BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 191

MISO 2026–27 CIL/CEL Final Results

PY 2026-2027 CIL/CEL Results

Loss of Load Expectation Working Group
October 30, 2025

Reposted: 10/28/25
Slide: 4

Purpose and Key Takeaways

Purpose:

Present Final Capacity Import and Capacity Export Limits (CIL/CEL) for PY 2026-2027

Key Takeaways

- Some CIL/CEL values and limiting elements have changed since the preliminary results presentation.
- Individual LRZ's results slides have been updated if there was a rerun in their study.
- CIL/CEL results for PY 2026-2027 are final. Any adjustments made between now and the Planning Resource Auction would be due to Controllable Export changes.

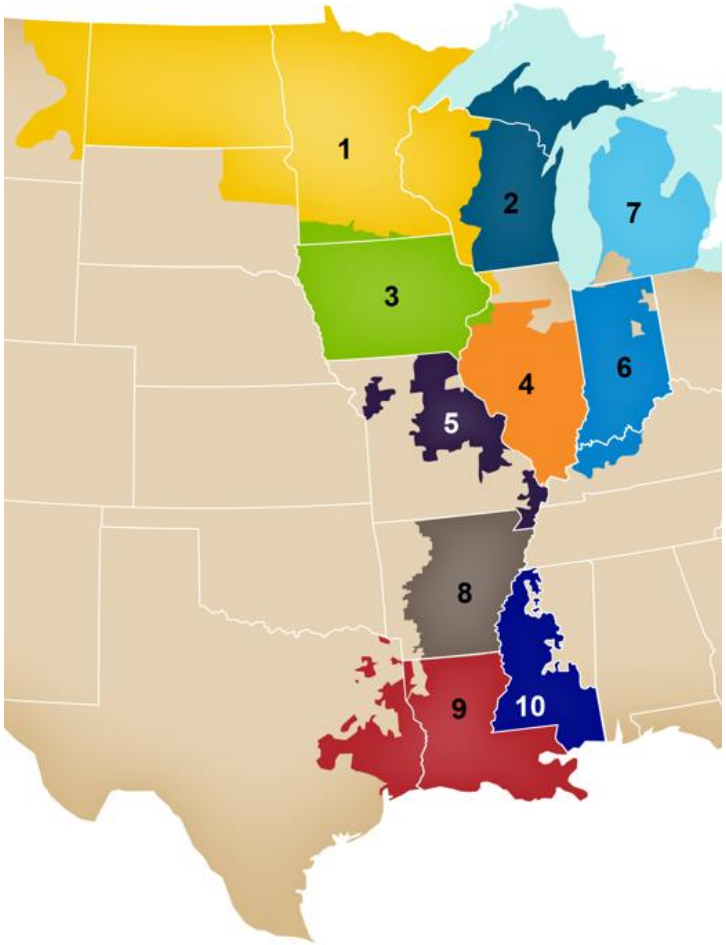
ZIA/ZEA Changes from September LOLEWG

LRZ	ZIA/ZEA	Season	Preliminary	Final	Reason
5	ZIA	Summer 26	3,450	4,417	Operational Guide established to mitigate previous identified constraint
5	ZIA	Fall 26	4,698	4,762	
4	ZIA	Winter 26-27	5,320	5,493	Load Updated in Winter Model
6	ZIA	Winter 26-27	5,558	8,208	
7	ZIA	Winter 26-27	3,420	4,123	
9	ZIA	Fall 26	4,108	4,761	Removed an improperly labeled generator for import/export exclusion in the subsystem file. Studies were done again with adjusted redispatch strategy
9	ZIA	Winter 26-27	3,128	3,690	
9	ZIA	Spring 27	3,994	4,657	
10	ZIA	Summer 26	2,777	5,322	
10	ZIA	Fall 26	2,669	4,379	
10	ZIA	Winter 26-27	2,774	3,154	
10	ZIA	Spring 27	3,280	4,187	
6	ZEA	Winter 26-27	6,625	3,378	Load Updated in Winter Model

2026-2027 PY Zonal Import Ability Results

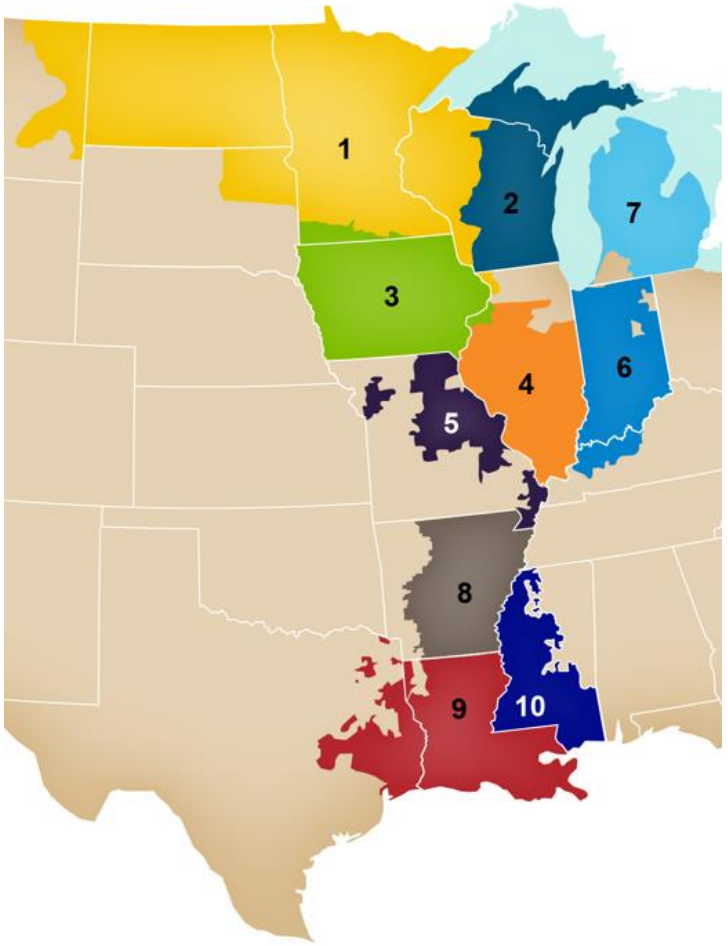
LRZ	Summer ZIA (MW)	Fall ZIA (MW)	Winter ZIA (MW)	Spring ZIA (MW)
1	7,042	7,245	4,533	6,690
2	5,072	6,050	5,294	6,133
3	5,400	9,191	9,620	9,311
4	8,517	6,491	5,493	6,533
5	4,417	4,762	6,379	4,733
6	6,440	7,012	8,208	7,999
7	4,628	5,193	4,123	5,338
8	3,981	6,170	3,366	5,374
9	4,309	4,761	3,690	4,657
10	5,322	4,379	3,154	4,187

Blue values indicate changes from previously presented values
Red value indicates corrected typo



2026-2027 PY Zonal Export Ability Results

LRZ	Summer ZEA (MW)	Fall ZEA (MW)	Winter ZEA (MW)	Spring ZEA (MW)
1	3,720	4,199	2,987	3,715
2	3,088	5,034	3,945	4,608
3	5,133	5,744	9,285	6,391
4	8,225	6,611	4,724	6,447
5	5,255	3,701	6,786	5,811
6	7,744	5,461	3,378	4,465
7	5,745	5,305	5,546	5,497
8	5,403	3,947	4,609	4,144
9	3,361	3,970	2,096	4,633
10	2,132	2,459	1,602	2,725



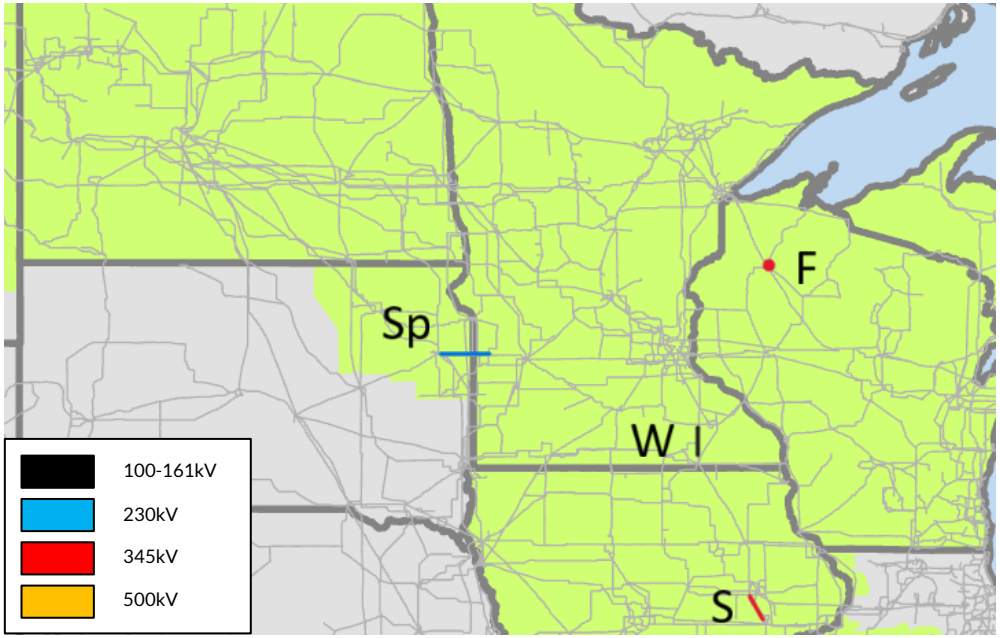
Blue values indicate changes from previously presented values

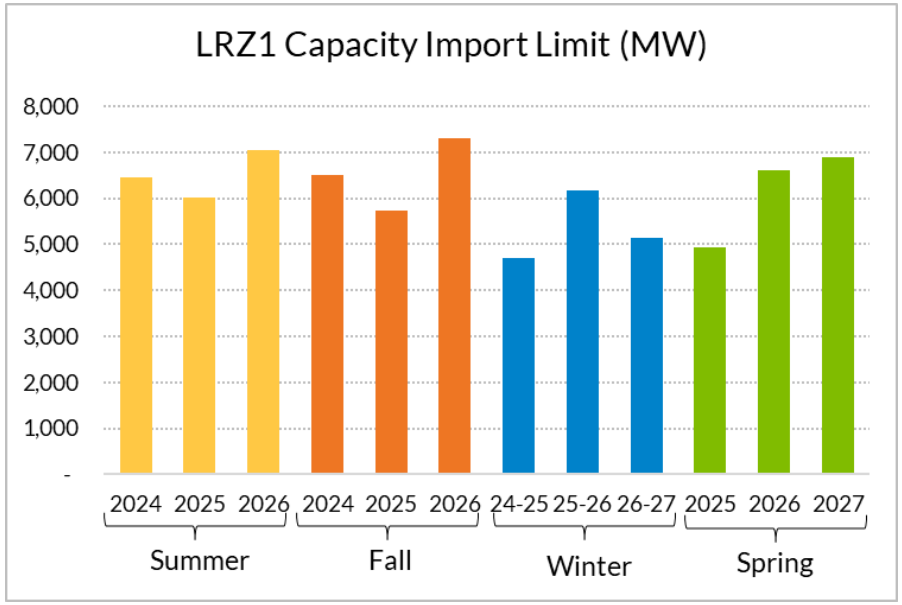
Planning Year 2026-2027 CIL Results

Capacity Import Limits

Zone 1: MN, MT, ND, SD and WI

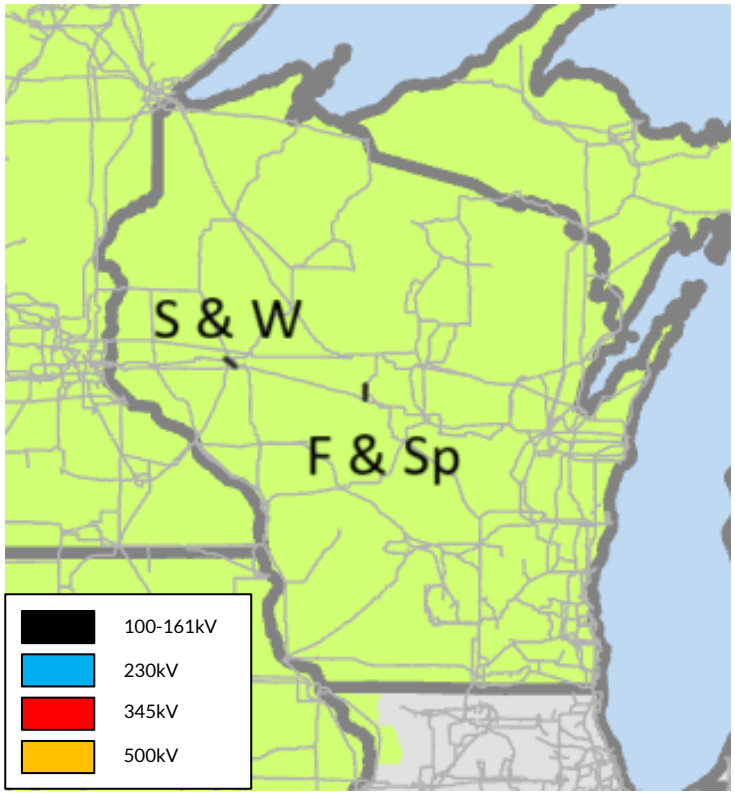
LRZ1	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2026	Tiffin - Morgan Valley 345 kV	Salem - Rock Creek 345 kV	None	852 MWx2	7042	7044
Fall 2026	Stone Lake 345/161 kV Transformer	Superior - Stone Lake 345 kV	None	721 MWx2	7244	7296
Winter 2026-27	Pleasant Valley - Byron 161 kV	Pleasant Valley - Byron 345 kV	None	1000 MWx2	4533	5135
Spring 2027	Watertown - Erec-Blair 230 kV	Astoria - Astoria North 345 kV	None	580 MWx2	6690	6892

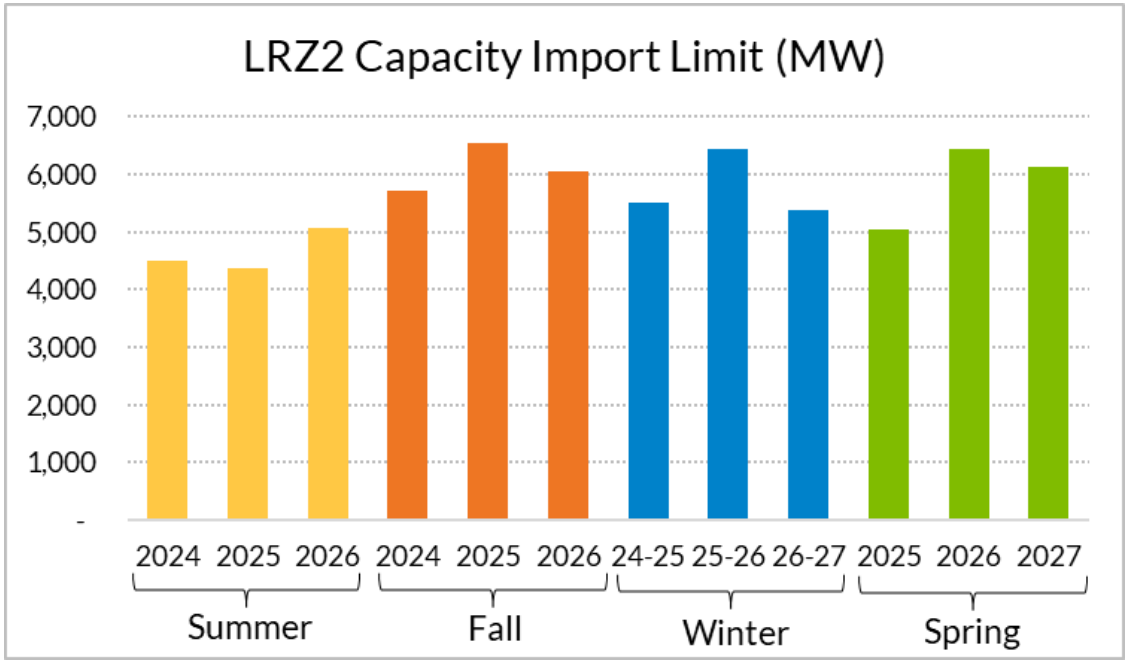




Capacity Import Limits
Zone 2: WI and MI

LRZ2	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2026	Elk Mound - Prairie View 161 kV	Eau Claire - AS King 345 kV	None	651 MWx2	5072	5072
Fall 2026	Arpin - Siegel 138 kV	Arpin - Rocky Run 345 kV	None	662 MWx2	6050	6050
Winter 2026-27	Elk Mound - Prairie View 161 kV	Eau Claire - AS King 345 kV	None	699 MWx2	5294	5381
Spring 2027	Arpin - Siegel 138 kV	Arpin - Rocky Run 345 kV	None	460 MWx2	6133	6133

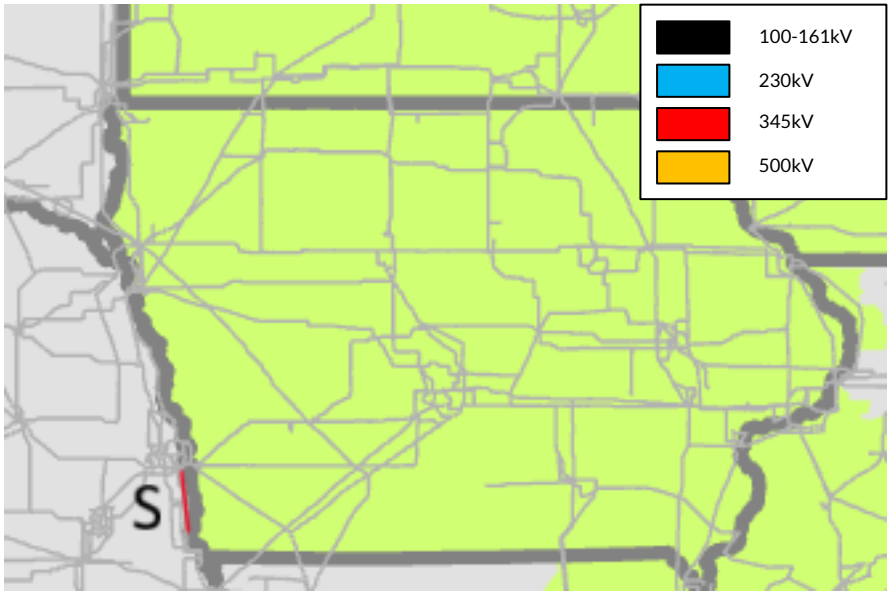


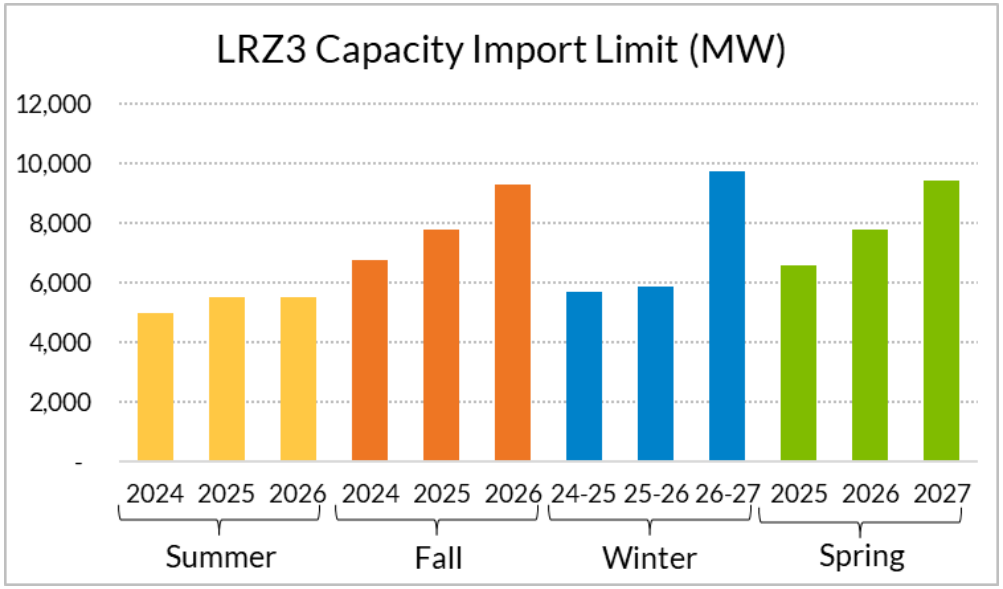


Capacity Import Limits
Zone 3: IA

LRZ3	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2026	Sub 3458 (Nebraska City) - Sub 3456 345 kV	Sub 3458 (Nebraska City) - Sub 3740 345 kV	None	265 MWx2	5400	5495
Fall 2026	None	None	None	1000 MWx2	9191	9284
Winter 2026-27	None	None	None	434 MWx2	9620	9712
Spring 2027	None	None	None	1000 MWx2	9311	9414

Fall 2026 & Spring 2027: After Tier 1 Redispatch, no elements were overloaded, using Tier 1 Capacity to calculate CIL
Winter 2026-2027: After Tier 1 & 2 Redispatch, no elements were overloaded, using Tier 1 & 2 Capacity to calculate CIL



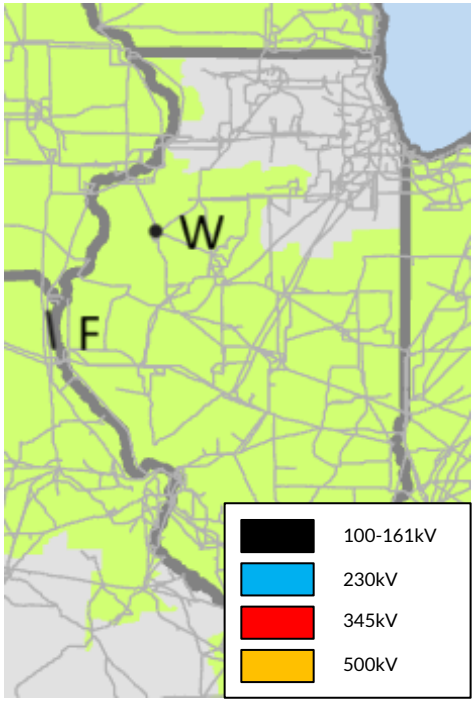


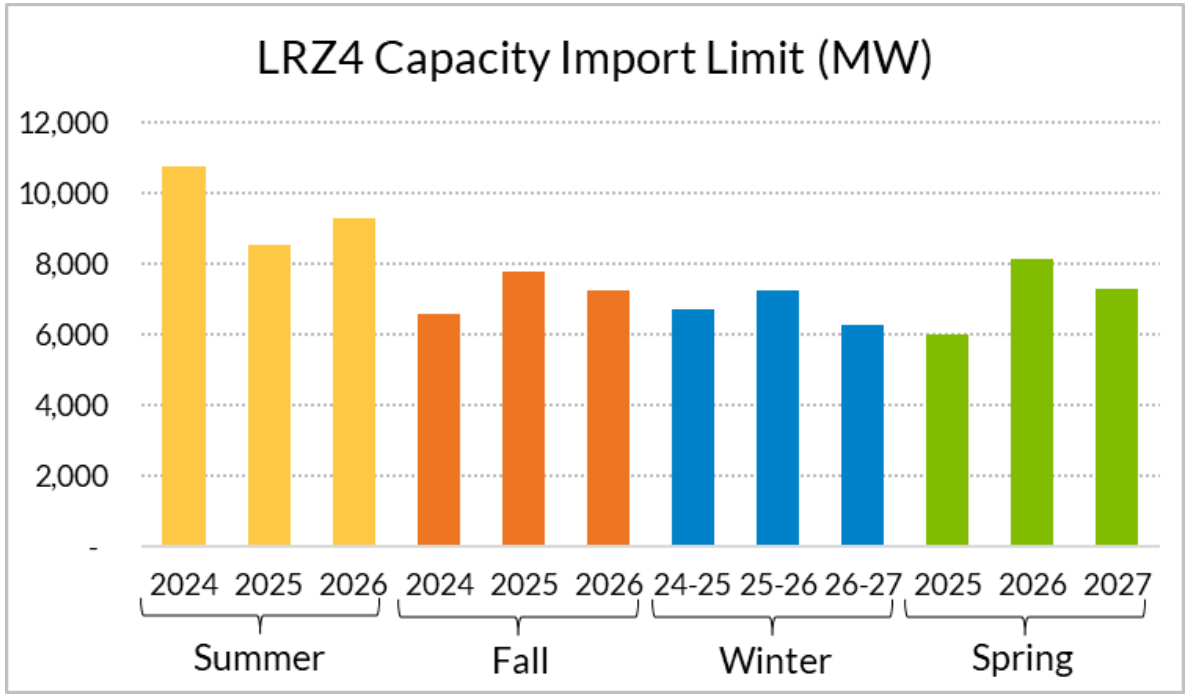
Fall, Winter, Spring Increase: Lack of overloads along Western Seam results in no overloads for the zone after Redispatch

Capacity Import Limits
Zone 4: IL

LRZ4	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2026	None	None	20%	N/A	8517	9285
Fall 2026	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	None	893 MWx2	6491	7251
Winter 2026-27	Sandburg 161/138 kV Transformer	Sandburg - Oak Grove 345 kV	None	795 MWx2	5493	6268
Spring 2027	None	None	20%	N/A	6533	7302

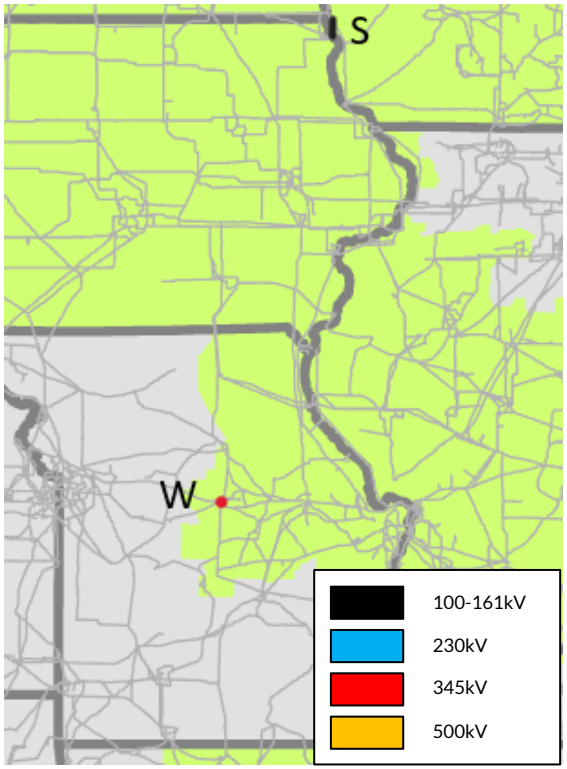
Summer 2026 & Spring 2027 : After 20% GLT, no elements were overloaded, using Tier 1 & 2 Capacity to calculate CIL

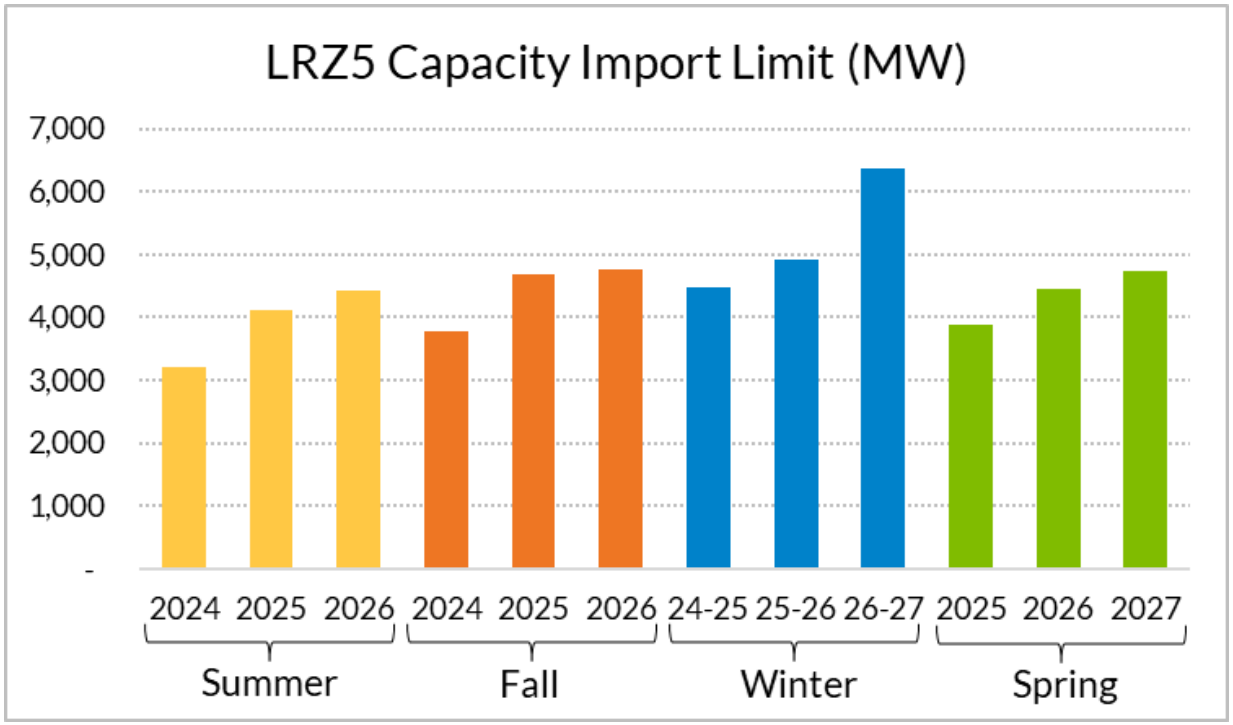




Capacity Import Limits
Zone 5: MO

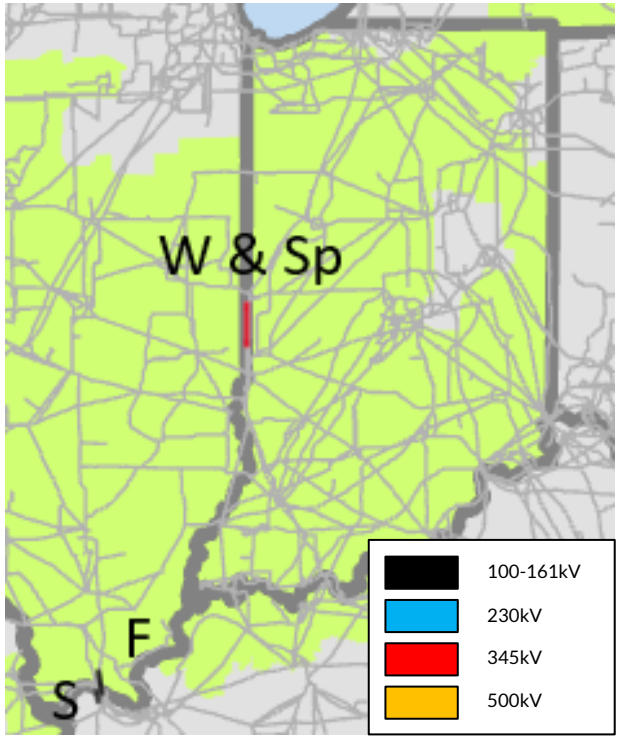
LRZ5	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2026	Lansing - Genoa 161 kV	Lansing 161/69 kV Transformer	None	655 MWx2	4417	4417
Fall 2026	None	None	50%	N/A	4762	4762
Winter 2026-27	Overton 345/161 kV Transformer	McCredie - Overton 345 kV	None	265 MWx2	6379	6379
Spring 2027	None	None	50%	N/A	4733	4733

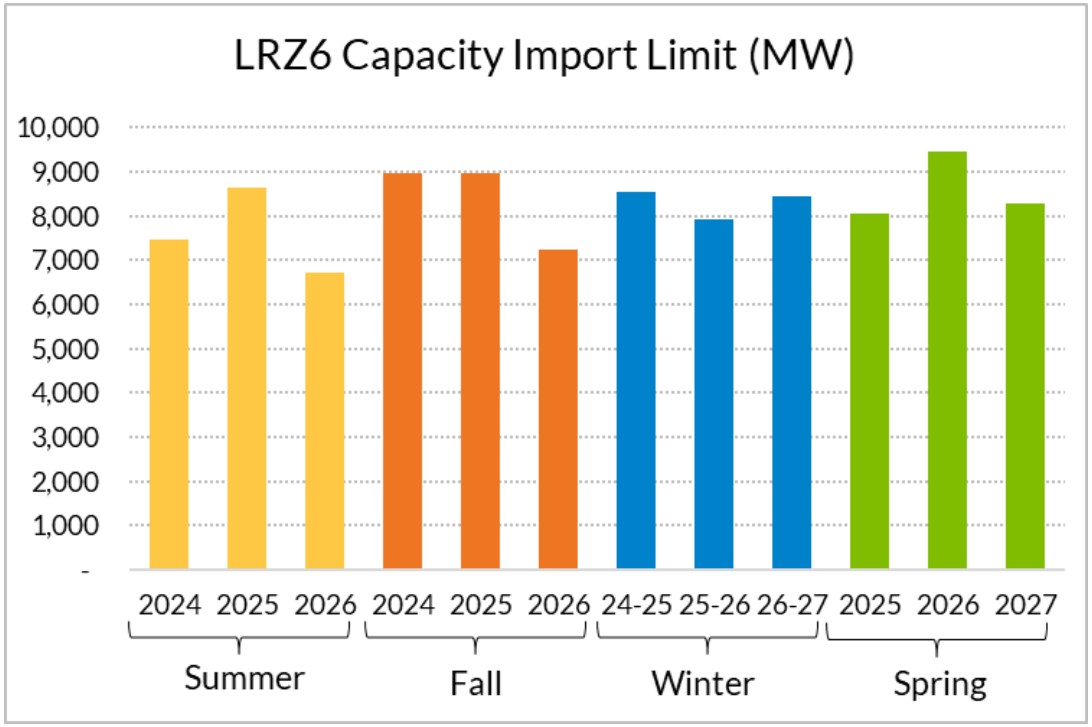




Capacity Import Limits
Zone 6: IN and KY

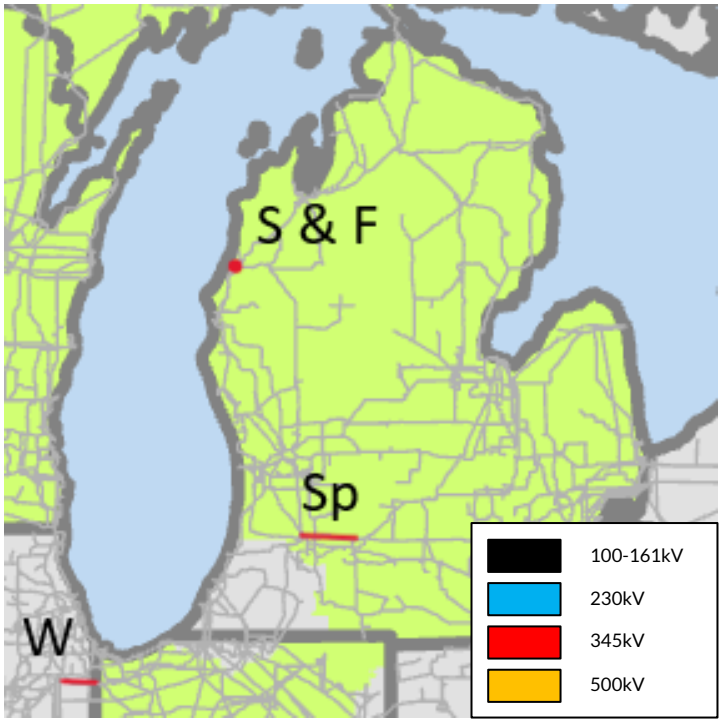
LRZ6	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2026	Joppa South - Joppa South Tap 161 kV	Joppa South - Grahmville 345 kV	None	865 MWx2	6440	6725
Fall 2026	Joppa South Tap - Mass 161 kV	Joppa North - Mass 161 kV	None	1000 MWx2	7012	7292
Winter 2026-27	Sugar Creek - Dresser 345 kV	Cayuga - Nucor 345 kV	None	1000 MWx2	8208	8445
Spring 2027	Sugar Creek - Dresser 345 kV	Merom #2 Generator	None	1000 MWx2	7999	8280

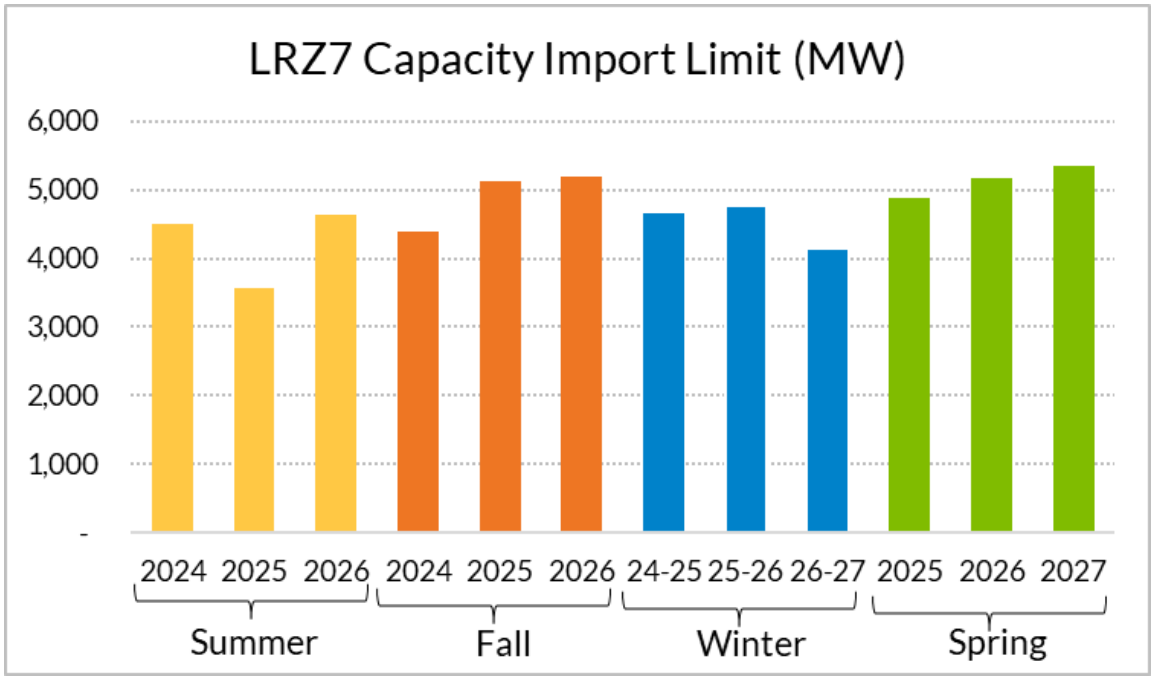




Capacity Import Limits
Zone 7: MI

LRZ7	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2026	Pere Marquette 345/138 kV Transformer	Keystone - Ludington 345 kV	None	1000 MWx2	4628	4628
Fall 2026	Pere Marquette 345/138 kV Transformer	Keystone - Ludington 345 kV	None	1000 MWx2	5193	5193
Winter 2026-27	Univ. Pk. N. - P9701 West 345 kV	Dumont - Wilton 765 kV	None	1000 MWx2	4123	4123
Spring 2027	Argenta - 18OXBY 345 kV	Argenta - Battle Creek 345 kV	None	1000 MWx2	5338	5338

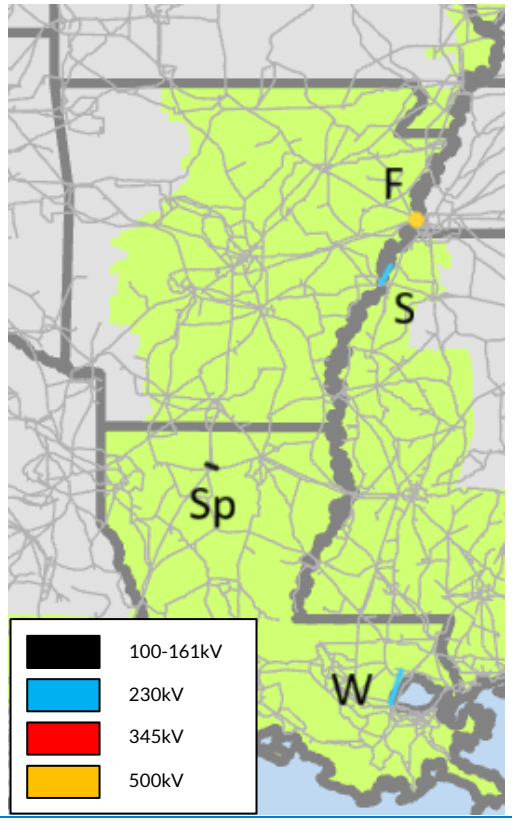


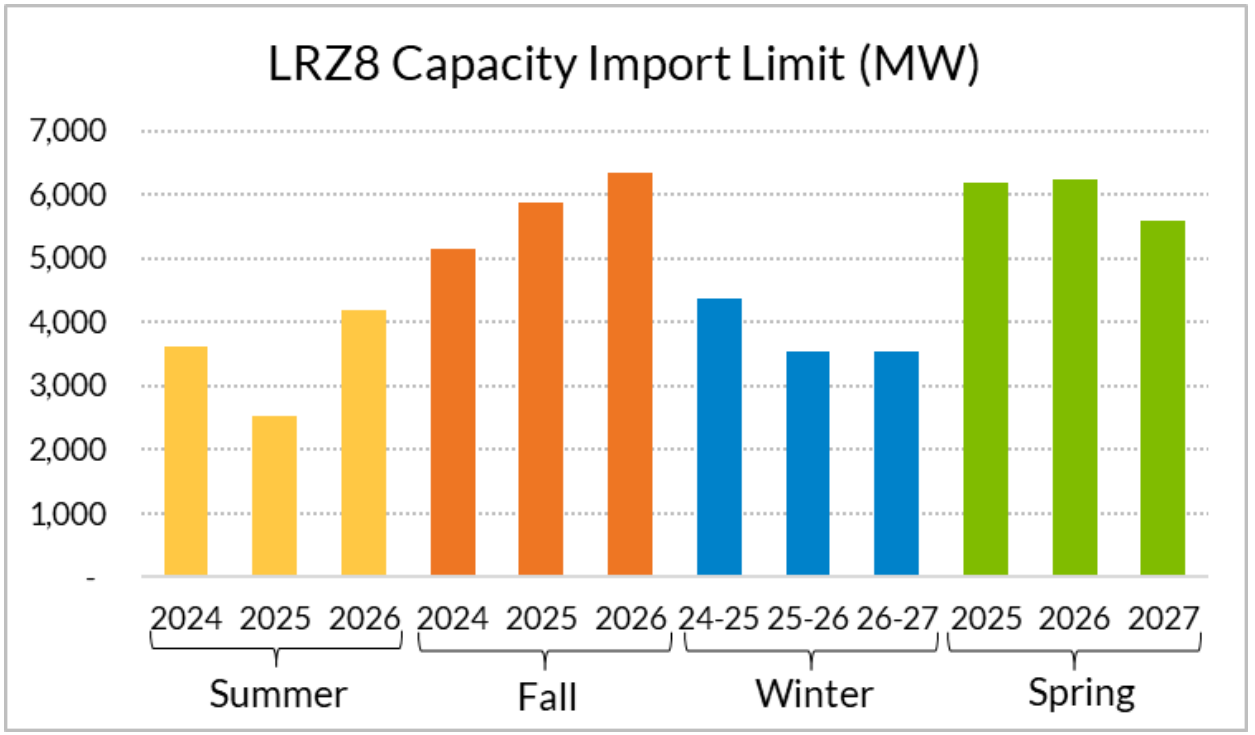


Capacity Import Limits

Zone 8: AR

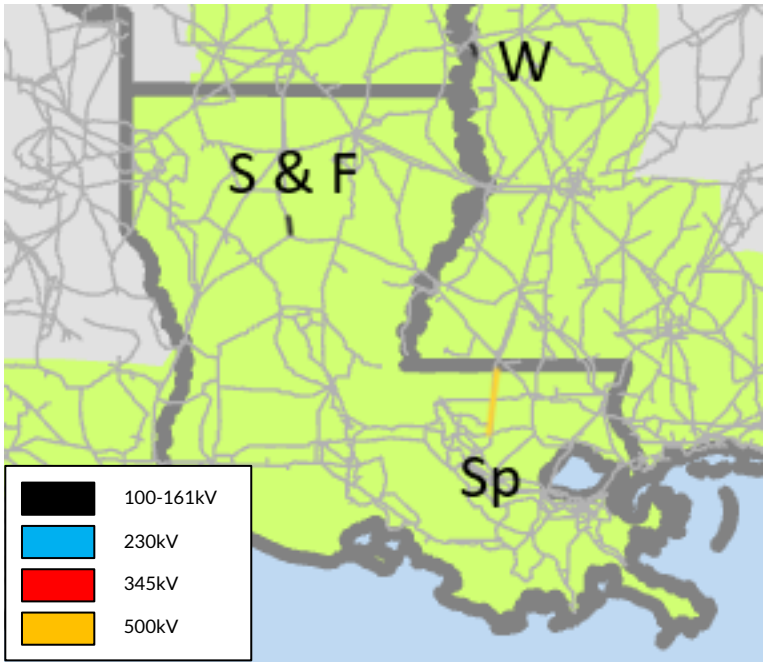
LRZ8	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2026	MEPS Clarkesdale - Moon Lake 230 kV	Tunica - J1440 POI 115 kV	None	579 MWx2	3981	4191
Fall 2026	West Memphis 500/161 kV Transformer	Sandy Bayou - Shelby 500 kV	None	1000 MWx2	6170	6334
Winter 2026-27	Little Gypsy - Fairview 230 kV	Michoud - Front Street 230 kV	None	762 MWx2	3366	3547
Spring 2027	Mount Olive - Vienna 115 kV	Mount Olive - El Dorado 500 kV	None	1000 MWx2	5374	5578

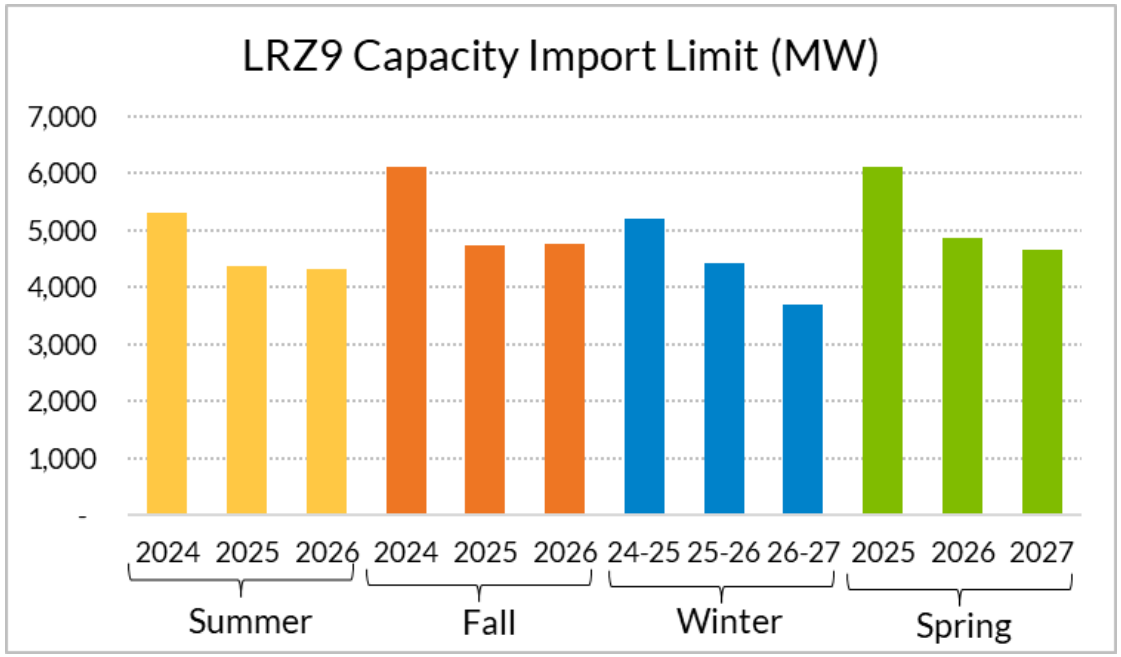




Capacity Import Limits
Zone 9: LA and TX

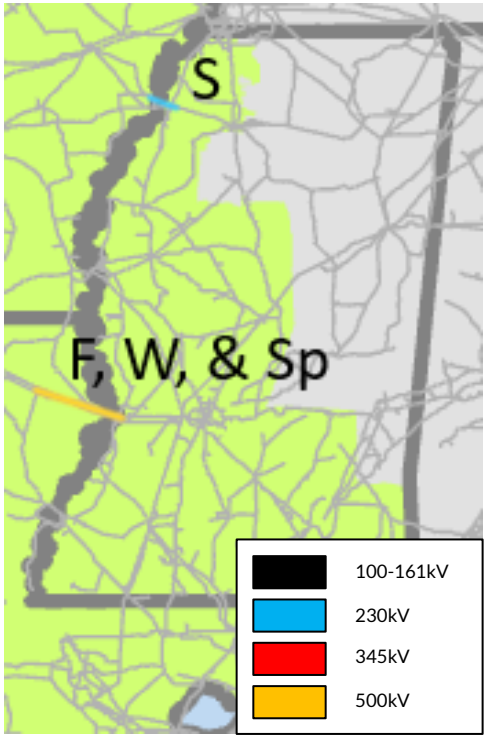
LRZ9	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2026	Danvile - Dodson 115 kV	Mount Olive - Layfield 500 kV	None	1000 MWx2	4309	4309
Fall 2026	Danvile - Dodson 115 kV	Mount Olive - Layfield 500 kV	None	1000 MWx2	4761	4761
Winter 2026-27	Greenville - Greenville Southeast 115 kV	Gerald Andrus - J1458 POI (Greer Solar) 230 kV	None	1000 MWx2	3690	3690
Spring 2027	Franklin - McKnight 500 kV	River Bend Unit 1 Generator	None	1000 MWx2	4657	4657

