negative variable operations and maintenance (O&M) costs. Wind produces almost three times as much energy as PV, therefore garnering nearly three times as many PTCs. The relatively greater amount of PTCs that wind enjoys grant it lower levelized annual costs, a primary reason that EGEAS has a tendency to select more wind than PV.

3.) Assumptions for:

3a.) Retirements

The Series 1A Futures use the same age-based figures as Series 1, but are updated with base retirement data from member survey responses.

	<i>Future 1</i>	<i>Future 2</i>	<i>Future 3</i>
<i>Coal</i>	46	36	30
<i>Natural Gas – CC</i>	50	45	35
<i>Natural Gas – Other</i>	46	36	30
<i>Oil</i>	45	40	35
<i>Nuclear & Hydro</i>	Retire if Publicly Announced	Retire if Publicly Announced	Retire if Publicly Announced
<i>Solar – Utility-Scale</i>	25	25	25
<i>Wind – Utility-Scale</i>	25	25	25

Figure 3. Series 1 Futures Age-Based Retirement Assumptions.

3b.) Load growth, hourly load profile

The Series 1A Futures use the same load growth and hourly load profiles as Series 1, but with the same trends continued through the year 2042 since the Series 1 data ended in 2039.

Annual Peak Load and Energy data is supplied to MISO by Applied Energy Group (AEG) on both a Regional and LRZ level.

- i. For LRZs, both System (coincident) and Zonal (non-coincident) peak are provided.
- ii. AEG also provides energy data for MISO and External DSM programs (described below).

Time shift in load data from Series 1 to Series 1A Futures.

- i. Series 1 utilized load data from 2020-2039.
- ii. Futures Refresh uses data from 2023-2042.

3c.) Intermittent resource accreditation

The Series 1A Futures assume accreditation values from last year's Planning Resource Auction. Accredited capacities for resources contribute toward PRM in EGEAS, with specific reserve capacity schedules developed for PV, Wind, Hybrid, and Battery in each year of the 20-year study period. These are the same values used in the 2022 Regional Resource Adequacy (RRA) study.

EGEAS accounts for and adds resources to address PRM needs based on accredited capacity, not nameplate or maximum rated capacity.

Accreditation by resource type, as percentage of nameplate capacity:

	PV/DGPV	Wind	Hybrid	Battery
2023	50.00%	16.60%	60.00%	100.00%
2024	50.00%	16.60%	60.00%	100.00%
2025	50.00%	16.60%	60.00%	100.00%
2026	50.00%	16.60%	60.00%	100.00%
2027	50.00%	16.60%	60.00%	100.00%
2028	47.00%	16.60%	57.00%	97.50%
2029	44.00%	16.60%	54.00%	95.00%
2030	41.00%	16.60%	51.00%	92.50%
2031	38.00%	16.60%	48.00%	90.00%
2032	35.00%	16.60%	45.00%	87.50%
2033	32.00%	16.60%	42.00%	85.00%
2034	29.00%	16.60%	39.00%	82.50%
2035	26.00%	16.60%	36.00%	80.00%
2036	23.00%	16.60%	33.00%	77.50%
2037	20.00%	16.60%	30.00%	75.00%
2038	20.00%	16.60%	30.00%	75.00%
2039	20.00%	16.60%	30.00%	75.00%
2040	20.00%	16.60%	30.00%	75.00%
2041	20.00%	16.60%	30.00%	75.00%
2042	20.00%	16.60%	30.00%	75.00%
Average:	34.30%	16.60%	44.30%	86.90%

3d.) Existing and planned resources included in the model

Incorporated member-submitted updates for existing and planned resources from both RRA 2022 data gathering (Spring 2022) and Futures Refresh Survey responses (Fall 2022).