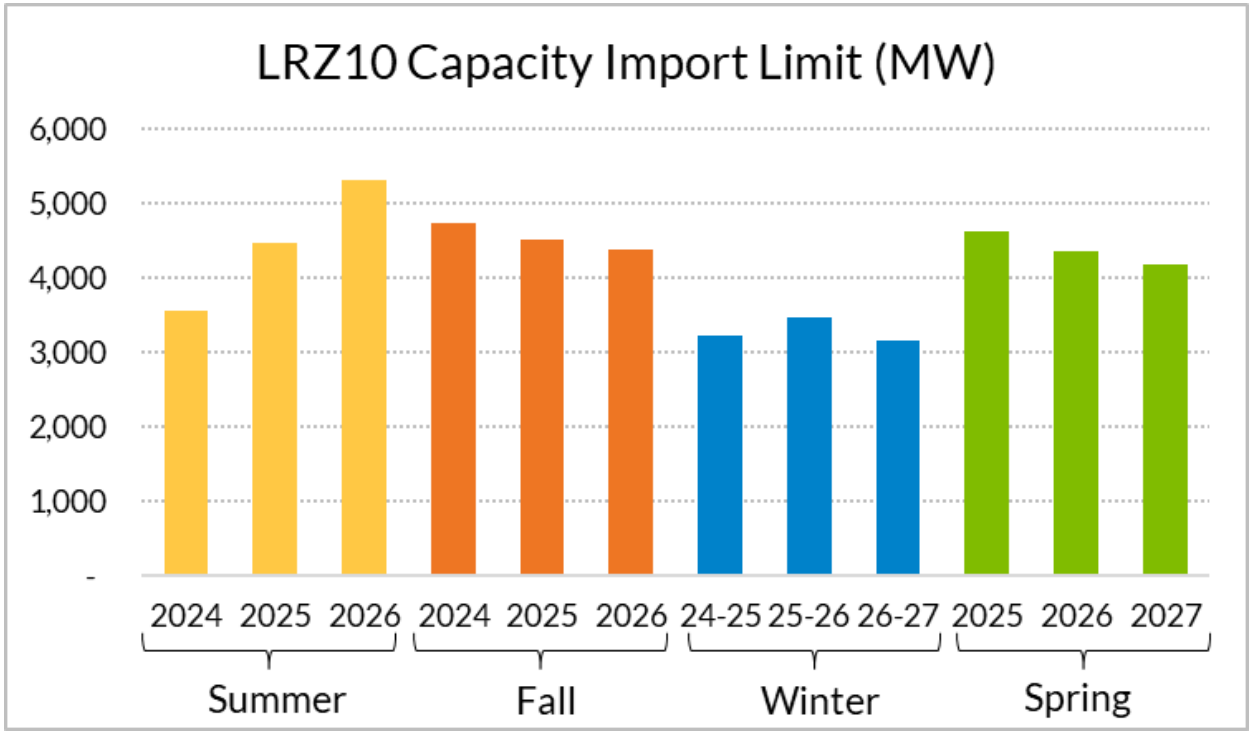




Capacity Import Limits
Zone 10: MS

LRZ 10	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2026	Moon Lake - Six Mile Lake 230 kV	Batesville Unit 3 Generator	None	542 MWx2	5322	5322
Fall 2026	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	None	404 MWx2	4379	4379
Winter 2026-27	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	None	413 MWx2	3154	3154
Spring 2027	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	None	456 MWx2	4187	4187



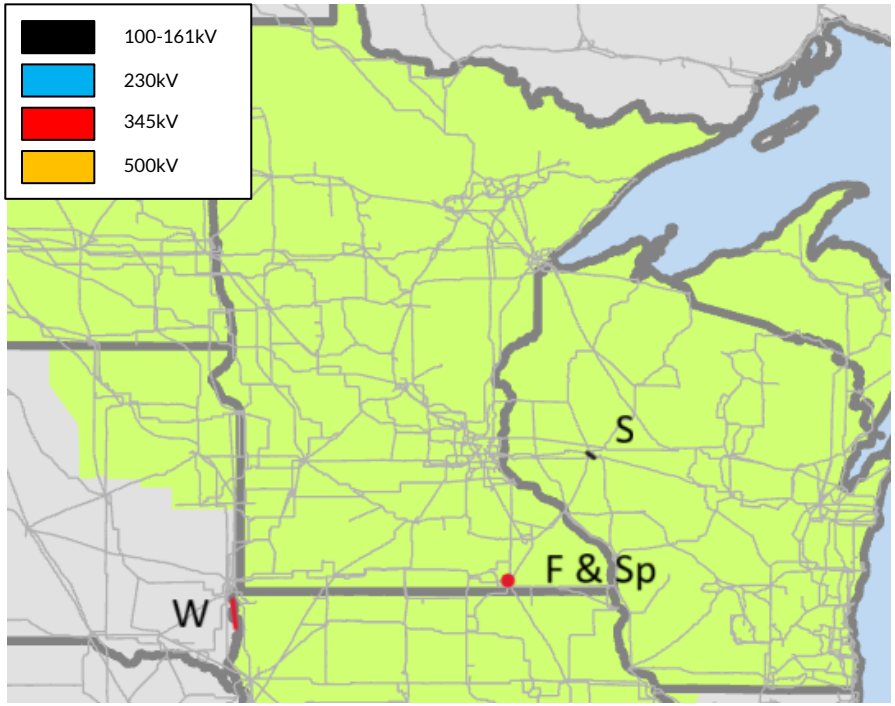


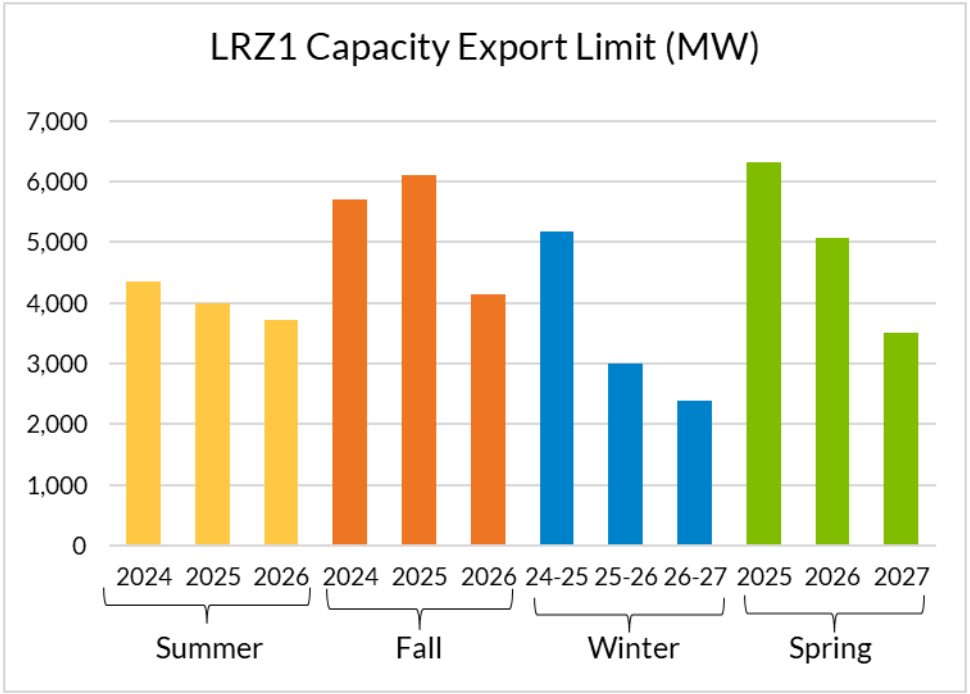
Planning Year 2026-2027 CEL Results

Capacity Export Limits

Zone 1: MN, MT, ND, SD and WI

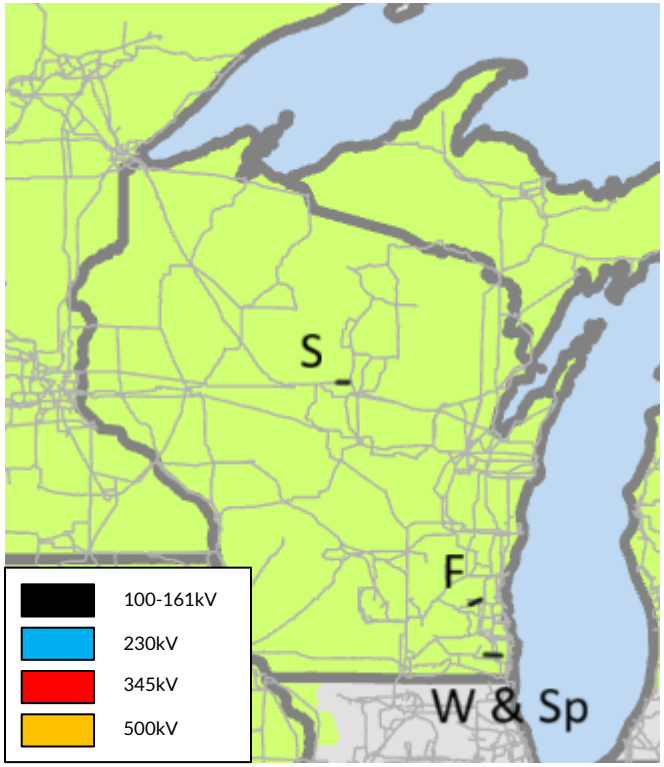
LRZ1	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2026	Elk Mound - Prairie View 161 kV	Eau Claire - King 345 kV	15%	300 MWx2	3720	3718
Fall 2026	Adams 345/161 kV Transformer	Adams - Pleasant Valley 345 kV	None	1000 MWx2	4199	4147
Winter 2026-27	Raun - S3451 345 kV	Grimes - Beaver Creek 345 kV	None	811 MWx2	2987	2385
Spring 2027	Adams 345/161 kV Transformer	Adams - Pleasant Valley 345 kV	None	671 MWx2	3715	3513

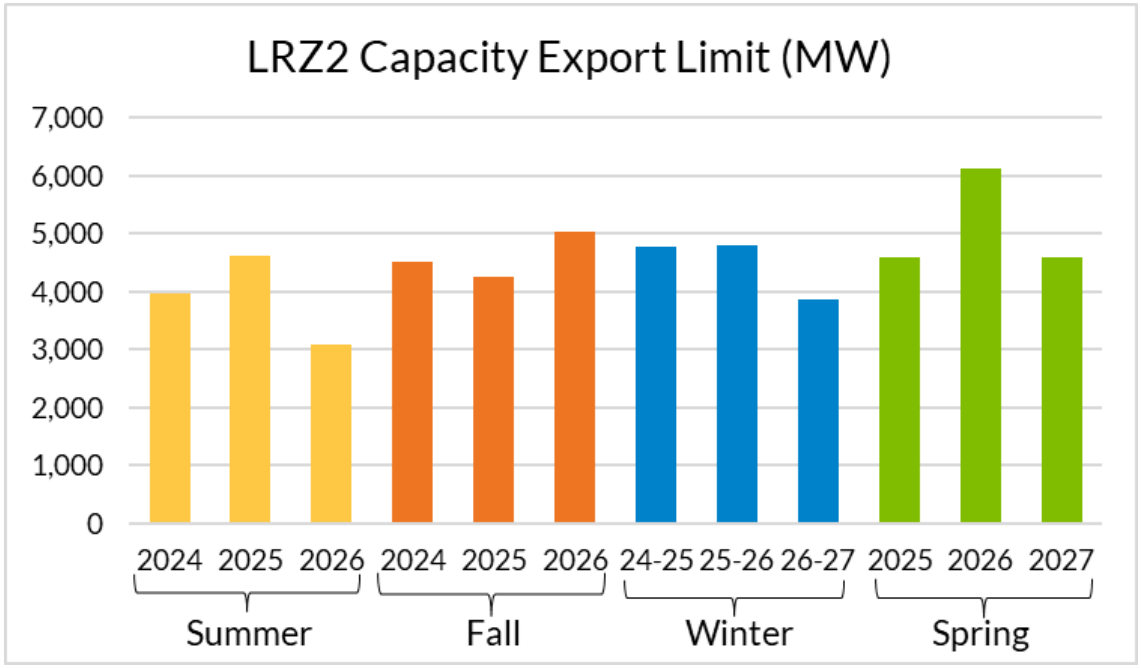




Capacity Export Limits
Zone 2: WI and MI

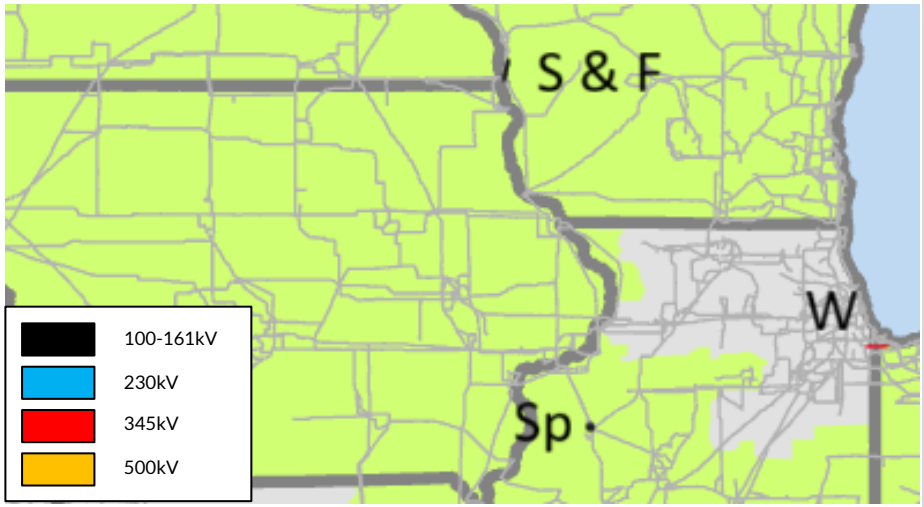
LRZ2	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2026	Sherman Street - Sunnyvale 115 kV	Arpin - Rocky Run 345 kV	20%	330 MWx2	3088	3088
Fall 2026	Germantown Bus6 - Bark River 138 kV	Germantown - Maple 138 kV	15%	1000 MWx2	5034	5034
Winter 2026-27	Paris - Berryville 138 kV	Paris 345/138 kV Transformer	5%	1000 MWx2	3945	3858
Spring 2027	Paris - Berryville 138 kV	Paris 345/138 kV Transformer	None	1000 MWx2	4608	4608

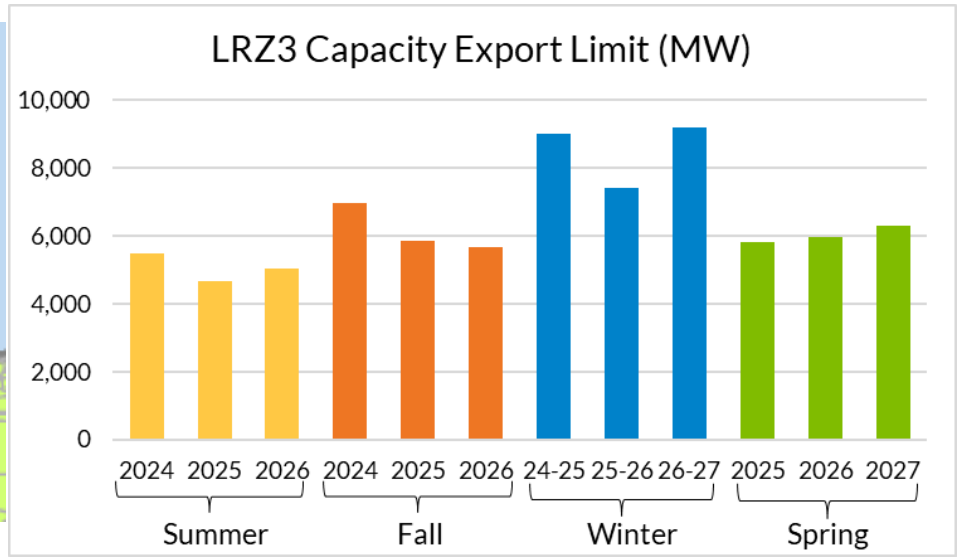




Capacity Export Limits
Zone 3: IA

LRZ3	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2026	Lansing East - Genoa 161 kV	Lasning East - Harmony 161 kV	40%	190 MWx2	5133	5038
Fall 2026	Lansing East - Genoa 161 kV	Harmony - Genoa 161 kV	30%	812 MWx2	5744	5651
Winter 2026-27	Univ. Pk. N. - P9701 West 345 kV	Dumont - Wilton 765 kV	None	1000 MWx2	9285	9193
Spring 2027	Sandburg 161/138 kV	Sandburg - Oak Grove 345 kV	30%	472 MWx2	6391	6288

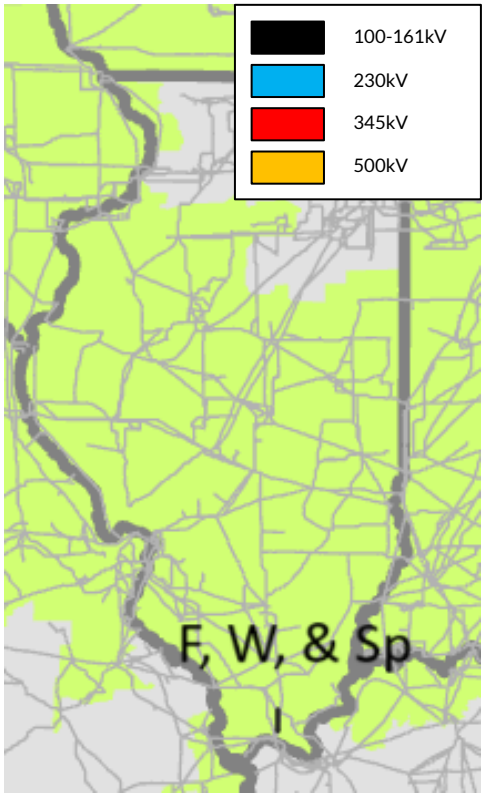


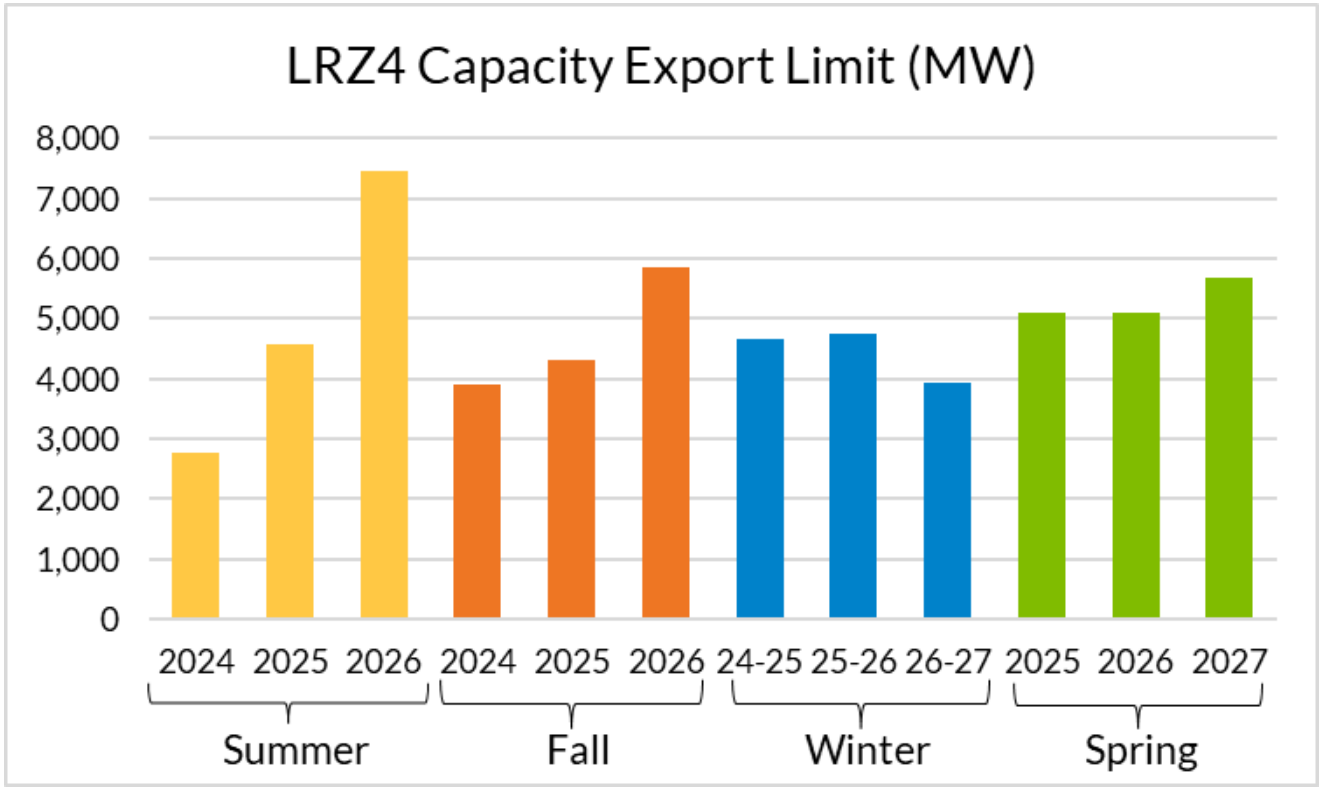


Capacity Export Limits

Zone 4: IL

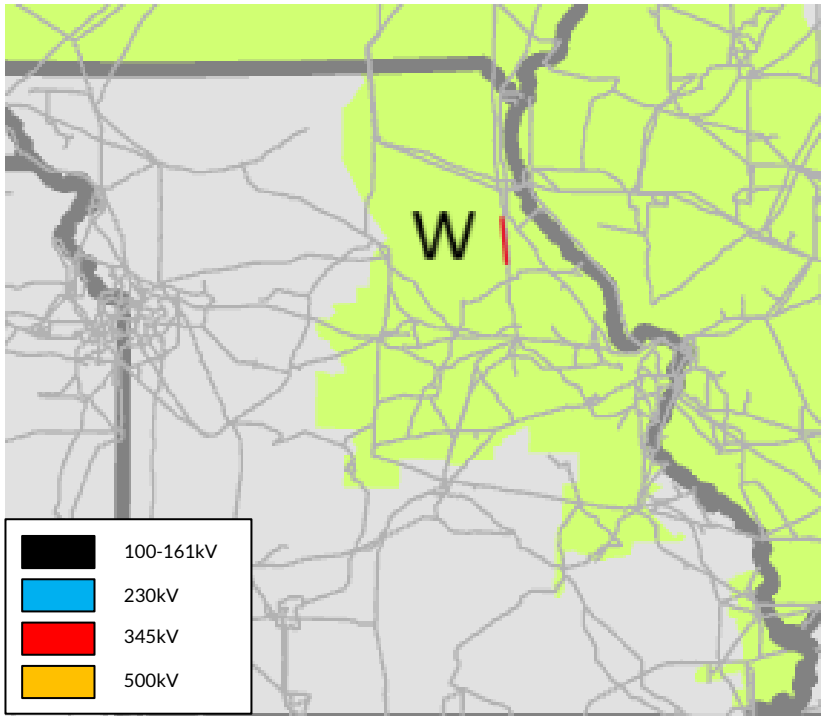
LRZ4	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2026	None	None	50%	N/A	8225	7457
Fall 2026	Joppa South - Mass 161 kV	Joppa North - Mass 161 kV	15%	1000 MWx2	6611	5851
Winter 2026-27	Joppa South - Mass 161 kV	Joppa North - Mass 161 kV	None	1000 MWx2	4724	3949
Spring 2027	Joppa South - Mass 161 kV	Joppa North - Mass 161 kV	10%	118 MWx2	6447	5678

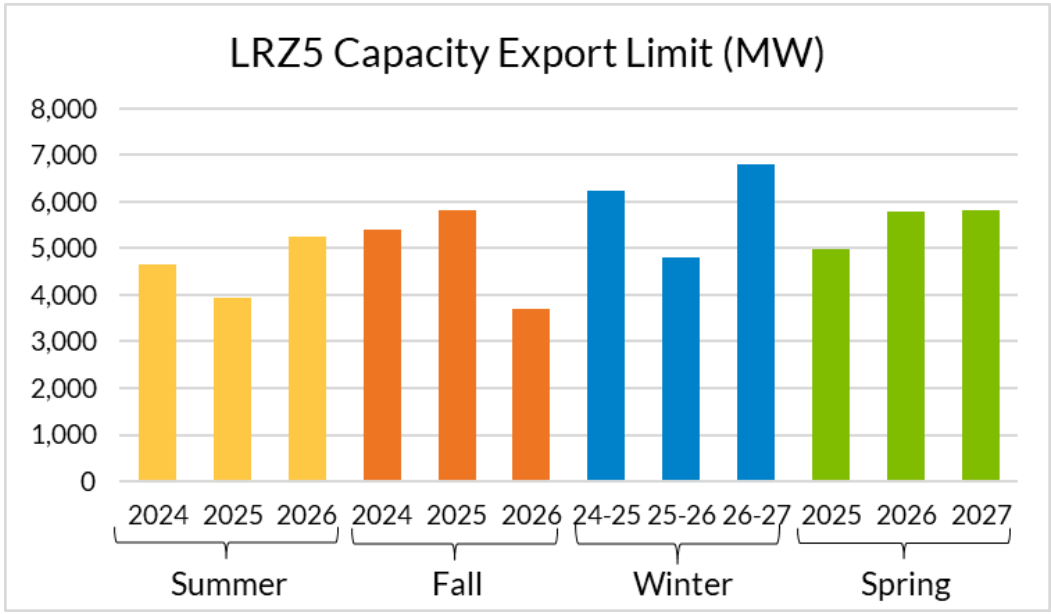




Capacity Export Limits
Zone 5: MO

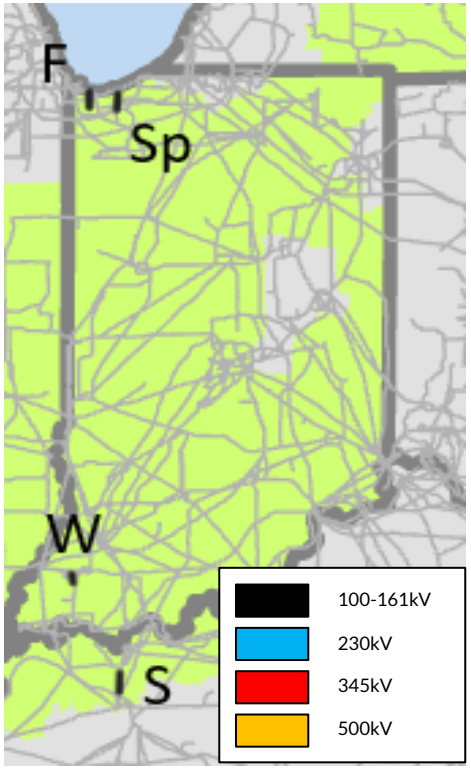
LRZ5	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2026	None	None	50%	N/A	5255	5255
Fall 2026	None	None	50%	N/A	3701	3701
Winter 2026-27	Spencer Creek - Vanhorn 345 kV	Palmyra Tap - Spencer Creek 345 kV	20%	1000 MWx2	6786	6786
Spring 2027	None	None	50%	N/A	5811	5811

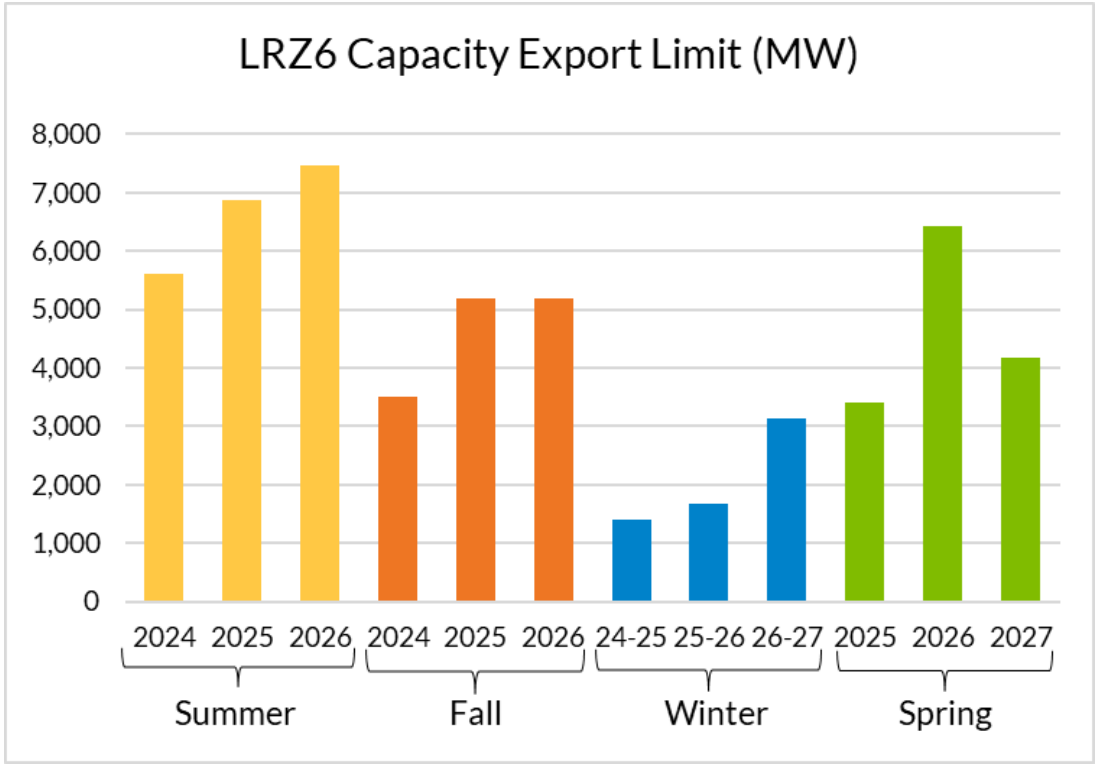




Capacity Export Limits
Zone 6: IN and KY

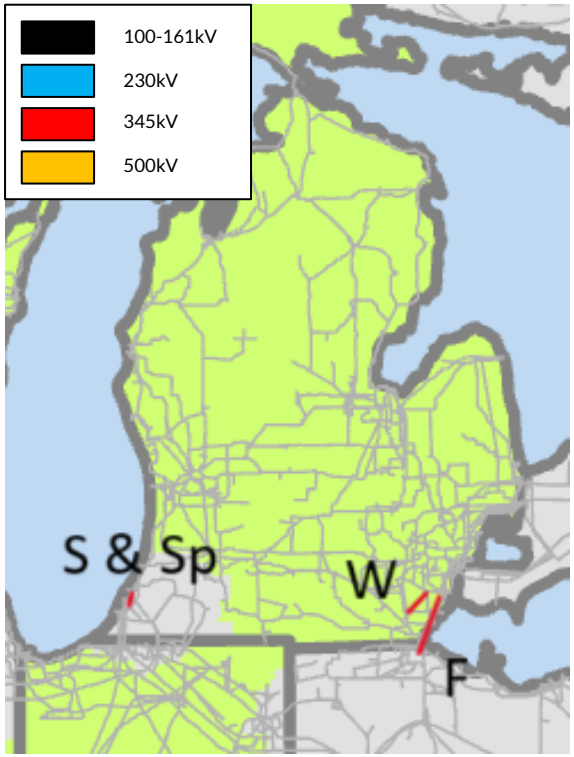
LRZ6	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2026	Wilson - Matanzas 161 kV	Green River - Wilson 161 kV	40%	113 MWx2	7744	7459
Fall 2026	Whiting Clean Energy - Praxair 6 138 kV	Marktown East - Whiting Clean Energy 138 kV	None	313 MWx2	5461	5181
Winter 2026-27	Holland - Dubois 138 kV	Duff - Francisco 345 kV	10%	923 MWx2	3378	3141
Spring 2027	Luchtman Road - Flint Lake 138 kV	Shoreline - Ridgeway 138 kV	None	1000 MWx2	4465	4184

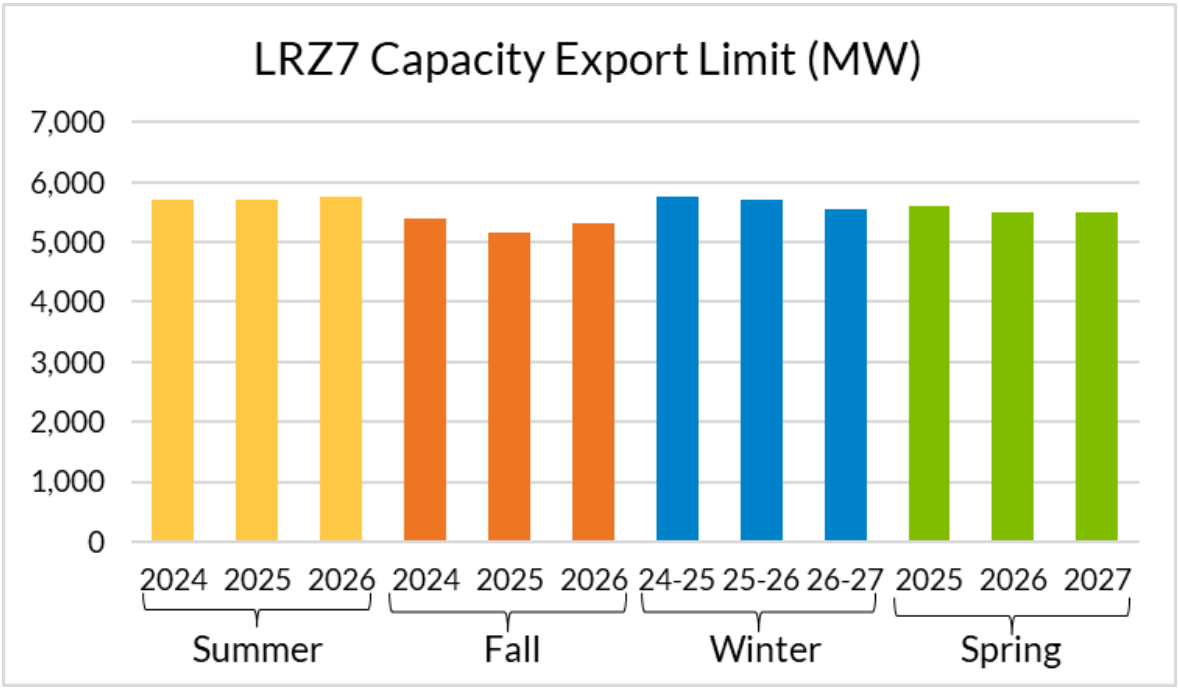




Capacity Export Limits
Zone 7: MI

LRZ7	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2026	Segreto - Benton Harbor 345 kV	Cook - Segreto 345 kV	15%	445 MWx2	5745	5745
Fall 2026	Monroe 1&2 - Lallendorf 345 kV	Morocco - Allen Jct 345 kV	None	1000 MWx2	5305	5305
Winter 2026-27	Morocco - Allen Jct 345 kV	Monroe 1&2 - Lallendorf 345 kV	None	696 MWx2	5546	5546
Spring 2027	Segreto - Benton Harbor 345 kV	Cook - Segreto 345 kV	None	1000 MWx2	5497	5497

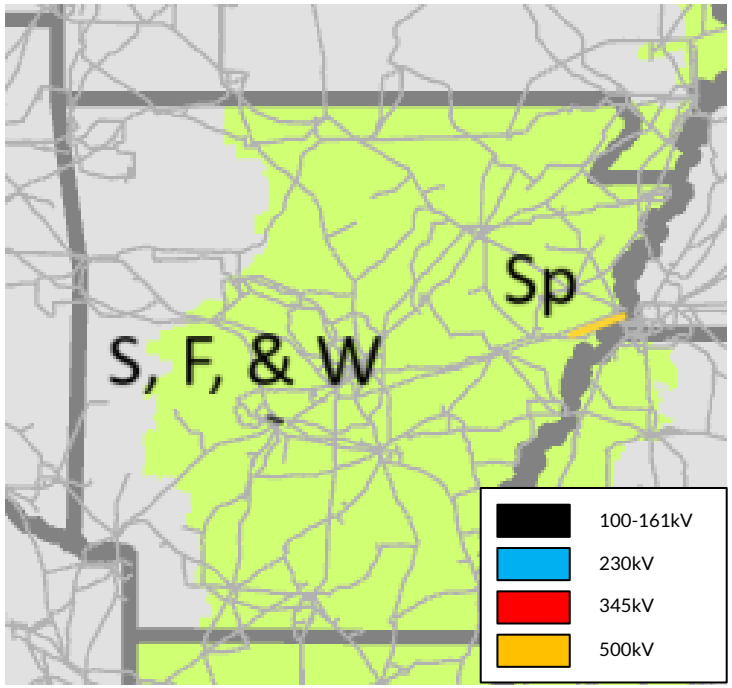


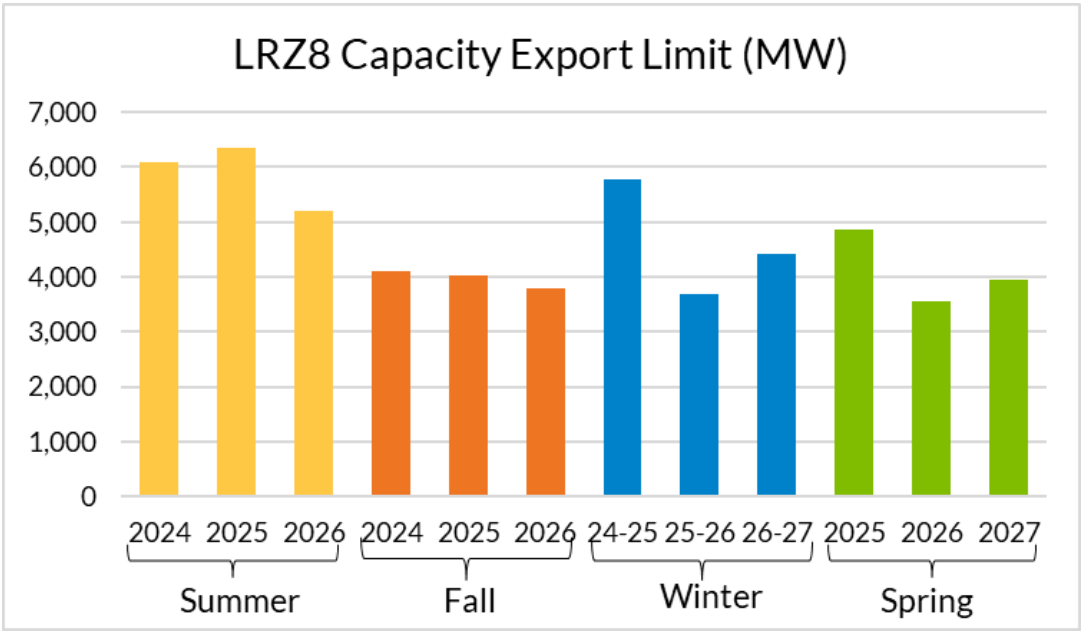


Capacity Export Limits

Zone 8: AR

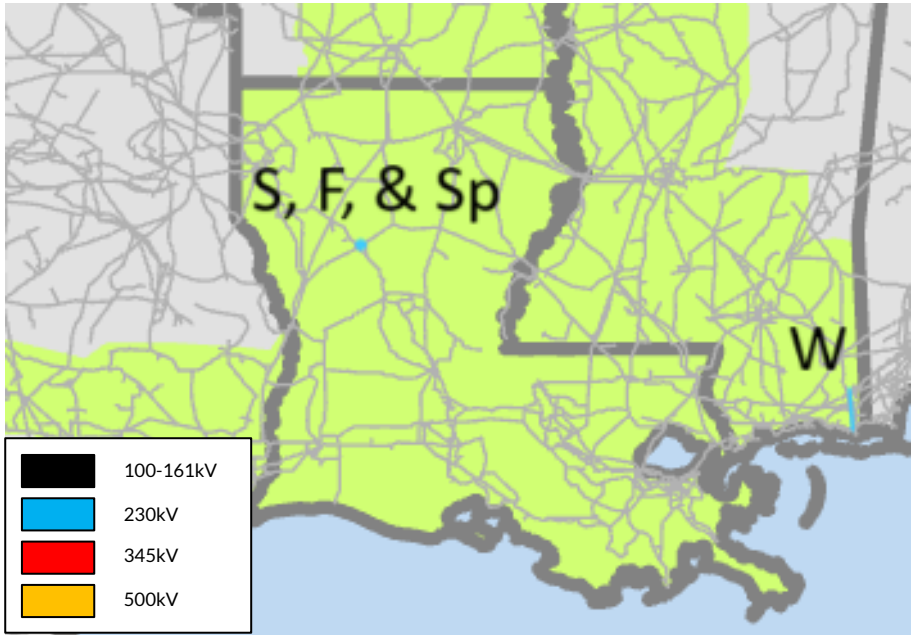
LRZ8	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2026	Arklahoma - Hot Springs East 115 kV	Arklahoma - Hot Springs West 115 kV	40%	1000 MWx2	5403	5193
Fall 2026	Arklahoma - Hot Springs East 115 kV	Arklahoma - Hot Springs West 115 kV	None	1000 MWx2	3947	3783
Winter 2026-27	Arklahoma - Hot Springs East 115 kV	Arklahoma - Hot Springs West 115 kV	25%	1000 MWx2	4609	4428
Spring 2027	Freeport - Cordova 500 kV	Sans Souci - Driver 500 kV	None	1000 MWx2	4144	3940

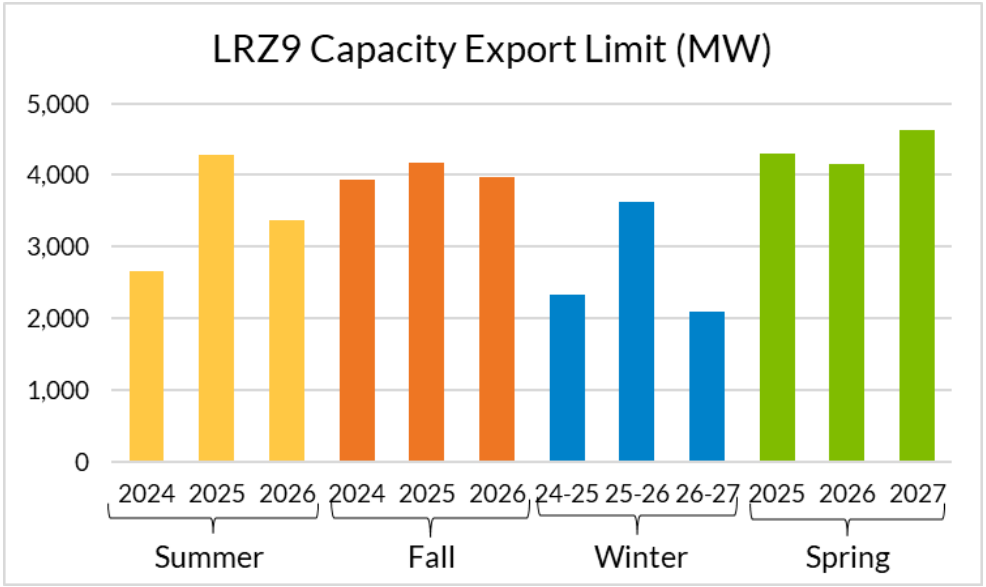




Capacity Export Limits
Zone 9: LA and TX

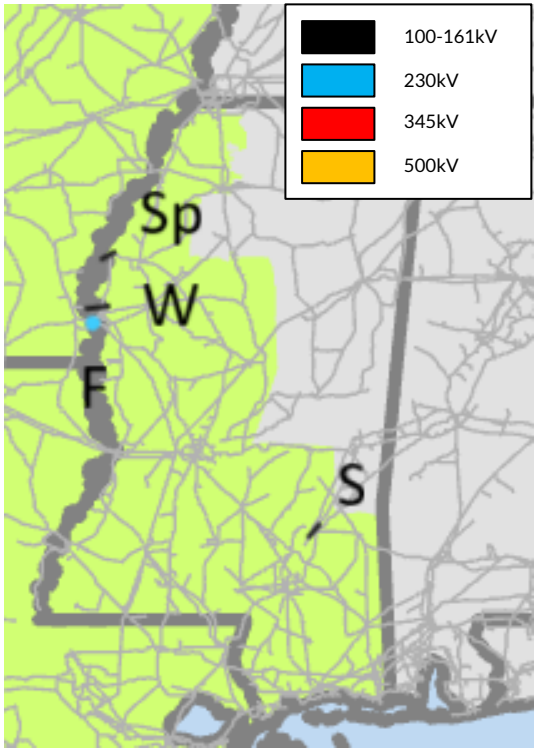
LRZ9	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2026	Winnfield 230/115 kV Transformer	Montgomery - Clarence 230 kV	None	1000 MWx2	3361	3361
Fall 2026	Winnfield 230/115 kV Transformer	Montgomery - Clarence 230 kV	None	1000 MWx2	3970	3970
Winter 2026-27	Moss Point East - North Theodore 230 kV	Big Creek - Daniel 230 kV	None	1000 MWx2	2096	2096
Spring 2027	Winnfield 230/115 kV Transformer	Montgomery - Clarence 230 kV	None	1000 MWx2	4633	4633

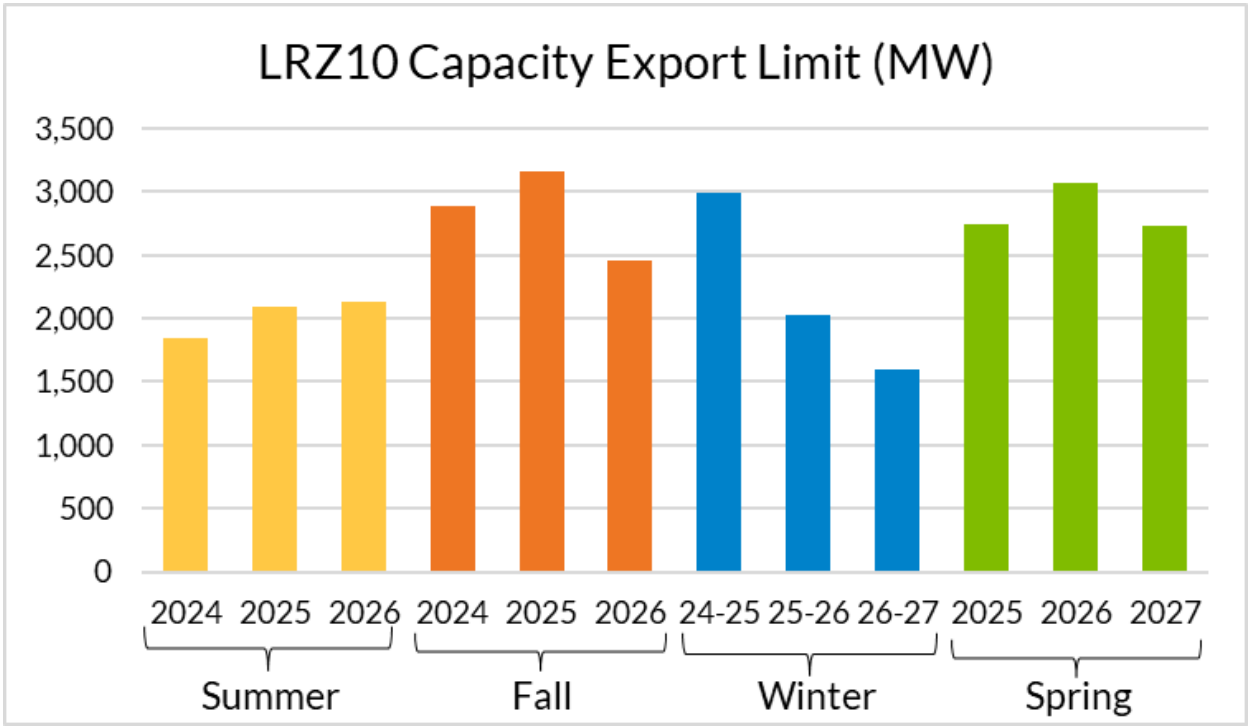




Capacity Export Limits
Zone 10: MS

LRZ10	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2026	Plant Moselle - MS Solar 4 161 kV	Plant Mosell - Cole Road 161 kV	None	612 MWx2	2132	2132
Fall 2026	Andrus 230/115 kV Transformer	Andrus - Indianola 230 kV	None	945 MWx2	2459	2459
Winter 2026-27	Greenville - Leland 115 kV	Andrus - Indianola 230 kV	None	1000 MWx2	1602	1602
Spring 2027	Clarksdale - Lyon 115 kV	MEPS Clarksdale - Moon Lake 230 kV	None	581 MWx2	2725	2725





There are multiple drivers to changes in the year-to-year CIL/CEL Final Results

- Material changes to the model YOY results in different generation dispatch, base transmission flows and line loadings, limiting contingencies, generation availability for transfers impacting YOY CIL/CEL values.
- Generation
  - 208 new machines added resulting in 19 GW of new nameplate.
  - 107 machines removed resulting in 7 GW of lost nameplate, primarily due to cancelled GIAs
  - This turnover results in changes to generation dispatch, base flows, & transmission line loadings
- Transmission
  - 1000 + Transmission Projects at $16B coming online by June 1, 2027
- Demand
  - 4% increase in Summer, 8% Fall, 7% Winter, and 10 % Spring

2026-27 CIL/CEL Model Generation Changes by Season

Positive is an increase over Planning Year 2025-26

- New Resources continue to be included into Powerflow models as GIAs are signed, resulting in an increased fleet size to meet the load requirements
- All Values are shown in MW PMax, which is similar to MISO's tariff ICAP

Gen (PMAX)	Summer	Fall	Winter	Spring
LRZ 1	1,244	1,350	2,441	2,570
LRZ 2	1,051	1,208	527	527
LRZ 3	665	462	463	463
LRZ 4	2,333	2,373	570	553
LRZ 5	1,262	599	483	-200
LRZ 6	3,291	3,241	1,519	1,318
LRZ 7	1,049	965	33	1,273
LRZ 8	499	398	1,128	1,058
LRZ 9	5,194	5,506	5,377	5,163
LRZ 10	211	204	54	-103
Total	16,799	16,305	12,596	12,622

2026-27 CIL/CEL Model Load Changes by Season

Positive is an increase over Planning Year 2025-26

- New Load is expected to be above the forecasts from last year for all LRZs in most seasons
- Powerflow model Load is comparable to non-coincident peak forecast values, and aligns with LOLE, OMS, and NERC LTRA

Load	Summer	Fall	Winter	Spring
LRZ 1	1,199 (+6%)	1,083 (+7%)	2,014 (+10%)	1,900 (+13%)
LRZ 2	453 (+3%)	591 (+6%)	142 (+1%)	751 (+8%)
LRZ 3	160 (+1%)	731 (+8%)	508 (+5%)	427 (+4%)
LRZ 4	142 (+2%)	1,010 (+14%)	266 (+3%)	1,354 (+18%)
LRZ 5	419 (+5%)	1,205 (+19%)	588 (+8%)	871 (+13%)
LRZ 6	755 (+4%)	399 (+2%)	1,011 (+5%)	663 (+4%)
LRZ 7	-260 (-1%)	1,513 (+9%)	-60 (0%)	1,941 (+12%)
LRZ 8	603 (+7%)	757 (+9%)	1,271 (+14%)	1,271 (+16%)
LRZ 9	2,175 (+8%)	2,119 (+9%)	3,193 (+12%)	2,089 (+9%)
LRZ 10	477 (+9%)	423 (+9%)	438 (+9%)	95 (+2%)
Total	6,124 (+4%)	9,831 (+8%)	9,371 (+7%)	11,362 (+10%)

Transmission Projects

From start of Planning Year 2025-26 to the end of Planning Year 2026-27

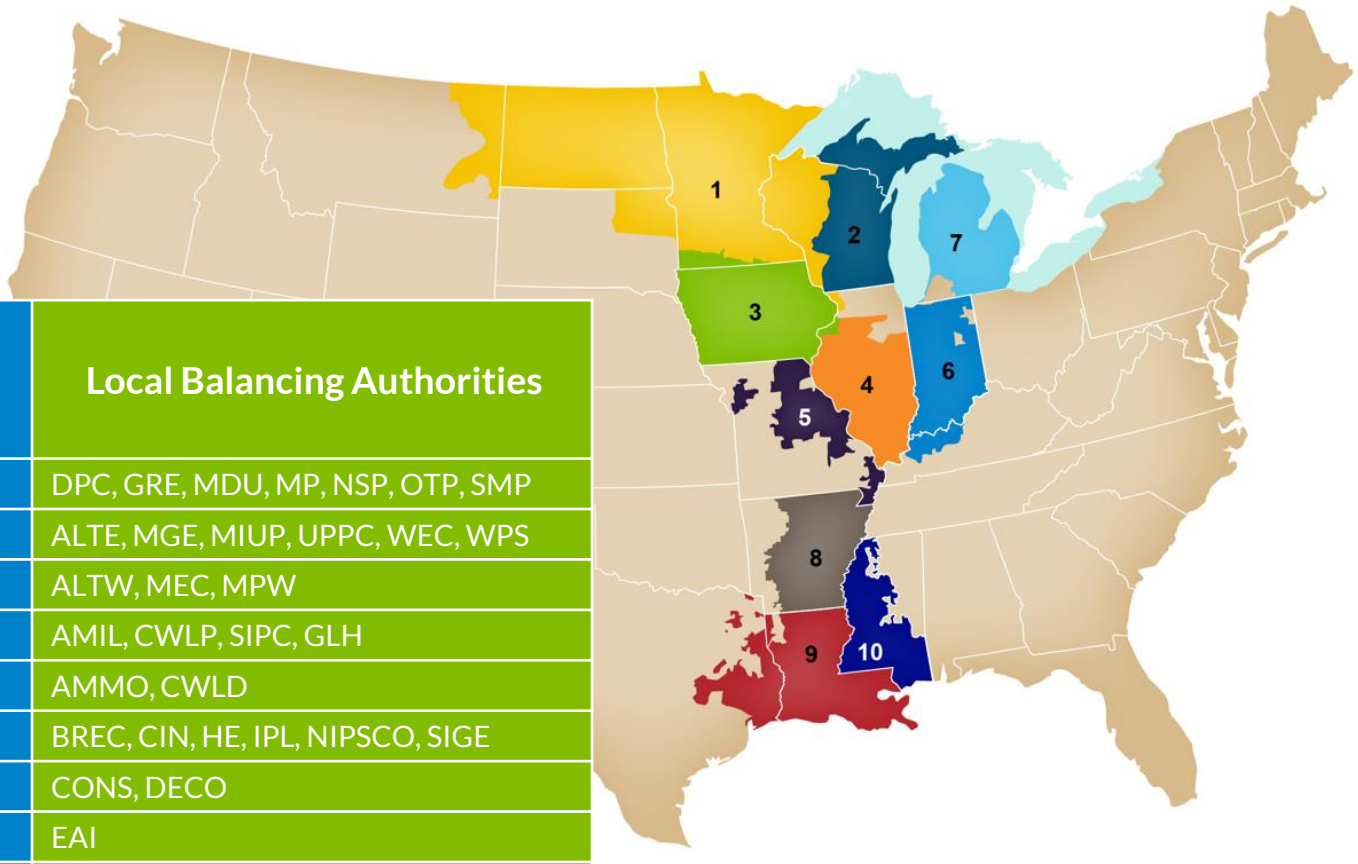
- Every LRZ is projected to experience significant transmission updates between June 1, 2025, & June 1, 2027
- These projects fall into three major categories
  - Baseline Reliability Projects (BRP)
    - Maintaining reliability for existing demand
  - Generation Interconnection Projects (GIP)
    - Integrating new resources
  - Other
    - Integrating new demand (EPR)
    - Asset Renewal

	# of Projects in service by 6/1/26	# of Projects in service by 6/1/27	Total Cost ($ Millions)
LRZ 1	95	176	$1,513
LRZ 2	40	94	$2,571
LRZ 3	61	124	$1,296
LRZ 4	47	113	$1,375
LRZ 5	18	50	$650
LRZ 6	76	144	$1,911
LRZ 7	97	173	$1,698
LRZ 8	16	30	$503
LRZ 9	33	69	$4,111
LRZ 10	16	33	$552
Total	499	1,006	$16,180

https://www.misoenergy.org/planning/transmission-planning/mtep/#t=10&p=0&s=&sd=

MISO Local Resource Zones

Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC, GLH
5	AMMO, CWLD
6	BREC, CIN, HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGT, LEPA
10	EMBA, SME



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 192

MISO Market Capacity Emergency Rev.25

MISO Market Capacity Emergency

SO-P-EOP-11-002 Rev: 25

ROLE			ROLE	
BAO	☑		SM	☑
IRAC	☑		RC	☑
UDS	☑		G&I	☑
SOE	☑		LBA	☑
TOP	☑		MP	☑
GOP	☑		ORM	☑

Rev History	Reason for Issue	Revised By	Issue Date	Effective Date
25	Replaced RTOpsCompliance@misoenergy.org email reference with DOENERCEventReporting@misoenergy.org	Alessandro Stammes	08/24/2026	08/24/2026
24	Out-of-Cycle Review. Removed Max Gen Alert. Consolidated content into Max Gen Warning step. Condensed Event Steps 1a-5 into distinct Event Steps aligned with NERC EEA levels. Grammar, formatting, sentence construction. Updated Attachment 1, 6, 7, and 8 tables and figures. Added Attachment 9 and 10 for MCE Checklists. Compliance Review Completed. Operating procedure owner approval on file. Removed mentions of SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing (retired).	Don Hunter/ Alessandro Stammes/Josh Womack/Austin Francis	6/1/2026	6/1/2026

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1.0 Purpose

Provide a set of Emergency operating instructions to address Capacity Emergencies and Energy Emergencies within the MISO Balancing Authority Area (MBAA), including preparation, management, and recovery from an Emergency.

2.0 Precautions and Limitations

1. As conditions require, MISO may provide instructions to move directly to any section or step within this procedure. Actions described in earlier levels or steps should still be completed as time permits.
2. If sufficient relief is obtained during the implementation of an action during a declaration step, subsequent actions within that declaration step do NOT need to be taken.
3. The Operating Reserve Requirement for the MBAA consists of Regulation and Contingency Reserve Requirements.
4. The Operating Reserve Requirement for a Region or Sub-Area consists of a Contingency Reserve Requirement based on the Most Severe Single Contingency (MSSC) within its boundaries.
5. Available economic Resources are calculated from the Available Economic Maximum Limits, including Behind the Meter Generation (BTMG), minus capacity that cannot be committed due to congestion or excessive Time-to-Start, and adjusted for Constraint Stranded MW and Net Scheduled Interchange (NSI) obligations.
6. South Region available economic Resources are the South Available Economic Maximum Limits (including BTMG, but reduced by Resources that cannot be committed due to congestion or excessive Time-to-Start), adjusted for South Constraint Stranded MW, Regional Dispatch Transfer (RDT) NSI, and Resources from the North/Central Region that are deliverable to the South via the RDT up to the Regional Dispatch Transfer Limit (RDTL) — typically 3,000 MW.
7. The Reserve Margin Entry Condition for an MBAA Capacity Advisory includes allowance for loss of the MSSC and subsequent recovery within 90 minutes for the second MSSC (if applicable), plus uncertainties.

8. Reserve Margin Entry Conditions will be based on the forecasted uncertainty level for the given operating day(s).
9. MISO will use the Mid-Term Load Forecast (MTLF) or Short-Term Load Forecast (STLF), as applicable, to determine available Operating Reserves. MISO may adjust Load Forecast values based on sustained error over time and will document the reasons for any adjustment.
10. Transmission System Emergencies requiring immediate action will be declared and resolved per SO-P-EOP-00-004 Transmission System Emergency. Transmission constraints that limit energy transfers to the MBAA or a sizable Sub-Area of the MBAA and result in a Capacity or Energy Emergency for such area will be managed through this procedure.
11. Energy deficient BA obligations include taking immediate actions to mitigate any undue risk to the Interconnection, including Load shedding, if required.
12. MISO posts the Max Gen Declaration notification to the MISO Market and Operations — Real-Time Operations Website.
13. Depending on the urgency of the Max Gen Emergency, manual Load Shedding may be used to control the Emergency at any time. This includes the immediate shedding of Load to return the Area Control Error (ACE) to zero.
14. MISO's posting of the Max Gen Declaration notification to the RT Ops Website via Operator Interface (OI) serves as notice of the existence and duration of the conditions requiring the implementation of the procedures set forth in Section 40.2.20 of the Tariff. Historical Max Gen Declarations can be found on MISO’s Open Access Same Time Information System (OASIS) page.
15. MISO will render all available Emergency assistance to others, as requested, in accordance with SO-I-NOP-00-479 Purchasing and Selling Emergency Energy, provided that the requesting entity has implemented their comparable Emergency procedures, unless such actions violate safety, equipment, regulatory, or statutory requirements.
16. If MISO is unable to issue Load Modifying Resource (LMR) implementation instructions through the MCS-LMR Tool, operators will reference LMR availability in CSAT or other resources, assuming the LMR database remains available, and issue implementation instructions via Operator Interface (OI) or verbal communication, as appropriate.
17. MISO Shift Manager (SM) should evaluate additional staffing requirements per SO-I-NOP-00-441 Real-Time Event Resolution.

18. The Reserve Procurement Enhancement (RPE) objective for the RDT North-to-South is to elevate Market Clearing Prices (MCP) and energy prices in the South Region to clear additional Contingency Reserves, allowing recovery of the RDT Flow to 116% post-contingent of the South MSSC. Operators must then determine how to further reduce the RDT Flow to 100%. When RPE on RDT is violated, additional generation should be started.
19. An infographic of MISO's Market Capacity Emergency Procedure steps is included in Attachment 8 — Summary of Market Capacity Emergency Procedure Steps.
20. An Emergency Operations Resource (EOR) is an online Generation Resource that is not an online Fast Start Resource and is started, synchronized, and injecting Energy, or a Demand Response Resource that reduces its Energy consumption, within two hundred forty (240) minutes of being notified, and that has a minimum run time of less than four (4) hours, and that will participate in setting price as described in Schedule 29A of the MISO Transmission, Energy, and Operating Reserve Market Tariff. EORs participate in setting prices automatically when either the Emergency Tier I or Tier II Offer Floors are established.
21. Refer to applicable Work Level Instructions (WLIs) for detailed step and tools. WLIs are internal and maintained by the role's business area and may change independently of this procedure. In the event of any conflict between a WLI and this procedure, the requirements in this procedure take precedence. WLIs maybe accessed by MISO Operators in the Work Level Instruction Index.

2.0 Roles and Responsibilities

1. In addition to the roles and responsibilities in SO-P-EOP-11 MISO Emergency Operation Plan, the following also apply:
   - MISO Operations Risk Management (ORM) Team
     - Issues forward-looking Market Capacity Declarations up to and including the FRAC Next Day (ND) Case.
     - Coordinates with the Shift Manager (SM) prior to issuance.
     - Capacity Advisories may be issued up to 5 days in advance but must be declared no later than 23:59 EPT the day prior to the operating day.
     - Capacity Advisories are not issued on a same-day basis, as the real-time process begins after the FRAC Handoff.
   - MISO Shift Manager (SM)
     - Issues real-time Market Capacity Declarations after the FRAC ND Handoff per SO-I-NOP-00-491 FRAC Handoff procedure, based on current system conditions.
     - Coordinates with the ORM Team prior to issuance.

3.0 Entry Conditions

3.1 Capacity Advisory

1. Entry conditions are based on the Reserve Margin, which is the Total Operating Reserves compared to the Operating Reserve Requirement, either in MW or as a % of the Load, plus Operating Reserve Requirements. See Attachment 1 — Reserve Margin Example Calculations for examples.
   - Reserve Margin:
     Total Operating Reserves - Operating Reserve Requirement
   - Reserve Margin (%):
     100 * (Total Operating Reserves - Operating Reserve Requirement) / (Load + Operating Reserve Requirement)
   - Total Operating Reserves MBAA:
     (Avail Eco Max - Constraint Stranded MW - NSI) - Load
   - Total Operating Reserves South Region:
     (Avail Eco Max - Constraint Stranded MW - RDT NSI + RDTL) - Load

ORM/ SM

Note

- IF Reserve Margin thresholds are forecasted below the associated uncertainty level, THEN:
- A Capacity Advisory may be declared up to 5 days in advance but must be declared no later than 23:59 EPT the day prior to the operating day.
- Capacity Advisories are not issued on a same-day basis.
- The decision to declare a Capacity Advisory may also consider other information such as time frame, weather, and other uncertainty factors.
- Increasing the Reserve Margin Entry Conditions may be required.

2. IF the following conditions are identified, THEN **PERFORM** Section 4.1 Capacity Advisory: [□]
   - MBAA, Region, or Sub-Area forecasted Reserve Margin is less than the Reserve Margin threshold based upon the associated forecasted uncertainty level.

3.2 Max Gen Warning

SM

Note

A negative Reserve Margin means that Load and Operating Reserve Requirements cannot be met with normal economic Resources. In this scenario, a Max Gen Warning or Event should be declared.

1. IF the following condition is identified, THEN **PERFORM** Section 4.2.3 Max Gen Warning - MISO Actions: [□]
   - MBAA, Region, or Sub-Area actual or forecasted Reserve Margin is less than zero.

3.3 Max Gen Event

SM

1. IF the following condition is identified, THEN **PERFORM** Section 4.2.3 Max Gen Event Step 1: [□]
   - MBAA, Region, or Sub-Area actual or forecasted Reserve Margin is less than zero, **and**
   - Warning level actions are NOT sufficient.

4.0 Instructions

4.1 Capacity Advisory

ORM/ SM

4.1.1 Capacity Advisory - MISO Actions

1. **COMMUNICATE** Capacity Advisory as follows: [□]
   - A. **DEFINE** the boundaries of the Capacity Advisory area. [□]
   - B. **DEFINE** the start and end time of the Capacity Advisory and **COMMUNICATE** those times to the UDS Operator to allow STR Default and RPE MSSC Overrides to be entered. [□]
   - C. **SEND** the Capacity Advisory declaration to affected members via OI per SO-I-NOP-00-448 Event Communications Matrix. [□]
   - D. **SEND** the Capacity Advisory declaration via Reliability Coordinator Information System (RCIS). [□]
   - E. **DECLARE** Conservative System Operations per SO-P-NOP-00-449 Conservative System Operations, if conditions warrant and not already declared. [□]

SM

2. IF OI is unavailable, or the SM determines a conference call is necessary, THEN **PERFORM** a conference call with affected reliability entities per SO-P-NOP-00-483 Reliability Coordination Conference Call. [□]

SM

3. IF a significant shortage of Operating Reserves is anticipated in any Reliability Assessment Commitment (RAC) process, THEN **DETERMINE** whether to issue LMR Scheduling Instructions in anticipation of a Max Gen Emergency Event Step 2 or higher. [□]
   - A. **SEND** an informational message via OI to the impacted area(s) indicating that LMRs have been called in

anticipation of a Max Gen Emergency. [□]

B. **SEND** LMR Scheduling Instructions (from longest to shortest lead time) via MISO Communication System (MCS) for the forecasted Max Gen Emergency. [□]

UDS

Note

For Steps 4 to 8, **REFER** to Attachment 7 — UDS Operator Actions During a MISO Market Capacity Emergency. **[See WLI: BA/UDS]**

4. IF a Capacity Advisory or higher is declared for the North/Central Region only, THEN **OVERRIDE** the STR RPE MSSC Default value(s) for Non-Zone only in the Energy Market Displays (EMD) Global Reserve Requirements menu, for the duration of the Capacity Advisory or higher declaration. [□]

UDS

5. IF a Capacity Advisory or higher declaration is made for the North/Central Region and a Capacity Advisory or higher declaration is added for the South Region, THEN **OVERRIDE** the System-Wide STR Default value(s) and **OVERRIDE** the South Region STR RPE MSSC in Zone 8 in the EMD Global Reserve Requirements menu for the duration of the Capacity Advisory or higher declaration. [□]

UDS

6. IF a Capacity Advisory is declared for the South Region only, THEN **OVERRIDE** the STR RPE MSSC Default value(s) for Zone 8 only in the EMD Global Reserve Requirements menu for the duration of the Capacity Advisory or higher declaration. [□]

UDS

7. IF a Capacity Advisory or higher declaration is made for the South Region and a Capacity Advisory or higher declaration is added for the North/Central Region, THEN **OVERRIDE** the System-Wide STR Default value(s) and **OVERRIDE** the North/ Central STR RPE MSSC for Non-Zone in the EMD Global Reserve Requirements menu for the duration of Capacity Advisory or higher declaration. [□]

ORM/UDS/SM

8. IF a System-Wide Capacity Advisory is declared, THEN **OVERRIDE** the STR Default value(s), the North/Central STR RPE MSSC for Non-Zone, and the South Region STR RPE MSSC for Zone 8 in the EMD Global Reserve Requirements menu, for the duration of the Capacity Advisory or higher declaration. [□]

ORM/ UDS/SM 9. **NOTIFY** Day Ahead (DA) and Forward Reliability Assessment and Commitment (FRAC) Operators when STR updates are complete. [□]

4.1.2 Capacity Advisory - MISO Stakeholder Actions

1. WHEN notified by MISO, THEN **ENSURE** all market data is updated with the best available information for the operating day(s), including the following: [□]
   - Facility and generation availability, outages, and de-rates
   - Generation Offers, including any changes to reflect fuel availability
   - Fuel supply and inventory concerns
   - Fuel switching capabilities
   - Environmental constraints
   - Load forecast Values
   - LMR Availability in the DSRI Tool
   - Voluntary Load Management information
   - Load Management Measures (LMM) and any Voluntary Load Management in the MCS
   - Emergency Demand Response (EDR) offers

MP

Note

LMRs should be implemented at NO less than the MW amount scheduled and following the guidelines provided by MISO.

2. IF notified by MISO, THEN **IMPLEMENT** LMRs. [□]

MP 3. **UPDATE** the DSRI Tool as follows: [□]

   A. **NAVIGATE** to the Active Event by selecting one of the following: [□]
      - The Scheduling Instruction event banner
      - The Active Event from the dashboard
      - The Events tab

   B. **REVIEW** the Event Timeline and LMR Instructions broken down by each LBA. [□]

   C. **ACKNOWLEDGE** the LMR Scheduling Instructions. [□]

   D. **NAVIGATE** to the Resource Deployment tab of the Active Event. [□]

   E. **ENTER** and **SUBMIT** the MW Amounts of Resources that will be deployed to meet the LMR Scheduling Instruction obligation per LBA. [□]

   F. Upon receiving the LMR Scheduling Instruction, **UPDATE** the LMR Availability for all Resources designated to respond, ensuring their availability accurately reflects what is now accessible to MISO. [□]

4.2 MISO Actions during a Max Gen Emergency

4.2.1 Max Gen Declaration - MISO Actions

SM 1. **DECLARE** applicable Max Gen Warning/Event as follows: [□]

A. **DEFINE** the boundaries of the declaration area. [□]

B. **DEFINE** the start and end time of the declaration. [□]

C. **SEND** the Max Gen Declaration via OI per SO-I-NOP-00-448 Event Communications Matrix. [□]

D. **SEND** the Max Gen declaration summary information via RCIS within 30 minutes. [□]

SM 2. **ENSURE** Conservative System Operations has been declared per SO-P-NOP-00-449 Conservative System Operations. [□]

SM 3. IF OI is unavailable or the SM determines whether a conference call is necessary, THEN **PERFORM** a conference call with affected reliability entities per SO-P-NOP-00-483 Reliability Coordination Conference Call. [□]

Note

- Actions are taken to preserve Resources dedicated to firm Load and to maintain Operating Reserves.
- Actions available at this level should be fully utilized, time permitting, by all entities within the defined declaration area prior to declaring an Emergency.

4.2.2 Max Gen Warning - MISO Actions

SM 1. IF starting the declaration at a Max Gen Warning or escalating from a Capacity Advisory, THEN **DECLARE** Max Gen Warning per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

UDS 2. **IMPLEMENT** Emergency Pricing – Tier I in EMD **[See WLI: BA/UDS]**. [□]

SM

Note

This survey is to gain an idea of the amount of LMM Load reduction expected to be available, if needed.

SM 3. **SEND** a survey via the MCS LMM Tool in the Load Management Tab to LBAs to ensure LMM information is updated. [□]

A. IF the Drill Mode is currently on, THEN **ENSURE** to “Switch to Live Mode.” [□]

BAO 4. IF changes in Operating Reserve availability are identified, THEN **NOTIFY** the SM. [□]

IRAC 5. **ENSURE** available economic Resources are committed to meeting Load, firm transactions, and reserve requirements. [□]

RC

Note
The following analysis should be completed in time for implementation during the Warning declaration.

6. **COORDINATE** with neighboring Reliability Coordinators (RCs) and MISO TOPs to raise transfer capability into the declaration area or make available Constraint Stranded MW from generation (on- or off-line) in the declaration area, including review of Transmission Loading Relief (TLR) activity, binding constraints, available reconfiguration options, and use of short-term Emergency ratings. [□]

SM 7. **REVIEW** EDR offers to determine EDR availability and MW amounts for the Warning period. [□]

SM 8. **OBTAIN** updated MW relief amount available during the effective Warning period by LBA from MCS.

- LMMs – Stage 1
- LMMs – Stage 2

SM 9. **REVIEW** LMR availability in the MCS-LMR Tool for the declaration period. [□]

SM/BAO 10. **DIRECT** the following actions to raise forecasted capacity:

A. **TERMINATE** Inadvertent Payback process pe SO-I-NOP-00-462 Inadvertent Interchange Management, if required to assist system conditions. [□]

B. **DETERMINE** if a request for Time Error Correction termination should be made per SO-P-NOP-00-455 Balancing Authority Operations. [□]

SM 11. **SEND** OI message to MPs to schedule remaining available External and Internal Resources (Module E Registered Capacity Resources) that are deliverable to the Warning area, considering transmission constraints. [□]

G&I 12. **NOTIFY** the SM of forecasted changes in MBAA NSI due to loss of imports. [□]

G&I 13. **MODIFY** webTrans E-tag validation mode to reflect the Max Gen in affected area (North, South, or All) per SO-I-EOP-00-006 Interchange Scheduling Operations during Emergency Conditions. [□]

G&I 14. **SUSPEND** Coordinated Transaction Scheduling (CTS) for the duration of the Capacity Emergency per SO-I-AOP-00-224 CTS Failure Modes. [□]

A. **COMMUNICATE** CTS suspension to PJM. [□]

G&I 15. **COORDINATE** to determine amount of non-firm and firm Export Schedules to curtail, as identified below. [□]

G&I 16. IF Export Schedule Limits are exceeded, THEN **CURTAIL** Export Schedules from the declaration area in amounts required to relieve shortage conditions in the following order per SO-I-EOP-00-006 Interchange Scheduling Operations during Emergency Conditions: [□]

A. Non-Firm Transmission Schedules.
B. Firm Schedules from Capacity (Module E) Resources that are NOT meeting their Schedule and Capacity requirements.
C. Firm Schedules from non-Capacity (Module E) Resources that are NOT meeting their Schedule requirements.
D. Firm Transmission schedules from Power Purchase Agreements (PPAs) that represent a Fleet of Resources, when those Resources are NOT meeting their collective Resource obligation.

G&I 17. **COORDINATE** with MPs to schedule in any non-scheduled MWs from external Resources up to their cleared Module E Capacity obligation. [□]

SM 18. IF forecasting an escalation to Max Gen Event Step 2 or higher, THEN **NOTIFY** GOPs via OI in the declaration area with Generators de-rated due to environmental restrictions, and request that they obtain waivers from the appropriate government agencies. [□]

RC 19. **NOTIFY** TOPs to implement reconfiguration options agreed upon to raise transfer capability into the declaration area or to make available Constraint Stranded MW from generation in the declaration [□]

Note

AME are Resources with a commit status of Emergency. If all available generation Resources are in use, proceed to Max Gen Event Step 1 and Declare EEA1.

IRAC/SM 20. **COMMIT** the following Available Max Emergency (AME) designated Resources and declare Max Gen Event Step 1 and EEA 1: [□]

- Generation Resources
- Demand Response Resources – Type 1
- Demand Response Resources – Type 2

ALL 21. **LOG** all actions taken and relevant information in response to the declaration. [□]

4.2.3 Max Gen Event Step 1 - MISO Actions

SM

Note

Actions in this section are taken to attempt to preserve Resources dedicated to firm Load and maintaining Regulating Reserves.

1. IF starting the declaration at a Max Gen Event Step 1 or escalating from a lower Max Gen level, THEN **DECLARE** Max Gen Event 1 and EEA1 per Section 4.2.1 Max Gen Declaration - MISO Actions.
   Actions. [□]

SM 2. **NOTIFY** On-Call Director to implement SO-P-AOP-00-217 MISO and State Officials 24X7 Communication Protocols During Emergencies. [□]

IRAC/ UDS

Note

The IRAC Operator ensures Emergency Ranges are available for use by UDS, and the UDS Operator verifies these ranges as preliminary actions to implementing them in Event Step 1.

UDS 3. IF Warning step skipped, THEN **IMPLEMENT** Emergency Pricing – Tier I in EMD **[See WLI: BA/UDS]**.

4. **ENSURE** unit Emergency Ranges are pushed in EMD . [□]

IRAC/ UDS

Note

Resources selected to provide Regulating Reserve for each Generation Resource, Demand Response Resource – Type II, and External Asynchronous Resource for use in MISO's RAC, Automatic Generation Control (AGC), and UDS for the MBAA (or Sub-Area due to a transmission constraint) are to be excluded when implementing Emergency Maximum Limits.

5. **ACTIVATE** Emergency Maximum Limits in EMD **[See WLI: BA/UDS]**. [□]

ALL 6. **LOG** actions taken and relevant information in response to the declaration. [□]

4.2.4 Max Gen Event Step 2 - MISO Actions

SM

Note

- LMM – Stage 1 and LMRs are utilized on a pro-rata basis within the declaration area based on availability of those actions, except for EDRs, which are committed in merit order.
- LMRs can be called in anticipation up to one hour prior to their required notification time. If MISO does NOT declare a Max Gen Emergency Event Step 2 or higher at least two hours prior to the start of the Scheduling Instructions issued in anticipation, then, the LMRs are NOT obligated to perform.

1. IF starting the declaration at a Max Gen Event Step 2 or escalating from a lower Max Gen level, THEN **DECLARE** Max Gen Event Step 2 and EEA2 per Section 4.2.1 Max Gen Declaration MISO Actions. [□]

UDS

2. **IMPLEMENT** Emergency Pricing - Tier II in EMD **[See WLI: BA/UDS]**. [□]

SM

3. **DETERMINE** Manitoba Hydro's EEA status. [□]

SM

4. IF Manitoba Hydro is in an EEA concurrently with MISO's EEA2 or higher, THEN **PERFORM** SO-I-NOP-00-481 MISO-Manitoba Hydro Concurrent EEA. [□]

SM

Note

- One MW value will be provided per LBA for Load reduction.
- Determination of individual LMMs to be utilized will be managed at the LBA level.
- Reduction MW amounts for each LBA will be determined by proration of the total amount available in the declaration area.
- If OI is unavailable, notifications will be made via phone.
- LMR Load reduction amounts communicated to LBAs are for information only; LBAs do not implement LMRs

5. **NOTIFY** LBAs of required Load reduction via LMM – Stage 1 and LMRs in MW amounts via MCS. [□]

SM

6. **COORDINATE** with MPs on implementing LMRs as follows: [□]

Note

LMR implementation amounts are determined by taking prorated amount of LMR availability in each LBA area as compared to total available in the declaration area, and based upon registration profile of each LMR, within the tolerances as set in the MCS-LMR Tool.

A. **DETERMINE** LMR implementation amounts by MPs. [□]

B. **PROVIDE** a MW minimum implementation amount to each MP based upon this pro-ration and profile of registered LMRs via MCS-LMR Tool. [□]

SM 7. **DETERMINE** OE-417 reporting responsibilities per SO-P-NOP-04 MISO Event Reporting Operations Plan. [□]

SM 8. **ENSURE** required notifications are performed per SO-I-NOP-00-448 Event Communications Matrix. [□]

SM 9. **COMMIT** EDR Resources, in merit order, to alleviate capacity shortages within the declaration area per SO-I-NOP-00-404 Emergency Demand Response Implementation. [□]

SM 10. **COORDINATE** with neighboring RCs and BAs to determine Emergency Energy available from external sources, either through interruptible firm Load or through Emergency Energy purchases. [□]

SM 11. **IMPLEMENT** Emergency Energy purchases from neighboring BAs to conserve Operating Reserves per SO-I-NOP-00-479 Purchasing and Selling Emergency Energy. [□]

SM 12. **EVALUATE** opportunities to reduce internal energy usage, such as sending non-essential personnel home, reducing lighting that is non-essential for personnel safety, and reducing large electric Loads. [□]

Note

DOE Form OE-417 filing requirements for issuing Public Appeals is the responsibility of the LBA.

SM 13. **INSTRUCT** LBAs in the declaration area to issue public appeals to reduce demand per their internal procedures. [□]

14. **NOTIFY** GOPs via OI in the declaration area with Generators de-rated due to environmental restrictions, instructing them to implement waivers from the appropriate government agencies [□]

SM

Note

Reduction of MW amounts for each LBA will be determined on a pro-rate basis of the total amount available in the declaration area.

SM 15. **NOTIFY** LBAs, via MCS, of the required Load reduction (in MW of interruptible demands) via LMM – Stage 2. [□]

RC 16. **COORDINATE** with neighboring RCs and BAs to identify additional available Emergency Energy, including Operating Reserves. [□]

G&I 17. **IMPLEMENT** Emergency Energy purchases from neighboring BAs per SO-I-NOP-00-479 Purchasing and Selling Emergency Energy. [□]

BAO 18. **IMPLEMENT** use of MISO's spinning and supplemental reserves, as needed and as time permits. [□]

SM 19. IF Contingency Reserves fall below minimum required (MSSC) for greater than 30 minutes and NO reasonable actions exist to restore them within 90 minutes, THEN **DECLARE** Max Gen Event Step 3 and EEA3 per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

BAO 20. **IMPLEMENT** a Reserve Call from Contingency Reserve Sharing Group (CRSG), utilizing MHEB's available contingency reserves. [□]

IRAC 21. **EVALUATE** the exclusion of Regulating Units that have room between Reg Max and Emergency Max from clearing Reg in EMD. [□]

Note
The SM and IRAC should coordinate to maintain an appropriate amount of Regulating Reserves to avoid shedding firm Load for normal ACE deviations.

ALL 22. **LOG** actions taken and relevant information in response to the declaration. [□]

4.2.5 Max Gen Event Step 3 - MISO Actions

SM 1. IF starting the declaration at a Max Gen Event Step 3 or escalating from a lower Max Gen level, THEN **DECLARE** Max Gen Event Step 3 and EEA3 per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

SM
Note
Attachment 4 — Slice-of-System PPAs Load/Schedule Curtailment provides additional information regarding sharing of Load shedding with Slice-of-System PPAs.

2. **DETERMINE** manual Load Shedding requirements. [□]

SM
Note
Issuing Emergency Operating Instructions for firm Load shed is based on the ratio of LBA forecasted or actual Load to the total forecasted or actual Load of the declaration area, considering applicable transmission security requirements.

SM

Note

The Shift Manager will ensure that firm Load Shed points are known and members are prepared to execute Load Shed when reserves are depleted and additional action is required such as increasing Load conditions or ACE recovery from generation loss.

3. **ISSUE** Emergency Operating Instructions to LBAs in the declaration area for MW amounts of Load to shed via the MCS Firm Load Shed Tool or verbally per SO-P-NOP-10-431 Communications Protocol for Operating Instructions [□]

UDS

4. WHEN notified by MISO SM, THEN **PERFORM** the following:
   A. In the EMD UDS tab, **CHECK** the appropriate box(es) in the column titled "Is Voll Price Enforced" for the applicable LBAs,. This action sets LMPs and MCPs to the Value of Lost Load (VOLL) **[See WLI: BA/UDS]**. [□]
   B. **SAVE** updates. [□]

SM

5. IF firm Load Shed is greater than 100 MW, THEN **DETERMINE** OE-417 reporting responsibilities per SO-P-NOP-04 MISO Event Reporting Operations Plan. [□]

SM

6. **ENSURE** required notifications are performed per SO-I-NOP-00-448 Event Communications Matrix. [□]

ALL

7. **LOG** actions taken and relevant information in response to the declaration. [□]

4.2.6 Max Gen Event Downgrade/Termination - MISO Actions

SM

Note

- Steps and levels during Termination may be skipped, as appropriate, based on system conditions and projections.
- Emergency steps shall be exited in a controlled and deliberate manner to avoid adversely affecting system reliability, while also minimizing the impact of these Emergency actions on the Load Serving Entities (LSEs).

1. WHEN actual obligations return below total MISO capability, THEN **DOWNGRADE/TERMINATE** Max Gen Event as follows: [□]

SM

   A. **SEND** Max Gen Downgrade/Termination to affected members via OI per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

UDS

   B. IF Max Gen Event Step 3 is being terminated, THEN **UNCHECK** the box(es) in EMD that previously set all LMPs and MCPs to the Value of Lost Load (VOLL). [□]

G&I C. **ENSURE** CTS is enabled per SO-I-AOP-00-224 CTS Failure Modes [□]

G&I D. **RETURN** webTrans E-tag validation to normal mode per SO-I-EOP-00-006 Interchange Scheduling Operations during Emergency Conditions. [□]

G&I E. **TERMINATE** any Emergency Energy purchases made during the event, as necessary. [□]

G&I F. **RELOAD** any Export curtailments made during the event, as necessary. [□]

IRAC G. **EVALUATE** and **DECOMMIT** any online Emergency generation (AME) that has met its Min Runtime. [□]

SM H. **PERFORM** necessary actions to back out of steps taken, in reverse order. [□]

UDS I. IF an STR requirement override is NOT needed for the remainder of the declared Emergency, THEN **REMOVE** STR requirement override in EMD from STR Default and STR MSSC Non-Zone and South Zone 8. [□]

SM 2. **ENSURE** all notifications are performed per SO-I-NOP-00-448 Event Communications Matrix. [□]

ALL 3. **LOG** actions taken and relevant information in response to the declaration. [□]

4.3 MISO Stakeholder Actions during a Max Gen Emergency

4.3.1 Max Gen Warning - MISO Stakeholder Actions

Note

Deferring generation/transmission maintenance until the Max Gen declaration has been terminated ensures trips are minimized.

1. **FOLLOW** MISO's SO-P-NOP-00-449 Conservative System Operations procedure. [□]

2. **DETERMINE** potential exclusions of constrained pockets within the declaration area where there is expected to be adequate generation that may NOT be transferred to other parts of the declaration area due to local constraints. [□]

TOP 3. **INFORM** MISO RC of identified constrained areas. [□]

GOP 4. IF generators are de-rated, THEN **PERFORM** the following:

GOP A. INFORM the following stakeholders of capacity-limited facilities: [□]

- LBAs
- TOPs
- MISO G&I Operator

GOP 5. **UPDATE** Limits and Offers. [□]

MP

Note

- Schedules that source from a Resource that is identified as a Capacity Resource in Module E for a MISO LSE must be identified in the tagging process per MISO BPM-007 Physical Scheduling Business Practice Manual Section 16 - Capacity Resource Scheduling.
  This also includes a Generation Resource internal to the MBAA that is identified as a Capacity Resource for an external BA.

MP 6. **ENSURE** accuracy of LMR availability and Self-Scheduled/ Voluntary Load Management LMRs in the DSRI Tool. [□]

LBA 7. **ENSURE** accuracy of Non-LMR Voluntary Load Management/ Self-Scheduled LMM information in the MCS-LMR Tool. [□]

TOP 8. **COORDINATE** with the MISO RC to determine reconfiguration options to raise transfer capability into the declaration area or to make available Constraint Stranded MW[□] from generation in the declaration area.

LBA 9. Based on Load Shed methodology, **PREPARE** for potential Load Shed during an Event stage. [□]

MP 10. **UPDATE** EDR offers for availability and MW amounts for the declaration period. [□]

LBA 11. **SUBMIT** LMM availability via MCS per Attachment 3 — Load Management Update Form Example. [□]

MP 12. **ENSURE** accuracy of registered LMR availability in the DSRI Tool. [□]

MP 13. **SCHEDULE** remaining available External and Internal Resources (Module E Registered Capacity Resources) that are deliverable to the declaration area. [□]

LBA 14. **NOTIFY** Interruptible Loads of potential interruption. [□]

LBA

.

15. **DETERMINE** whether Generators are de-rated due to environmental restrictions, and request waivers from the appropriate government agencies as directed by MISO. [□]
16. **IMPLEMENT** agreed upon reconfiguration options to raise transfer capability into the declaration area or to make Available Constraint Stranded MW from generation in the declaration area. [□]
17. WHEN notified by MISO, THEN **START** applicable off-line AME Generation Resources. [□]

4.3.2 Max Gen Event Step 1 - MISO Stakeholder Actions

GOP

Note

- MPs should ensure Emergency Range limits reflect actual Resource capabilities.
- Specific information, limitations, and concerns regarding Emergency Range usage should be communicated to the MISO G&I Operators, as applicable.

1. WHEN Resources are dispatched, THEN **ENSURE** Resources move into Emergency Ranges. [□]

2. **ENSURE** all co-generation and independent power producers are at maximum output and availability. [□]

3. IF additional reliability capacity is available (such as adding additional mills, duct burners, etc.), THEN **COORDINATE** adjustments with the MISO G&I Operator. [□]

4.3.3 Max Gen Event Step 2 - MISO Stakeholder Actions

LBA 1. IF in the declaration area and notified by MISO to reduce Load via LMM – Stage 1, THEN **PERFORM** the following: [□]

LBA A. **REDUCE** Load via LMM – Stage 1. [□]

LBA

Note

- Reductions through Load Management are NOT precise to the MW.
- Determination of individual LMMs to be utilized will be managed at the LBA level.

B. WHEN Load reduction actions have been implemented, THEN **NOTIFY** MISO. [□]

MP

Note

LMRs should be implemented at NO less than the MW amount scheduled and following the guidelines provided by MISO.

2. WHEN notified by MISO, THEN **IMPLEMENT** LMRs. [□]

MP 3. **UPDATE** the DSRI Tool as follows: [□]

A. **NAVIGATE** to the Active Event by selecting one of the following: [□]

- The Scheduling Instruction event banner
- The Active Event from the dashboard
- The Events tab

B. **REVIEW** Event Timeline and LMR Instructions broken down by each LBA. [□]

C. **ACKNOWLEDGE** LMR Scheduling Instructions. [□]

D. **NAVIGATE** to the Resource Deployment tab of the Active Event. [□]

E. **ENTER** and **SUBMIT** MW Amounts of Resources that will be deployed to meet the LMR Scheduling Instruction obligation per LBA. [□]

F. Upon receiving the LMR Scheduling Instruction, **UPDATE** the LMR Availability for all Resources designated to respond, ensuring their availability accurately reflects what is now accessible to MISO. [□]

MP 4. WHEN notified by MISO, THEN **COMMIT** EDR Resources. [□]

Note

- Public appeals to reduce demand is based on internal LBA procedures, system conditions, and Event projections provided by MISO.
- The public appeals should include an educational message on how the public may reduce demand and conserve power.
- DOE Form OE-417 filing requirements for issuing Public Appeals is the responsibility of the LBA.

LBA

5. WHEN instructed by MISO, THEN **ISSUE** public appeals to reduce demand per internal procedures. [□]

LBA

6. **EVALUATE** opportunities to reduce internal energy usage, such as sending non-essential personnel home, reducing lighting that is non-essential for personnel safety, and reducing large electric Loads.

LBA

7. IF in the declaration area, THEN **PREPARE** to shed Load. [□]

GOP

8. IF requested by MISO to dispatch available capacity THEN **DISPATCH** as follows: [□]
   A. **VERIFY** Generators in the declaration area with de-rates from environmental restrictions. [□]
   B. IF approved waiver from government regulations, THEN **DISPATCH** available generation. [□]

LBA

9. IF in the declaration area and notified by MISO to reduce Load via LMM – Stage 2, THEN **PERFORM** the following:
   A. REDUCE Load via LMM – Stage 2. [□]

Note

- Reductions through LMMs are NOT precise to the MW.
- Determination of individual LMMs to be utilized will be managed at the LBA level.

   B. WHEN Load reduction actions have been implemented, THEN **NOTIFY** MISO via MCS. [□]

GOP/ MP

10. **REVIEW** Offers. [□]

GOP/ MP

11. **ENSURE** all available Emergency Ranges and Resources are offered. [□]

GOP/ MP

Note

All Resources should be committed, producing energy or committed for reserves, except Emergency Ranges on Resources providing Regulating Reserves.

GOP/ MP

12. IF there are available Resources or capacity NOT being utilized, THEN **NOTIFY** the MISO G&I Operator. [□]

LBA

4.3.4 Max Gen Event Step 3 - MISO Stakeholder Actions

Note

In addition to ensuring Load shed schemes are capable of implementation in a time frame adequate for mitigating the Emergency for Load shed directed by MISO, LBAs are responsible for coordinating with TOPs for any Load shed requirements, critical load evaluation in Load shed schemes, and coordinating rotation of selected Loads with any other automatic Load shed schemes such as Underfrequency and Undervoltage. The minimum MISO directed Load shed per LBA should always be maintained until Load restore directions are provided by MISO.