- a. All Queue resources with signed Generator Interconnection Agreement at beginning of modeling are included in the base model
- b. EGEAS expansion built based off existing and planned resources, load assumptions, and system constraints, including:
 - i. Reliability/Planning Reserve Margin
 - ii. Clean Energy/Renewable Portfolio Standards
 - iii. Decarbonization Goals

3e.) Distributed Energy Resources/Demand-Side Management (DERs/DSM)

Also referred to generally as DSM, as in previous Futures studies, DERs (including Energy Efficiency, Demand Response, and Distributed Generation) are developed into program blocks by Applied Energy Group (AEG) and implemented as generating unit proxies in EGEAS.

- a. The generation of Energy Efficiency resources is netted out of total system load.

- b. Futures Refresh: While there may appear to be fewer DERs selected by EGEAS, the Futures Refresh incorporates greater amounts than previous studies.
- c. DER program block data were updated and extended through 2042 for the new study period.
- d. According to AEG data, F1 DER program levels represent minimum expected resource levels. Therefore, Future 1A programs are included as minima within the base model of all refreshed Futures.
 - i. Futures 2A and 3A employ all F1A programs and allow F2A/F3A program increments (the difference of F2A/F3A and F1A resources) for selection.
- e. Similar to previous Futures studies, F2A and F3A incremental programs are selected via the DSM Ranking process:
 - i. Identical EGEAS cases run, each with one DSM program forced in, plus one null hypothesis or “do-nothing” scenario.
 - ii. All DSM programs whose cases yield lower total system cost than the “do-nothing” case are included.

3f.) Emissions, decarbonization, and RPS goals

- a. Member utilities submitted yearly CO₂ and RPS goals in Futures Refresh Survey alongside existing and planned resource updates.
- b. Model also accounts for state decarbonization goals (legislative and executive) and RPS.
- c. Member plans and other public data are incorporated into base models, regardless of their effect on overall carbon emissions or renewable energy percentages.
- d. Most utilities requested that their goals be implemented stepwise rather than gradually in MISO’s models, resulting in significant decreases in allowed CO₂ emissions in benchmark years and leading in significant RRF buildout to meet carbon constraints in those years.

3g.) Unmet energy

- a. Utilizing a Load Duration Curve, EGEAS observes System Peak, Hourly Energy, and PRM constraints, meeting all three
- b. Since EGEAS is a non-chronological model, final expansion is validated in a chronological model (PROMOD) to validate energy adequacy
- c. If shown necessary from the PROMOD validation, additional units are manually added.
- d. Coupled with chronological energy adequacy validation in PROMOD, as well as announced fleet additions and retirements, EGEAS ensures that sufficient generation is added to meet all system reliability requirements regardless of resource mix.

4.) Capital costs and implementation of the Inflation Reduction Act of 2022 (IRA)

4a.) Inflation rate

- a. Set to 2.5% throughout the planning period for most capital costs
- b. Set to 2.0% for IRA-related tax credits

4b.) Cost calculation for new resource types

- a. All cost data is sourced from NREL Annual Technology Baseline dataset
 - i. For non-IRA resources, “Overnight Capital Cost” is applied for capital cost
 - ii. EGEAS incorporates calculations for cost of construction, financing, etc.
 - iii. Each resource uses NREL ATB’s values for Fixed Operation and Maintenance and Variable Operation and Maintenance
 - iv. All of the above values converted into nominal current-year dollars based on inflation rate from St. Louis Federal Reserve Economic Data
- b. For IRA resources, CAPEX is used as a base value to calculate production tax credit (PTC) and investment tax credit (ITC)
- c. PTC and ITC calculated using inflation rate, tax rate, and depreciation factor from ATB

4c.) Inflation Reduction Act key assumptions

- a. PTC implemented at 100% of base rate and applied to wind, solar, and hybrid
 - i. PTC already available for wind generation; also available for solar and hybrid now
 - ii. PTC tends to be more financially beneficial for larger projects like wind and solar; computationally more straightforward to treat resources similarly and apply the same tax credits across the board
 - iii. ITC implemented at 30% and applied to standalone storage
 - iv. Both tax credits reduced by 80% by default, then restored to full amount if prevailing wage rate and apprenticeship requirements are met
 1. This is assumed to be the case by default for all future renewables
- b. No phaseout of any tax credits, PTC or ITC
 - i. Phaseout would begin if an economy-wide emissions reduction of 75% is achieved by early to mid-2030s; EIA does not project this level of decarbonization until past 2050
- c. 10% bonus credits available for domestic content, construction in energy communities
- d. Bonus credits applied as follows:

	Year 0	Year 5	Year 10	Year 15
Wind	1	1	1	1.5
Solar	0	1	1	1.5
Hybrid	0	0	1	1.5
Storage	0	0	1	1.5

- i. For “1.5 bonus credits,” assumed that most/all generators will receive ≥ 1 bonus credit, and roughly half will receive 2
- ii. Domestic content threshold increasingly likely, especially for wind resources, as domestic construction infrastructure expands
- iii. GIS tools identifying energy communities already exist; new units are often sited on retired plant sites to take advantage of transmission right-of-way (areas around recently retired coal plants qualify as energy communities)

4d.) Inflation Reduction Act implementation

- a. Base-level tax credits assume 1.5¢/kWh in 1992, per IRA
 - i. Credit values increase based on historical inflation rates from St. Louis FRED

- b. Tax credits implemented as a negative Variable O&M rate
- c. Applied to the Planning Alternative resources that define new units built by EGEAS and planned resources from members—not applied to any existing resources

	Fixed O&M \$/kW	Var. O&M \$/MWh '22	Var. O&M 2027	Var. O&M 2032	Var. O&M 2037	Var. O&M 2042
Wind	44.66	-30.56	-33.74	-37.25	-43.00	-47.47
Solar	23.48	-27.78	-33.74	-37.25	-43.00	-47.47
Hybrid	35.84	-27.78	-30.67	-37.25	-43.00	-47.47
Storage	31.99	-30	-25.13	-32.60	-38.84	-40.93

5.) Other information around new resources

Parameter	CC	CT	Wind	PV	Hybrid	Battery
Operating life	45	36	25	25	25	25
Book life	30	36	25	25	25	25
Forced outage rate (%)	5.11	5.93	0	0	0	3.25
Fixed O&M (\$/kW/year)	29.1	22.28	44.66	23.48	35.84	31.99
Direct construction cost (\$/kW)	954	845	1366	1140	1836	1364
Variable O&M (\$/MWh)	1.85	5.27	(See above)			
Fuel cost (\$/MMBtu)	5.33	5.33				

Construction cost schedule

Years prior to on-line	CC	CT	Wind	PV	Hybrid	Battery
1	30	50	80	100	100	80
2	60	50	10	0	0	10
3	10	0	10	0	0	10

6.) Climate and Equitable Jobs Act (CEJA) passed by the State of Illinois:

6a.) Key Provisions of CEJA emission goals:

- a. Private oil- and coal-powered generating facilities must phase out by 2030.
- b. Public oil and coal facilities are allowed to continue operation until 2045. Any source or plant with such units must also reduce their CO₂ emissions by 45% from existing emissions by no later than January 1, 2035.
- c. Public gas facilities must phase out by 2045.
- d. The phaseout of private gas facilities is more complex in order to speed up both emission reductions and the retirement of plants that emit higher levels of air quality emissions (i.e., NO_x and SO_x) and that are nearer to environmental justice communities. These phaseout specifications are illustrated below.