1. **SHED** firm Loads per MISO issued Emergency Operating Instruction. [□]

LBA

2. **CONFIRM** actions taken with the MISO RC via MCS Firm Load Shed Tool or verbally per SO-P-NOP-10-431 Communications Protocol for Operating Instructions. [□]

LBA

3. IF requested by MISO during Event Step 3, THEN **COMPLETE** Department of Energy (DOE) Form OE-417 as follows: [□]
   A. **COMPLETE** DOE Form OE-417 for actions taken to reduce Load via Load Management Procedures per NERC EOP-004-4 and SO-P-NOP-04 MISO Event Reporting Operations Plan. [□]
   B. **SUBMIT** completed DOE Form OE-417 to the following: [□]
      - DOE
      - NERC
   C. **FORWARD** a copy of the submitted DOE Form OE-417 to the following: [□]
      - Regional Entities
      - DOENERCEventReporting@misoenergy.org

4.3.5 Max Gen Event Downgrade/Termination - MISO Stakeholder Actions

LBA/ MP/ TOP/ GOP

1. **PERFORM** requests of the MISO SM or designee to back out of each level. [□]

5.0. Definitions

1. **Reserve Margin** - The difference between Total Operating Reserves and the Operating Reserve Requirement.
2. **Constraint Stranded MW** - Resource MW that are NOT available to meet Load due to congestion on the electric grid.
3. **Emergency Demand Response (EDR)** - Load reductions, Behind the Meter Generation (BTMG), and other demand resources that are available to reduce demand or increase generation in exchange for guaranteed recovery of costs associated with the response in accordance with Schedule 30 (EDR Provisions) of the Tariff.
4. **Load Management Measures (LMM) Stage 1** – Load management actions that can be taken to reduce demand to preserve or maintain Operating Reserves that are NOT included in EDRs or LMRs.
5. **Load Management Measures (LMM) Stage 2** – Load management actions that can be taken to reduce demand including voltage reductions and reducing Loads that, by contract, CANNOT be interrupted until reserves are being or expected to be depleted and energy from Emergency Offers by Market Participants are being or expected to be depleted. These do NOT include EDRs or LMRs.
6. **Load Modifying Resource (LMR)** - These are either Demand resources or Behind the Meter Generation that have an obligation to reduce demand or increase generation during declared system emergencies.
7. **Maximum Generation (Max Gen) Capacity Advisory** - Provides advanced notice of forecasted capacity shortage and will request stakeholder update data.
8. **Max Gen Warning** - MISO foresees or is experiencing conditions where all available economic Resources are committed to meeting Load, firm transactions, and reserve requirements, and is concerned about sustaining required Operating Reserves.

9. **Max Gen Event** – IF MISO's forecasted or real-time energy demand and Operating Reserve Requirements within the MBAA (or Sub-Area due to a transmission constraint) CANNOT be satisfied with Economic Maximum Limits of all available Resources, then, MISO issues a Max Gen Event due to a shortage of economic Resources.

6.0 References

6.1 NERC References

1. EOP-011-4 Emergency Operations
   - R2.2.1[Section 4.1.1 Step 1.]
   - R2.2.2 [Section 4.2.3 Step 1.][Section 4.2.4 Step 1.] [Section 4.2.5 Step 1.]
   - R2.2.3 [Section 4.1.2]
   - R2.2.4 [Section 4.2.4 Step 13.]
   - R2.2.5 [Section 4.2.4 Step 14.]
   - R2.2.6 [Section 4.2.4]
   - R2.2.7
   - [Section 4.2.2 Step 11.][Section 4.2.2 Step 21.][Section 4.2.4 Step 6.][Section 4.2.4 Step 9.]R2.2.9 [Section 4.2.5 Step 3.]
   - R2.2.10 [Section 3.1 Note after Step 1]
   - R5 [Section 4.2.1 Step 1.D.]
   - R6 [Section 4.2.3 Step 1.][Section 4.2.4 Step 1.] [Section 4.2.1][Section 4.2.5 Step 1.]
2. IRO-014-4 Coordination Among Reliability Coordinators
3. R1 [Section 4.1][Section 4.2]
4. TOP-001-6 Transmission Operations
   - R2 [Section 4.1][Section 4.2]

6.2 FERC References

1. MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff, Section 40.2.20

6.3 MISO References

1. BPM-007 Physical Scheduling Business Practice Manual Section 16 – Capacity Resource Scheduling
2. SO-I-EOP-00-006 Interchange Scheduling Operations during Emergency Conditions
3. SO-I-AOP-00-224 CTS Failure Modes
4. SO-I-NOP-00-404 Emergency Demand Response Implementation
5. SO-I-NOP-00-441 Operations Real-Time Event Resolution
6. SO-I-NOP-00-448 Event Communications Matrix
7. SO-I-NOP-00-462 Inadvertent Interchange Management
8. SO-I-NOP-00-479 Purchasing and Selling Emergency Energy
9. SO-I-NOP-00-481 MISO-Manitoba Hydro Concurrent EEA
10. SO-I-NOP-00-483 Reliability Coordination Conference Call
11. SO-I-NOP-00-491 FRAC Handoff
12. SO-P-AOP-00-217 MISO and State Officials 24X7 Communication Protocols During Emergencies
13. SO-P-EOP-00-004 Transmission System Emergency
14. SO-P-EOP-11 MISO Emergency Operating Plan
15. SO-P-NOP-10-431 Communications Protocol For Operating Instructions
16. SO-P-NOP-00-449 Conservative System Operations
17. SO-P-NOP-00-455 Balancing Authority Operations
18. SO-P-NOP-04 MISO Event Reporting Operating Plan

Attachment 1 — Reserve Margin Example Calculations

1.0 Example 1: Projection for MBAA

Table 1: Calculation

Description	Value
MBAA Peak Load Forecast:	100,000
Operating Reserve Requirement:	2,410
Load plus Operating Reserve Requirement:	102,410
Available Economic Maximum in Area:	97,000
Constraint Stranded MW:	2,000
Available Economic Resources in Area:	95,000
Net Scheduled Interchange (NSI) into Area:	7,000
Reserve Margin = 95,000+7,000-102,410	- 410
Reserve Margin (%) = (590/102,410)*100:	- 0.4%

Assessment: Reserve Margin is forecasted to be -410 MW. Load plus Operating Reserve Requirement is not met and the Reserve Margin is less than 0 MW. A Max Gen Warning declaration may be necessary.

2.0 Example 2: Projection for South Region

Table 2: Calculation

Description	Value
MBAA Peak Load Forecast:	30,000
Operating Reserve Requirement:	1,500
Load plus Operating Reserve Requirement:	31,500
Available Economic Maximum in Area:	29,000
Constraint Stranded MW:	1,000
Available Economic Resources in Area:	28,000
Net Scheduled Interchange (NSI) into Area (RDT NSI):	400
RDT Import Capability up to RDTL of 3,000	3,000
Reserve Margin = 28,000+3,400-31,500	-100
Reserve Margin (%) = (-100/31,500)*100:	- 0.3%

Assessment: Reserve Margin is -100 MW, meaning the South Region Load plus Operating Reserve Requirement is 100 MW short of being met. This means Load will be covered but the 1,500 MW Operating Reserve Requirement will not be. A Max Gen Warning or Event declaration may be necessary.

Attachment 2 — Maximum Generation Declaration Template

Maximum Generation Declaration Type: [Warning/Event]

The MISO RC is Declaring/Updating a Maximum Generation Warning/Event effective from [MM/DD/YYYY] [HH:MM] EST and [MM/DD/YYYY] [HH:MM] EST for the following entities:

[List the affected entities within the boundaries of the declaration by LBA. Include any constrained pockets within the declaration area with adequate generation that should be excluded from the Maximum Generation Emergency.]

The reason for the declaration is:
State the reason(s): Forced Transmission Outage, Forced Generation Outage, Higher than Forecasted Load, Above/Below Normal Temperatures, Loss of Import Interchange Schedules, Reduction in RDT limit, etc.

Members are to prepare for a Maximum Generation Emergency by performing the applicable MISO Member Maximum Generation [Warning/Event] Level Actions of SO-P-EOP-002 MISO Market Capacity Emergency procedure.

CTS Suspension: Attention Market Participants: CTS (Coordinated Transaction Scheduling) is Suspended as of [MM/DD/YYYY] [HH:MM] EST. Alternative scheduling methods should be utilized.

Projections (to LBAs and TOPs only):

- Peak hour for Area is Hour Ending [MM/DD/YYYY] [HH:MM] EST.
- Load plus Operating Reserve Requirement for Area: _____
- Amount of available economic Resources in Area: _____
- Imports into Area: _____
- Reserve Margin shortfall(-)/surplus(+) for Area: _____

1. Summary information (only) at the top of the OI Message/template will be communicated to MPs via the following:
   A. OI
   B. MISO public web site – Real Time Notifications Tab via OI View Real-Time Operations Updates at https://www.misoenergy.org/markets-and-operations/notifications-overview/

2. Completed OI message/template (summary & projections) will be communicated to TOPs, LBAs, BAs and neighboring BAs, and RCs as follows:
   A. OI
   B. RCIS
3. MISO will provide summary information to the following email exploder lists via OI message:
   - *MISO Alerts BA and TO
   - *MISO Alerts FERC, State Comm., RRO, Neighboring RCs and BAs

Attachment 3 — Load Management Update Form Example

Local Balancing Authorities (LBAs) report via MCS or phone to the RC Load reductions that would be available, time permitting, via Load Management should a Maximum Generation Emergency Event be implemented during the same time frame the Warning is effective. MISO will provide the expected notification time* for LBAs to assume when completing form.

Load Management may include but are NOT limited to public appeals, voltage reduction, and interruption of end use Loads in accordance with applicable contracts, demand-side management, utility Load conservation measures, and starting behind the meter generation*.

Load Management is separated into LMM – Stage 1 and LMM – Stage 2.

*Excludes Registered DRR Type 1 and DRR Type 2 Resources

Table 3: LBAs report the following estimated values:

LBA:	
Notification time for Load Management Measures (i.e. less than 4 hours)	
LMM Stage 1 available:	10
LMM Stage 2 available:	5
Total:	15
LBAs should list LMM Stage 1 and LMM Stage 2 that are already or projected to be implemented at the Event time:	
LMM Stage 1:	100
LMM Stage 2:	0
Total:	100

Attachment 4 — Slice-of-System PPAs Load/Schedule Curtailment

1.0 Slice-of-System Power Purchase Agreements (PPAs) Curtailed Pro-Rata with Load in the Source Balancing Authority when Source Balancing Authority is in Emergency Procedures

1. PPAs in this category will continue to qualify as Planning Resources so long as the PPA only will be curtailed pro-rata along with Load in the source Balancing Authority and only when the source Balancing Authority is operating under Emergency Procedures.
2. Under this situation, a PPA with a 1,000 MW Export schedule from an external Balancing Authority with a 3,000 MW Load will be curtailed pro-rata along with the Load when the external Balancing Authority is operating under Emergency Procedures. That is, curtailment would take place three-quarters to firm Load and one quarter to the firm schedule. This pro-rata treatment is triggered when MISO experiences Emergency Conditions at the same time as the external Balancing Authority.

2.0 Slice-of-System PPA in a Balancing Authority that Coordinates Planning Reserve Qualifications and Shares Emergency Responsibilities with MISO's Balancing Authority

1. In addition to the slice-of-system PPA treatment noted in category (1.0) above, slice-of-system PPAs can continue to qualify as External Resources under this category, and MISO and the external BA will share Load Shedding on a pro-rata basis in proportion to the Load in the area under the Capacity Emergency, so long as the requirements of this category are met.
2. This qualification category has several requirements for the host BA:
   A. It must be in MISO's RC area.
   B. It must share Operating Reserves with the MISO BA.
   C. It must have a Seams Operating Agreement with MISO containing several features.
3. Seams Operating Agreement must specify the following:
   A. The host BA has established planning reserve processes and criteria similar to MISO's.
   B. Actions that will be taken by both entities – MISO and the host BA – during Emergency Procedures prior to implementing Load Shedding.
   C. BA responsibilities include:
      (1.) Submitting Load estimates to MISO in a similar manner as submitted by other Load entities under Module E-1.

(2.) Providing generator testing data for all resources used to serve firm requirements of the host Balancing Authority.

(3.) Providing transparency to such resource plans in the form of a Fixed Resource Adequacy Plan, pursuant to Module E-1.

4. With these requirements in place, when both BAs have exhausted other Emergency operating actions and are in a firm Load shedding event, Load shedding is shared on a pro-rata basis in proportion to the Load in the area under the Capacity Emergency.

Example 1

If the load of an external BA in Capacity Emergency is 3,000 MW and the Load of the area in MISO in Capacity Emergency is 17,000 MW, then pro-rata Load shed is 3/20 of the total for the external Balancing Authority and 17/20 for the area in MISO in the Capacity Emergency.

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5. This treatment is appropriate for BAs that meet the requirements indicated above because MISO can count on the fact that the external BA is planning and testing its resources in an equivalent manner to MISO, is part of MISO's RC area, and is subject to Emergency Procedures it has developed with MISO. It has also agreed to operate its system in a similar manner, including the agreement to share its Operating Reserves with MISO during Emergency Conditions.

3.0 When MISO is in an EEA and the external BA with PPA is not, then MISO will determine if the PPA should flow or determine the curtailable MWs of the PPA.

1. LBA NET (Excess Capability) =
   Σ(LBA_online RTmw - LBA_online MaxObligation)
   - Where RTmw = Current RT MWs of Resource
   - Where MaxObligation = The lesser of a resource's Effective ICAP (capacity obligation) and their Real-Time Must Offer availability
2. Prior to any curtailments, MISO will contact the external BA by phone.
3. If the BA indicates that the curtailment will cause the BA to enter an EEA, then MISO will initiate SO-I-NOP-00-481.
4. If the BA indicates that the curtailment will NOT cause the BA to enter an EEA, then MISO will curtail any relevant schedule(s).

Attachment 5 — Additional Information

1.0 Max Gen Emergency

1. MISO may call for a Max Gen Warning, Event, or EEA level prior to the actual forecasted start time of such Warning, Event, or EEA level.
   A. The purpose of this is to communicate forecasted conditions that meet the criteria of these levels, as well as to provide notice of certain implementation steps that require longer notifications times.
   B. An example would be an LMR which has a 4-hour notification time, requiring implementation instructions to be sent prior to the actual start time of the Event or EEA.
   C. Due to the dynamic nature of the Bulk Electric System (BES), these preliminary declarations and instructions may be canceled prior to the actual start time of the forecasted Warning, Event, or EEA as conditions warrant.
   D. At the Max Gen Warning level, Emergency Pricing - Tier I is in effect until termination of the Warning or increasing Max Gen level to Step 2 or higher.
2. Max Gen Warning
   A. EDRs may also be registered as LMRs in Module E. If a Market Participant (MP) has decided to offer all or part of their resource as an EDR for an operating day, the MP should reduce the availability of that resource as an LMR in the DSRI Tool for all 24 hours of the same operating day by the maximum MW amount offered for that resource as an EDR. In addition, if an MP has voluntarily implemented any resources registered as an LMR, the MP should adjust the availability of that resource in the DSRI Tool.
   B. Tier I prices are in effect from Max Gen Warning until an Emergency Event Step 2, when Tier II prices are implemented. This is an ex-post ELMP pricing change and does NOT affect system commitment or dispatch. Emergency Pricing will be utilized as necessary on an LBA basis.
3. Max Gen Event
   A. MISO will implement Emergency Pricing - Tier II during Step 2 of an Emergency Event. This is an ex-post ELMP pricing change and does NOT affect system commitment or dispatch. Emergency Pricing will be utilized as necessary on an LBA basis.

Attachment 6 — Maximum Generation Emergency Overview

The following is an overview of Max Gen Emergency actions and should be used for reference only during an actual event.

Table 4: Maximum Generation Emergency Overview

Level	MISO Major Actions	Stakeholder Major Actions
Capacity Advisory	Send OI Declaration message and RCIS notification	Prepare to implement this procedure and follow internal procedures for Emergency Conditions Update market data (availability, offers, constraints, load forecast values, etc.)
	Declare Conservative System Operations (if conditions warrant)	Follow instructions per Conservative System Operations procedure and declaration
	Determine if LMR Scheduling Instructions should be issued (in anticipation of Event Step 2 or higher) – send informational message and LMR Scheduling Instructions via MCS if needed	LBAs/MPs ensure accuracy of LMM/LMR availability and Self-Scheduled values in MCS/DSRI Tools
	Increase STR Default if System-Wide or STR MSSC if North/Central or South Region	Implement LMRs if notified by MISO
Warning	Implement Emergency Pricing - Tier I	LBAs/TOPs provide potential exclusion of constrained pockets within the declaration area
	Send LBAs LMM survey	Affected GOPs communicate capacity-limited facilities to MISO and update Limits/Offers
	Raise transfer capability or make Constraint Stranded MW from generation available	TOPs coordinate with MISO RC to identify potential reconfiguration options
	Request MPs/LBAs ensure accuracy of LMM/ LMR availability and Self-Scheduled values	LBAs/MPs ensure accuracy of LMM/LMR availability and Self-Scheduled values in MCS/ DSRI Tools

Table 4: Maximum Generation Emergency Overview

Level	MISO Major Actions	Stakeholder Major Actions
Warning	Determine EDR availability and MW amounts	MPs update EDR availability and MW amounts
	Obtain updated MW amounts of relief available via Load Management Form in MCS	LBAs update LMM availability via Load Management Form in MCS
	Review LMR availability using MCS-LMR Tool	MPs ensure LMR availability data is correct in the DSRI Tool
	Schedule available Module E Resources into the declaration area	MPs schedule available Module E Resources into the declaration area
	Suspend CTS	
	Curtail Export Schedules as required	
	Notify affected GOPs with Generators de-rated due to environmental restrictions to request waivers from appropriate government agencies	Affected GOPs request waivers from the appropriate government agencies for Generators de-rated due to environmental restrictions
	Evaluate options for returning Transmission and Generation services	
	Instruct TOPs to implement reconfiguration options	As directed by MISO RC, implement reconfiguration options
	Commit AME Resources and Declare Event Step 1/EEA 1	As directed by MISO, LBAs/GOPs/MPs start AME Resources
Event Step 1/EEA1	Implement Emergency Pricing – Tier I, if not already completed in the Warning step	
	Declare EEA1	
	Activate Emergency Maximum Limits	MPs review Offers and ensure all available Emergency Ranges and Resources are offered

Event Step 2/EEA2	Declare EEA2	
	Implement Emergency Pricing - Tier II	
	Instruct Load to be reduced via LMMs - Stage 1 and LMRs	As directed by MISO, LBAs reduce Load via LMM - Stage 1
	Implement LMRs	MPs implement LMRs via DSRI Tool
	Commit EDR Resources	As directed by MISO, MPs commit EDRs
	Implement Emergency Energy purchases	
	Instruct LBAs to issue Public Appeals	LBAs issue public appeals to reduce demand per internal procedures and OE-417 filings
		LBAs in defined Event area shall prepare to shed Load
	Notify affected GOPs with de-rated Generators to implement waivers for dispatch	Affected GOPs implement waivers to dispatch de-rated Generators
	Implement Emergency Energy purchases from neighboring BAs (Operating Reserves)	
	Instruct Load to be reduced via LMMs – Stage 2	Affected LBAs reduce Load via LMM – Stage 2
	Implement spinning and supplemental reserves	
	Implement Reserve Call from CRSG	

Table 4: Maximum Generation Emergency Overview

Level	MISO Major Actions	Stakeholder Major Actions
Event Step 3/EEA3	Declare EEA3	
	Issue Emergency Operating Instruction to shed Load if Contingency Reserves are depleted or to recover ACE from loss of Generation	LBAs shed Load per MISO instructions and confirm action via MCS Firm Load Shed Tool
	Set LMPs and MCPs to the VOLL	LBAs review OE-417 filing requirements

Attachment 7 — UDS Operator Actions During a MISO Market Capacity Emergency

- If a North/Central declaration is in place and a South declaration is subsequently implemented, Increase STR Default Values.

SO-P-EOP-00-002 MISO Market Capacity Emergency - UDS Operator Actions								
		Increase STR RPE MSSC Default Values for **Zone 8** (South) if not done in previous declaration*	Increase STR RPE Default Values for **Non-Zone** (N/C) if not done in previous declaration*	Increase STR Default Values for System Current (**System-Wide**) if not done in previous declaration*	Implement Emergency Pricing **Tier I**	Activate **Emergency Limits**	Implement Emergency Pricing **Tier II**	Check **Is VOLL Price Enforced** in EMD
System-Wide Declaration Level	Capacity **Advisory**	■	■	■				
	Max Gen **Warning**	■	■	■	■			
	Max Gen **Event Step 1**	■	■	■	■	■		
	Max Gen **Event Step 2**	■	■	■		■	■	
	Max Gen **Event Step 3**	■	■	■		■	■	■
North/Central Declaration Level	Capacity **Advisory**		■					
	Max Gen **Warning**		■		■			
	Max Gen **Event Step 1**		■		■	■		
	Max Gen **Event Step 2**		■			■	■	
	Max Gen **Event Step 3**		■			■	■	■
South Declaration Level	Capacity **Advisory**	■						
	Max Gen **Warning**	■			■			
	Max Gen **Event Step 1**	■			■	■		
	Max Gen **Event Step 2**	■				■	■	
	Max Gen **Event Step 3**	■				■	■	■
Single Region (North or Central) Declaration Level	Capacity **Advisory**							
	Max Gen **Warning**				■			
	Max Gen **Event Step 1**				■	■		
	Max Gen **Event Step 2**					■	■	
	Max Gen **Event Step 3**					■	■	■

Figure 1: UDS Operator Actions During a MISO Market Capacity Emergency

Attachment 8 — Summary of Market Capacity Emergency Procedure Steps

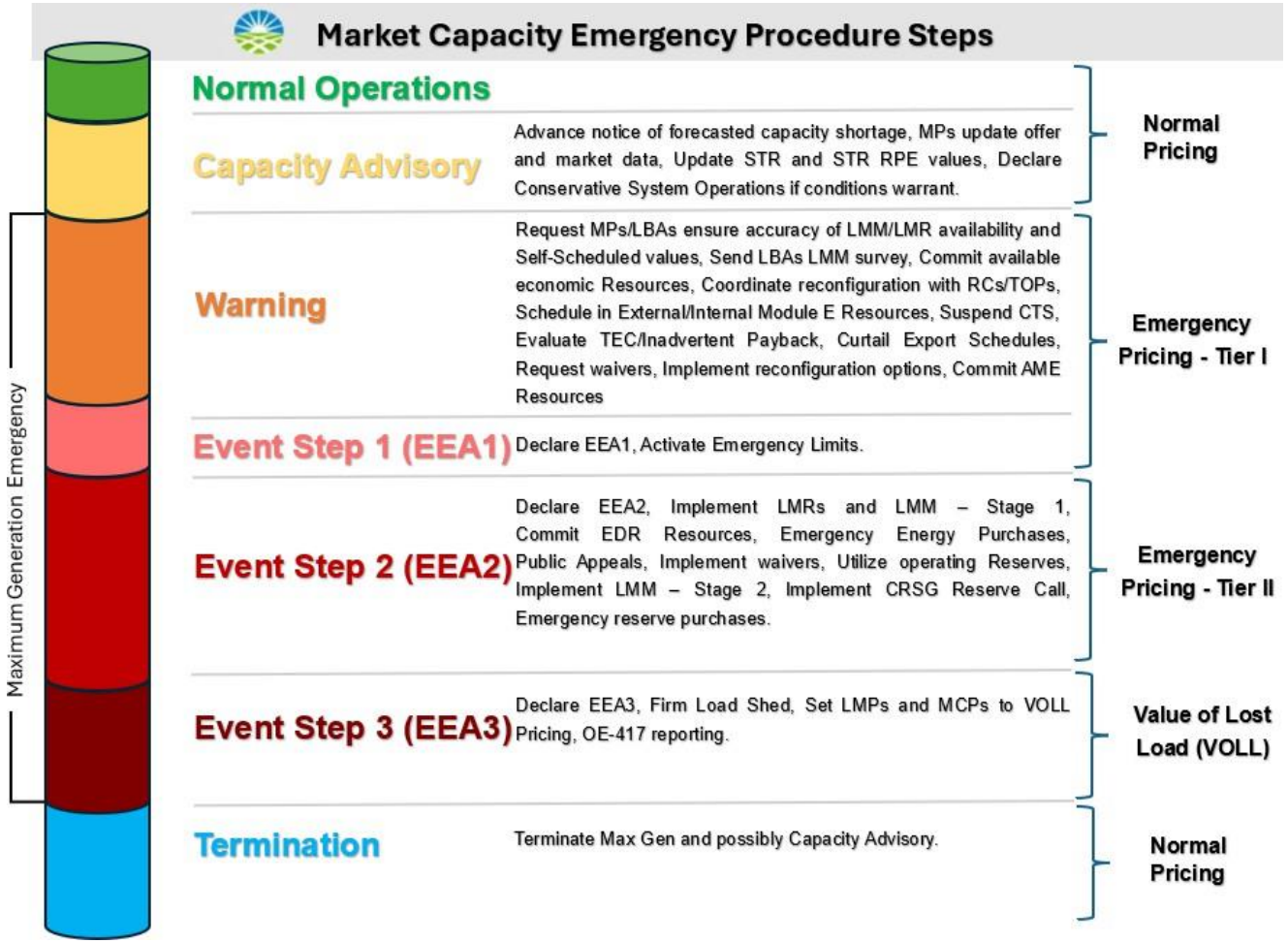


Figure 2: Market Capacity Emergency Procedure Steps

Attachment 9 — Market Capacity Emergency Checklist – MISO Actions

MCE CHECKLIST - MISO ACTIONS

4.1.1 Capacity Advisory

☐ Start_____End_____SM – **COMMUNICATE** Capacity Advisory declaration area boundaries, start time, and end time to MISO members via OI and RCIS. I**NFORM** UDS Operator for STR Default and RPE MSSC Overrides.

☐ Start_____ End_____ SM – **DECLARE** Conservative Operations if conditions warrant and not already declared.

☐ Start_____ End_____ SM – If a significant shortage of Operating Reserves is anticipated in any RAC process, THEN **DETERMINE** whether to issue LMR Scheduling Instructions in anticipation of a Max Gen Event Step 2.

☐ Start_____ End_____ UDS – **UPDATE** STR Default and/or RPE MSSC Overrides based on Capacity Advisory Region(s).

☐ Start_____ End_____ SM/ORA – **NOTIFY** DA and FRAC Operators when STR Default or RPE MSSC Overrides are updated.

4.2.2 Max Gen Warning

☐ Start_____End_____SM – **COMMUNICATE** Max Gen Warning declaration area boundaries, start time, and end time to MISO members via OI and RCIS.

☐ Start_____ End_____ UDS – **IMPLEMENT** Emergency Pricing - Tier I.

☐ Start_____ End_____ SM – **SEND** survey via MCS LMM Tool in the Load Management Tab to LBAs.

☐ Start_____ End_____ G&I – **COORDINATE** with MPs that have Module E Resources.

☐ Start_____ End_____ RC – **COORDINATE** with neighboring RCs and MISO TOPs to **RAISE** transfer capability into declaration area, make available Constraint Stranded MW from generation, review TLR activity, binding constraints, reconfiguration options, and use of short-term ratings.

☐ Start_____ End_____ SM – **REVIEW** EDR offers to determine EDR availability and MW amounts during the Warning period.

☐ Start_____ End_____ SM – **OBTAIN** updated LMM Stage 1 & 2 MW amounts of relief available during the effective Warning period by LBA from MCS.

☐ Start_____ End_____ SM – **REVIEW** LMR availability in MCS-LMR Tool for the declaration period.

☐ Start_____ End_____ SM/BAO – SM **DIRECT** BAO to **TERMINATE** Inadvertent Payback and Time Error Correction if required to assist system conditions.

☐ Start_____End_____SM – **SEND** OI message to MPs to **SCHEDULE** remaining available External and Internal Module E Registered Capacity Resources that would be deliverable to the Warning area.

☐ Start_____ End_____ SM/GI – **COORDINATE** to notify MPs to **SCHEDULE** Module E Resources into the MBAA declaration area.

☐ Start_____ End_____ G&I – **NOTIFY** SM of forecasted changes in MBAA NSI due to loss of imports.

☐ Start_____ End_____ G&I – **MODIFY** webTrans E-tag validation mode to reflect Max Gen in the affected area per SO-I-EOP-00-006 Interchange Scheduling Operations during Emergency Conditions.

☐ Start_____ End_____ G&I – **COORDINATE** to determine the amount of non-firm and firm Export Schedules to curtail per SO-I-EOP-00-006 Interchange Scheduling Operations during Emergency Conditions.

☐ Start_____ End_____ G&I – **CURTAIL** Export Schedules from the declaration area in amounts required to relieve shortage conditions.

☐ Start_____ End_____ SM – **NOTIFY** GOPs via OI in the declaration area with Generators de-rated due to environmental restrictions to **REQUEST** waivers from appropriate government agencies if forecasts show probable escalation to Max Gen Event Step 2.

☐ Start_____ End_____ RC – **NOTIFY** TOPs to **IMPLEMENT** reconfiguration options agreed upon to raise transfer capability into the declaration area or make available constraint stranded MW from generation.

☐ Start_____ End_____ G&I – **SUSPEND** Coordinated Transaction Scheduling (CTS) for the duration of the Capacity Emergency per SO-I-AOP-00-224 CTS Failure Modes.

☐ Start_____ End_____ SM/IRAC – **COMMIT** AME designated resources AND **DECLARE** Max Gen Event Step 1 and EEA1.

4.2.3 Max Gen Event Step 1/EEA1

☐ Start_____ End_____ SM – **COMMUNICATE** Max Gen Event Step 1/EEA1 declaration area boundaries, start time, and end time to MISO members via OI and RCIS.

☐ Start_____ End_____ SM – **NOTIFY** Director On-Call to implement SO-P-AOP-00-217 MISO and State Officials 24x7 Communication Protocols During Emergencies.

☐ Start_____ End_____ UDS – **IMPLEMENT** Emergency Pricing - Tier I in EMD, if not already implemented.

☐ Start_____ End_____ IRAC – **ENSURE** Emergency Ranges are pushed in EMD.

☐ Start_____ End_____ UDS – **ACTIVATE** Emergency Maximum Limits in EMD , excluding units providing Regulation.

☐ Start_____ End_____ SM – If increasing load forecasts continue to result in negative Reserve Margin after all resources are committed and dispatched into Emergency Ranges, THEN **PREPARE** to move to Max Gen Event Step 2 and EEA2.

4.2.4 Max Gen Event Step 2/EEA2

☐ Start_____ End_____ SM – **COMMUNICATE** Max Gen Event Step 2/EEA2 declaration area boundaries, start time, and end time to MISO members via OI and RCIS.

☐ Start_____ End_____ UDS – **IMPLEMENT** Emergency Pricing - Tier II in EMD.

☐ Start_____ End_____ SM – If Manitoba Hydro (MHEB) is in an EEA concurrently with MISO's EEA2 or higher, THEN **PERFORM** SO-I-NOP-00-481 MISO-Manitoba Hydro Concurrent EEA.

☐ Start_____ End_____ SM – **NOTIFY** LBAs of required Load reduction via LMM – Stage 1 and LMRs in MW amounts via MCS.

☐ Start_____ End_____ SM – **COORDINATE** with MPs on implementing LMRs.

☐ Start_____ End_____ SM – **DETERMINE** OE-417 reporting responsibilities per SO-P-NOP-04 MISO Event Reporting Operations Plan.

☐ Start_____ End_____ SM – **ENSURE** required notifications are performed per SO-I-NOP-00-448 Event Communications Matrix.

☐ Start_____ End_____ SM – **COMMIT** EDR resources, in merit order, to alleviate capacity shortages within the declaration area per SO-I-NOP-00-404 Emergency Demand Response Implementation.

☐ Start_____ End_____ SM – **COORDINATE** with neighboring RCs and BAs to determine Emergency Energy available from external sources, either through interruptible firm Load or through Emergency Energy purchases.

☐ Start_____ End_____ SM/G&I – **IMPLEMENT** Emergency Energy purchases from neighboring BAs to conserve Operating Reserves per SO-I-NOP-00-479 Purchasing and Selling Emergency Energy.

☐ Start_____ End_____ SM – **EVALUATE** opportunities to reduce internal energy usage, such as sending non-essential personnel home, reducing lighting that is non-essential for personnel safety, and reducing large electrical Loads.

☐ Start_____ End_____ SM – **INSTRUCT** LBAs in the declaration area to **ISSUE** public appeals to reduce demand per their internal procedures.

☐ Start_____ End_____ SM – **NOTIFY** GOPs via OI in the declaration area with Generators de-rated due to environmental restrictions to implement waivers from the appropriate government agencies.

☐ Start_____ End_____ SM – **NOTIFY** LBAs, via MCS, of required Load reduction via LMM - Stage 2 in MW of interruptible demands.

☐ Start_____ End_____ RC – **COORDINATE** with neighboring RCs and BAs to identify additional available Emergency Energy, including their Operating Reserves.

☐ Start_____ End_____ G&I – SM/G&I – **IMPLEMENT** Emergency Energy purchases of neighboring BAs Operating Reserves if available.

☐ Start_____ End_____ BAO – **IMPLEMENT** the use of MISO's Spinning and Supplemental Reserves, as needed and as time permits.

☐ Start_____ End_____ SM – If Contingency Reserves fall below MSSC for greater than 30 minutes and NO reasonable actions exist to restore them in 90 minutes, THEN **DECLARE** EEA3.

☐ Start_____ End_____ BAO – **IMPLEMENT** a Reserve Call from Contingency Reserve Sharing Group (CRSG), utilizing MHEB's available Contingency Reserves.

☐ Start_____ End_____ SM/IRAC – **EVALUATE** excluding Regulating Units that have room between Reg Max and Emergency Max from clearing Regulation, while **ENSURING** enough Regulating Reserve is available to avoid firm Load shed for normal ACE deviations.

4.2.5 Max Gen Event Step 3/EEA3

☐ Start_____ End_____ SM - **COMMUNICATE** Max Gen Event Step 3/EEA3 declaration area boundaries, start time and end time to MISO members via OI and RCIS.

☐ Start_____ End_____ SM – **DETERMINE** manual Load Shedding requirements based on increasing Load or potential loss of MSSC and ability to recover ACE. **ENSURE** Load Shed points are known and members are prepared to execute Load Shed when Contingency Reserves are depleted and Load continues to increase or ACE recovery from generation loss is only possible through Load Shed.

☐ Start_____ End_____ SM – **ISSUE** Emergency Operating Instructions to LBAs in the declaration area for MW amounts of Load to shed via the MCS Firm Load Shed Tool or verbally per SO-P-NOP-10-431 Communications Protocol for Operating Instructions.

☐ Start_____ End_____ UDS – When notified by SM, in the EMD UDS tab, **CHECK** the appropriate box(es) in the column titled “Is Voll Price Enforce” for the applicable LBAs. **SAVE** updates.

☐ Start_____ End _____ SM – If firm Load Shed is greater than 100MW, THEN **DETERMINE** OE-417 reporting responsibilities per SO-P-NOP-04 MISO Event Reporting Operations Plan.

☐ Start_____ End_____ SM – **ENSURE** required notifications are performed per SO-I-NOP-00-448 Event Communications Matrix.

4.2.6 Max Gen Event Downgrade/Termination

☐ Start_____ End_____ SM – When actual obligations return below total MISO capability, then Downgrade/Terminate Max Gen Event by reversing the order of entry into each step.

Attachment 10 — Market Capacity Emergency Checklist – Member Actions

MCE CHECKLIST - MEMBER ACTIONS

4.1.2 Capacity Advisory

☐ Start_____ End_____ LBA/TOP/GOP/MP - WHEN notified by MISO, THEN **ENSURE** all market data is updated with the best available information for the operating day(s).

- Facility and generation availability, outages, and de-rates
- Generation Offers, including any changes to reflect fuel availability
- Fuel supply and inventory concerns
- Fuel switching capabilities
- Environmental constraints
- Load forecast Values
- LMR Availability in the DSRI Tool
- Voluntary Load Management information
- Load Management Measures (LMM) and any Voluntary Load Management in the MCS
- Emergency Demand Response (EDR) offers

☐ Start_____ End_____ MP - IF notified by MISO, THEN **IMPLEMENT** LMRs.

☐ Start_____ End_____ LBA/TOP/GOP – **FOLLOW** MISO's SO-P-NOP-00-449 Conservative System Operations procedure, if declared.

4.3.1 Max Gen Warning

☐ Start_____ End_____ LBA/TOP – **DETERMINE** potential exclusions of constrained pockets within the declaration area where there is expected to be adequate generation that may NOT be transferred to other parts of the declaration area due to local constraints.

☐ Start_____ End_____ TOP – **INFORM** MISO RC of identified constrained areas from previous step.

☐ Start_____ End_____ GOP – If generators are de-rated, then **INFORM** LBAs, TOPs, and the MISO G&I Operator of capacity-limited facilities.

☐ Start_____ End_____ MP – **ENSURE** accuracy of LMR availability and Self-Scheduled/Voluntary Load Management LMRs in the DSRI Tool.

☐ Start_____ End_____ LBA – **ENSURE** accuracy of Non-LMR Voluntary Load Management/ Self-Scheduled LMM information in the MCS-LMR Tool.

☐ Start_____ End_____ TOP – **COORDINATE** with the MISO RC to determine reconfiguration options to raise transfer capability to declaration area or make available Constraint Stranded MW from generation in the declaration area.

☐ Start_____ End_____ LBA – Based on Load Shed methodology, **PREPARE** for potential Load Shed during an Event stage.

☐ Start_____ End_____ MP – **UPDATE** EDR offers for availability and MW amounts for the declaration period.

☐ Start_____ End_____ LBA – **SUBMIT** LMM availability via MCS per Attachment 3 — Load Management Update Form Example.

☐ Start_____End_____MP – **ENSURE** accuracy of registered LMR availability in the DSRI Tool.

☐ Start_____ End_____ MP – **SCHEDULE** remaining available External and Internal Resources (Module E Registered Capacity Resources) that are deliverable to the declaration area.

☐ Start_____ End_____ LBA – **NOTIFY** Interruptible Loads of potential interruption.

☐ Start_____ End_____ GOP – **REQUEST** waivers for de-rated Generators from government agencies as directed by MISO.

☐ Start_____ End_____ TOP – **IMPLEMENT** agreed upon reconfiguration options to raise transfer capability into the declaration area or make available Constraint Stranded MW from generation in the declaration area.

☐ Start_____ End_____ GOP – WHEN notified by MISO, THEN **START** applicable off-line AME Generation Resources.

4.3.2 Max Gen Event Step 1/EEA1

☐ Start_____ End_____ GOP – WHEN Resources are dispatched, THEN **ENSURE** Resources move into Emergency Ranges.

☐ Start_____ End_____ GOP – **ENSURE** all co-generation and independent power producers are at maximum output and availability.

☐ Start_____ End_____ GOP – IF additional reliable capacity is available (such as adding additional mills, duct burners, etc.), THEN **COORDINATE** adjustments with the MISO G&I Operator

.

4.3.3 Max Gen Event Step 2/EEA2

☐ Start_____ End_____ LBA – IF in the declaration area and notified by MISO to reduce Load via LMM – Stage 1, THEN **REDUCE** load via LMM – Stage 1. WHEN Load reduction actions have been implemented, THEN **NOTIFY** MISO.

☐ Start_____ End_____ MP – WHEN notified by MISO, THEN **IMPLEMENT** LMRs.

☐ Start_____ End_____ MP – WHEN notified by MISO, THEN **COMMIT** EDR Resources.

☐ Start_____ End_____ LBA – WHEN instructed by MISO, THEN **ISSUE** public appeals to reduce demand per internal procedures.

☐ Start_____ End_____ LBA – **EVALUATE** opportunities to reduce internal energy usage, such as sending non-essential personnel home, reducing lighting that is non-essential for personnel safety, and reducing large electrical Loads.

☐ Start_____ End_____ LBA – IF in the declaration area, THEN **PREPARE** to shed load.

☐ Start_____ End_____ GOP – IF requested by MISO to dispatch available capacity, THEN **VERIFY** Generators in the declaration area with de-rates from environmental restrictions AND IF approved waiver from government regulations, THEN **DISPATCH** available generation.

☐ Start_____ End_____ LBA – IF in the declaration area and notified by MISO to reduce Load via LMM – Stage 2, THEN **REDUCE** Load via LMM – Stage 2. WHEN Load reduction actions have been implemented, THEN **NOTIFY** MISO via MCS.

☐ Start_____ End_____ GOP/MP – **REVIEW** Offers, **ENSURE** all available Emergency Ranges and Resources are offered. IF there are available Resources or capacity NOT being utilized, THEN **NOTIFY** the MISO G&I Operator.

4.3.4 Max Gen Event Step 3/EEA3

☐ Start_____ End_____ LBA – **SHED** firm Loads per MISO issued Emergency Operating Instruction.

☐ Start_____ End_____ LBA – **CONFIRM** actions taken with the MISO RC via the MCS Firm Load Shed Tool or verbally per SO-P-NOP-10-431 Communications Protocol for Operating Instructions.

☐ Start_____ End_____ LBA – IF requested by MISO during Event Step 3, THEN **COMPLETE** Department of Energy (DOE) Form OE-417.

4.3.5 Max Gen Event Downgrade/Termination

☐ Start_____ End_____ LBA/MP/TOP/GOP – **PERFORM** requests of MISO SM or designee to back out of each level.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 193

MISO Seasonal Readiness Workshop Summer 2026



Seasonal Readiness Workshop: Summer 2026

May 6, 2026

Agenda

1. **Welcome** – JT Smith, Executive Director, MISO System Operations
2. **Seasonal Assessments**
   - Weather – Adam Simkowski/Ella Dankanics, MISO Meteorologists
   - Generation – Andy Taylor, Manager, MISO Resource Adequacy
   - Transmission – Fisseha Zewdu, Sr. Engineer, MISO Operations Planning
3. **Seasonal Risk / Uncertainty Management** – Matt Campbell, Manager, Operations Risk Assessment
4. **Emergency Procedure & Technical Training Updates**
   - Capacity Emergency Changes – Don Hunter, Manager, MISO Control Room Operations
   - 202(c) Emergency Orders – Don Hunter, Manager, MISO Control Room Operations
   - Transmission System Emergency Procedure Updates– Clayton Umlor, Manager, MISO Reliability Coordination
   - Technical Development – Anita Hurst, Sr. Manager, MISO Technical Development
5. **Q&A**

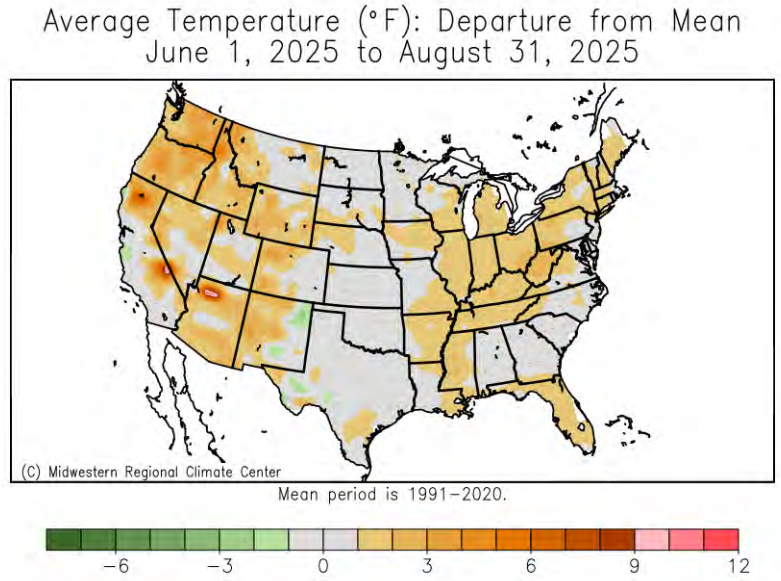


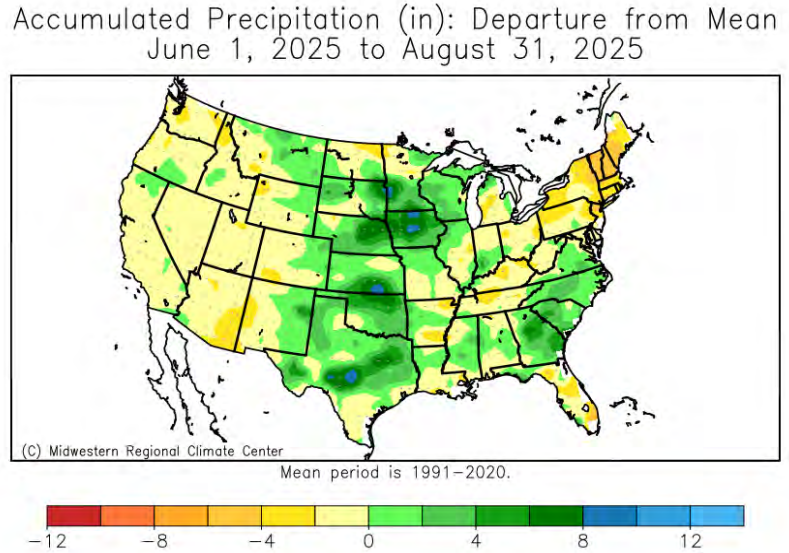
Seasonal Assessment: Weather

Adam Simkowski and Ella Dankanics, MISO Meteorologists

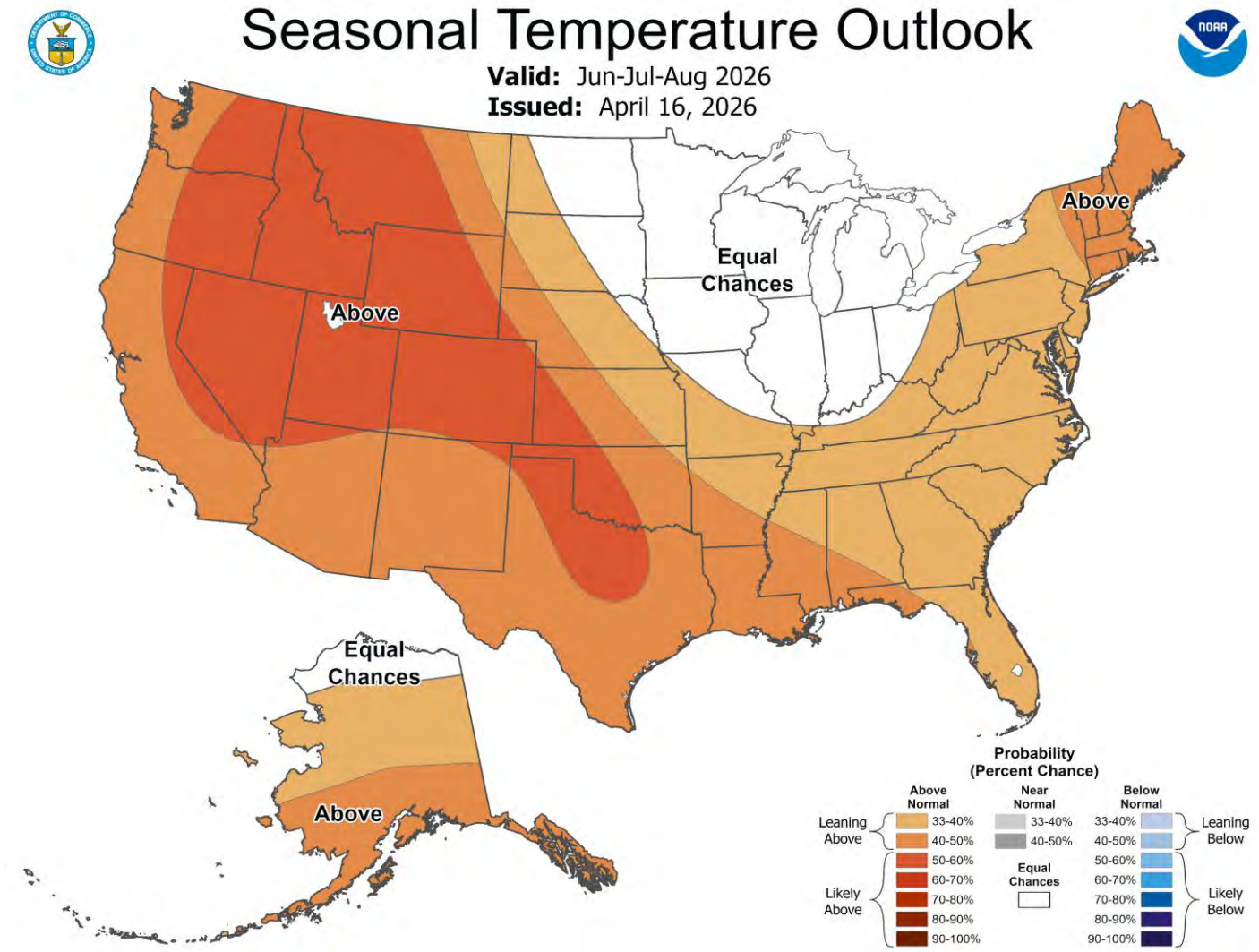
Despite Above Normal Precipitation, La Niña Drove Above Normal Temperatures Across MISO's Footprint

- Last summer, we experienced:
- Above normal temperatures across the North/Central Region
- Slightly above normal temperatures in the South Region
- There were 6 days recorded above 90°F Systemwide temperature
- Near to slightly above normal precipitation was observed across much of the MISO footprint

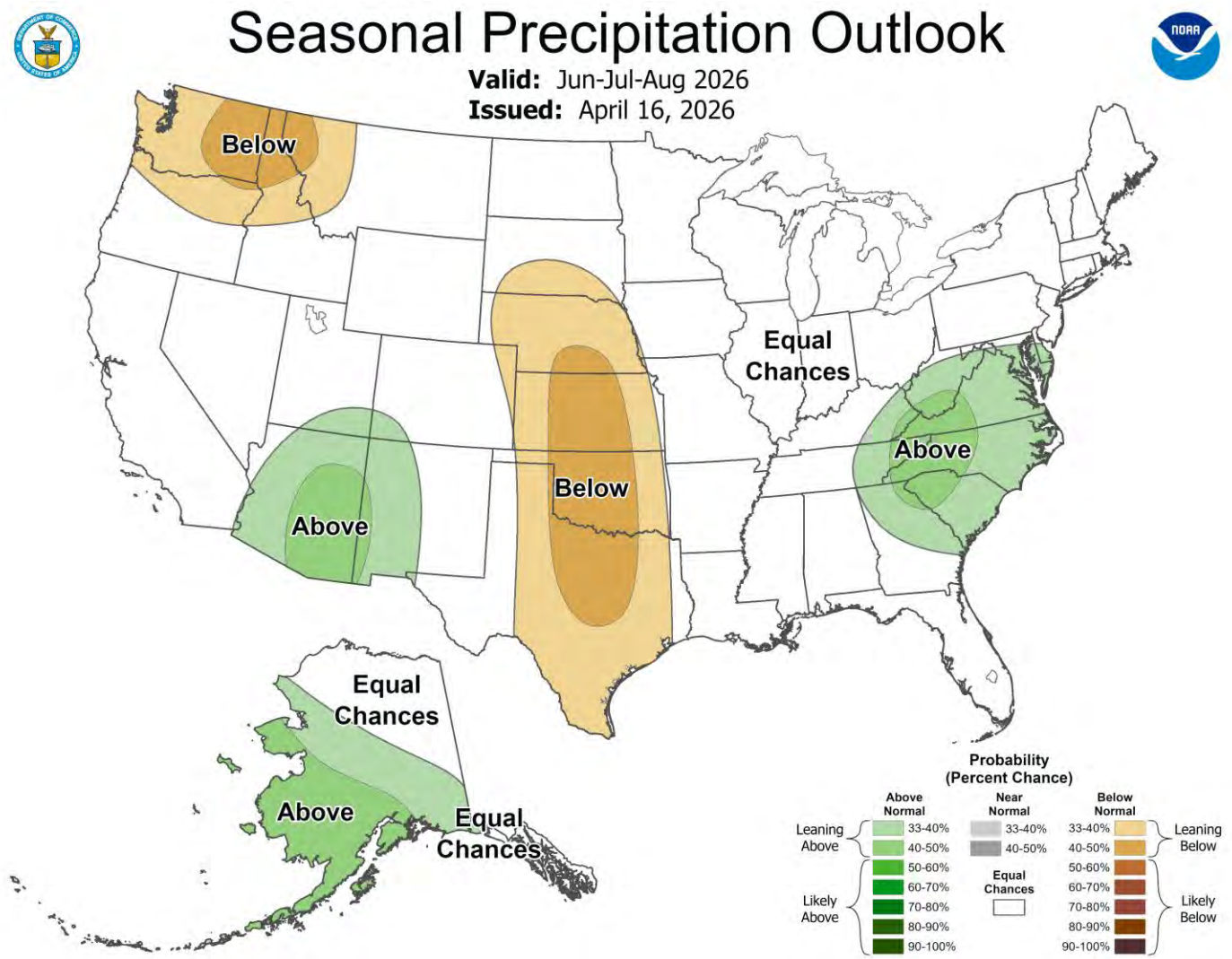




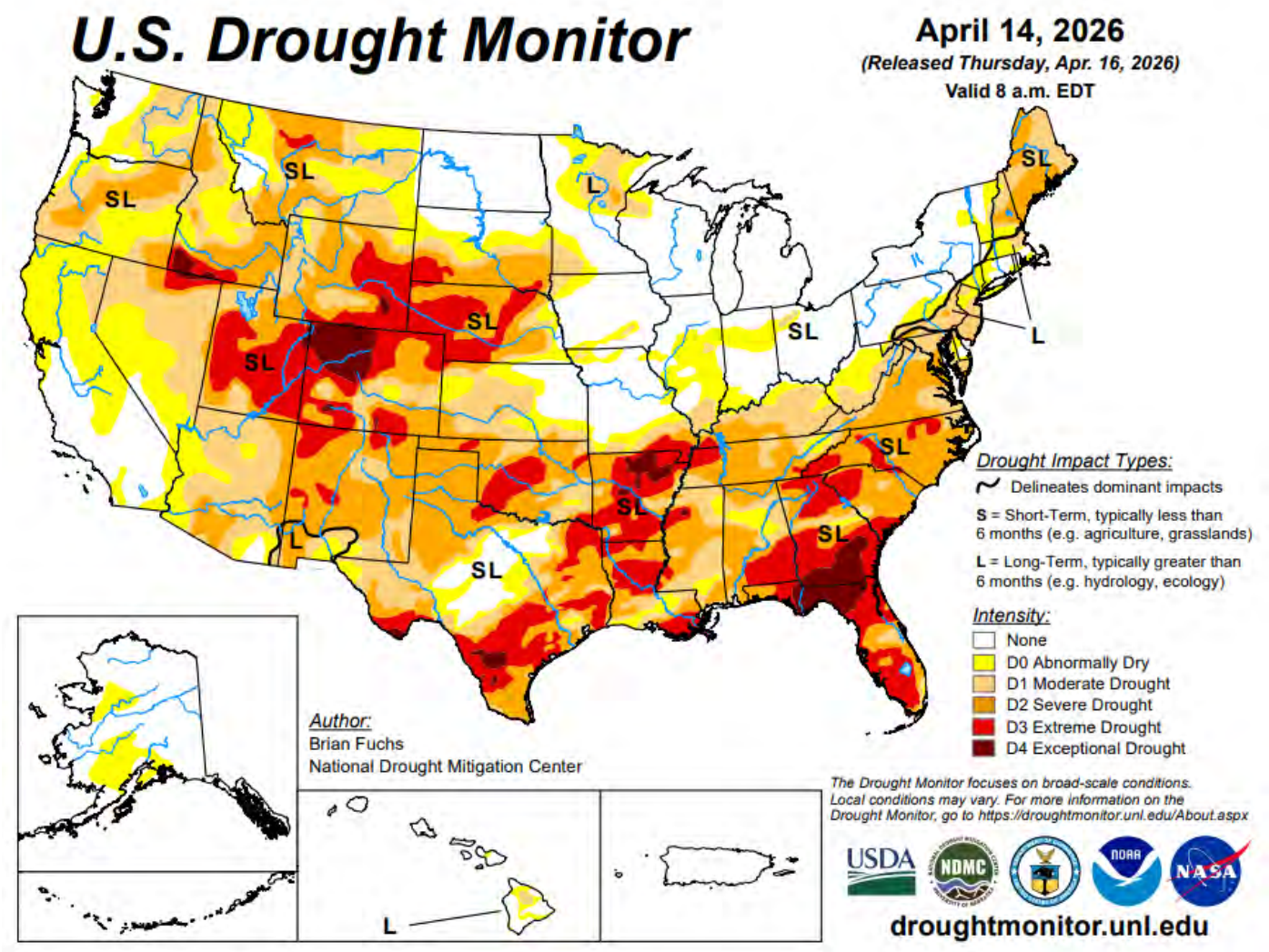
NOAA is forecasting above normal temperatures for June through August in MISO's South Region with near normal temperatures across MISO's North/Central Region holding the core of the heat in the intermountain West



NOAA anticipates normal precipitation rates across the majority of MISO's footprint



US drought conditions will need to be monitored as pervasive drought can exacerbate heat concerns over MISO footprint



Circled years are the best historical analog (reference) years to this upcoming summer

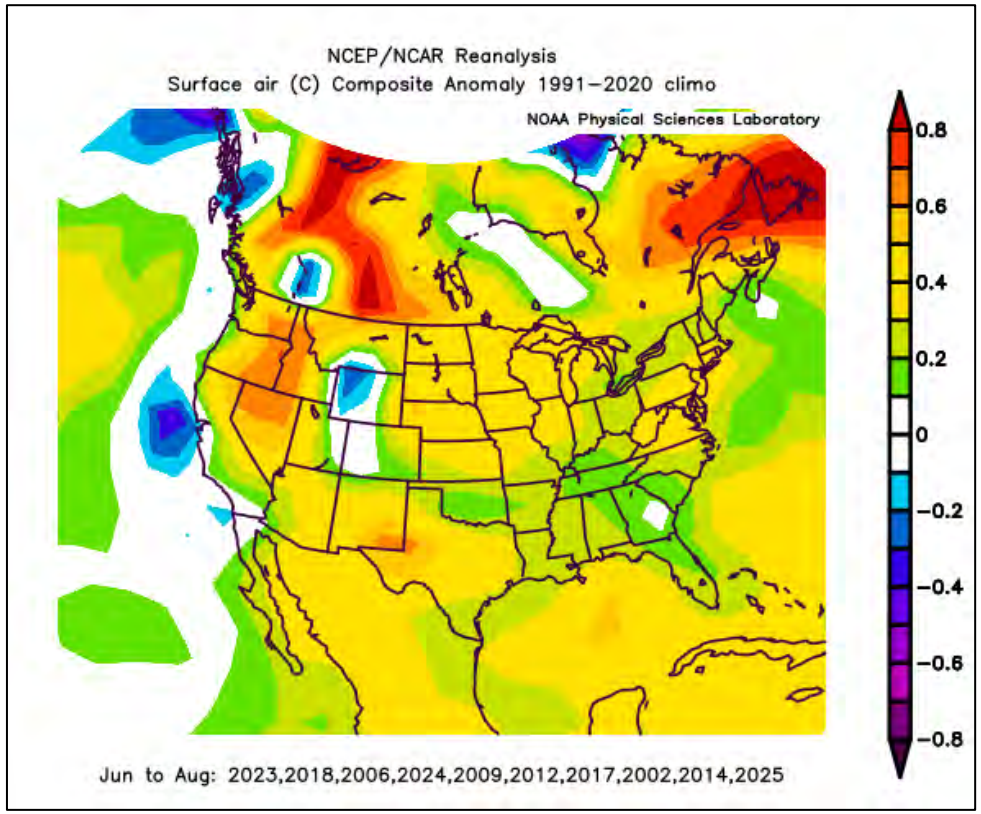
Analog years for Summer 2026

Year(s)	Vendor A	Vendor A Rank	Vendor B	Vendor B Rank
	2023	1	2015	1
	2018	2	2023	2
	2006	3	2009	3
	2024	4	1951	4
	2009	5	1997	5
	2012	6	2006	6
	2017	7	2002	7
	2002	8	1963	8
	2014	9	2012	9
	2025	10	1991	10

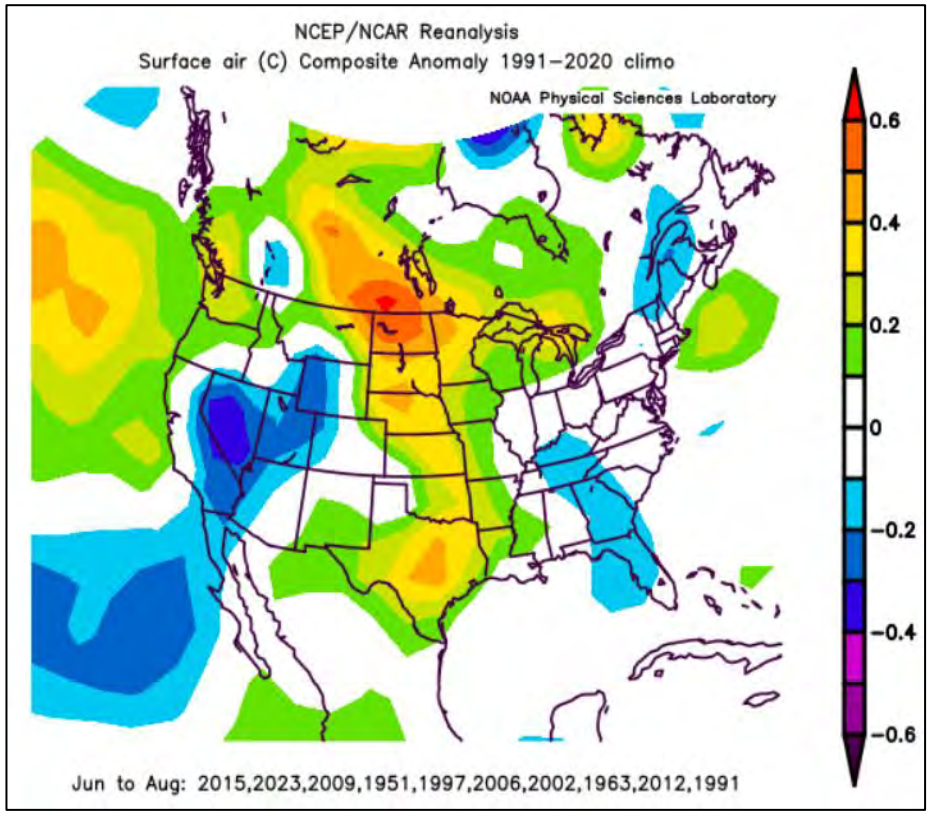
Cool MISO Summer
Warm MISO Summer
Normal MISO Summer

While both vendors' analog year selections favor heat across MISO's footprint, their selections were created in late winter with more El Niño uncertainty. With high certainty of El Niño now, top analog years are under-weighted in the images below.

Vendor A

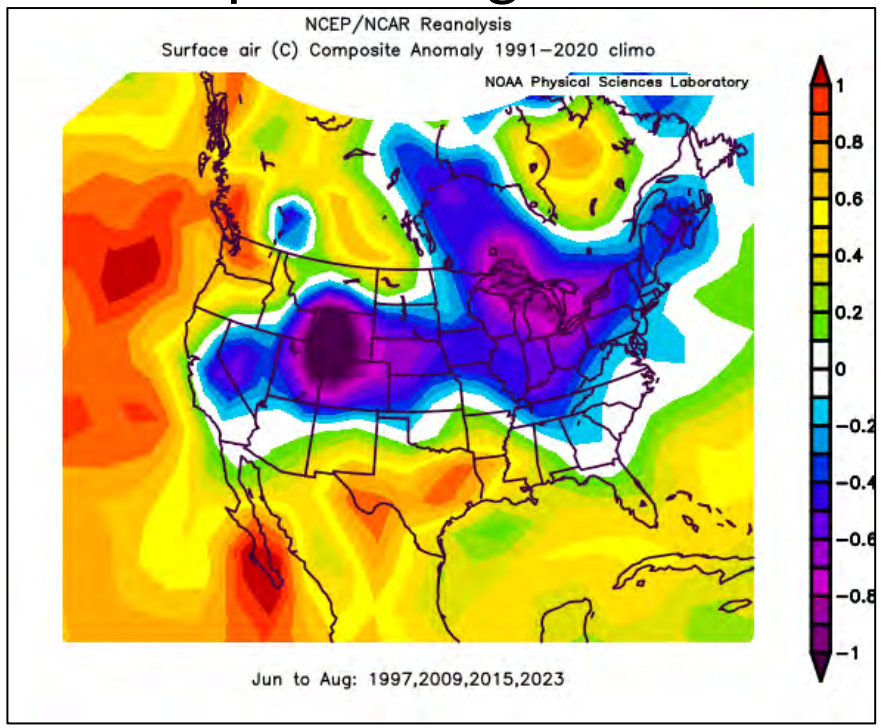


Vendor B



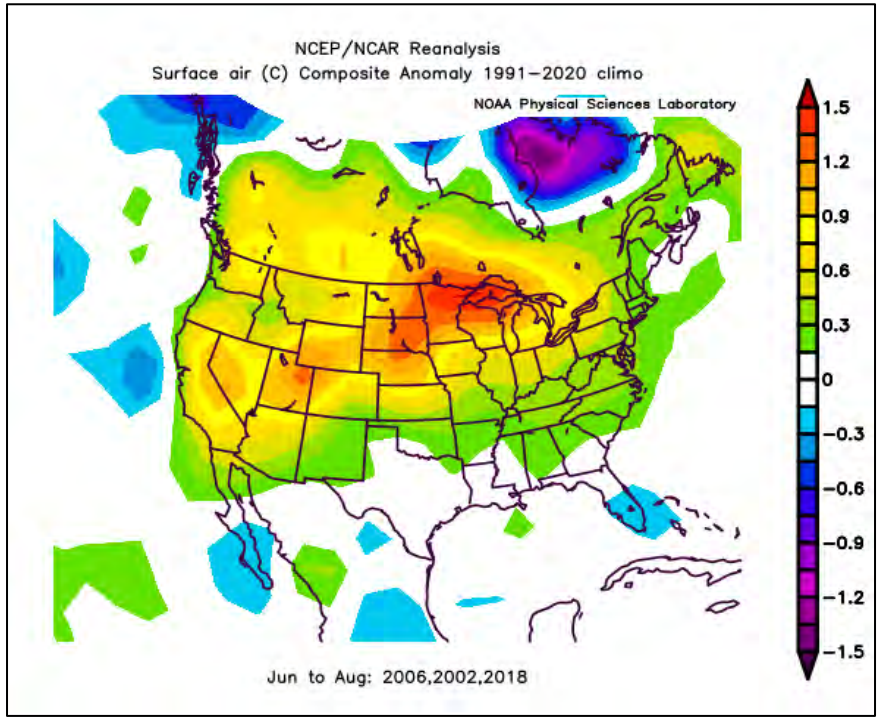
MISO's analysis of historical analog years from each vendor support a cooler to average summer for MISO's North/Central Region, but there is a higher likelihood for above normal temperatures in MISO's South Region

Top 4 Analog Years



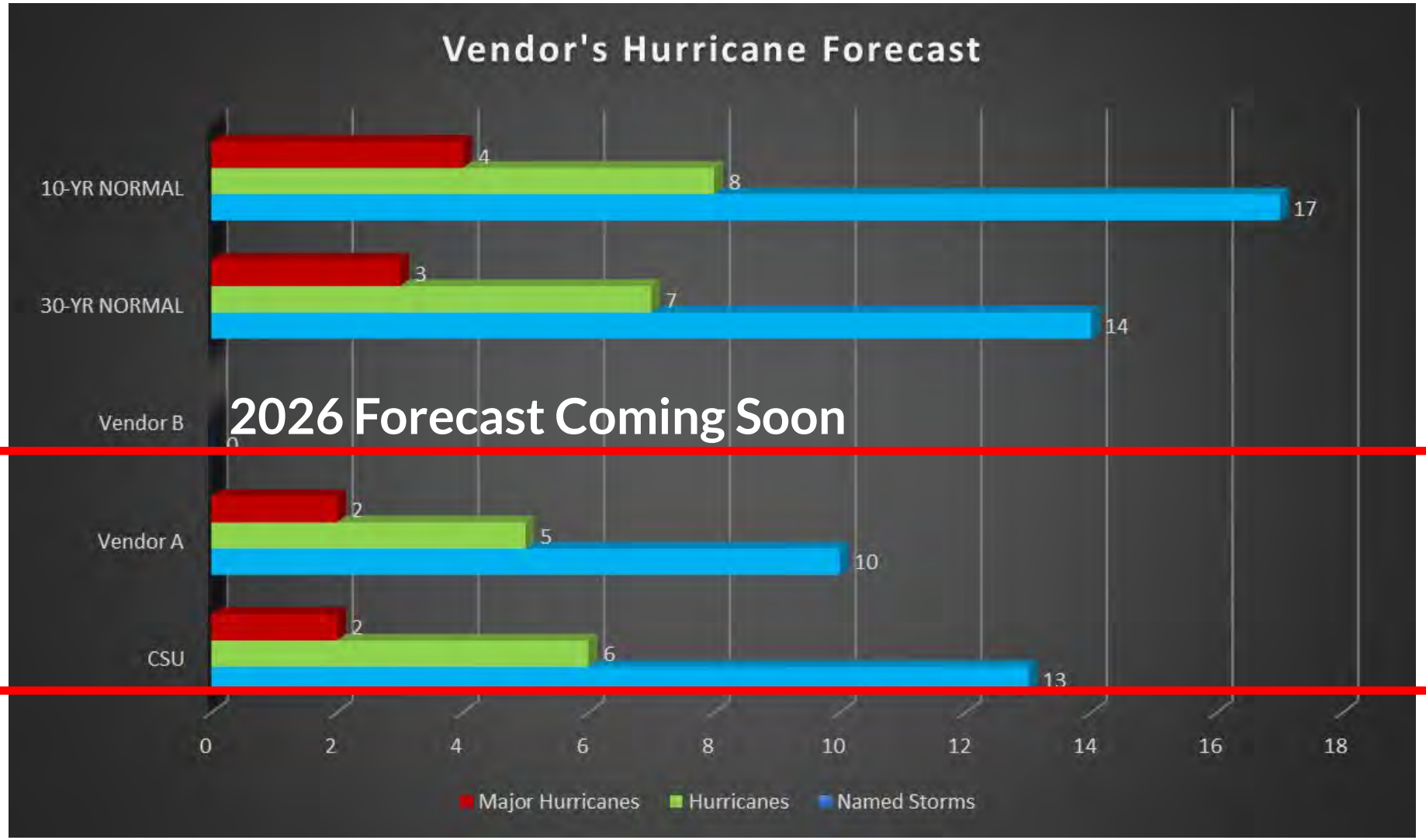
- More likely scenario
- Good agreement with vendors forecast on TX/LA heat

Top 3 Warm Analog Years

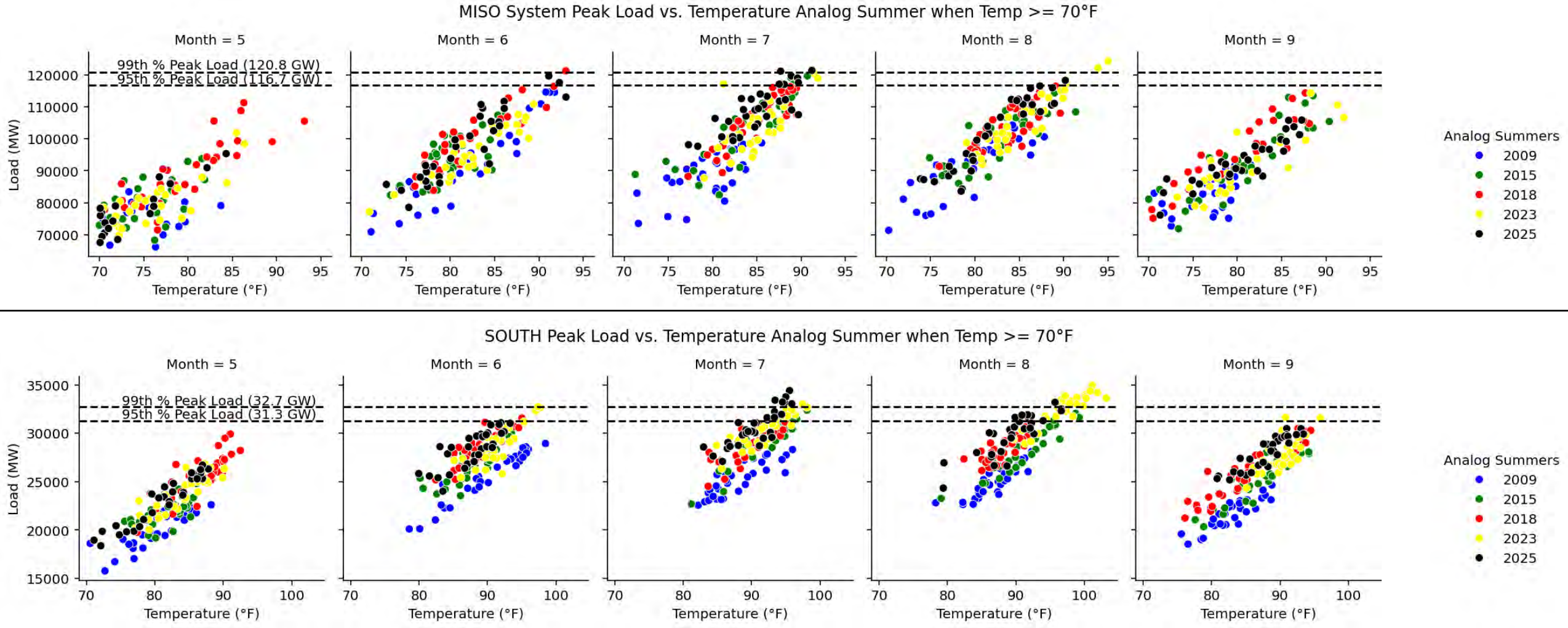


- Less likely scenario
- Heat extends from the intermountain west to MISO North/Central Region

A slightly below normal hurricane season is expected from all vendors; threats to MISO are best evaluated in a two-week forecast window

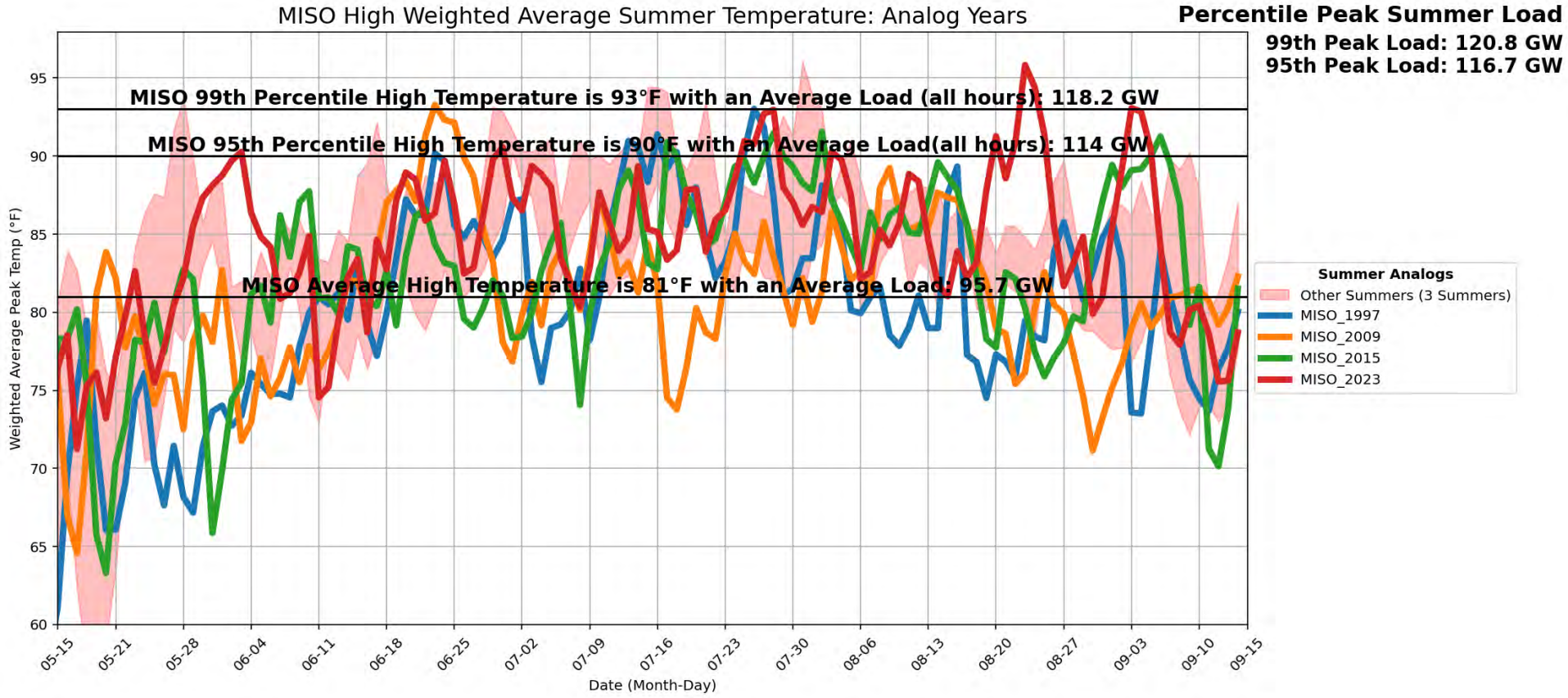


Systemwide, comparing top analog years to last year and lower match 2018, top analog years contain minimal hours reaching 99th percentile peak load. TX/LA heat did bring South load at/above 99th percentile in top years

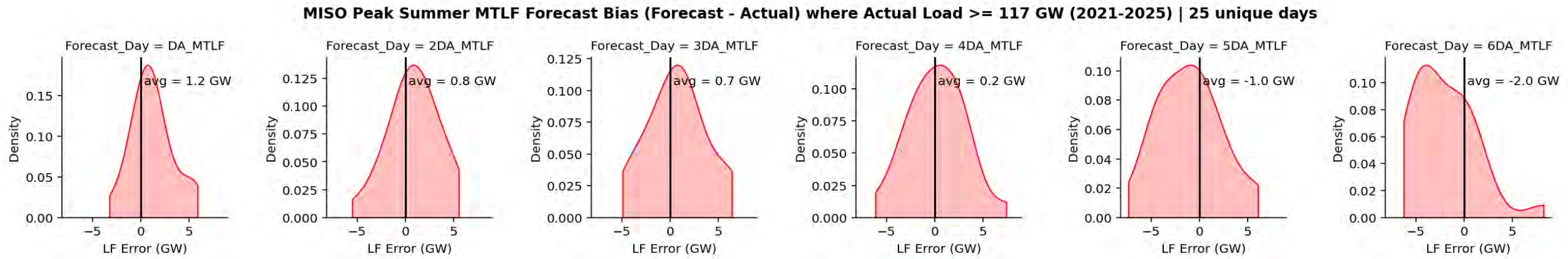


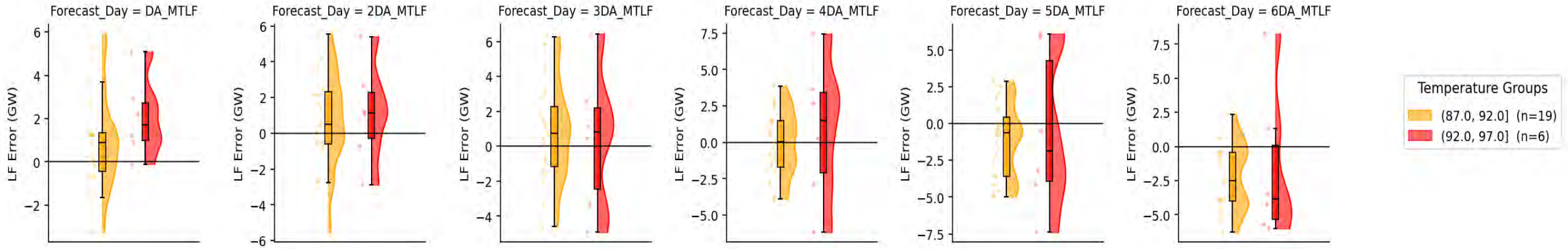
Key analog summers saw daily peak temperatures above the 95th percentile high temperature threshold, but few periods at 99th percentile high temperature threshold

The top analog year (2023) had major MISO heatwave reaching above the 99th percentile average load threshold driven by TX/LA heat dome



Summer peak load forecast bias is positive at DA and 2-DA primarily due to storm risks where peak load >= 95th percentile (117 GW)





Adam and Ella's Opinion

- While normal to below normal summer is expected in the North/Central, heat waves will be more likely and confined to the South region, especially if drought conditions persist.
- 2023 being the top analog had a similar orientation to this year's expectations. In August of that year, the South heat dome expanded north encompassing MISO's footprint producing our all-time peak load (not reconstituted). We'll monitor that risk closely this summer with El Niño strength.
- Solar growth will continue throughout the summer. Wind generation is forecast to be **below normal** and risks around the **daily cycle** (AM ramp down, PM ramp up) with ample solar will produce challenging Net Load ramps.
- With warm ocean waters over the Caribbean and Gulf, risks for 'homegrown' storms will have to be monitored closely despite a projected below normal season.

Summary

- A normal to slightly below normal summer is expected in the North/Central region with above normal temperatures in MISO South.
- Despite cooler signals for the Midwest and Plains, with heat more likely in the southern Plains and Gulf Coast, heat can expand northward periodically.
- Monitoring the development and strength of El Niño will provide confidence on both the cooler North/Central signal and lower tropical development potential.
- A near to slightly-below-normal hurricane season is expected in the Atlantic Basin this hurricane season.

Contact: Adam Simkowski, asimkowski@misoenergy.org
Ella Dankanics, edankanics@misoenergy.org



Seasonal Assessment: Generation

Andy Taylor, Manager, MISO Resource Adequacy

Seasonal Capacity Outlook – Summer 2026

LRZ	Price ($/MW-Day)
1-7	$424.30
8,10	$384.10
9	$412.10

Initial PRMR	ZRC Offered + FRAP	Final PRMR
137,922.8	142,553.1	142,374.3

- Implementation of the Reliability-Based Demand Curve has resulted in significant value for capacity beyond the 1-in-10 LOLE Requirement.
- Initial PRMR represents the traditional 1-in-10 LOLE Requirement.
- 4,451.5 ZRCs cleared beyond the 1-in-10 LOLE Requirement, resulting in the Final PRMR noted above.

Planning Resource	Offered (ZRC)	Cleared (ZRC)
Generation	124,690.1	124,511.3
External Resources	4,490.6	4,490.6
Behind the Meter Generation	4,272.9	4,272.9
Demand Resources	9,099.5	9,099.5
Energy Efficiency	0.0	0.0
Total	**142,553.1**	**142,374.3**

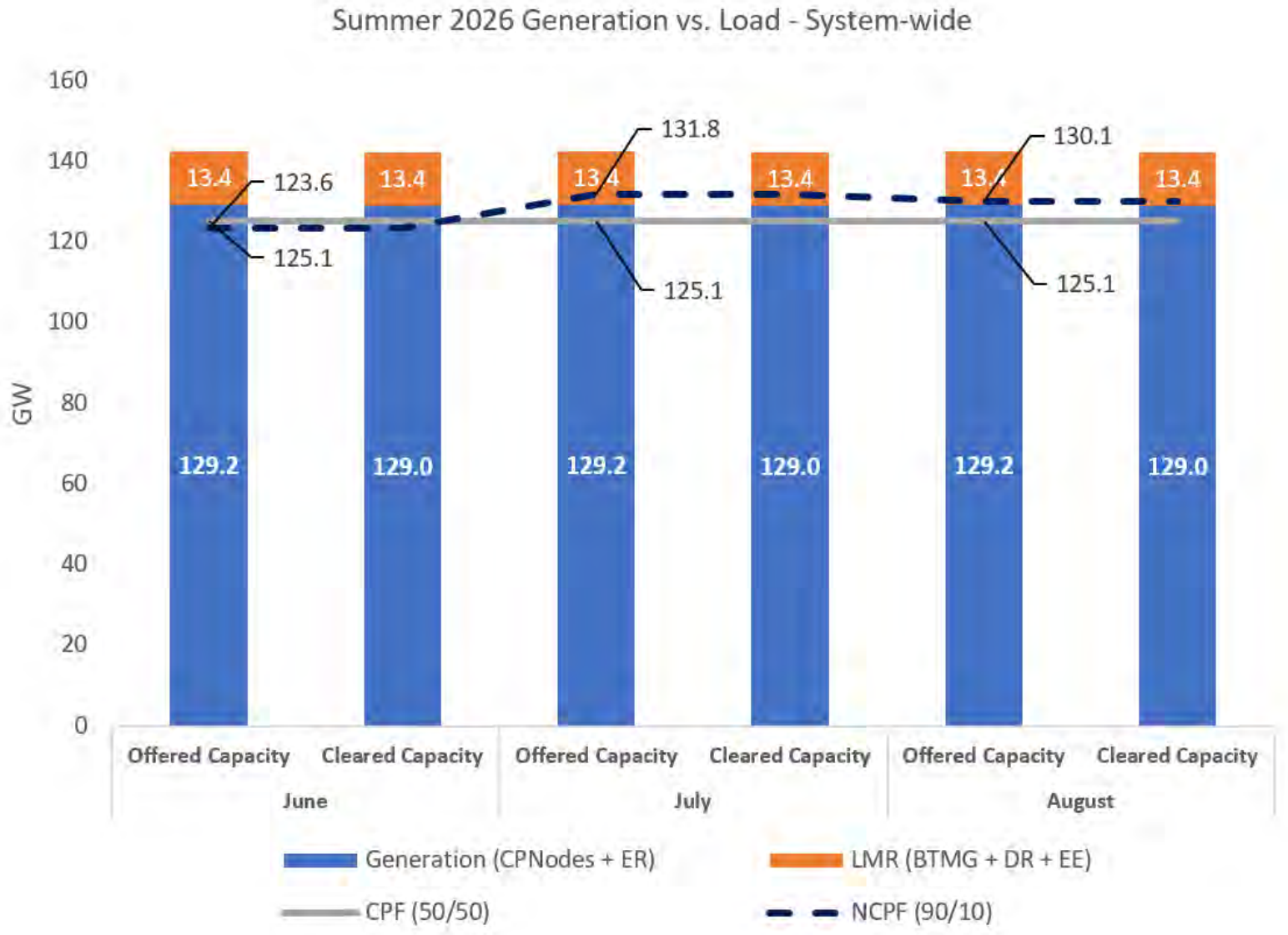
LRZ: Local Resource Zone PRMR: Planning Reserve Margin Requirement ZRC: Zonal Resource Credit FRAP: Fixed Resource Adequacy Plan

RBDC: Reliability-Based Demand Curve LOLE: Loss of Load Expectation

MISO systemwide accredited capacity compared to demand submitted by LSEs

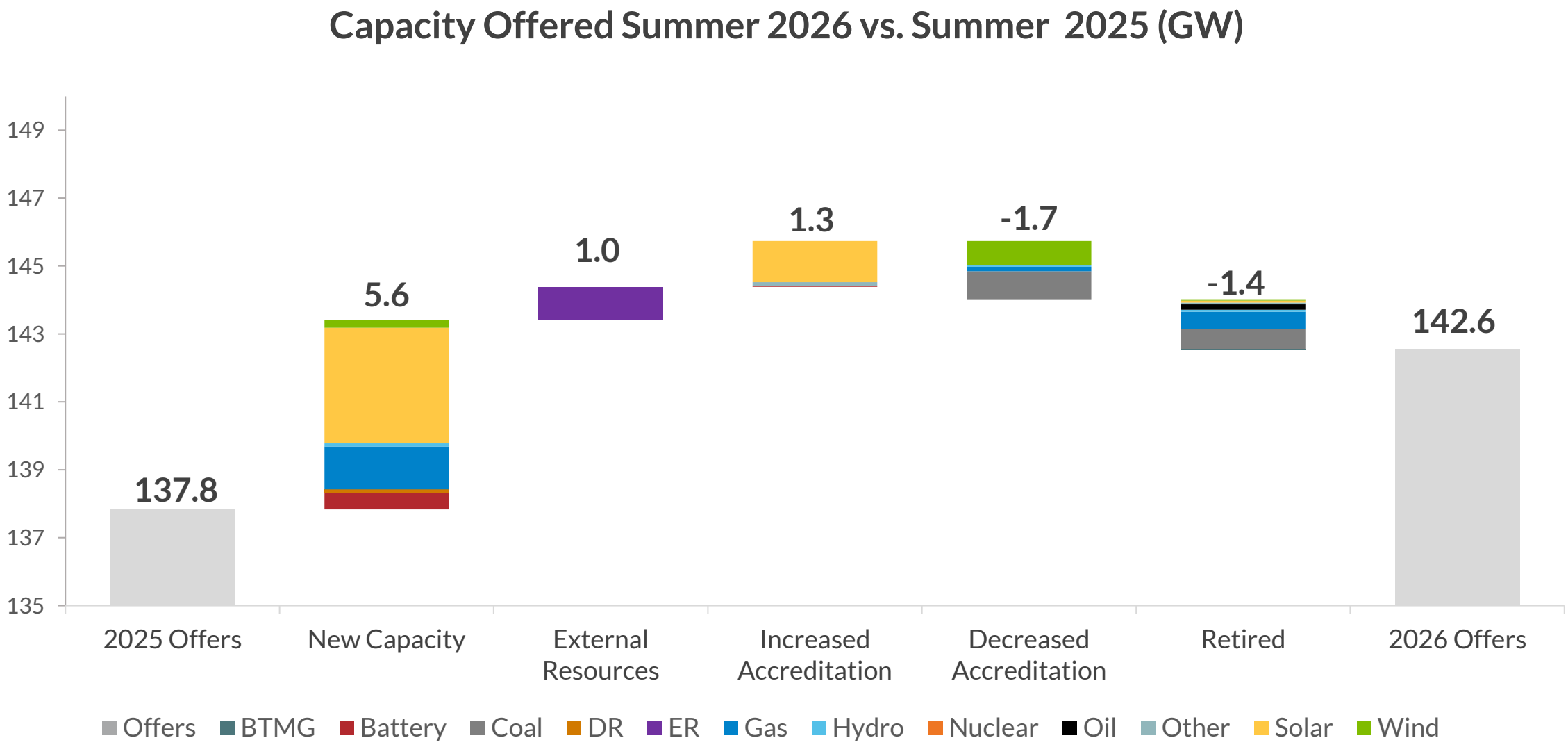
Coincident Peak Forecast is submitted by MISO LSEs relative to the MISO seasonal peak and calculated on a seasonal basis

Non-Coincident Peak Forecast is the peak load submitted by each LSE per month



LMR: Load Modifying Resource CPNodes: Commercial Pricing Nodes ER: External Resource
BTMG: Behind the Meter Generation DR: Demand Resource EE: Energy Efficiency
CPF: Coincident Peak Forecast NCPF: Non-Coincident Peak Forecast

New capacity additions outpaced decreased accreditation and suspensions/retirements



BTMG: Behind the Meter Generation. Capacity indicated is offered accredited value.



Contact: Andy Taylor, ataylor@misoenergy.org



Seasonal Assessment: Transmission

Fisseha Zewdu, Sr. Engineer, MISO Operations Planning FRES

The Coordinated Seasonal Assessment study is used to identify potential issues and develop plans before these issues occur in real time

Purpose:

Evaluate expected conditions across MISO footprint for summer season

Identify potential limitations and issues for upcoming season and develop operating plans

Coordinate with MISO members

Study Focus:

Steady-State Analysis

Bidirectional Transfer Studies

Load Pocket Studies

The 2026 summer model was built from the Eastern Interconnection base case with MISO Transmission projects and planned outages applied

Base Case:

- Built on the 2025/26 Summer ERAG MMWG model
- Generator Retirements approved on or before December 1, 2025, are offline
- Outages: Transmission and Generator Outages are modeled if they are greater than or equal to two months between the months of June through August
- TO's can recommend outages outside the period if deemed necessary

MOD Projects:

- MTEP Appendix A – Planned
- All the generation interconnection projects applied

Generation Assumptions:

- Renewables: Wind and Solar units dispatched at their capacity credit levels
- Qualified Facilities (QFs) and MISO South Load Pocket Op Guides honored

Steady State AC Contingency Analysis did not reveal any contingencies without operating plans for the summer season

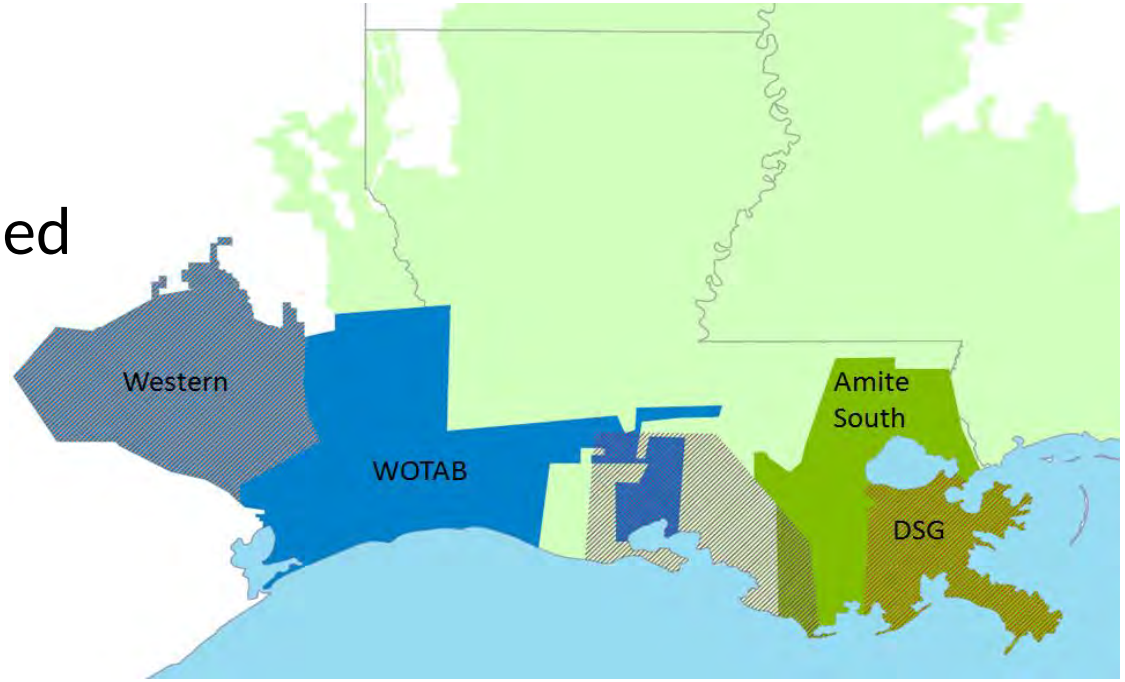
Approximately 18,900+ contingencies were studied

NERC defined Category P1 contingencies

- **P1.1** – three phase faulted generator (>50 MW)
- **P1.2** – three phase faulted transmission circuit
- **P1.3** – three phase faulted transformer
- **P1.4** – three phase faulted shunt device
- **P1.5** – single line to ground dc pole

MISO regularly runs import studies for the Load Pockets

- The peak load conditions for the three MISO load pockets are simulated:
  - Amite South at 7,592 MWs
  - Down stream of Gypsy (DSG) at 3,247 MWs
  - Western at 2,735 MWs
- Transfer studies into the pockets are performed
- Results are used to identify import limits for the pockets



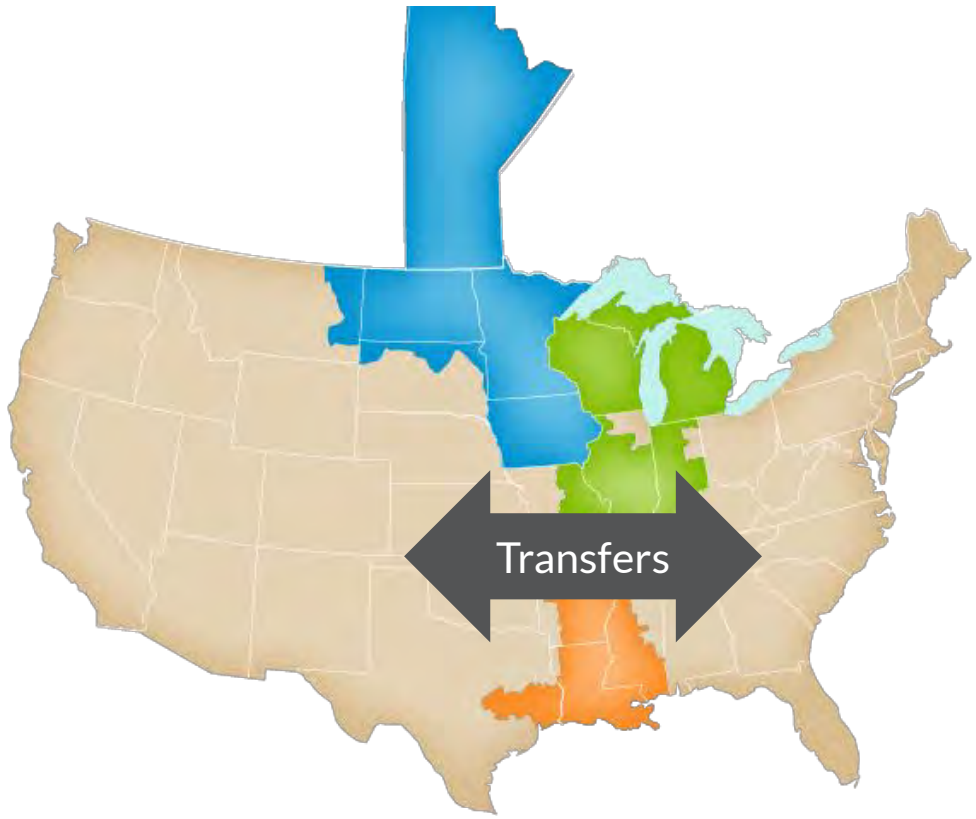
Load Pocket transfer results indicate that import limits are in line with current operating guides

Load Pocket	Monitored Element	Limiting Contingency	Violation Type	Import Capability (MW)
AMITE SOUTH	Slidel – Front Street 230kV	Marion – Hatisburg 230kV and 1SOXY Unit 1	Thermal	3,622
DSG	Good Hope – Prospect 230kV	Waterford – Churchill 230kV and Ninemile Point Unit 5	Thermal	2,365
*Western	Grimes – MT. Zion 138kV	*Cypress – Honey 138kV and MCPS Full Station	Thermal & Voltage	1,234

* Additional generation or reactive resources are required to maintain voltage/reactive balance under this contingency.
* The limit is with Frontier generation at full capacity during summer peak loading condition. N1G1 would not solve without it.