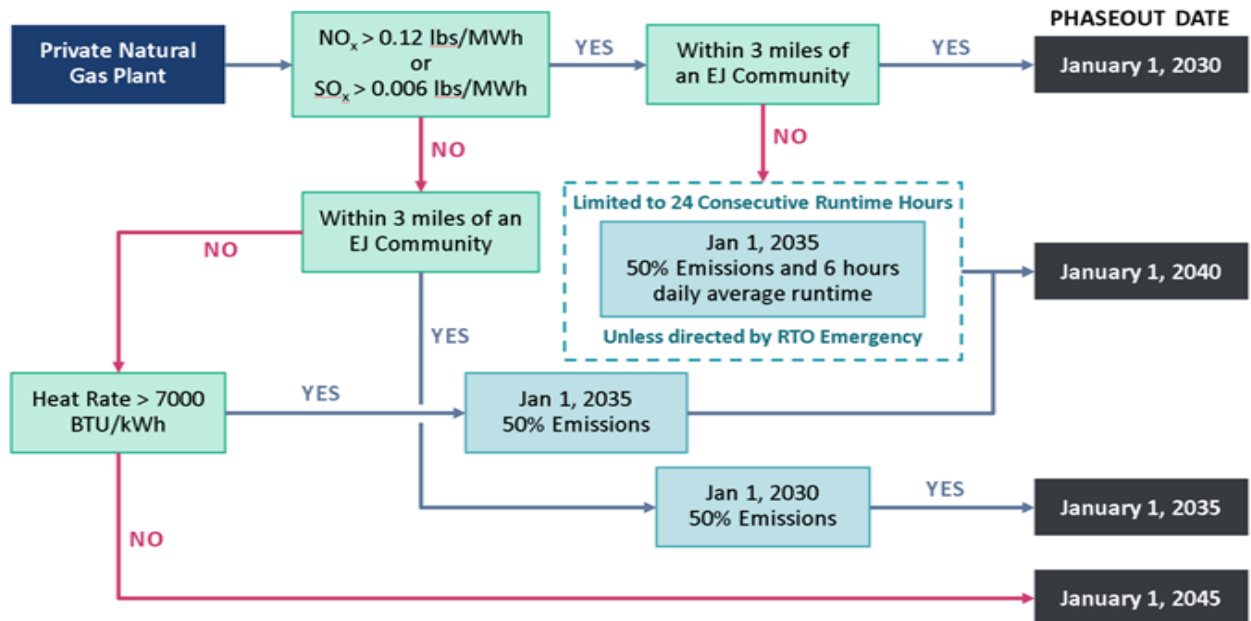


Figure 4. Phaseout of Private Gas Plants in CEJA. Source: Illinois Commerce Commission

6b.) CEJA Implementation in MISO/PJM models:

- Phase out all private oil and coal-fired units in IL by 2030.
- Phase out all public oil and coal units in IL by 2045, with an intermediate requirement of 45% emission reduction by 2035.
- Phase out all public gas units in IL by 2045.
- Implementation for private gas units is more complex due to consideration of other factors, such as: NO_x/SO_x emissions, heat rate, and proximity to environmental justice communities to determine their emission guidelines. Private gas units were categorized based on the above criteria, with emission limits placed accordingly.
- The emission caps on the units are implemented by enabling Unit Emission Constraints in EGEAS.

7.) Resource Siting

- Model-built resources sited to address:
 - Local/regional RPS and carbon reduction goals
 - Tranche Priority sites
 - Each Local Resource Zone (LRZ) meeting its Local Clearing Requirement (LCR) and Planning Reserve Margin Requirement (PRMR)
- Capacity sited at 5-year milestone intervals (2027, 2032, 2037, 2042)
- Bus (guidelines/restrictions)
 - No more than 1,200 MW of capacity sited at a single bus
 - No more than 3 individual uses of a single bus
 - Both rules overridden by direct stakeholder feedback
- 80-20 split
 - ~80% of model-built capacity sited at Queue Priority sites

- ii. Remaining ~20% sited at Vibrant Clean Energy (VCE) sites and available N-1 buses split among LBAs in proportion to the total Queue capacity of each LBA for a given resource type
- e. Battery siting
 - i. ~80% of model-built capacity sited at Queue Priority sites, remaining 20% distributed:
 - 1. ~80% of battery capacity sited in close proximity to centers of high load
 - 2. ~20% of battery capacity sited in close proximity to generation
- f. Thermal siting
 - i. Thermal capacity sited at Active Definitive Planning Phase (DPP)/Generator Interconnection Queue sites
 - ii. Remaining thermal capacity sited at brownfield/thermal retirement sites
- g. Flexible Attribute Unit siting
 - i. Flex unit capacity sited at brownfield/thermal sites