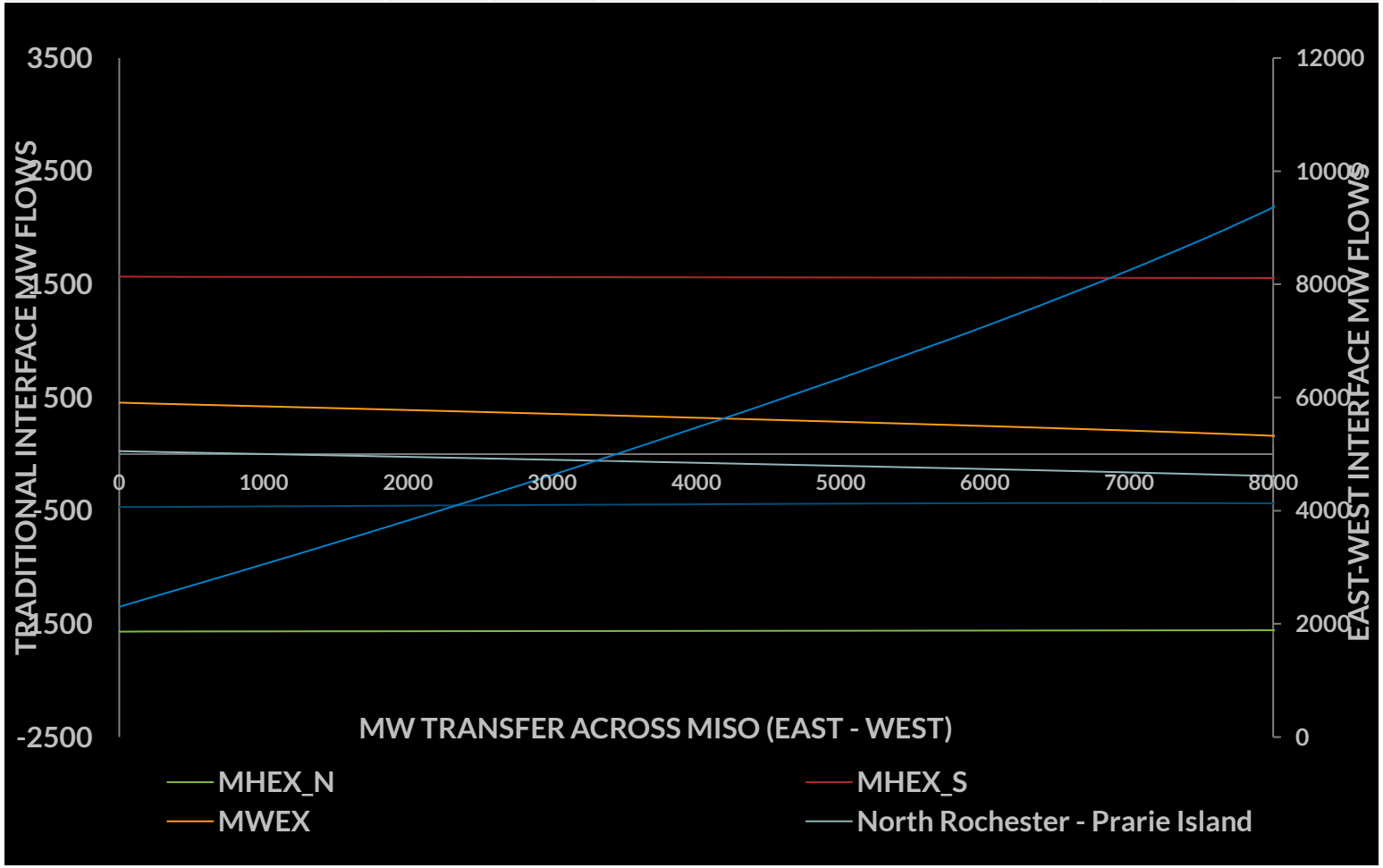
Bidirectional transfer studies across the MISO footprint to identify main constraints with transfers between MISO neighbors

- Transfers across MISO between East and West systems:
  - East system – PJM, SERC (without AECI)
  - West system – SPP and AECI
- Transfer value selected above realistic transfers to identify leading constraints
  - 15,000 MW used
- Flows measured at all tie points and lines bypassing MISO



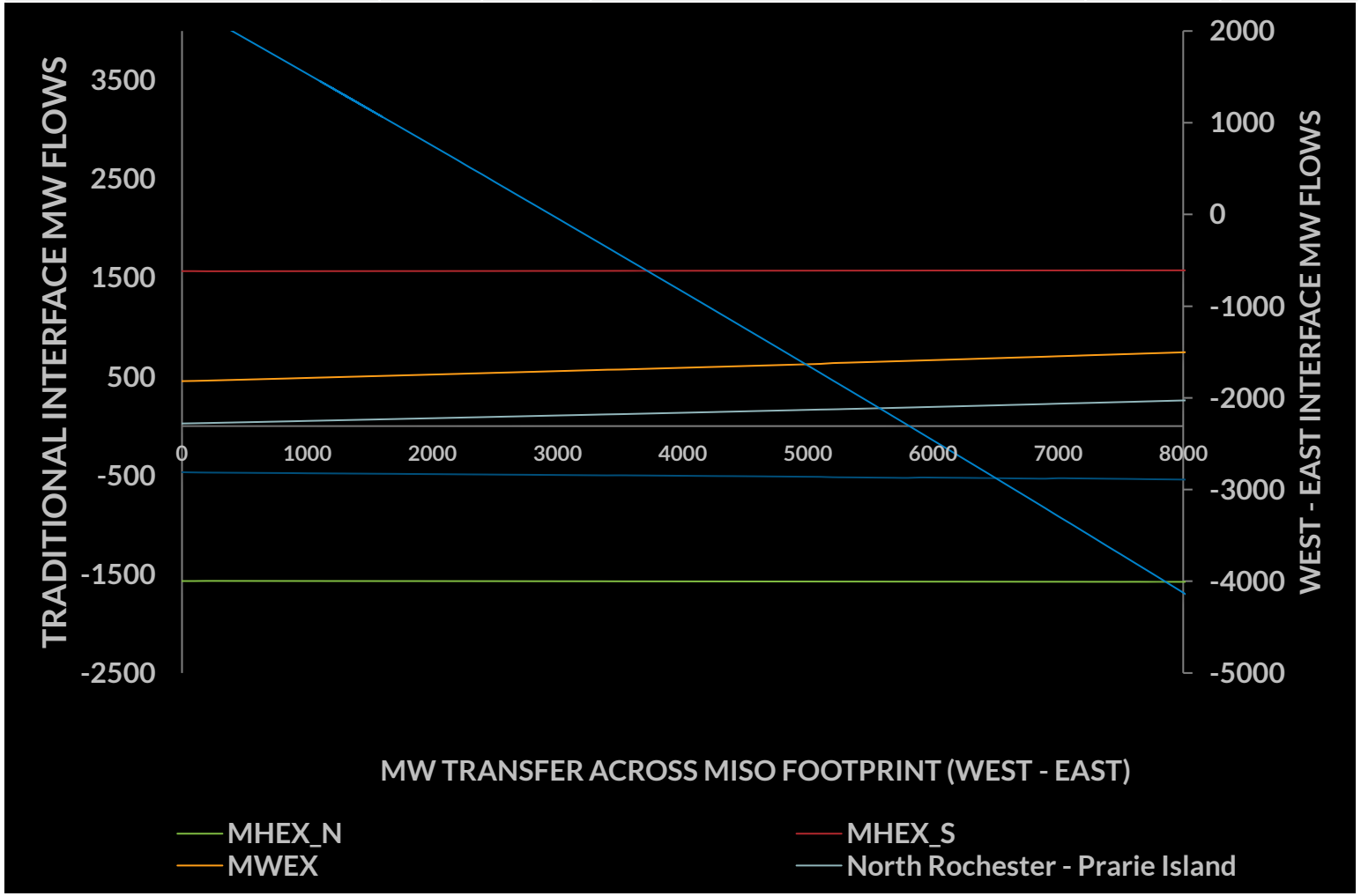
East to West transfer leading constraints and interface flows identified during study

Monitored Facility	Rating	Area	Contingency Name	DC TrLim	AC TrLim
SOUTHLAND - MT HOME 161kV	162	EES_EAI	EA16039: HARRISON EAST-HILLTOP 161	1441.6	1441.6
LAKEOVER 500/230 AT2	615	EES_EMI	EE50X47: LAKEOVER 500/115 AT1	2010.9	2010.9
INDEPENDENCE SES – MOOREFIELD 161	310	EES_EAI	EA16098: QUITMAN - CLINTON WEST 161	3172.9	3172.9



West to East transfer leading constraints and interface flows identified during study

Monitored Facility	Rating	Area	Contingency Name	DC TrLim	AC TrLim
GIBSON – PETERSBURG 345kV	1279	DEI/IPL	CIN34027: BEDFORD-GIBSON 345kV	3710.8	5533.3
PATMOS WEST - LEWISVILLE 115kV	159	EES-EAI	CSW34X40: CROCKETT 345/138 TA TB	5152.2	5347.5
OVERTON 345/161 kV Xfmr	560	AMMO	AEC34014: KINGDOM - MCCREDIE 345kV	6249.5	6249.5





Contact: Fisseha Zewdu, fzewdu@misoenergy.org



MISO

Seasonal Risk / Uncertainty Management

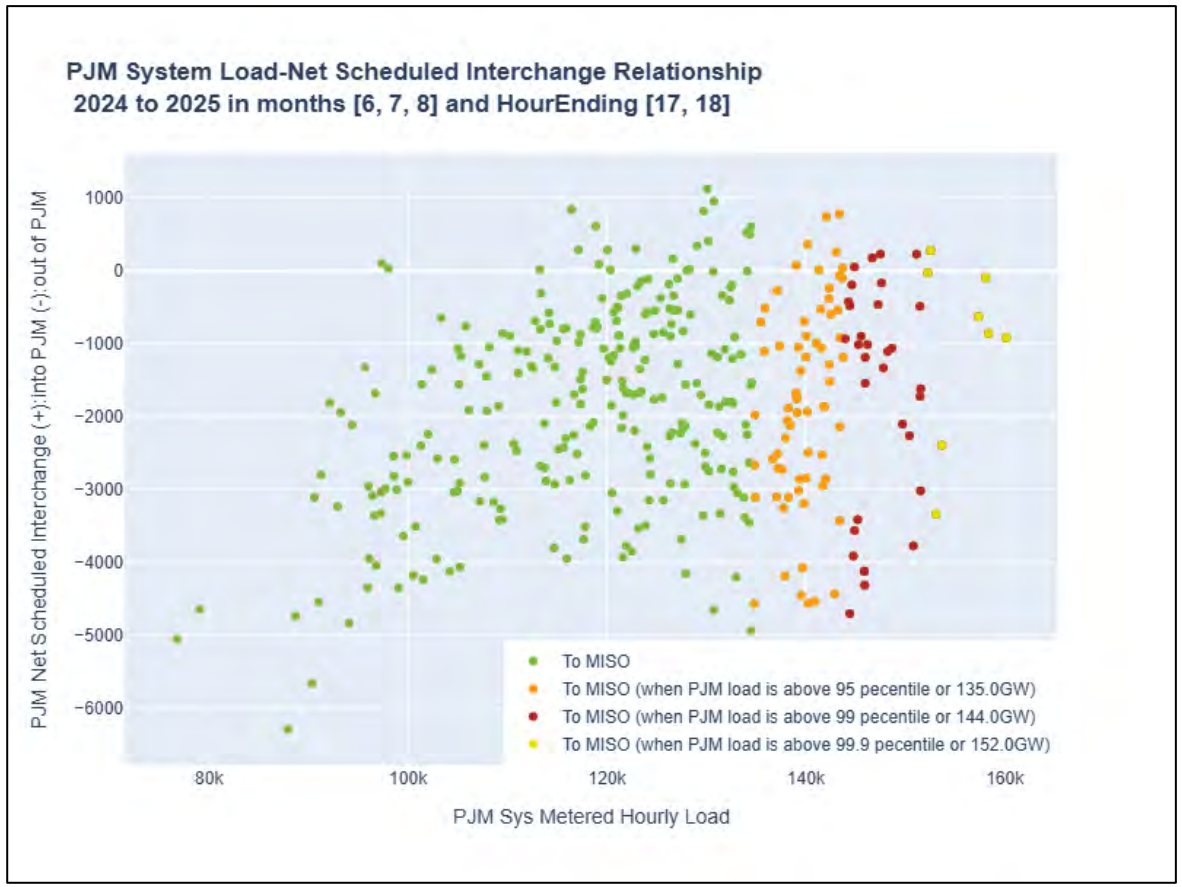
Matt Campbell, Manager, Operations Risk Assessment

Net Scheduled Interchange (NSI)

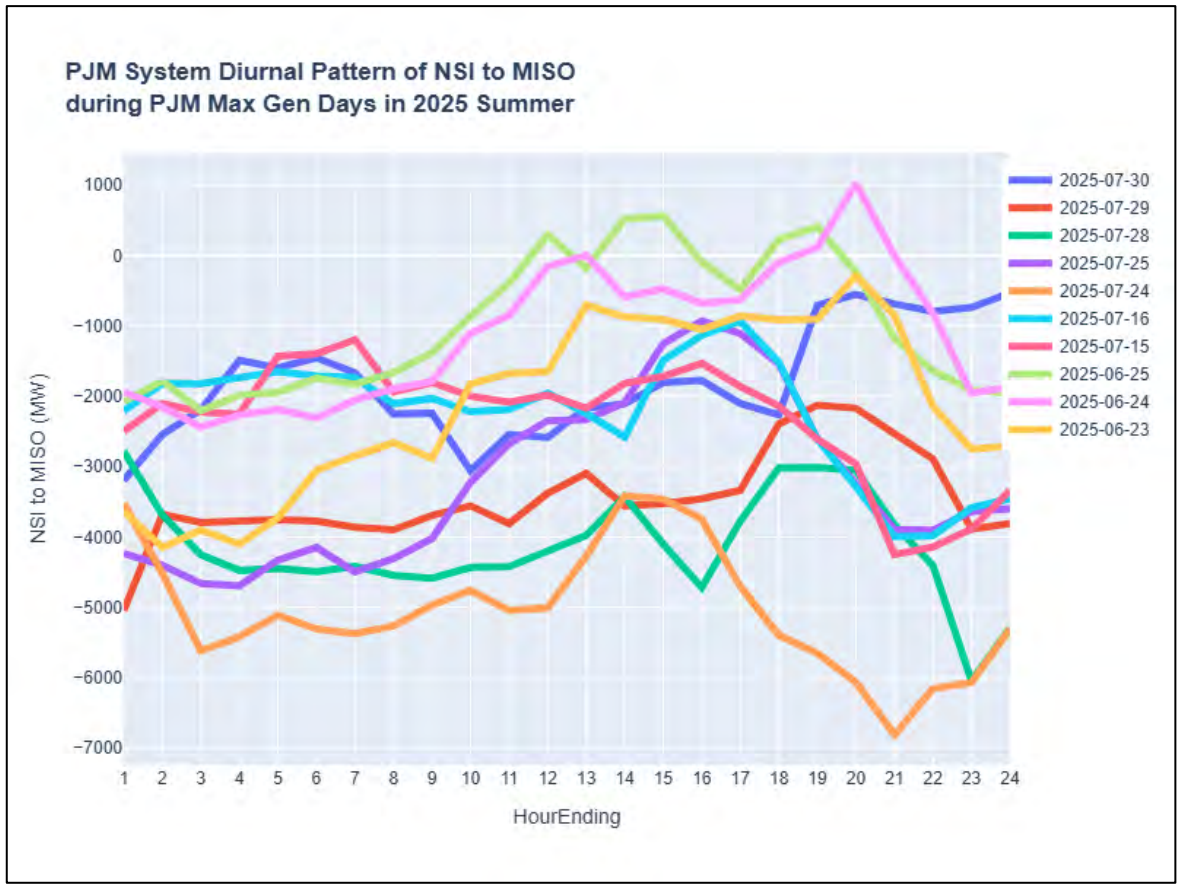
- Using historical NSI-load relationship for NSI risk assessment.
- Actively tracking neighbors' system forecasts, particularly during extreme conditions.

Net Scheduled Interchange Risk

Using historical NSI-load relationship for NSI risk assessment

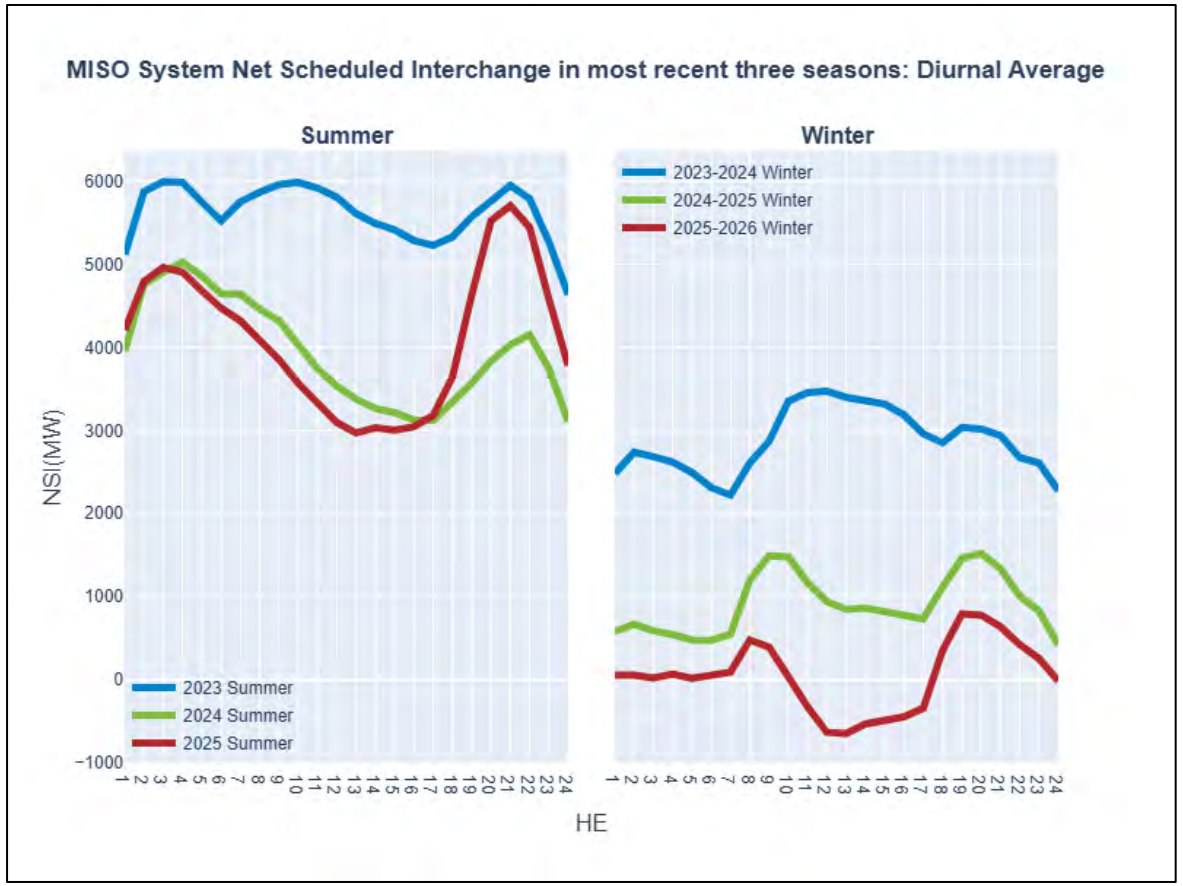


PJM's capability of import energy into MISO has great variation across its Max Gen days

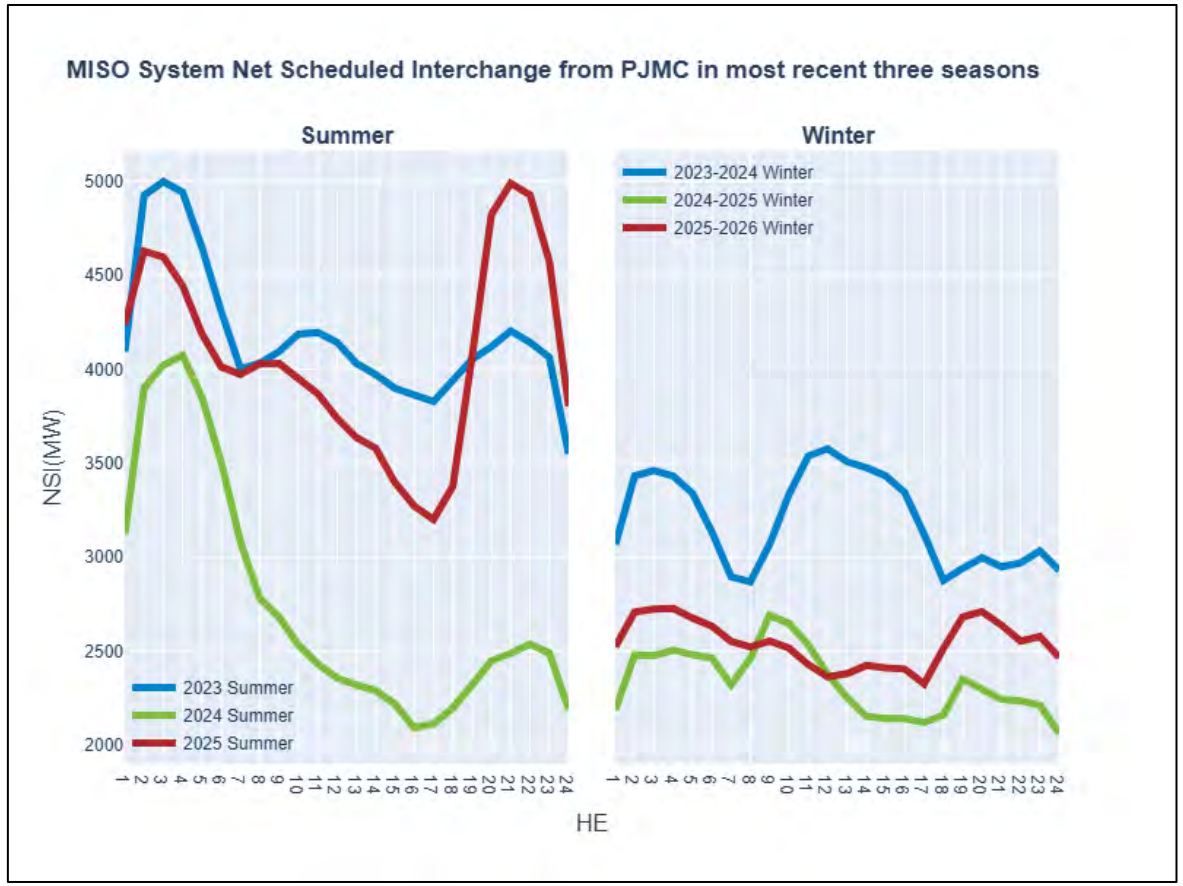


Net Scheduled Interchange Risk

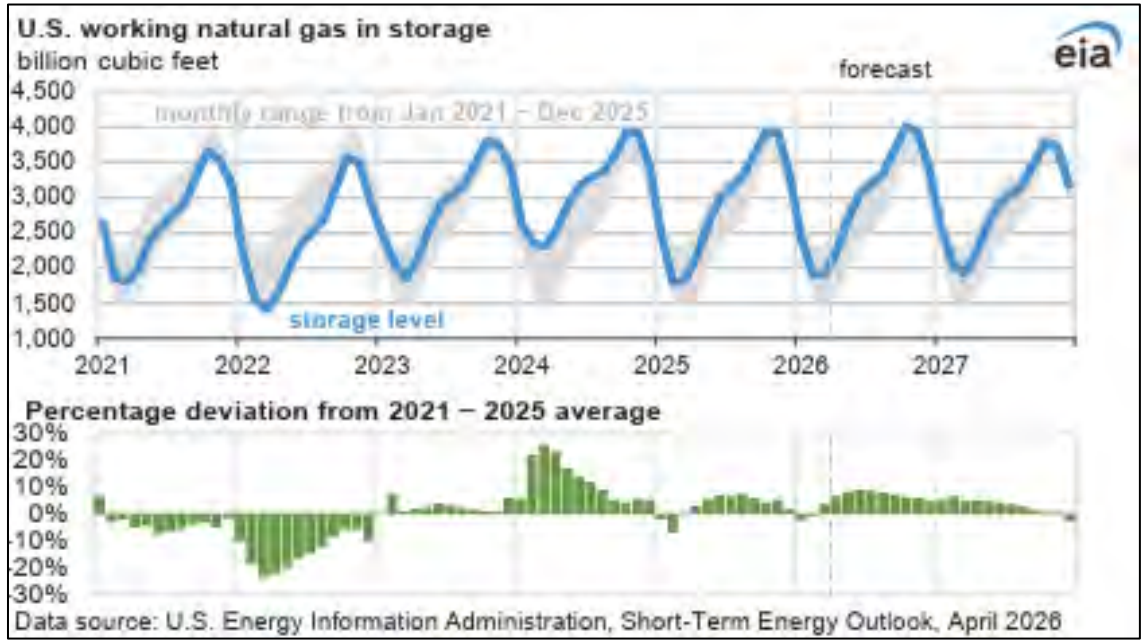
On average, MISO relies more on NSI import during summer months than in winter season



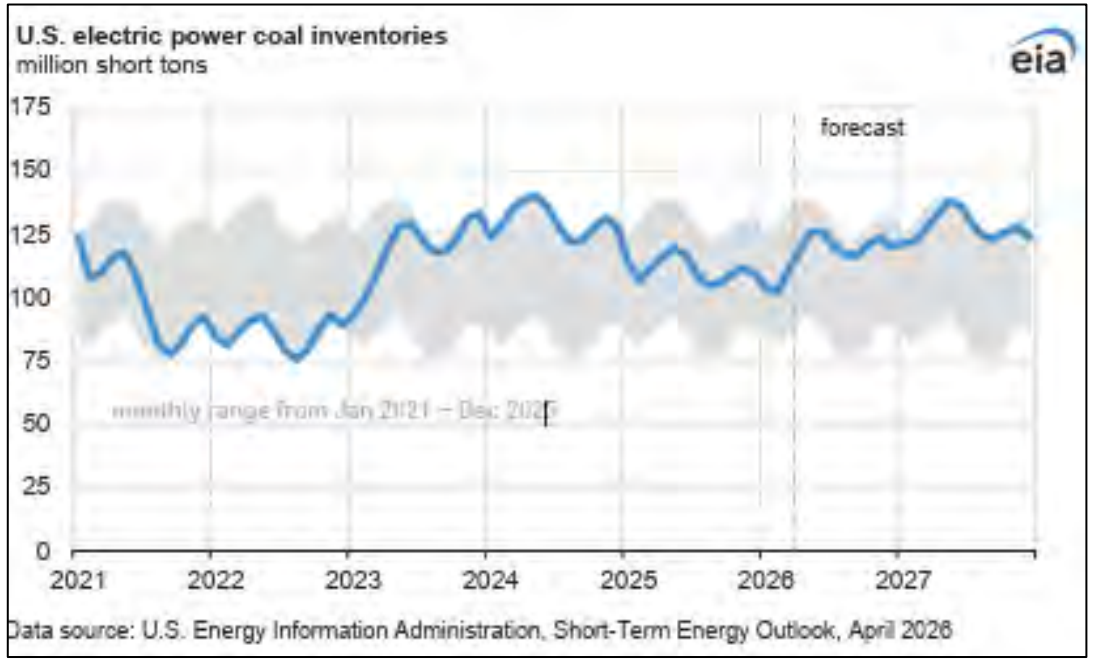
PJM accounts for the bulk of NSI import in summer months, with great variation in past three seasons



Dispatchable Thermal Generation Risk

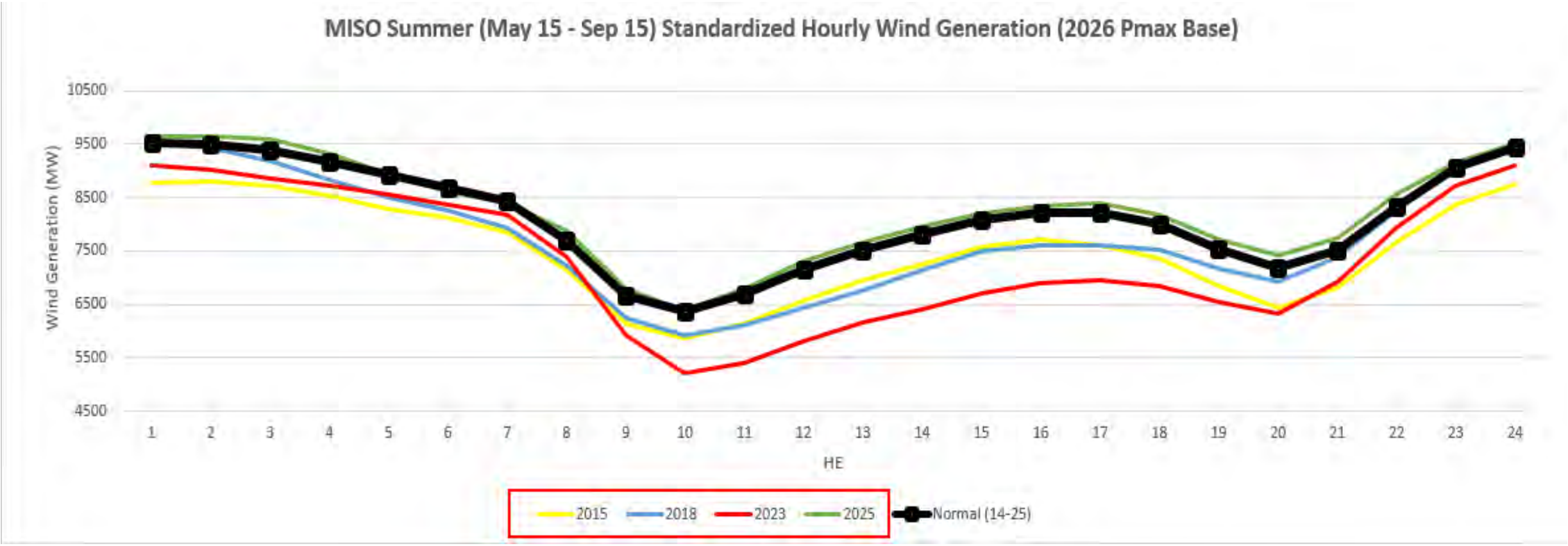


- The balance between natural gas and coal generation will depend on fuel availability and delivery. Natural gas storage is projected to be higher than the 5-year average each month.

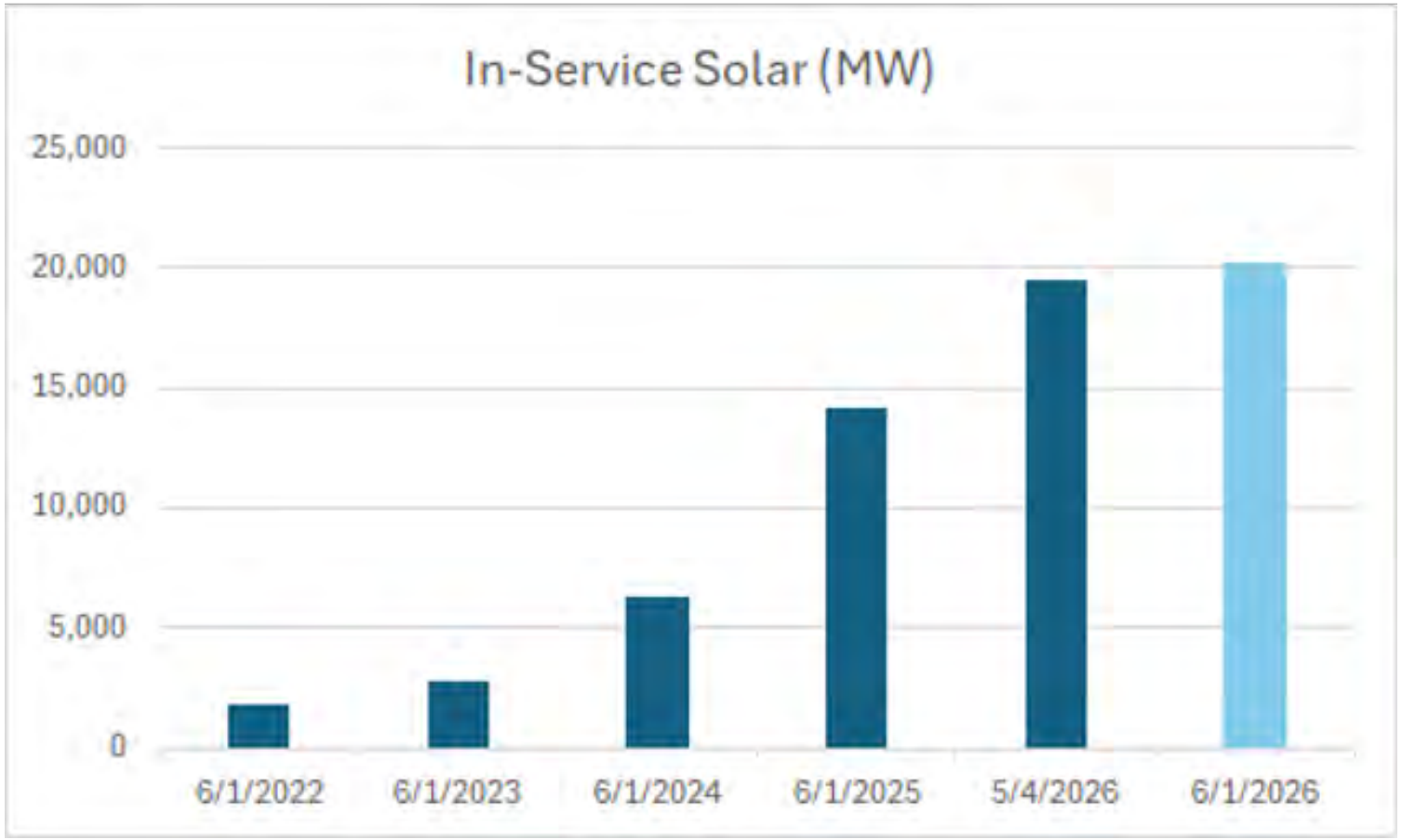


- Coal inventories at power plants are expected to be higher than last summer and on the high end of the 5-year average.

Analog years for summer 2026 indicate **below normal** wind output

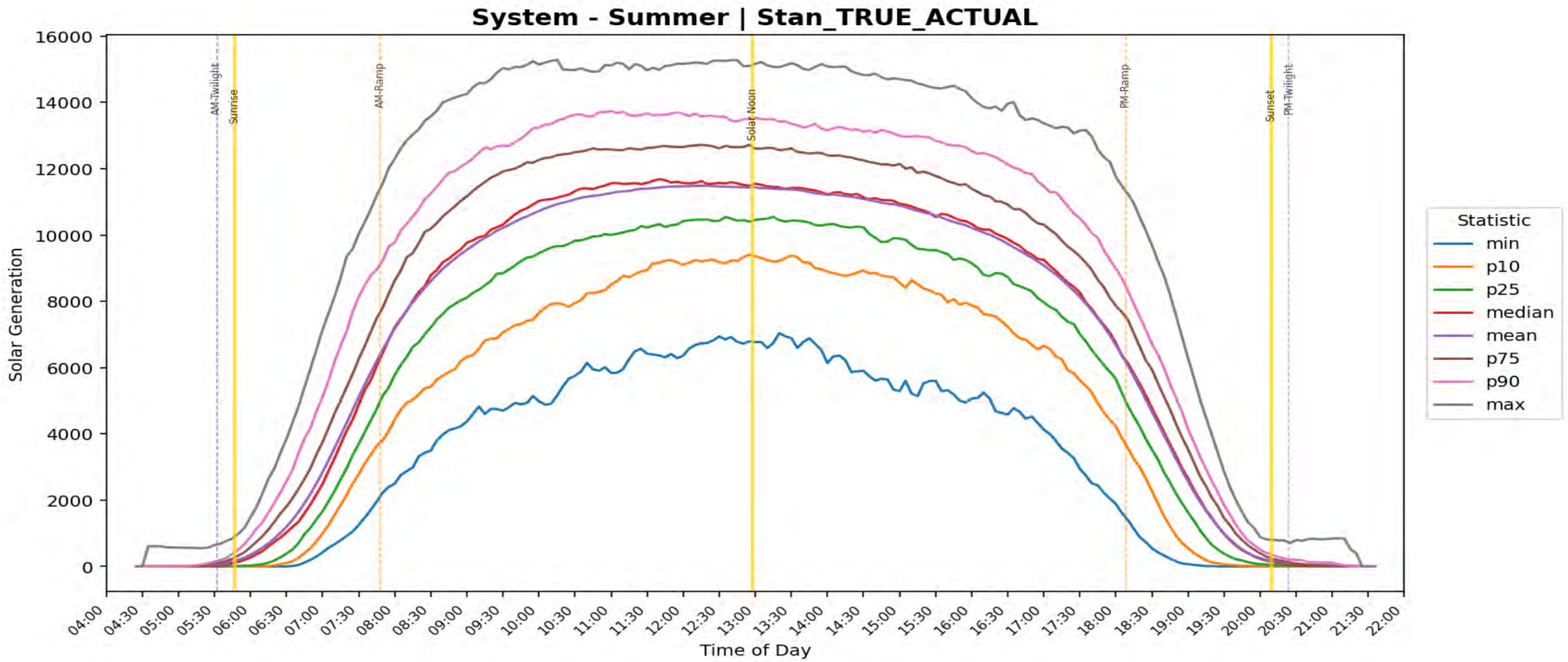


MISO is projected to have 20 GW of solar in our market in June 2026

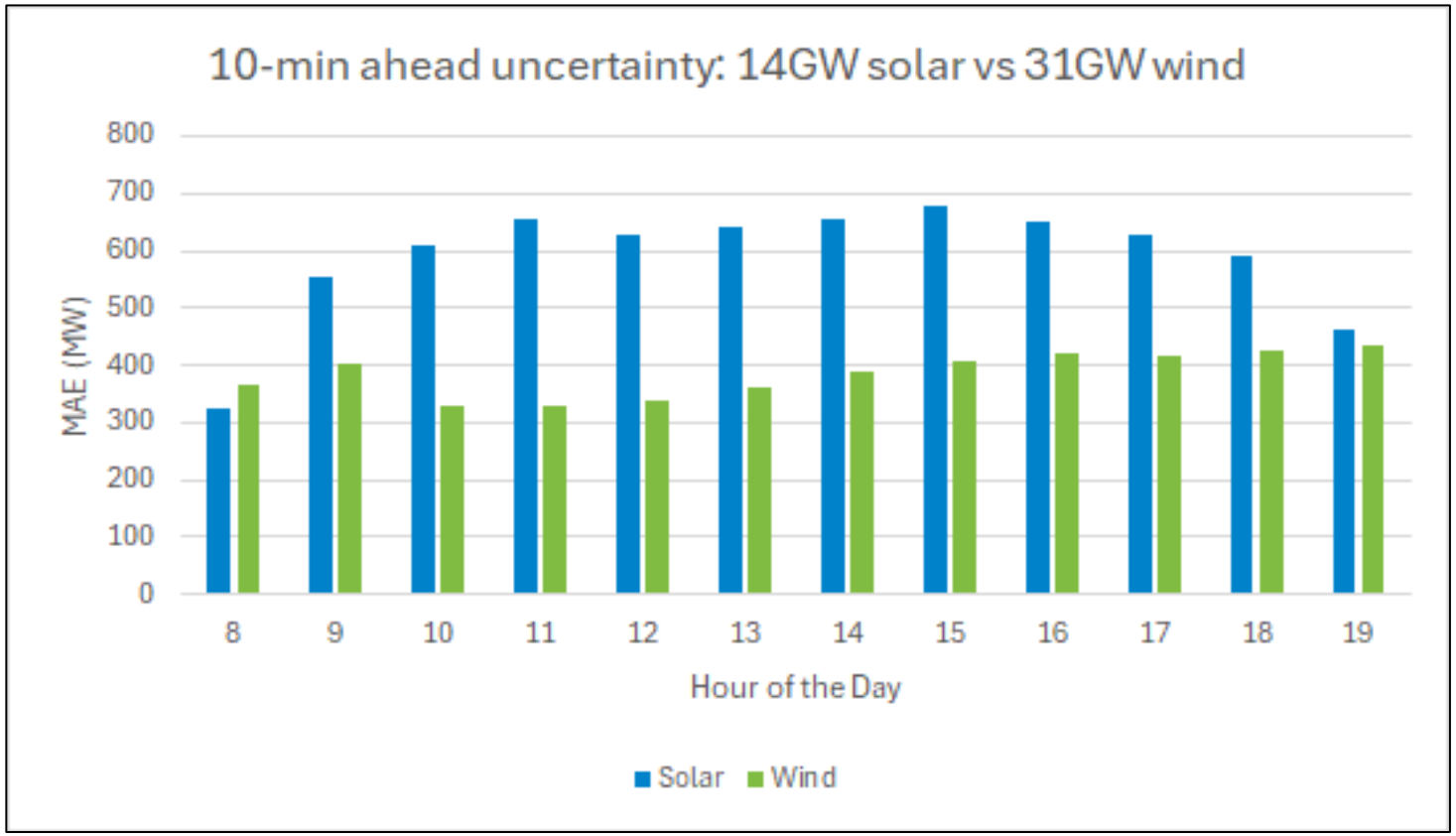


Solar expectations based for summer

Data standardized to latest MISO Pmax: Average daytime solar expected to be ~11 GW

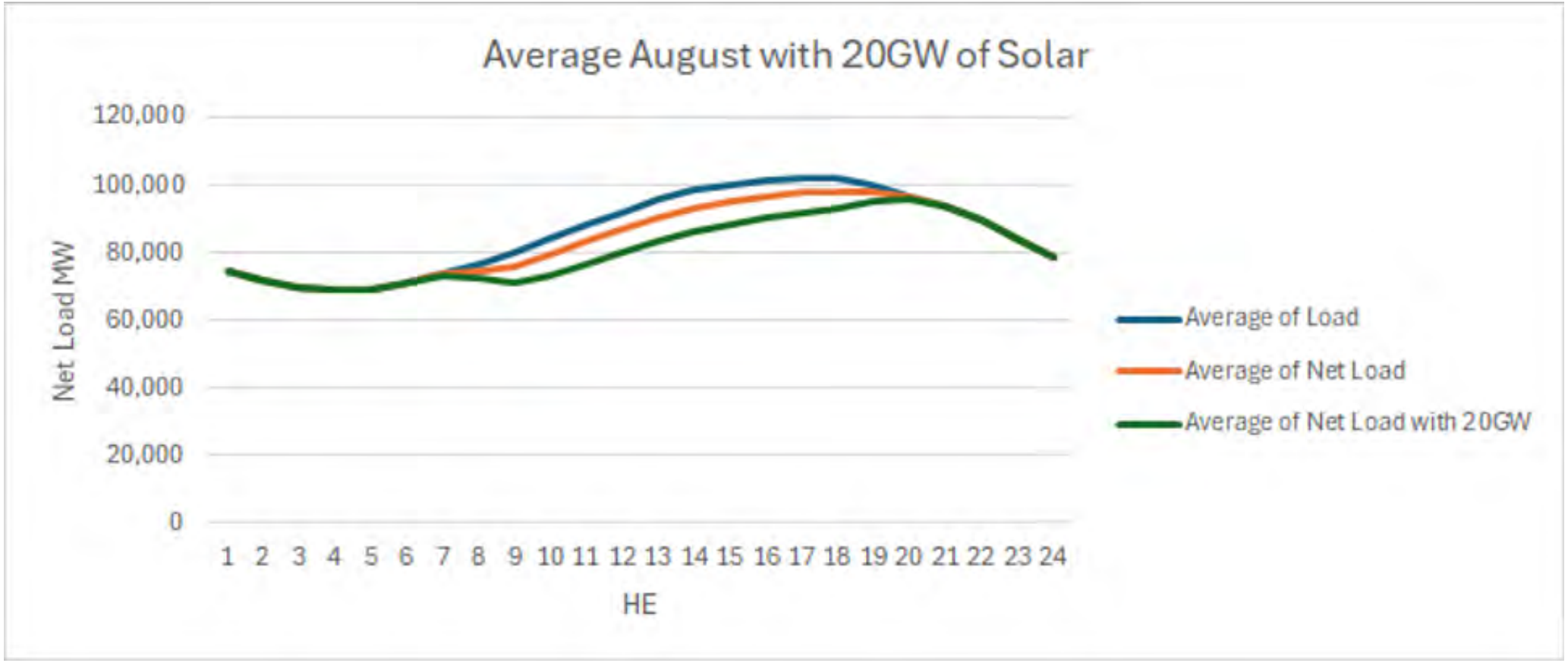


Solar uncertainty more challenging in real time than wind



Performance over last summer

Expected in service solar shifts peak hour from HE17 to HE20



Enhanced uncertainty management based on learned opportunities

- Enhanced quantification models to derive seasonal reserve requirements
- Shift from Peak Hour to ALL HOUR process
- Assess all 24-hour ND-FRAC Net Uncertainty forecast to determine Low/Medium/High prediction for setting Commitment Threshold
- Assess Commitment Threshold across all 24-hour conditional on load and renewable level
- Prepare implementation of Dynamic Regulation Requirement expected June 2026

Assess all 24-hour ND-FRAC Net Uncertainty forecast to determine low/medium/high prediction for setting Commitment Threshold

- A market day will be labeled as low/medium/high based on:
  - L/M/H at peak hour; or
  - Count of M/H hours in a day

Using 3/16/2026 as example:

- Medium at Peak Hour HE 20
- High when counting M/H hrs
- Final determination: HIGH

MKTDAY	HE	Uncertainty
3/16/2026	1	1-Low (Green)
3/16/2026	2	1-Low (Green)
3/16/2026	3	2-Medium (Yellow)
3/16/2026	4	2-Medium (Yellow)
3/16/2026	5	2-Medium (Yellow)
3/16/2026	6	2-Medium (Yellow)
3/16/2026	7	2-Medium (Yellow)
3/16/2026	8	2-Medium (Yellow)
3/16/2026	9	2-Medium (Yellow)
3/16/2026	10	2-Medium (Yellow)
3/16/2026	11	3-High (Orange/Red)
3/16/2026	12	3-High (Orange/Red)
3/16/2026	13	3-High (Orange/Red)
3/16/2026	14	3-High (Orange/Red)
3/16/2026	15	3-High (Orange/Red)
3/16/2026	16	3-High (Orange/Red)
3/16/2026	17	3-High (Orange/Red)
3/16/2026	18	3-High (Orange/Red)
3/16/2026	19	3-High (Orange/Red)
3/16/2026	20	2-Medium (Yellow)
3/16/2026	21	1-Low (Green)
3/16/2026	22	1-Low (Green)
3/16/2026	23	1-Low (Green)
3/16/2026	24	1-Low (Green)

Assess commitment threshold across all 24-hour conditional on load and renewable level

April 13, 2026

Next-Day FRAC Commitment Thresholds Details (ALL HOUR PROCESS)

Select Forecast Market Day: April 13, 2026

Region	PEAKHOUR	ALLHOUR	FINAL	Primary Commitment Threshold	Supplement Commitment Threshold	Commitment Threshold (MW)
Systemwide	Low	Low	Low	5,000	6,600	6,600

Systemwide

HE	FORECAST MTLF Input	FORECAST WIND Input	Supplement Commitment Th..
1	63,924	20,093	6,300
2	62,525	19,066	4,800
3	61,826	17,677	4,800
4	61,937	16,219	4,800
5	63,573	15,314	4,800
6	65,462	15,070	5,400
7	69,705	14,943	5,400
8	72,904	14,934	5,000
9	74,352	15,010	5,000
10	75,681	15,449	5,000
11	76,982	16,339	5,000
12	78,219	17,366	6,000
13	79,439	18,670	6,600
14	80,021	19,763	6,600
15	80,958	20,249	6,600
16	82,023	20,187	6,600
17	83,027	19,834	6,600
18	83,339	19,167	6,600
19	82,810	18,311	6,000
20	81,993	17,740	6,000
21	80,978	17,392	6,000
22	77,599	17,050	5,000
23	73,018	16,633	5,000
24	68,865	15,965	5,400



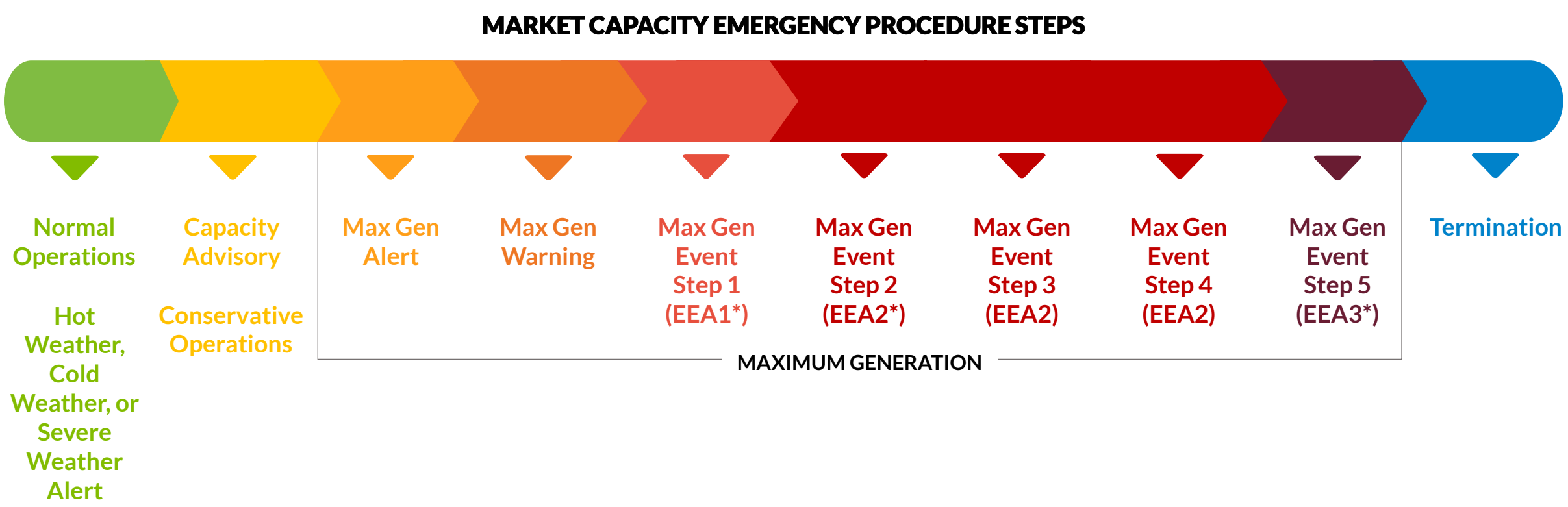
Contact: Matt Campbell, mcampbell@misoenergy.org



Emergency Procedure & Capacity Emergency Changes

Don Hunter, Manager, MISO Control Room Operations

Current Procedures through May 30, 2026

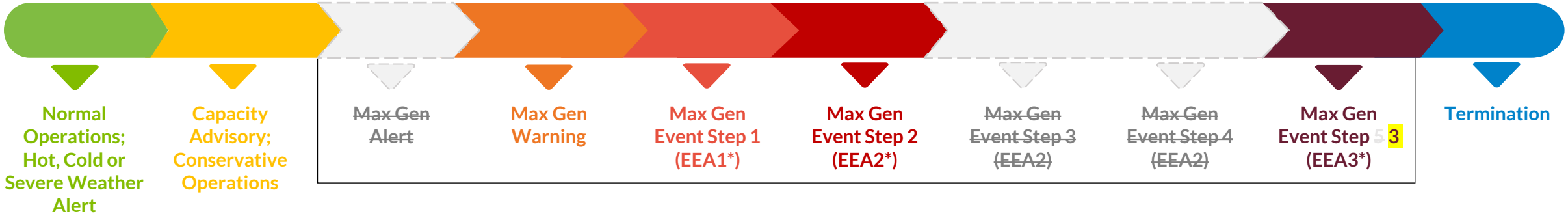


Emergency procedures escalate as capacity conditions tighten; associated actions are designed to balance the real-time supply of energy with demand on the system

*See appendix for definitions

What's Changing

PROPOSED MARKET CAPACITY EMERGENCY PROCEDURE STEPS



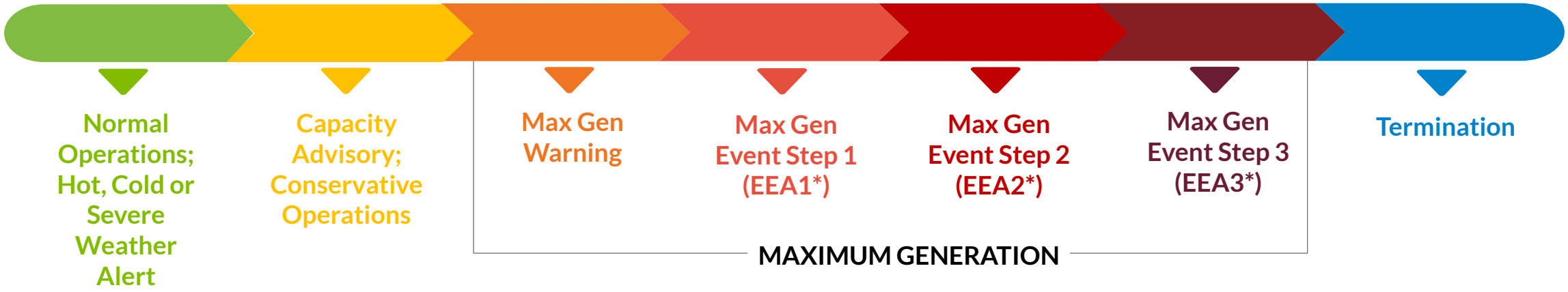
CHANGES INCLUDE

- Eliminate Maximum Generation Alert
- Move procedure Step 1a (commitment of emergency-only resources) from Step 1 to Maximum Generation Warning
- Merge Maximum Generation Steps 3 and 4 with Step 2
- Rename Maximum Generation Event Step 5 to Event Step 3

*See appendix for definitions

Effective June 1, 2026

MARKET CAPACITY EMERGENCY PROCEDURE STEPS



Emergency procedures escalate as capacity conditions tighten; associated actions are designed to balance the real-time supply of energy with demand on the system

*See appendix for definitions

The grid conditions gauge on MISO's website reflects active market capacity conditions for members and the public

Green	Yellow	Orange	Dark Orange	Red
Grid is stable and conditions are normal	*Grid is stable and advisories or warnings are issued*	*Grid is stable and power demand could exceed supply available*	*Grid is stable and emergency power and/or reduced demand is needed*	*Power interruptions imminent or happening*
Hot Weather Alert	**Capacity Advisory**	**NERC Energy Emergency Alert 1 (EEA1)**	**NERC Energy Emergency Alert 2 (EEA2)**	**NERC Energy Emergency Alert 3 (EEA3)**
Cold Weather Alert	**Conservative Operations**			
Severe Weather Alert	**Maximum Generation Warning**			

Grid Conditions Gauge vs. Capacity Emergency Notifications

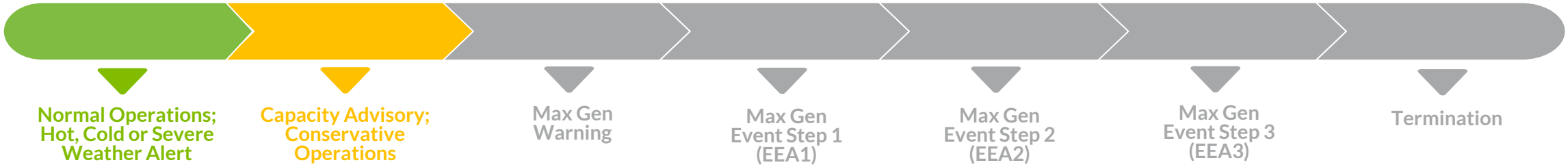
The gauge needle moves when an alert, advisory, warning, event or termination *takes effect*, not when a notification is sent. Notifications take precedence over what is seen on the gauge.



[Grid Conditions at a Glance]

MARKET CAPACITY EMERGENCY PROCEDURE STEPS

(1 of 3)



STATUS	TRIGGER	COMMUNICATION	AVAILABLE MISO ACTIONS*	REGULATORY	STAKEHOLDER/MEDIA
Normal Operations	None	None	Normal operating procedures	None	None
Hot, Cold, or Severe Weather Alert	Could be approaching tight supply due to weather-related circumstances, like extreme heat or cold, or severe wind, storms, and tornados	**Alert for situational awareness**	• Review outage plans for deferral or cancellation • *Normal pricing*	MISO alerts FERC, NERC, DOE, State Commissions, and Regional Entities	• Message to members and neighboring RCs through Operator Interface and RCIS • Notification posted to MISO website • Email sent to Real-Time Market Mailing List
Capacity Advisory	Capacity shortage is forecast within the next few days	**Advisory for situational awareness**	• Request market participants update offer data • Allows MISO to line up LMRs that are unavailable under normal operating conditions • Increase STR requirements • *Normal pricing*	Same as above	Same as above
Conservative Operations	Reliability issue possible for defined area (may be capacity-driven or caused by other abnormal circumstances)	**Alert for situational awareness**	• Potentially suspend transmission maintenance • Review outage plans for deferral or cancellation • Define boundaries • Suspend maintenance • *Normal pricing*	Same as above	Same as above

*MISO's Shift Manager determines which actions are needed and that is shared through Operator Interface.
See appendix for definitions

Effective June 1, 2026

MARKET CAPACITY EMERGENCY PROCEDURE STEPS

(2 of 3)

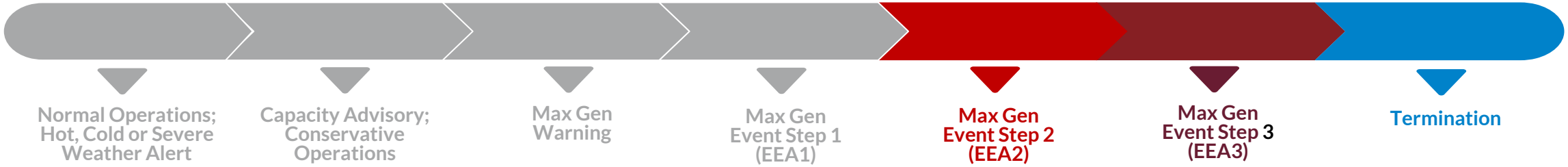


STATUS	TRIGGER	COMMUNICATION	AVAILABLE MISO ACTIONS*	REGULATORY	STAKEHOLDER/MEDIA
Maximum Generation Warning	Reserve margin shortage is forecast	**Warning to prepare for possible event**	• Declare *Conservative System Operations* • Prepare for potential Maximum Generation event • Schedule all available economic resources • Curtail non-firm exports • Reconfiguration • Commit emergency-only resources** • Request environmental waivers as appropriate • *Emergency Tier 1 Offer Floor*	Same as above	Same as above
Maximum Generation Event Step 1 (EEA1)	Reserve margin requirements cannot be met through normal economic resources; all available resources in use	**Declare EEA1**	• Activate emergency operating ranges • *Emergency Tier 1 Offer Floor*	• EEA Notification • MISO NERC Alert • MISO contacts state/local leaders	MISO corporate communications initiates contact with impacted member communicators

*MISO's Shift Manager determines which actions are needed and that is shared through Operator Interface.
**Moved from previous Step 1a
See appendix for definitions

MARKET CAPACITY EMERGENCY PROCEDURE STEPS

(3 of 3)

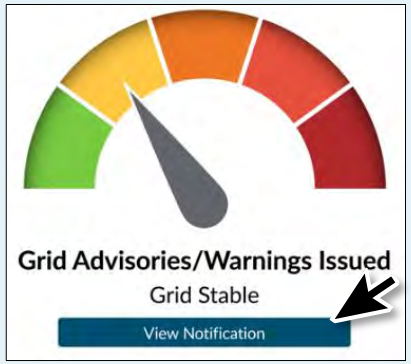


STATUS	TRIGGER	COMMUNICATION	AVAILABLE MISO ACTIONS*	REGULATORY	STAKEHOLDER/MEDIA
Maximum Generation Event Step 2 (EEA2)	Demand cannot be met; actions needed to reduce demand and/or acquire additional supply	**Declare EEA2**	• Instruct load to be reduced via LMMs-Stage 1 or Stage 2 and LMRs or EDRs • Implement emergency energy purchases • Instruct LBAs if public appeals needed** • Implement spinning and supplemental reserves • Request and implement environmental waivers • Initiate external emergency energy purchases • *Emergency Tier 2 Offer Floor*	Same as above	Same as above
	Attempting to maintain minimum Contingency Reserves				
	All available MISO resources used				
Maximum Generation Event Step 3 (EEA3)	Unable to maintain minimum Contingency Reserves	**Declare EEA3**	• Coordinated load shed • *VOLL pricing*	Same as above	Same as above
Termination	Max Gen and, possibly, Capacity Advisory termination	**Event terminated**	• Update stakeholder market data • *Normal pricing*	Same as above	Same as above

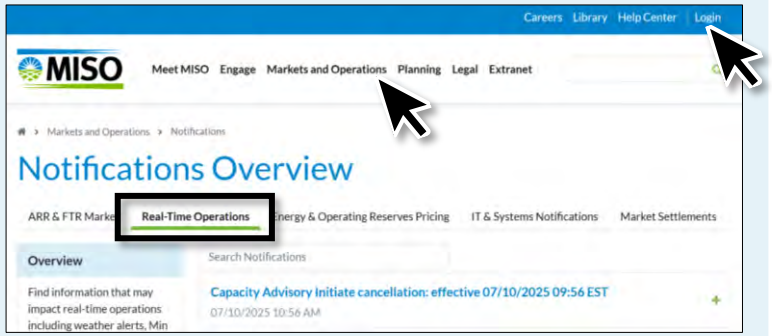
*MISO's Shift Manager determines which actions are needed and that is shared through Operator Interface.
**Public appeals to reduce demand is based on internal LBA procedures, system conditions and Event projections provided by MISO
See appendix for definitions

View MISO's real-time grid status and subscribe to notifications

Website



Grid Conditions Gauge
(Homepage)



Real-Time Operations Notifications
(Markets and Operations > Notifications > Real-Time Operations)
Login to subscribe to email notifications

MISO App

Download on the App Store
GET IT ON Google Play



Enable notifications

View notifications

Grid Conditions Gauge
(My Dashboard)

Real-Time Operations Notifications
(Notifications > Real-Time Operations)

Social Media

@MISO_energy

Midcontinent Independent System Operator (MISO)





Public Notifications on Website & Email

- Public declarations will include time and impacted region(s) and entity(ies)
- Notifications will be posted to the website and sent via the Real-Time Notification email list
- Operating instructions will be shared via Operator Interface only
  - Full and view-only access is managed by each LBA, TO or MP

Notification

Severe Weather Alert

04/04/2026 9:21 AM EST

MISO has issued a Severe Weather Alert due to High Winds and Heavy Rainfall.

Start Time: 04/04/2026 09:15 EST

End Time: 04/04/2026 20:00 EST

Affected Region(s):

- South Region - EES, CLEC, LAFA, SME, EAI, EMBA

This public notification is for awareness only. Impacted entities receive detailed instructions and information via the Operator Interface.

Visit https://help.misoenergy.org/ for more information

New Public Appeal Notification on Website & Email

MISO will issue separate notifications for Public Appeals. This action is at the discretion of the shift manager when in EEA2.

- Notifications will be posted to the website and sent via the Real-Time Notification email list

Notification

Public Appeal Notification

06/01/2026 7:17 AM EST

MISO has instructed the utilities listed below to issue a public appeal for electricity conservation due to reduced power supply and high demand.

Start Time: 06/01/2026 09:15 EST

Affected Region(s):

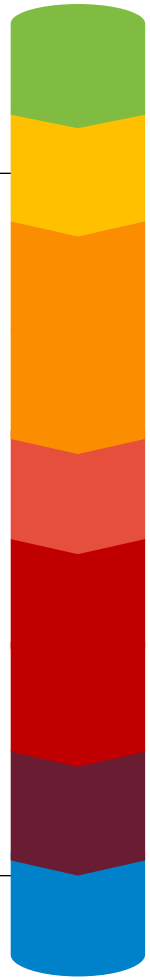
- North Region – DPC, GRE, MDU, MP, NSP, OTP, SMP

This public notification is for awareness only. Impacted entities receive detailed instructions and information via the Operator Interface.

Visit https://help.misoenergy.org/ for more information

The emergency operating procedures address adverse conditions by signaling conditions to MISO's members and allowing or requiring certain actions

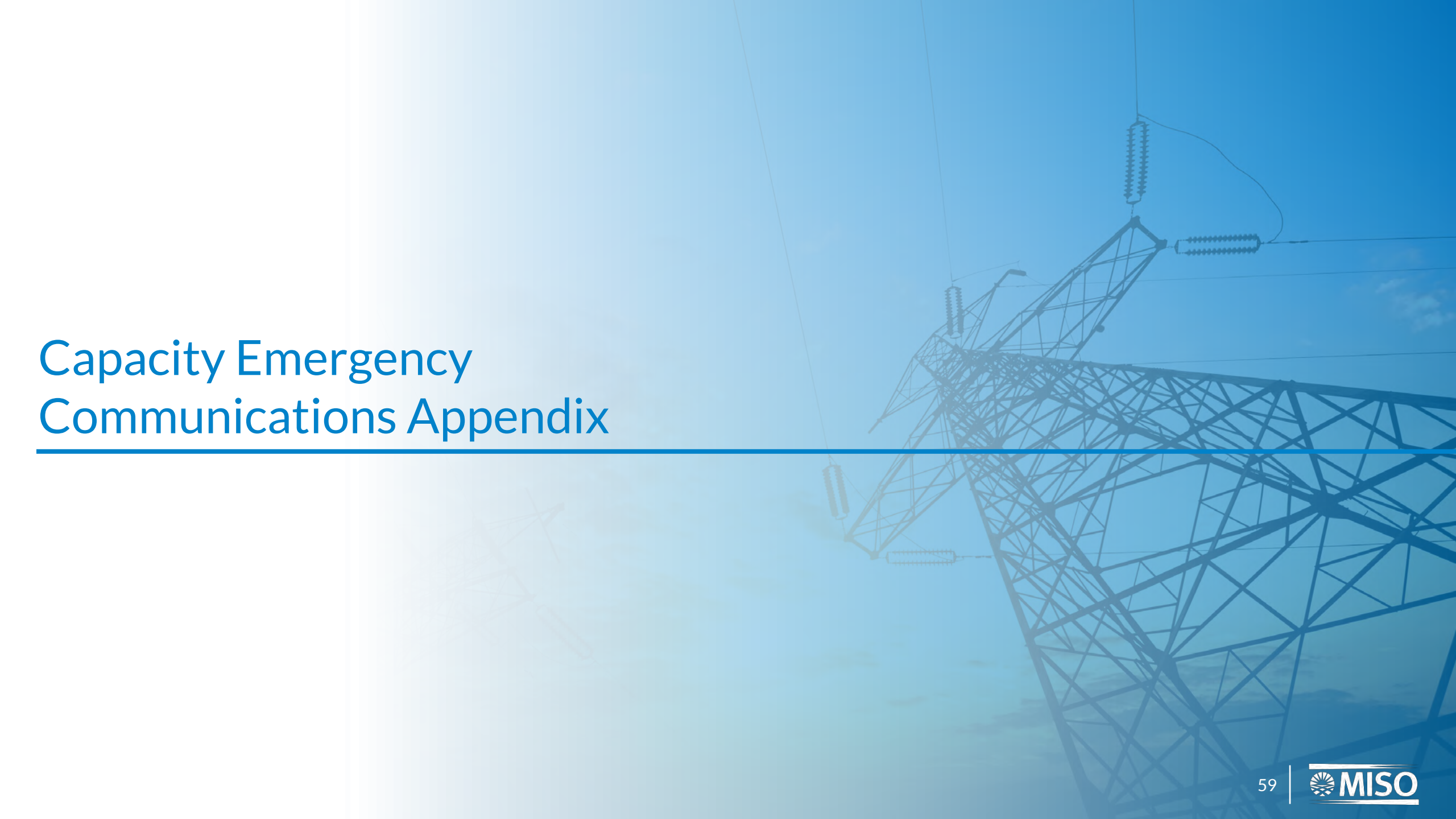
MARKET CAPACITY EMERGENCY PROCEDURE STEPS



Normal Operations		
Capacity Advisory	Advance notice of forecasted capacity shortage; request stakeholders update offer and market data; updated STR and STR RPE values; declare Conservative System Operations if conditions warrant	Normal Pricing
Warning	Request MPs/LBAs ensure accuracy of LMM/LMR availability and self-scheduled values; send LBAs LMM survey; commit available economic resources; coordinate reconfiguration with RCs/TOPs; schedule external/internal Module E resources; suspend CTS, evaluate TEC/inadvertent payback; curtail export schedules; request waivers; implement reconfiguration options; commit AME resources	Emergency Pricing Tier 1 Offer Floor
Event Step 1	Declare NERC EEA1; activate emergency limits	
Event Step 2	Declare NERC EEA2; implement LMRs, LMMs (Stage 1 or 2); commit EDRs; emergency energy purchases; public appeals; implement waivers; utilize operating reserves; implement CRSG reserve call; emergency reserve purchases	Emergency Pricing Tier 2 Offer Floor
Event Step 3	Declare NERC EEA3; firm load shed; set LMPs and MCPs to the VOLL	VOLL* Pricing
Termination	Terminate declarations and return to normal pricing	Normal Pricing

See appendix for definitions

Capacity Emergency Communications Appendix



Some declarations are *not* driven by capacity challenges

Transmission

Transmission Advisory

Notification of forecasted transmission system conditions that may adversely impact the BES but do not yet warrant a Conservative Operations declaration.

Load Pocket Advisory

Notification of potential capacity concerns within a load pocket where the loss of transmission into the area or generation in the load pocket could lead to additional reliability actions.

NEW

JUNE 1

Transmission Warning

Notification that system conditions present a credible risk to the BES, where mitigation actions are expected to be insufficient and more than 100 MW of load may be lost.

Transmission Emergency

Notification of actual or imminent IROL exceedance requiring immediate emergency actions to maintain BES reliability and prevent widespread impacts.

System Status Levels

Indicates infrastructure failures at MISO or MISO Member facilities

SSL 0 Low – Green

System status is normal. No adverse impacts

SSL 1 Elevated – Yellow

Short, minor impact to system, can be quickly remedied

Examples: Temporary infrastructure issue

SSL 2 High – Orange

Longer term, major impact to system, cause unknown

Examples: Loss of monitoring data or member infrastructure

SSL 3 Severe – Red

Major impact on MISO's ability to reliably operate system or market

Examples: Hardware failure, bomb threat, sabotage, control center evacuation

See Appendix for definitions

Notification for a capacity emergency (EEA) is different from a transmission emergency

Capacity Emergency



Occurs when there is not enough generation to meet demand

Typically linked to extreme weather (summer or winter peak)

Follows MISO's Maximum Generation and NERC's Energy Emergency Alert (EEA) process

Supported with various communications including advisories, declarations, EEA Alerts and website updates

Transmission Emergency



Occurs when there is an actual or imminent IROL violation on the transmission system

Happens very quickly with no public declarations

Requires corrective action within 30 minutes to maintain grid stability

Follows MISO's Transmission System Emergency process

See Appendix for definitions

Definitions

Contingency Reserves	A type of operating reserve that is held to address the loss of a significant generating unit or transmission line. At MISO, this is the sum of supplemental and spinning reserves.
Emergency Demand Response (EDR)	Load reductions, behind the meter generation, and other demand resources that are available to reduce demand or increase generation in exchange for guaranteed recovery of costs associated with the response in accordance with Schedule 30 (EDR Provisions) of the Tariff. EDRs are operated outside the Operator Interface (OI) by the shift manager by using the EDR Tool.
Energy Emergency Alert Level 1 (EEA1)	A NERC-mandated alert when all available generation resources are in use. It means MISO is experiencing conditions where all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
Energy Emergency Alert Level 2 (EEA2)	A NERC-mandated alert when load management procedures are in effect. It means MISO is no longer able to provide its expected energy requirements and is an energy deficient. MISO has implemented its operating plans to mitigate emergencies and is still able to maintain minimum contingency reserve requirements.
Energy Emergency Alert Level 3 (EEA3)	A NERC-mandated alert when firm load interruption is imminent or in progress. It means MISO is unable to meet minimum contingency reserve requirements.
Interconnection Reliability Operation Limit (IROL)	A NERC System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Bulk Electric System.
Load Management Measures (LMM) Stage 1	Load management actions that can be taken to reduce demand to preserve or maintain operating reserves that are NOT included in EDRs or LMRs.
Load Management Measures (LMM) Stage 2	Load management actions that can be taken to reduce demand including voltage reductions and reducing loads that, by contract, cannot be interrupted until reserves are being or are expected to be depleted and energy from emergency offers by market participants are being or are expected to be depleted. These do NOT include EDRs or LMRs.
Load Modifying Resource (LMR)	These are either demand resources or behind-the-meter generation that have an obligation to reduce demand or increase generation during declared system emergencies
Maximum Generation Capacity Warning (Max Gen)	MISO foresees or is experiencing conditions where all available economic Resources are committed to meeting Load, firm transactions, and reserve requirements, and is concerned about sustaining required Operating Reserves.
Reserve Margin	The difference between total operating reserves and the operating reserve requirement. MISO is required to keep a certain reserve margin to ensure there is enough capacity to meet peak demand, plus a buffer.
Short-Term Reserve (STR)	A 30-minute rampable generation capacity product. It's designed to address short-term needs for managing system reliability.
Spinning Reserves	Reserves held that are synchronized to the system and available immediately.
Supplemental Reserves	Reserves for abnormal supply deficiencies that must be ready within 10 minutes.
System Operating Limit (SOL)	The NERC value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria.
Value of Lost Load (VOLL) Pricing	The price at which MISO values the cost of unserved energy; essentially, what customers would be willing to pay to avoid an outage.



202(c) Emergency Orders

Don Hunter, Manager, MISO Control Room Operations

Department of Energy 202(c) Orders

- Section 202(c) of the Federal Power Act (FPA)
  - Authorizes the Department of Energy (DOE) to issue emergency orders
    - Require power plants to remain in operation in lieu of retirement
    - Permit generators to exceed environmental operating limits
    - Direct backup generation facilities to run when EEA3 is imminent
  - MISO did not use 202(c) during Winter Storm Fern
    - Actions taken prior to use of the 202(c) sufficient to relieve capacity issues



Contact: Don Hunter, dhunter@misoenergy.org



Transmission System Emergency Procedure Updates

Clayton Umlor, Manager, MISO Reliability Coordination

Purpose & Key Takeaway



Purpose

Communicate improvements coming to the Transmission System Emergency (TSE) procedure to enhance operational readiness.

Key Takeaways

- Transmission Warning declaration is a tool to communicate an increased level of transmission risk (internally & externally)
- Transmission System Emergency procedure updates are drafted and under review for inclusion of the Transmission Warning declaration to be effective June 1, 2026
- Future updates of the procedure will include clarifying criteria and responsibilities for identifying Transmission System Emergencies in both real-time and planning processes

Transmission Warning Entrance Criteria

Transmission Warning Declaration: Notification that system conditions present a credible risk to the BES, where mitigation actions are expected to be insufficient and more than 100 MW of load may be lost.

A transmission warning will be declared when…

ALL of the following conditions are met:

- There is 100 MW or more of load at risk
- Normal congestion management tools have been exhausted and are not sufficient to mitigate risk
- Available emergency actions are not sufficient to mitigate risk (e.g., emergency ranges of units, emergency only units, EDRs, and LMRs, etc.

AND

AT LEAST ONE of the following applies:

- Facilities > 100kV have post-contingent flow greater than or equal to 115% of the highest emergency limit
- The RC determines that system conditions warrant heightened awareness of potential transmission risk

Transmission Warning Exit Criteria

A transmission warning should be terminated when…

EITHER of the following conditions apply:

- The criteria for declaring the Transmission Warning are no longer satisfied
- RCs and TOPs agree that the risk no longer poses a significant threat to load shed or load loss

Timeline & Upcoming Procedure Updates

Transmission Warning: June 1

Criteria and responsibilities for defining Transmission System Emergencies and IROLs are currently being evaluated in the MISO stakeholder processes.

TSE procedure redline document will be posted and available for review.

TSE/IROL criteria & responsibility changes expected Q4 2026



Contact: Clayton Umlor, CUmlor@misoenergy.org



Technical Development & Training Updates

Anita Hurst, Sr. Manager, MISO Technical Development

MISO & Member Summer Readiness Training

Market Capacity Emergency Drill



- Review of recent procedural changes and escalation flow (rev 23 vs rev 24)
- Reinforces how procedure updates affect operational decisions and communications
- Practice applying revised steps of the updated MISO Market Capacity Emergency procedure (SO-P-EOP-11-002, rev 24)

Hurricane Drill



- Overview of 2025 season and vendor forecasts for 2026
- MISO and Member roles before landfall, during, and following a hurricane
- Three separate, simulated scenarios spanning one storm from pre-to-post-landfall; scenarios covered:
- Supply Surplus (Min Gen Event)
- Tool Failure (Loss of State Estimator)
- Restoration efforts (Including the islanding or generation facility, requiring use of blackstart resources)

MISO Operator Summer Readiness Training

Drill Participation

- MISO operators participate in Hurricane Drill and Market Capacity Emergency Drill

Interconnection Reliability Operating Limit (IROL) Simulation Training

- Define, identify, and mitigate System Operating Limits and IROLs
- Declare Transmission System Emergencies



Contact: Anita Hurst, ahurst@misoenergy.org

Thank you for joining us today!

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Midcontinent	)
Independent System Operator	)
(MISO)	)
	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 194

Konidena Sept. 2026 Decl.

Declaration of Rao Konidena

I, Rao Konidena, declare as follows:

I. Introduction

1. I am an electrical engineer and the principal of Rakon Energy LLC, an engineering firm that consults on energy markets such as the Midcontinent Independent System Operator (MISO).

2. I spent 15 years at MISO forecasting resource adequacy and working on policy matters, including in management and in public-facing roles. I have extensive experience on engineering and planning issues associated with distributed energy resources, storage, and transmission planning, advising state commissions, consumer advocates, and clean energy developers nationwide.

3. In my professional opinion, MISO's operating conditions during Summer 2026, do not support the Department of Energy's and Secretary Chris Wright's (DOE) claim of a shortage of electric energy or a shortage of facilities for the generation of electricity.

4. During Summer 2026, MISO maintained real-time operating reliability using its reliability operating procedures. MISO also experienced several capacity alerts and advisory declarations but only one event rose to the level of Step 2 – the July 15th event.

5. MISO experienced its tightest grid conditions during Summer 2026 on July 15. On that day, MISO declared a "Step 2" event. Even in those tight conditions, MISO had access to unused available capacity above the amount needed to both meet demand and maintain a buffer known as operating reserves requirements. Across the hours of the Step 2 event, I calculate that the surplus ranged from approximately 5,000 MW to over 8,500 MW.

6. MISO managed the Step 2 event using its established procedures. Among other things, MISO secured additional output from generators, used load-modifying resources, and obtained imports from neighbors. MISO's operations on July 15 performed as intended: MISO forecasted tightening conditions, employed its established procedures, and subsequently returned to normal operations.

7. I conclude that there is no evidence that MISO needed the capacity from the J.H. Campbell, Culley, and Schahfer plants to prevent a shortfall.

II. Education and Experience

8. My professional and educational experience is summarized in the curriculum vitae attached to this declaration (Attachment A).

9. I received a Bachelor of Engineering in Electrical and Electronics Engineering from Bangalore University, a Master of Science in Electrical Engineering from the University of Texas at Arlington, and a Master of Business Administration from the University of Minnesota.

10. I have more than two decades of experience in U.S. wholesale electricity markets, distribution system planning, and the integration of distributed energy resources. As Principal of Rakon Energy LLC, I have provided expert testimony before state commissions and FERC on issues involving resource adequacy, transmission planning, distributed energy resources, and energy storage. My clients have included retail customer aggregators, state attorneys general, generation developers, consumer advocates, and environmental organizations. Through this work, I have analyzed and advised on the implications of utility distribution system plans, distributed energy resource tariffs, interconnection rules, and the evolving seasonal capacity constructs of organized wholesale markets.

11. From 2003 to 2018, I served at MISO in roles ranging from resource forecasting to policy studies. At MISO, I led studies on demand response, energy efficiency, distributed generation potential, and grid-scale storage, as well as independent load forecasting and economic transmission planning. I represented MISO in national and international forums, including the Department of Energy's U.S. DRIVE technical team and the GO-15 group of global grid operators. This combination of independent consulting and ISO experience provides me with a deep understanding of how MISO's market structures, its planning processes, and its operational practices affect reliability, investment, and consumer costs.

III. Purpose of Declaration

12. I am familiar with DOE's Section 202(c) orders associated with the Campbell plant, including Order Nos. 202-26-22 and 202-26-39, as well as DOE's Section 202(c) orders associated with the Schahfer and Culley plants, including Order Nos. 202-26-29 and 202-26-30.

13. In addition, I am aware that the power plants subject to those orders have nameplate capacity as follows: Schahfer Units 17 and 18 (each approx. 361 MW); F.B. Culley Generating Station Unit 2 (approx. 90 MW); J.H. Campbell Unit 1 (approx. 265 MW), Unit 2 (approx. 379 MW), and Unit 3 (approx. 917 MW). I am also aware of basic operational details about the plants, including that Schahfer Unit 18 has not been operational this year.

14. The purpose of my declaration is to review the operating conditions MISO experienced on July 15 with a focus on evaluating the resources MISO had available to prevent any shortfall of generating resources on that day.

IV. Analysis

A. Summer 2026 Generally

15. Across Summer 2026, MISO maintained real-time operating reliability using its reliability operating procedures. MISO also declared Capacity Advisory[1] and/or

[1] The trigger for a Capacity Advisory declaration is "Capacity shortage is forecast within the next few days". Source: Slide 52, MISO May 6, 2026, presentation "Seasonal Readiness Workshop: Summer 2026"

Conservative Operations[2] — precursor declarations two tiers below a Step 1/EEA1 event — on four separate occasions for Conservative Operations[3] and six separate occasions for Capacity Advisory,[4] in June, July, and August. Several of the Conservative Operations were declared on the same date as Capacity Advisories,[5] and I followed MISO's convention and counted them as a single event.[6] On only one of those occasions, July 13–15, did conditions escalate beyond that precursor tier to an actual Max Gen Warning and Step 1/Step 2 event.

B. MISO Change in Procedures

16. Starting June 1, 2026, MISO consolidated the steps it takes to address tight grid conditions. Previously, MISO had gradients within each Step such as Step 2c within Step 2, and had five overall Steps all the way to Step 5 for EEA3. Now, MISO has Steps 1–3.[7] What were previously three steps for EEA2 events have been consolidated as one event.

C. MISO's Operations on July 15, 2026

17. To start this analysis, I have listed the stepwise events MISO declared for the North/Central subregion on July 15 below in a chronological manner, with times reported in Eastern Time.[8] MISO declared the stepwise events only in the North/Central subregion, not the South subregion.

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https://cdn.misoenergy.org/20260506%20Summer%20Readiness%20Workshop%20Presentation_UPDATED755608.pdf .

[2] The trigger for a Conservative Operations declaration is "Reliability issue possible for defined area (may be capacity-driven or caused by other abnormal circumstances)". Source: *Id.*

[3] The four dates are: 6/10, 6/17, 6/24, and 7/1. Source: MISO Monthly Operations Report for June, slide 2, found at https://cdn.misoenergy.org/202606%20Markets%20and%20Operations%20Report769996.pdf and MISO Monthly Operations Report for July, slide 2, found at https://cdn.misoenergy.org/202607%20Markets%20and%20Operations%20Report776924.pdf and MISO Real Time notifications for August found at https://www.misoenergy.org/markets-and-operations/notifications/.

[4] The six dates are: 6/8, 7/8, 8/9, 8/10, 8/19, and 8/28. Source: *Id.*

[5] For example, 6/8, 7/13, 8/9, 8/10, and 8/28.

[6] "If an event is escalated, then de-escalated, it should only count as a single event of the highest emergency declaration made" Source: "Read Me" tab in the spreadsheet posted for Demand Response (DR) and Load Modifying Resource (LMR) Reforms Workshop - August 24, 2026, available at https://cdn.misoenergy.org/20260824%20DR%20and%20LMR%20Reforms%20Workshop%20Historical%20Capacity%20Advisory%20and%20Max%20Gen%20Declaration%20Data777221.xlsx.

[7] Slide 49, MISO's presentation titled, "Seasonal Readiness Workshop: Summer 2026", on May 6, 2026, Summer Readiness Workshop, https://cdn.misoenergy.org/20260506%20Summer%20Readiness%20Workshop%20Presentation_UPDATED755608.pdf.

[8] Slide 10, MISO's presentation titled "July 15, 2026, Max Gen Event Review" on August 18, 2026, Reliability Sub Committee.

a. 00:00 to 14:00: Normal operations.
b. 14:00 to 16:00: MISO declared Step 1.
c. 16:00 to 17:30: MISO declared Step 2.
d. 17:30 to 17:52: MISO declared Step 1.
e. 17:52 to 23:59: Normal operations.

18. I assembled all the data as shown in the table below.

Table 1 - MISO North/Central Region - Total Capacity Minus Load Minus Operating Reserves[9]

Description	Step 1	Step 1	Step 2	Step 2	Step 1
Hour Ending ("HE")	HE 15:00	HE 16:00	HE 17:00	17:30	17:52
A - Real Time Actual Load	91,617	90,978	89,442	89,442	89,258
B - Operating Reserve Requirement (ORR)	2,750	2,750	2,750	2,750	2,750
C - Actual Load + ORR (*A* + *B*)	94,367	93,728	92,192	92,192	92,008
D - Real Time Gen Fuel Mix	79,627	79,640	77,859	77,859	76,968
E – Generators' Additional Output	500	500	500	500	
F – Imports from Neighboring Balancing Authorities	12,208	12,208	13,101	13,101	13,800
G – Internal Transfers (South --> North/Central)	1,025	1,023	1,121	1,254	1,207
H - Load Modifying Resources	2,000	2,000	3,000		
I – Short-Term Reserves	4,450	4,450	5,200	5,200	5,200
J - Total Capacity (*D*+*E*+*F*+*G*+*H*+*I*)	99,810	99,821	100,781	97,914	97,175
K - Total Capacity minus Load minus ORR (*J* - *C*)	5,444	6,094	8,589	5,721	5,167

19. Consider, for example, MISO's Step 2 at HE 17:00. As shown in Row C, to meet demand and maintain a reserve margin requirement, MISO needed at least 92,192 MW of available supply. In fact, MISO had 100,781 MW of available capacity, as shown in Row J. Thus, at this time, MISO had unused available capacity of 8,589 MW, as shown in Row K.

20. To conduct my analysis, I downloaded[10] MISO real time data for the entire July 15th date, including actual load, the generation fuel mix data, the net actual interchange data that

https://cdn.misoenergy.org/20260818%20RSC%20Item%2012%20July%2015%20Max%20Gen%20Event775901.pdf.

[9] All figures in rows A through K are in megawatts. HE refers to "hour ending." For instance, HE15:00 is the hour ending at 3:00PM Eastern.

[10] MISO Data Exchange, https://data-exchange.misoenergy.org.

shows how much power flowed from neighboring grid operators, and the amount of support that was flowing from MISO's South region to the North and Central region.

21. I supplemented this real time data for July 15th with the demand response data (called Load Modifying Resources) from MISO's presentations to the Market Subcommittee and Reliability Subcommittee. I used the most conservative figures from information published by MISO.[11]

22. I also downloaded the Multiday Operating Margin report available on MISO's website[12] to find how much operating reserves MISO needed per NERC's balancing authority reliability standard requirements. This amount was 2,750 MW for July 15th. I added this 2,750 MW to the real time actual load.

23. Additionally, I downloaded the Short Term Reserve (STR) requirements for 2026 summer,[13] to identify the short term reserves that applied to July 15th. STR was developed by MISO with stakeholders in 2020–21 to address market-wide, sub-regional, and local reliability needs not met by existing products;[14] while not created in response to a specific NERC directive, MISO's operating reserve and STR procurement practices support the balancing authority's compliance with NERC reliability standards. Per STR procurement practices MISO needed to maintain 4,450 MW during Hour Ending 15-16 and 5,200 MW during Hour Ending 17-21 for MISO North/Central region. I added the 4,450/5,200 MW amounts to the capacity side of the equation. Both the Multiday Operating Margin and Short Term Reserve requirements reports enabled me to compare how much capacity MISO had compared to the load plus operating reserve requirement during the Steps 1-2 hours (Hour Ending 15:00 – 17:52) on July 15th to meet NERC's reliability standards.

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[11] Slide 5 of the MISO Market Sub Committee presentation stated that LMRs were terminated at 16:36, but slide 10 of the MISO Reliability Sub Committee presentation stated that the LMRs were terminated at 16:45 EST. Slides 4–5, MISO's presentation titled "Review Market Outcomes for July 15 EEA 2" on August 20, 2026, Market Sub Committee, https://cdn.misoenergy.org/20260820%20MSC%20Item%2009%20Review%20Market%20Outcomes%20for%20July%2015th%20EEA2775968.pdf; Slides 5, 10, MISO's presentation titled "July 15, 2026, Max Gen Event Review" on August 18, 2026, Reliability Sub Committee. https://cdn.misoenergy.org/20260818%20RSC%20Item%2012%20July%2015%20Max%20Gen%20Event775901.pdf.

[12] Multiday Operating Margin Forecast report for July 15th published https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3ASummary&t=10&p=0&s=MarketReportPublished&sd=desc.

[13] Seasonal STR Requirements spreadsheet found at https://cdn.misoenergy.org/Seasonal%20STR%20Requirements625749.xlsx (last updated July 31, 2026).

[14] MISO presentation "Short Term Reserve (STR) (MSC-2018-8) Post Implementation Analysis" January 19, 2023, https://cdn.misoenergy.org/20230119%20MSC%20Item%2008%20Short%20Term%20Reserves%20(MSC-2018-8)627536.pdf.

24. I now proceed to explain the source of those figures and provide additional context.

25. The generators' additional output (Table 1, Row E) available upon declaration of step 1 is the amount of output that generators can produce above ordinary economic maximum limits.[15] I estimate these values based on MISO's August 2026 presentation.[16]

26. MISO and its neighboring balancing areas regularly exchange power through imports and exports. Additionally, MISO has existing arrangements by which it can obtain supply from neighboring balancing areas when conditions are tight in MISO.[17] My source for the amount of supply available to MISO from neighboring balancing areas (Row F) is MISO data.[18] Notably, the values in Table 1 are actual real-time values, *i.e.*, megawatts that were physically flowing on the system during each hour. As such, these values constitute a floor on the amount of purchases available to MISO, and the actual amount available may have been greater.

27. MISO can also use internal transfers (Row G) to bring power from the South subregion to the North/Central subregion.[19] The MISO South subregion was in a position to support the MISO North/Central subregion because MISO declared Step 2 only in the North/Central subregion.

28. On July 15, MISO had access to a portfolio of Load Modifying Resources (LMRs) (Row H). Load Modifying Resources reduce demand through measures such as curtailing industrial process loads, reducing residential and commercial HVAC usage, and activating behind-the-meter generators. Load Modifying Resources provide significant flexibility to address tight system conditions.

29. MISO's total capacity minus the load minus the Operating Reserve Requirement (ORR) had fallen to a range of 1,000 – 1,200 MW in the late morning (HE 11–13), and MISO pre-positioned by declaring Step 1 at 10:12 AM for a forecast 14:00 start. This led to MISO accessing 500 MW of additional output from its generators, accessing 12,000 - 13,000 MW

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[15] See MISO Tariff definition of "Hourly Emergency Maximum Limit," available in Module A at https://www.misoenergy.org/legal/rules-manuals-and-agreements/tariff/.

[16] MISO August 2026 Market Subcommittee Presentation,

https://cdn.misoenergy.org/20260820%20MSC%20Item%2009%20Review%20Market%20Outcomes%20for%20July%2015th%20EEA2775968.pdf, at 4.

[17] Page 235 of 316, Energy and Operating Reserve Markets Business Practices Manual BPM-002-r26 Effective Date: SEP-30-2025.

[18] MISO Data Exchange API, Load-Generation-Interchange API, NAI by Adjacent BA endpoint, July 15 2026; negative=MISO export, positive=MISO import.

[19] Real-Time Intraregional Scheduled Flow data for July 15th, found at MISO -> Market Reports -> Real Time https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#t=10&p=0&s=MarketReportPublished&sd=desc.

of imports from neighboring balancing authorities, and dispatching 2,000 - 3,000 MW of LMRs.

30. By the time Step 2 took effect (HE 17 00), MISO's surplus had grown to roughly 8,500 MW, driven by rising imports from neighboring balancing authorities (climbing to 13,101 MW), a 3,000 MW LMR deployment, and deploying short-term reserves — combined with load that had already begun declining during the preceding Step 1 hour and continued falling.

31. As imports kept rising and reached a record level, MISO terminated the LMR dispatch early (~16:36–16:45, still within HE 17 00) rather than completing the full planned deployment and continued releasing additional output from its generators, as conditions eased. The surplus settled back to roughly 5,000 MW by the time Step 1 was allowed to expire 17:52 EST, at which point MISO returned to normal operations.

32. Had MISO declared Step 3, operators would have had authority to deploy all spinning and supplemental reserves for energy.[20] MISO co-optimizes several reserve products — Spinning Reserves, Ramp Capability, Supplemental Reserves, and Short Term Reserves — but these products are nested: a megawatt clearing a faster product (such as Spinning Reserves, deployable within 10 minutes) also satisfies the requirements of slower products (such as Short Term Reserves (Table 1, Row I), deployable within 30 minutes). Because of this nesting, the total additional capacity available to MISO at Step 3 is best represented by the Short Term Reserve requirement, which encompasses all other reserve products.[21]

33. In summary, MISO had 5,000-8,000 MW of surplus during the July 15th Step 2 event above the amount needed to meet demand and maintain a reserve margin. Overall, this demonstrates that MISO's operations performed as required: they observed falling surplus, followed standard operating procedures, and accessed additional output from generators, imports from neighbors and dispatched LMRs, and subsequently returned to normal operations.

V. Conclusion

34. In conclusion, MISO had more than sufficient capacity to meet demand and maintain operating reserves on July 15, 2026. During the Summer 2026 as a whole, MISO experienced several capacity alerts and advisory declarations but only one event rose to

[20] "IMPLEMENT use of MISO's spinning and supplemental reserves, as needed and as time permits." Page 17 of 45, MISO Market Capacity Emergency SO-P-EOP-11-002 Rev: 25 Information Use Public (Aug. 24, 2026), https://cdn.misoenergy.org/SO-P-EOP-11-002%20Rev%2025%20MISO%20Market%20Capacity%20Emergency757883.pdf.

[21] Seasonal STR Requirements, *supra* note 13.

the level of Step 2 – the July 15th event. Even then, MISO had sufficient capacity to meet demand and maintain operating reserves.

35. Under these conditions, and based on the materials I have reviewed (including the materials referenced in DOE's orders), there is no evidence that MISO needed the capacity from J.H. Campbell, Culley, and Schahfer to prevent a shortfall during Summer 2026 generally or on July 15, 2026 specifically.

I declare under penalty of perjury under the laws of the United States, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on September 11, 2026, in Roseville, Minnesota.

Rao Konidena

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Rao Konidena
Rakon Energy LLC

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 195

Consumers 2026 IRP Application

September 3, 2026

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Post Office Box 30221
Lansing, MI 48909

Re: MPSC Case No. U-22127 – In the matter of the application of Consumers Energy Company for approval of an Integrated Resource Plan and Certificates of Necessity under MCL 460.6s and 460.6t, certain accounting approvals, and for other relief.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case, please find the Redacted version of **Consumers Energy Company's Application with Supporting Testimony and Exhibits of Company Witnesses**. Also included is a Proof of Service showing service upon the parties in Consumers Energy Company's last Integrated Resource Plan Case No. U-21090 and last Electric Rate Case No. U-21870, pursuant to the filing procedures adopted by the Michigan Public Service Commission in Case No. U-21867. This is a paperless filing and is therefore being filed only in PDF.

Please direct any correspondence about this filing to me at the address below.

Sincerely,

Spencer A. Sattler
Phone: 517-474-6638
Email: spencer.sattler@cmsenergy.com

cc: Parties to Case Nos.U-21090 and U-21870

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan and Certificates of Necessity under MCL 460.6s and 460.6t, certain accounting approvals, and for other relief.	)))))))	Case No. U-22127

APPLICATION

Consumers Energy Company ("Consumers Energy" or the "Company") submits this Application for approval of a reliable, affordable, equitable, and clean supply plan that delivers real, measurable benefits to customers and advances Michigan's clean energy future. The Company's supply plan consists of its Integrated Resource Plan ("IRP") Proposed Course of Action ("PCA"), being filed consistent with MCL 460.6t; four Certificates of Necessity ("CONs") for new Company-built and power purchase agreement ("PPA") resources that provide reliable peaking and baseload energy and capacity, being filed consistent with MCL 460.6s; and its Clean Energy Plan, being filed consistent with MCL 460.1051. The Company asks the Michigan Public Service Commission ("MPSC" or "Commission") to approve its supply plan, approve the related accounting and ratemaking treatment, and grant other relief needed to carry it out.

The numbers and facts back the Company's proposals. The supply plan adds approximately 8,800 megawatts ("MW") of solar, 3,200 MW of wind, and 3,300 MW of battery energy storage beyond the resources the Company has already committed to. It also includes a new PPA with Midland Cogeneration Venture Limited Partnership ("MCV") for 1,240 MW of dispatchable capacity; a new clean PPA with [CONFIDENTIAL]

[END CONFIDENTIAL]; a new 919 MW simple-cycle facility at the Company's existing Thetford site; and a new 456 MW simple-cycle facility at the Company's D.E. Karn ("Karn") site. At the same time, the Company is proposing to innovatively expand its virtual power plant capability, which already reduces peak demand by 2,100 MW, as it shifts electric vehicle ("EV") charging toward daytime hours when solar output is high to minimize the stress this new load would otherwise place on the system.

This overall resource mix matters. It allows the Company to add large amounts of clean energy without sacrificing reliability, replace approximately 1,120 MW of capacity from retiring Karn Units 3 and 4, manage tightening MISO capacity conditions, and meet growing customer demand—including approximately 1.9 GW of large load growth already on the system or with executed contracts. Together, these resources give customers a portfolio that is not just cleaner, but more reliable and more resilient. The Company's supply plan pairs large-scale renewable additions with firm, dispatchable, on-demand capacity and storage; avoids overreliance on any single resource type; and positions the Company to meet the State's 80% Clean Energy Standard by 2035 and 100% Clean Energy Standard by 2040. And it does all this while maintaining a rate trajectory that stays within projected inflation.

The following facts support the Application:

[1] [CONFIDENTIAL] [END CONFIDENTIAL].

I. BACKGROUND

1. Consumers Energy is a public utility that generates, distributes, and sells electric energy to 1.9 million retail customers in the state of Michigan. The Company serves a diverse mix of residential, commercial, industrial, and other electric and natural gas customers across Michigan's Lower Peninsula. The Company's retail electric system is operated as a single utility system, within which uniform rates are charged.

2. Consumers Energy's retail electric business is subject to the Commission's jurisdiction under various provisions of 1909 Public Act ("PA") 106, as amended, MCL 460.551 et seq.; 1919 PA 419, as amended, MCL 460.54 et seq.; and 1939 PA 3, as amended, MCL 460.1 et seq. These statutes give the Commission authority to regulate Consumers Energy's retail electric rates.

3. Consumers Energy filed its first IRP on June 15, 2018, in Case No. U-20165, and the Commission approved a contested settlement agreement resolving that case. The PCA approved in that case helped shape the Company's clean energy strategy, paving the way for a significant solar buildout and demand-side resources while accelerating the retirement of D.E. Karn Units 1 and 2. The PCA established a competitive procurement process for future supply-side capacity resources and allowed that process to be used to determine the Company's Public Utility Regulatory Policies Act of 1978 ("PURPA") avoided cost rates and capacity position.

4. Consumers Energy filed its second IRP on June 30, 2021, in Case No. U-21090, and the Commission also approved a contested settlement agreement resolving that case. The approved 2021 IRP advanced the Company's clean energy goals by supporting renewable expansion, the planned retirement of all three J.H. Campbell generating units by May 31, 2025, the acquisition of the New Covert Generating Facility, continued operation of Karn Units 3 and 4

through May 2031, additional energy storage, continued demand-side resources, and continued competitive procurement.

5. Since the 2021 IRP, the electric supply industry has changed in material ways. Consumers Energy has seen substantial economic development in its service territory, resulting in approximately 1.5 GW of contracted new large load growth, above the approximately 400 MW of large load growth that is already online or otherwise reflected in the Company's near-term load outlook. The Company is also talking with existing and prospective new customers who are considering the Company's electric service territory for expanded or new business opportunities, which could add even more load in the future. At the same time, the energy and regulatory landscape is changing:

a. The regional capacity conditions in MISO have tightened;

b. MISO has adopted and is implementing resource adequacy reforms;

c. Federal tax policy affecting renewable and clean energy resources has changed; and

d. There are new requirements in Michigan for clean energy, renewable energy, energy storage, energy waste reduction, demand response, affordability, electrification, emissions, and environmental justice.

6. The Company's 2026 IRP appropriately responds to these evolving conditions. The IRP evaluates the 25-year period from January 1, 2026 through December 31, 2050. The Company's PCA identifies a balanced resource portfolio designed to provide safe, reliable, affordable, clean, and equitable electric service while meeting applicable legal and regulatory requirements.

7. Consumers Energy's PCA represents the most reasonable and prudent means of meeting the Company's energy and capacity needs over the 5-year, 10-year, and 15-year planning periods, consistent with MCL 460.6t, and it should be approved. The Company also asks the

Commission to approve CONs for four resources that form the PCA's reliability and clean backbone. Those CON approvals, along with the related approvals requested in this case, are needed to carry out the supply plan and reliably serve customers for many years to come.

8. The supply plan is an integrated proposal. All proposals made by the Company in this IRP and CON proceeding are integral components of that plan. Rejecting or materially changing one part of the supply plan may affect the supply plan's viability or the Company's willingness and ability to execute remaining components of the plan. The Company, therefore, reserves the rights granted it by law, including the right to update cost estimates under MCL 460.6t(7) if they materially change and the right to abandon or amend its PCA if the Commission rejects or modifies any of the Company's proposals.

II. OVERVIEW

1. MCL 460.6t governs the IRP filing, establishing the components a utility must include in an IRP and the standard for Commission approval. MCL 460.6t(5), (8). Section 6t requires an IRP to give the Commission a comprehensive view of how the utility plans to meet customer needs over the planning period. Among other things, the filing must address proposed supply-side and demand-side resources, the sales forecast and peak demand, energy storage, transmission options, rate impacts, environmental justice impacts, environmental compliance, and emissions.

2. Section 6t also requires the Commission to establish IRP modeling scenarios and assumptions, filing requirements, application forms, and filing deadlines. The Commission has issued orders establishing and updating those requirements in Case Nos. U-18418, U-18461, U-20633, U-21219, U-21570, and U-21867. The Company's filing meets the applicable IRP filing

requirements, clean energy filing requirements, emissions reporting requirements, and related planning requirements.

3. An IRP must be approved if the Commission determines that it represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs. MCL 460.6t(8). In making that determination, the Commission must consider whether the proposed IRP appropriately balances the statutory planning factors, including reliability, competitive pricing, supply diversity, environmental compliance, and resource adequacy and capacity.

4. Since the Company's last IRP, Michigan law has changed significantly. Public Act 231 of 2023 expanded the IRP statute to address clean energy, environmental justice, emissions, affordability, and electrification, while Public Act 235 of 2023 increased the state's renewable energy standards and created new Clean Energy Standards, updated energy waste reduction ("EWR") and demand response ("DR") requirements, and created a statewide energy storage target.

5. The Company was already well on its way toward cleaner energy before the Michigan Legislature enacted these laws, and the IRP and Clean Energy Plan included with these filings build on that progress. The Company has accomplished this through a broad planning process. It has evaluated supply-side and demand-side resource options, existing resources, resource retirements, load forecasts, transmission options, MISO market rules, resource accreditation, environmental justice impacts, emissions requirements, affordability, reliability, and more.

6. Through its planning process, the Company evaluated portfolios under scenarios, sensitivities, and stressors designed to show how they perform in different conditions. It also accounted for several recent major developments: large load growth and economic development

in its service territory and the region at large; lower federal production and investment tax credits for renewable resources; changes to how MISO counts resource capacity; a tighter regional capacity market; updated Clean Energy Standards; and project development constraints.

7. The PCA selected through this process is the best overall portfolio for customers. It balances reliability, affordability, resource diversity, execution risk, clean energy progress, and the need for equity. It also adds dependable near-term capacity to maintain reliability as existing resources retire, customer load grows, regional capacity tightens, and intermittent and energy-limited resources become a larger part of the system.

8. The supply plan does all the following and more:

a. It adds baseload and peaking Company-built resources and PPAs to replace the expiring MCV PPA and retiring Karn Units 3 and 4 and reliably serve load.

- it includes approximately 1,240 MW of dispatchable capacity from the new MCV PPA;
- it includes the construction of a new 919 MW natural gas simple cycle generating facility at the Company's existing Thetford site ("Thetford Project");
- it includes [CONFIDENTIAL] [END CONFIDENTIAL]from a new clean PPA [CONFIDENTIAL] [END CONFIDENTIAL]to help meet the Clean Energy Standard;
- it includes the construction of a new 456 MW natural gas simple cycle generating facility at the Company's existing Karn site ("Karn Project");

b. It further diversifies the Company's resource mix to stay ahead of growing clean, renewable, and battery storage requirements.

- it adds solar resources, including approximately 8,800 MW of additional solar resources beyond resources already committed to;
- it adds approximately 3,200 MW of wind resources beyond resources already committed to;

- it adds approximately 3,300 MW of four-hour battery energy storage resources through 2040;

- it expands virtual power plant capabilities, including EWR, DR, distributed generation, electric vehicle load shaping, conservation voltage reduction ("CVR"), and other demand-side resources from 2,100 MW to 3,500 MW;

9. The PCA reflects continued compliance with the Company's approved 2021 IRP, including the completed acquisition of the New Covert Generating Facility; continued operation of Karn Units 3 and 4 through the approved retirement date; the ongoing effort to retire the J.H. Campbell Generating Plant consistent with the approved plan; and competitive bidding for renewable, storage, and demand-side resources.

10. Although the Company planned to retire Campbell Units 1, 2, and 3 by May 31, 2025 under its approved 2021 IRP, since May 2025 the United States Department of Energy has issued emergency orders requiring Campbell to remain available to support regional reliability. The Company does not treat Campbell as a long-term Company utility resource in this case. Rather, the Company still plans to retire Campbell when temporary federal emergency orders end.

11. The Company's testimony and exhibits show that the PCA is the most reasonable and prudent way to meet the Company's energy and capacity needs. It adds dependable, near-term capacity; complies with clean energy and environmental requirements; reduces reliance on uncertain market capacity purchases; and gives the Company flexibility to respond as market, policy, tax, technology, and customer load conditions change.

III. CERTIFICATES OF NECESSITY

1. MCL 460.6s authorizes an electric utility to seek a CON for construction of an electric generation facility or PPA for the purchase of electric capacity for a period of six years or

longer if the facility or PPA costs $100 million or more and a portion of the costs would be allocated to Michigan retail customers.

2. Under MCL 460.6s(3), the Commission may grant a CON that (i) the power to be supplied as a result of the proposed construction, investment, or purchase is needed; (ii) the size, fuel type, and design characteristics of the proposed facility or the terms of the PPA represent the most reasonable and prudent means of meeting that power need; (iii) the price specified in the PPA will be recoverable in rates; and (iv) the estimated purchase or capital costs and financing plan for the facility will be recoverable in rates consistent with MCL 460.6s(4)(c).

3. MCL 460.6t(13) further provides that, if an IRP includes construction of new capacity owned by the electric utility that is 225 MW or greater, the utility shall submit a CON application under MCL 460.6s. The Company is therefore seeking CON approval in this case for the Karn and the Thetford projects. The Company is also seeking CON approval for the new MCV PPA and the new clean PPA [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], each of which has a term longer than six years and satisfies the statutory criteria for review.

4. The Company seeks CON approval for the Karn Project. The Karn Project is a proposed 456 MW natural gas simple cycle generating facility at the Company's existing Karn site. The Company requests a CON confirming that (i) the power to be supplied by the Karn Project is needed; (ii) the size, fuel type, and design characteristics of the Karn Project represent the most reasonable and prudent means of meeting that need; and (iii) the estimated capital costs and financing plan for the Karn Project will be recoverable in rates consistent with MCL 460.6s.

5. The Company seeks CON approval for the Thetford Project. The Thetford Project is a proposed 919 MW natural gas simple cycle generating facility at the Company's existing Thetford site. The Company requests a CON confirming that (i) the power to be supplied by the

Thetford Project is needed; (ii) the size, fuel type, and design characteristics of the Thetford Project represent the most reasonable and prudent means of meeting that need; and (iii) the estimated capital costs and financing plan for the Thetford Project will be recoverable in rates consistent with MCL 460.6s.

6. The Company seeks CON approval for the MCV PPA. The MCV PPA provides 1,240 MW of firm, dependable capacity and energy from an existing resource beginning in 2030. The Company requests a CON confirming that (i) the power to be supplied under the MCV PPA is needed; (ii) the terms of the MCV PPA represent the most reasonable and prudent means of meeting that need; and (iii) the price specified in the MCV PPA will be recoverable in rates consistent with MCL 460.6s.

7. The Company seeks CON approval for a new clean PPA [CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

8. The proposed projects are needed to maintain reliable service and support the PCA as existing resources retire, demand grows, and regional capacity conditions tighten. The Company's witnesses describe the need for the proposed projects; demonstrate that the size, fuel type, design characteristics, and PPA terms are reasonable; show that the estimated capital and purchase costs are reasonable; and explain why those costs should be recovered in rates.

IV. CLEAN ENERGY PLAN AND COMPLIANCE WITH UPDATED MICHIGAN ENERGY LAW

1. The Company requests approval of its Clean Energy Plan as part of this IRP filing. The Company's Clean Energy Plan demonstrates how the PCA will empower the Company to comply with Michigan's Clean Energy Standard, Renewable Energy Standard, energy storage target, EWR requirements, DR requirements, and related statutory obligations.

2. The Company's supply plan will allow it to meet all statutory renewable and clean energy standards while still building two dispatchable natural gas plants, entering a new PPA for energy and capacity from MCV, and operating existing natural gas assets to continue reliably serving customers and meeting resource adequacy requirements. The Company can do all this simultaneously because Michigan's energy laws set a floor for renewable and clean resources but do not set a ceiling for other resources needed to meet reliability and resource adequacy requirements.

3. Through the Clean Energy Plan and PCA, the Company will be able to meet Michigan's ambitious requirement to achieve 80% clean energy by 2035 and 100% clean energy by 2040. The Company will do so through a balanced mix of renewable resources, existing and new clean energy resources, battery energy storage, demand-side resources, and [CONFIDENTIAL] [END CONFIDENTIAL], carbon-free capacity and energy from the new PPA [CONFIDENTIAL] [END CONFIDENTIAL].

4. Through the Clean Energy Plan and PCA, the Company can also build on the strong foundation established in its Renewable Energy Plan approved in Case No. U-21816 and meet Michigan's Renewable Energy Standard of 50% by 2030 and 60% by 2035. It does so by adding more renewable resources, by continuing competitive procurement, and by planning for project development, tax credits, interconnection, transmission, and execution risks.

5. The Company plans to comply with Michigan's energy storage objectives by adding battery energy storage resources. It is further asking the Commission to approve a process that will allow future battery storage projects to be brought to the Commission for timely review and approval, as described in this Application and the Company's testimony.

6. EWR, DR, CVR, distributed generation, EV load shaping, and other virtual power plant resources are core parts of the Clean Energy Plan and PCA and will reduce customer demand, lower peak needs, support affordability, and reduce the need for additional supply-side resources.

7. The Company describes the PCA's projected rate impacts, the effects of electrification and load growth, the projected emissions outcomes for the PCA and alternatives, and the environmental justice review required by Michigan law and Commission filing requirements.

V. COST APPROVALS

1. MCL 460.6t(11) provides that, in approving an IRP, the Commission is to specify the costs approved for future recovery for the construction of or significant investment in an electric generation facility, the purchase of an existing electric generation facility, the purchase of power under the terms of a PPA, or other investments or resources included in the IRP that will be used to meet energy and capacity needs. Costs included in an approved IRP for investments commenced within three years after the Commission issues an order "are considered reasonable and prudent for cost recovery purposes." *Id.*

2. Consistent with MCL 460.6t(11), the Company asks the Commission to approve costs for EWR, DR, and CVR resources that will begin within three years after the IRP is expected to be approved. The Company requests a finding that these costs are reasonable and prudent for cost recovery purposes.

3. Specifically, the Company asks the Commission to approve the following demand-side resource costs:

a. DR costs for January 1, 2028 to August 31, 2030, consisting of $3,579,375 in capital costs, $69,992,433 in operation and maintenance ("O&M") costs, and a $13,355,590 incentive to achieve a total of 549 MW, or 645 Zonal Resource Credits ("ZRCs"), in 2029;

b. EWR costs for January 1, 2030 to August 31, 2030, consisting of $91,205,607 in O&M costs and a $13,680,841 incentive, with projected savings of 315,226 MWh and 1,312 MW; and

c. CVR costs for January 1, 2028 to August 31, 2030, consisting of $11,265,239 in capital costs, with projected savings of 136,351 MWh and 56.81 MW.

4. The Company also asks the Commission to pre-approve cost recovery, consistent with MCL 460.6s(3)(d), (6), and (9), for the Company's proposed CON resources, including the Karn Project, Thetford Project, MCV PPA, and [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], as described in the Company's direct testimony and exhibits. This includes cost recovery for the capital costs and financing plan for the Karn and Thetford projects and approval of the MCV PPA and [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] prices.

5. The Company further seeks a financial incentive for the new MCV PPA, consistent with MCL 460.6s(6), and a financial incentive for the new clean PPA with [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], consistent with MCL 460.6t(15) and MCL 460.1028(8), [END CONFIDENTIAL] based on the Company's weighted average cost of capital. These financial incentives would apply for the duration of the agreements, and the amount would be updated based on the most recently approved electric rate case.

VI. REQUESTED ACCOUNTING AND RATEMAKING APPROVALS

1. The Company seeks approval to include Construction Work In Progress ("CWIP") in rate base during construction of the Karn and Thetford projects and to eliminate the corresponding Allowance for Funds Used During Construction ("AFUDC") offset in general rate

case revenue requirements to the extent financing costs are recovered in rates during the construction period.

2. CWIP treatment for the Karn and Thetford projects supports the Company's ability to finance large, needed generation investments while maintaining financial stability and managing customer affordability. The proposed treatment aligns cost recovery with the construction period and reduces the accumulation of AFUDC that would otherwise increase the final cost of the projects placed into service.

3. The Company seeks approval of accounting and ratemaking treatment for reasonably and prudently incurred costs associated with retaining Karn Units 3 and 4 through their approved retirement date, with recovery to be addressed consistent with the Company's testimony and future rate proceedings.

4. The Company also asks the Commission to approve any other accounting and ratemaking approvals necessary to carry out the supply plan and the relief described in this Application, testimony, and exhibits.

VII. COMPETITIVE PROCUREMENT, PURPA, AND BATTERY STORAGE APPROVAL PROCESS

1. The Company proposes to continue using its competitive solicitation process to acquire supply-side resources identified in the PCA, subject to modifications described in the Company's testimony. The Company's updated procurement approach includes two competitive solicitations per year, which improves market visibility; provides more opportunities to identify cost-effective resources; supports timely procurement of resources needed to implement the PCA; and gives the Company flexibility to respond to changing market prices, tax-credit deadlines, interconnection timelines, and customer load developments.

2. The Company also requests approval of its PURPA implementation and avoided cost proposal. The proposal envisions competitive bidding that continues to inform avoided cost values; prospective modifications to capacity-related avoided cost eligibility for qualifying facilities that provide bundled energy, capacity, and renewable energy credits; an annual eligibility limit for fully bundled renewable QF resources receiving capacity-related avoided cost compensation; and annual avoided cost updates.

3. The Company also requests approval of an ex parte process for future battery storage projects selected through competitive solicitations or bilateral negotiations, subject to Commission review and an objective cost benchmark not to exceed a 140% threshold explained in testimony. This process would allow the Company to timely pursue cost-effective storage resources needed to carry out the PCA while preserving customer protections.

4. The Company requests continued recognition that, so long as the Company is implementing its approved PCA and competitive procurement process, the Company's PURPA capacity position should be determined consistent with the approved planning and procurement framework and identified resource needs.

VIII. TESTIMONY, EXHIBITS, PROTECTIVE ORDER, AND OTHER MATTERS

1. Consumers Energy is, concurrently with this Application, filing written testimony and exhibits in support of its IRP, Clean Energy Plan, CON requests, accounting and ratemaking requests, PURPA proposal, battery storage approval process, and other relief requested in this case. This material further supports this Application and the relief being sought and is incorporated by reference.

2. The Company's IRP Report, sponsored as Exhibit A-2 (SQM-2), describes the analysis underlying the PCA, includes the required Clean Energy Report, and supports the

included as Exhibit A-1 (SQM-1) and identifies the testimony and exhibits where each IRP Filing Requirement is addressed. The Company's CON Filing Requirements Checklists are included as Exhibits A-5 (KGT-3) and A-14 (TPC-9) and identify the testimony and exhibits where each CON Filing Requirement is addressed.

3. As required by the Commission's IRP Filing Requirements and Clean Energy Plan Filing Requirements, Consumers Energy has included a Verification and Letter of Transmittal as Attachments A and B to this Application. The Letter of Transmittal expresses the Company's commitment to its preferred resource plan, resource acquisition strategy, and approved Clean Energy Plan. The letter is signed by an officer of the Company with authority to commit the Company to the resource acquisition strategy and Clean Energy Plan, subject to the Company's right to make changes as appropriate due to changing circumstances.

4. Because confidential information is included in and submitted with the Company's filing, Consumers Energy proposes entry of a protective order. The Company requests that the Administrative Law Judge ("ALJ") or the Commission enter the protective order, included as Attachment C, to govern confidential information submitted in this proceeding.

IX. REQUEST FOR RELIEF

WHEREFORE, Consumers Energy requests that the Michigan Public Service Commission:

A. Approve Consumers Energy's IRP, consistent with MCL 460.6t, by approving the PCA that includes all the Company's proposals presented in this case, as the most reasonable and prudent means of meeting its energy and capacity needs;

B. Approve Consumers Energy's Clean Energy Plan and find that the Company's filing satisfies applicable clean energy, renewable energy, energy storage, EWR, DR, electrification, affordability, emissions, and environmental justice requirements;

C. Approve a CON for the Karn Project, consistent with MCL 460.6s, including findings that the power to be supplied is needed; that the size, fuel type, and design characteristics represent the most reasonable and prudent means of meeting that need; and that the estimated capital costs and financing plan will be recoverable in rates;

D. Approve a CON for the Thetford Project, consistent with MCL 460.6s, including findings that the power to be supplied is needed; that the size, fuel type, and design characteristics represent the most reasonable and prudent means of meeting that need; and that the estimated capital costs and financing plan will be recoverable in rates;

E. Approve a CON for the MCV PPA, consistent with MCL 460.6s, including findings that the power to be supplied is needed, that the terms of the agreement represent the most reasonable and prudent means of meeting that need, and that the price specified in the agreement will be recoverable in rates;

F. Approve a CON for the [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] consistent with MCL 460.6s, including findings that the power to be supplied is needed, that the terms of the agreement represent the most reasonable and prudent means of meeting that need, and that the price specified in the agreement will be recoverable in rates;

G. Approve a financial incentive for the MCV PPA and [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] based on Consumers Energy Company's weighted average cost of capital, for the duration of the agreements with updates based on the Company's most recently approved electric rate case;

H. Approve Consumers Energy's proposed EWR, DR, and CVR costs as reasonable and prudent for cost recovery purposes under MCL 460.6t for costs to be commenced within three years after this IRP is approved;

I. Approve Consumers Energy's request to include CWIP in rate base during construction of the Karn and Thetford projects and to eliminate the corresponding AFUDC offset in general rate case revenue requirements to the extent financing costs are recovered in rates during construction;

J. Approve Consumers Energy Company's proposed accounting and ratemaking treatment for reasonably and prudently incurred costs associated with retaining Karn Units 3 and 4 through the approved retirement date, including its request to defer expenses related to the Karn retention and separation agreement by recording those amounts as a regulatory asset;

K. Approve Consumers Energy Company's proposed competitive procurement process, including the use of two annual competitive solicitations to create more opportunities to identify cost-effective resources;

L. Approve Consumers Energy Company's PURPA avoided cost and implementation proposal, including continued use of competitive procurement to inform avoided cost values, prospective modifications to capacity-related avoided cost eligibility, an annual eligibility limit for fully bundled renewable QF resources receiving capacity-related avoided cost compensation, and annual avoided cost updates;

M. Find that Consumers Energy Company's PURPA capacity position should be determined consistent with the Company's approved PCA, competitive procurement process, and identified resource needs;

N. Approve Consumers Energy Company's proposed ex parte approval process for future battery storage projects selected through competitive solicitations or bilateral negotiations, subject to Commission review and the objective cost benchmark described in testimony;

O. Enter an appropriate protective order governing confidential information submitted in this proceeding;

P. Accept the Company's Verification and Letter of Transmittal and find that the Company has satisfied the applicable IRP filing requirements; and

Q. Grant Consumers Energy Company any other relief that is just and reasonable.

Respectfully submitted,

CONSUMERS ENERGY COMPANY

Date: September 3, 2026 By: 

Anita J. Griffin
Vice President, Commercial Operations & Planning
Consumers Energy Company



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ATTACHMENT A

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan and Certificates of Necessity under MCL 460.6s and 460.6t, certain accounting approvals, and for other relief.	)))))))	Case No. U-22127

VERIFICATION

Anita J. Griffin, being duly sworn, deposes and says that she is the Vice President of Commercial Operations & Planning for Consumers Energy Company; that she has executed the above Application for, and on behalf of, Consumers Energy Company; that she has read the Application and is familiar with its contents; that the facts contained in the Application are true, to the best of her knowledge and belief; and that she is authorized to execute the Application on behalf of Consumers Energy Company.

Date: September 3, 2026 By: 

Anita J. Griffin
Vice President, Commercial Operations & Planning
Consumers Energy Company

ATTACHMENT B

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan and Certificates of Necessity under MCL 460.6s and 460.6t, certain accounting approvals, and for other relief.	)))))))	Case No. U-22127

LETTER OF TRANSMITTAL

I, Anita J. Griffin, express Consumers Energy Company's commitment to the Company's Integrated Resource Plan Proposed Course of Action, which represents the most reasonable and prudent resource plan and resource acquisition strategy, and its commitment to the Clean Energy Plan and four projects for which the Company seeks Certificates of Necessity, as described in this Application. I sign this Letter of Transmittal as an officer of the Company having authority to commit the Company to the resource acquisition strategy, acknowledging that the Company reserves the right to make changes to its resource acquisition strategies, clean energy plan, and proposed projects as appropriate due to changing circumstances and as permitted by law.

Date: September 3, 2026 By: 

Anita J. Griffin
Vice President, Commercial Operations & Planning
Consumers Energy Company

ATTACHMENT C

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan and Certificates of Necessity under MCL 460.6s and 460.6t, certain accounting approvals, and for other relief.	)	Case No. U-22127

PROTECTIVE ORDER

This Protective Order governs the use and disposition of Protected Material that any Party discloses to another Party during the course of this proceeding. This Protective Order protects non-public, confidential information and materials so designated by the Disclosing Party as Protected Material, as defined herein. Accordingly, it is ordered:

I. "Protected Material" and Other Definitions

A. "Protected Material" consists of trade secrets or confidential, proprietary, or commercially sensitive information provided in Disclosing Party's application, exhibits, discovery or audit responses, any witness' related exhibits and testimony, motions, objections, briefing, responses to an order issued by the presiding hearing officer or the Michigan Public Service Commission ("MPSC" or the "Commission), and any arguments of counsel describing or relying upon the Protected Material. Subject to challenge under Paragraph IV.A, Protected Material shall also consist of non-public confidential information and materials including, but not limited to, the following information disclosed during the course of this case if it is marked as required by this Protective Order:

1. To the extent permitted, information received from or concerning a third party that is subject to any confidentiality, non-disclosure, non-

transferability, license, or similar contractual restriction. This information includes reports; analyses; models (including related inputs and outputs); trade secrets; and confidential, proprietary, or commercially sensitive information that the Disclosing Party or one of its witnesses is authorized to disclose consistent with the terms and conditions of this Protective Order.

2. Information that is protected as confidential in another jurisdiction that the Applicant provides utility service, and the source of the other jurisdiction's protective designation is made known to the Receiving Party.

3. Information that could identify the bidders and bids, including the winning bid, in a competitive solicitation for a power purchase agreement or in a competitively bid engineering, procurement, or construction contract at any stage of the selection process (*i.e.,* before the Disclosing Party has entered into a power purchase agreement or selected a contractor).

B. The information subject to this Protective Order does not include:

1. Information that is or has become available to the public through no fault of the Receiving Party or Reviewing Representative and no breach of this Protective Order, or information that is otherwise lawfully known by the Receiving Party without any obligation to hold it in confidence;

2. Information received from a third party free to disclose the information without restriction;

3. Information that is approved for release by written authorization of the Disclosing Party, but only to the extent of the authorization;

4. Information that is required by law or regulation to be disclosed, but only to the extent of the required disclosure; or Information that is disclosed in response to a valid, non-appealable order of a court of competent jurisdiction or governmental body, but only to the extent the order requires.

C. "Applicant" refers to the filing party in this proceeding.

D. "Disclosing Party" means a Party producing Protected Material in this proceeding.

E. "Party" refers to the Applicant, MPSC Staff ("Staff"), Michigan Attorney General, or any other person, company, organization, or association that is granted intervention in this case under the Commission's Rules of Practice and Procedure, Mich Admin Code, R 792.10401 et al.

F. "Receiving Party" means any Party to this proceeding who requests or receives access to Protected Material. A Receiving Party is responsible for assuring that persons, representatives, or agents under its control or supervision comply with this Protective Order.

G. "Reviewing Representative" means a representative of the Receiving Party who is:

1. An attorney who has entered an appearance in this proceeding for a Receiving Party;

2. An attorney, paralegal, or other employee associated, for the purpose of this case, with an attorney described in Paragraph I.G.1;

3. An expert or employee of an expert retained by a Receiving Party to advise, prepare for, or testify in this proceeding; or an employee or other representative of a Receiving Party with significant responsibility in this case.

H. "Nondisclosure Certificate" refers to Attachment 1 to this Protective Order.

Except as otherwise provided herein, the Reviewing Party and Reviewing Representatives will be required to sign Nondisclosure Certificates. However, Nondisclosure Certificates will not be required from administrative law judges, members of the Commission and its support staff, Staff (excluding consultants, third-party experts, agents or other similar persons), and Staff counsel, for whom by virtue of their employment are presumed to be bound by the terms of this Protective Order.

II. Access to and Use of Protected Material

A. This Protective Order governs the use of all provided Protected Material. This Protective Order protects: (i) the Protected Material; (ii) any copy or reproduction of the Protected Material made by any person; and (iii) any memorandum, handwritten notes, or any other form of information that copies, contains, or discloses Protected Material. All Protected Material in the possession of a Receiving Party and a Reviewing Representative shall be

maintained in a secure place. Access to Protected Material shall be limited to the Receiving Party and the Reviewing Representative, after each has executed the Nondisclosure Agreement and provided a copy of the Nondisclosure Agreement to the Disclosing Party, subject to the limited exception in Paragraph I.H.

B. Protected Material must be used and disclosed by the Receiving Party solely in accordance with the terms and conditions of this Protective Order. A Receiving Party and Reviewing Representative may analyze the Protected Material; make or respond to discovery; present evidence; prepare testimony, argument, briefs, or other filings; prepare for cross-examination; consider strategy; and evaluate settlement. A Reviewing Representative shall not release or disclose the content of Protected Material to any other person or use the information for any other purpose.

C. The Disclosing Party may request the Receiving Party withhold certain information from a Reviewing Representative and retains the right to object to any designated Reviewing Representative if the Disclosing Party has reason to believe that there is an unacceptable risk of misuse of confidential information. If a Disclosing Party objects to a Reviewing Representative, then the Disclosing Party shall submit the dispute to the presiding hearing officer simultaneously upon objection. If the Disclosing Party notifies a Receiving Party of an objection to a Reviewing Representative, then the Protected Material shall not be provided to that Reviewing Representative until the objection is resolved by agreement or by the presiding hearing officer.

D. If a Receiving Party seeks access to Critical Energy Infrastructure Information ("CEII") as defined in 16 U.S.C § 824o-1(a)(3) and FERC rules, specifically 18 CFR § 388.113(c), the Receiving Party and Reviewing Representative shall also sign the CEII Nondisclosure Certificate (Attachment 2 to this Protective Order) and provide a copy of the

executed CEII Nondisclosure Certificates to the Disclosing Party.

E. The obligations under this Protective Order do not expire by entry of a final order in this case and are enforceable by the MPSC or a court of competent jurisdiction. To the extent Protected Material is not returned to a Disclosing Party, it remains subject to this Protective Order. Members of the Commission, Commission staff assigned to assist the Commission with its deliberations, and the presiding hearing officer shall have access to all Protected Material that is submitted to the Commission under seal.

F. A Party retains the right to seek further restrictions on the dissemination of Protected Material to persons who have or may subsequently seek to intervene in this MPSC proceeding.

G. Nothing in this Protective Order precludes a Party from asserting a timely evidentiary objection to the proposed admission of Protected Material into the evidentiary record for this case.

III. Procedures

A. The Disclosing Party shall identify what portion(s) of any document designated confidential it considers confidential. This can be done through highlights or other clear identifier. The Disclosing Party must mark any information that it considers confidential as "CONFIDENTIAL: SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-22127." Software executable files containing Protected Material may not be capable of being marked with the foregoing required protective language. The inability to mark software executable files containing Protected Material with such protective language shall not diminish the requirements of this Protective Order. It shall be sufficient if the medium used to deliver software executable files containing Protected Material is marked with the required protective language. However, any output from the software executable files containing Protected Material that is generated only as a reproducible document, whether electronic or non-electronic, that is capable of being marked with the required

protective language, shall be marked by the party who generated the output with such protective language and subject to the requirements of this Protective Order. If the Receiving Party or a Reviewing Representative makes copies of any Protected Material, they shall conspicuously mark the copies as Protected Material. Notes of Protected Material shall also be conspicuously marked as Protected Material by the person making the notes.

B. If a Receiving Party wants to quote, refer to, or otherwise use Protected Material in pleadings, pre-filed testimony, exhibits, cross-examination, briefs, oral argument, comments, or in some other form in this proceeding (including administrative or judicial appeals), the Receiving Party shall do so consistent with procedures that will maintain the confidentiality of the Protected Material. For purposes of this Protective Order, the following procedures apply:

1. Written submissions using Protected Material shall be filed in a sealed record to be maintained by the MPSC's Docket Section, or by a court of competent jurisdiction, in envelopes clearly marked on the outside, "CONFIDENTIAL – SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-22127." Simultaneously, identical documents and materials, with the Protected Material redacted, shall be filed and disclosed the same way that evidence or briefs are usually filed;

2. Oral testimony, examination of witnesses, or argument about Protected Material shall be conducted on a separate record to be maintained by the MPSC's Docket Section or by a court of competent jurisdiction. These separate record proceedings shall be closed to all persons except those furnishing the Protected Material and persons otherwise subject to this Protective Order. The Receiving Party presenting the Protected Material during the course of the proceeding shall give the presiding officer or court sufficient notice to allow the presiding officer or court an opportunity to take measures to protect the confidentiality of the Protected Material; and

3. Copies of the documents filed with the MPSC which contain Protected Material, including the portions of the exhibits, transcripts, or briefs that refer to Protected Material, shall be marked or identified as, "CONFIDENTIAL - SUBJECT TO PROTECTIVE ORDER IN CASE NO. U-22127" and shall be maintained in a separate portion of the record under seal, segregated in the files of the Commission, and withheld from inspection by any person not bound by the terms of this Order.

C. The Protected Material subject to this Order shall be shielded from disclosure to the extent permitted by law. If any person files a request under the Freedom of Information Act

("FOIA") with the MPSC or the Michigan Attorney General seeking access to documents subject to this Protective Order, the MPSC's Executive Secretary, Staff, or the Attorney General shall promptly notify the Disclosing Party, and the Disclosing Party may take whatever legal actions it deems appropriate to protect the Protected Material from disclosure. In light of Section 5 of the Freedom of Information Act, MCL 15.235, the notice must be given at least five (5) business days before the MPSC, Staff, and/or the Michigan Attorney General grant the request in full or in part.

IV. Termination of Protected Status

A. A Receiving Party reserves the right to challenge by motion whether a document or information is Protected Material and whether this information can be withheld under this Protective Order. The Receiving Party challenging the protected status of the document must explicitly state its reason for challenging the confidential designation. In response to a motion, the Commission or the presiding hearing officer in this case may revoke a document's protected status after notice and hearing. If the presiding hearing officer revokes a document's protected status, then the document loses its protected status after 14 days unless a Party files an application for leave to appeal the ruling and a request for a stay to the Commission pursuant to R 792.10433. If the application for leave is timely, the document's protected status will continue during the Commission appeal process. Any Party opposing the application for leave to appeal and the stay shall file an answer with the Commission no more than 14 days after the filing and service of the appeal. Continued protected status post order, will be determined by the Commission in its order addressing the application for leave and the request for stay. Nothing in this paragraph shall prohibit the Disclosing Party from seeking a stay on appeal of the Commission's decision regarding the revocation of any document's protected status.

B. The Disclosing Party bears the burden of proving that the document should continue to be protected from disclosure.

V. Retention of Documents

Protected Material remains the property of the Disclosing Party and, except as required by applicable law and State retention schedules, only remains available to the Receiving Party until the time expires for petitions for rehearing of a final MPSC order, until the MPSC has ruled on all petitions for rehearing in this case (if any), or until judicial review is completed and the time to take further appeal has expired. If the Disclosing Party seeks to have the Receiving Party return all Protected Material in the Receiving Party's possession or in the possession of its Reviewing Representatives, or certify in writing that all Protected Material has been destroyed, it is the responsibility of the Disclosing Party to contact the Receiving Party and make its request no earlier than the expiration of time for filing petitions for rehearing of a final MPSC order, until the MPSC has ruled on all petitions for rehearing in this case (if any), or until judicial review is completed and the time to take further appeal has expired. Further, for a Receiving Party that is associated with the State, the request must be consistent with the expiration of the State retention requirement.

Notwithstanding the foregoing, counsel for the Receiving Party may maintain a single confidential file of Protected Material subject to all other provisions in this Order. Should counsel seek to refer to the Protected Material in another Commission proceeding, the Disclosing Party must be the Applicant in said proceeding and counsel must ensure there is a protective order in said proceeding which protects the Protected Material from public disclosure.

VI. Limitations and Disclosures

This Protective Order does not apply to a particular document, or portion of a document, described in Paragraph II.A if a Receiving Party can demonstrate that it has been previously disclosed by the Disclosing Party on a non-confidential basis or meets the criteria set forth in Paragraphs I.B.1 through I.B.4. A Receiving Party intending to disclose information taken

directly from materials identified as Protected Material must-before actually disclosing the information-do one of the following: (i) contact the Disclosing Party's counsel of record and obtain written permission to disclose the information, or (ii) challenge the confidential nature of the Protected Material and obtain a ruling under Paragraph IV that the information is not confidential and may be disclosed in or on the public record.

VII. Remedies

If a Receiving Party violates this Protective Order by improperly disclosing or using Protected Material, the Receiving Party shall take all necessary steps to remedy the improper disclosure or use. This includes promptly notifying all Parties and the presiding hearing officer in writing. The written notice must identify the person known or reasonably suspected to have obtained the Protected Material. A Party or person that violates this Protective Order remains subject to this paragraph regardless of whether the Disclosing Party could have discovered the violation earlier than it was discovered. This paragraph applies to both inadvertent and intentional violations. Nothing in this Protective Order limits the Disclosing Party's rights and remedies, at law or in equity, against a Party or person using Protected Material in a manner not authorized by this Protective Order, including the right to obtain injunctive relief in a court of competent jurisdiction to prevent violations of this Protective Order.

VIII. Modification

Formal Addendums to this agreement may be established by an ALJ upon motion by any party and after notice and hearing.

MICHIGAN ADMINISTRATIVE HEARING SYSTEM
For the Michigan Public Service Commission

_____
Administrative Law Judge

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan and Certificates of Necessity under MCL 460.6s and 460.6t, certain accounting approvals, and for other relief.	)))))))	Case No. U-22127

Attachment 1

NONDISCLOSURE CERTIFICATE

By signing this Nondisclosure Certificate, I acknowledge that access to Protected Material is provided to me under the terms and restrictions of the Protective Order issue in Case No. U-21227, that I have read the Protective Order, and that I agree to be bound by the terms of the Protective Order.

Reviewing Representative:

Date:_____ _____

Receiving Party:

_____

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan and Certificates of Necessity under MCL 460.6s and 460.6t, certain accounting approvals, and for other relief.	)))))))	Case No. U-22127

Attachment 2

NONDISCLOSURE CERTIFICATE

FOR CRITICAL ELECTRIC INFRASTRUCTURE INFORMATION

I hereby agree and certify my understanding that access to Critical Electric Infrastructure Information ("CEII") as defined at 16 USC Section 824o-1(a)(3) and 18 CFR Section 388.113(c) is provided to me pursuant to the terms and restriction of this CEII Nondisclosure Certificate and the Protective Order issued in Case No. U-21227, that I have been given a copy of and have read the Protective Order, and I agree to be bound by the terms of this CEII Nondisclosure Certificate and the Protective Order. I further agree that:

1. I will use CEII only for the purpose for which it was requested;

2. I will only discuss CEII with a Party and/or Reviewing Representative;

3. I will keep CEII in a secure place in a manner that prevents unauthorized access;

4. I will destroy CEII or return it to the disclosing party upon request;

5. I understand that CEII is not subject to release under the Freedom of Information Act;

6. I understand that I am obligated to protect CEII even after a designation as CEII has lapsed until a determination by the administrative law judge that the information should no longer be designated as CEII; and

7. I will report all unauthorized disclosures of CEII to the Disclosing Party.

Reviewing Representative:

Date:_____ _____

Title:_____

Receiving Party:_____

Printed Name:_____

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan and Certificates of Necessity under MCL 460.6s and 460.6t, certain accounting approvals, and for other relief.	)))))))	Case No. U-22127

PROOF OF SERVICE

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Melissa K. Harris, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on September 3, 2026, she served an electronic copy of **Consumers Energy Company's Application with Supporting Testimony and Exhibits of Company Witnesses** upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

Melissa K. Harris

Subscribed and sworn to before me this 3rd day of September, 2026.

Crystal L. Chacon

Crystal L. Chacon, Notary Public
State of Michigan, County of Eaton
My Commission Expires: 05/25/30
Acting in the County of Jackson

ATTACHMENT 1 TO CASE NO. U-22127
(Including Parties to Case Nos. U-21090 and U-21870)

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* Receives Confidential Materials

ATTACHMENT 1 TO CASE NO. U-22127
(Including Parties to Case Nos. U-21090 and U-21870)

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* Receives Confidential Materials

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan and Certificates of Necessity under MCL 460.6s and 460.6t, certain accounting approvals, and for other relief.	)))))))	Case No. U-22127

REDACTED

DIRECT TESTIMONY

OF

STEVEN Q. MCLEAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2026

INTRODUCTION AND PURPOSE OF TESTIMONY

Witness Background

Q. Please state your name and business address.

A. My name is Steven Q. McLean, and my business address is 1945 W. Parnall Rd., Jackson, Michigan 49201.

Q. By whom are you employed and what is your present position?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as the Director of Regulatory Operations in the Electric Supply department.

Q. Please review your educational background.

A. I earned a Bachelor of Science in Political Science and Economics from Central Michigan University in May 2003. I earned a Master of Arts in Economics from Central Michigan University in December 2007.

Q. Please review your business experience.

A. In January 2006, I joined the Michigan Public Service Commission ("MPSC" or the "Commission") where I held various positions of increasing responsibility. In 2011, I was promoted to the Manager of the Rates and Tariffs section. The responsibilities of that section included, but were not limited to, analyzing utility reports, financial records, and rate case filings to determine the appropriate level of rates for regulated energy utilities utilizing laws, regulations, and Commission policies. In August 2014, I was hired by SEMCO Energy Gas Company ("SEMCO") as the Rates and Regulatory Affairs Manager. In December of 2016, I was promoted to Director of Regulatory Affairs. As Director of Regulatory Affairs, I was responsible for all state and federal regulatory matters for SEMCO. In addition, I was responsible for SEMCO's Energy Waste Reduction ("EWR")

program. In September 2019, I was hired by Consumers Energy as the Director of Customer Experience Regulatory Strategy, Reporting and Quality within the Clean Energy department, and in October 2021, I was promoted to Director of Customer Regulatory and Compliance. From there, I transitioned into leading our Transportation, Renewables and Innovation department in June 2024 before assuming my current role as Director of Regulatory Operations, within the Electric Supply Strategic Planning organization, in August 2025.

Q. What are your responsibilities as the Director of Regulatory Operations?

A. In this position, I am responsible for providing strategic leadership and oversight of regulatory operations supporting the Company's Integrated Resource Planning. My responsibilities include developing, managing, and executing regulatory strategy, planning, and filings before the MPSC, the Federal Energy Regulatory Commission ("FERC"), and other applicable forums. This includes regulatory filings and testimony associated with Integrated Resource Planning, and other related regulatory initiatives.

I oversee the development of business cases, testimony, discovery responses, audits, and monthly and annual regulatory reporting, and work closely with internal and external stakeholders to ensure alignment between business unit operations, long-term resource planning objectives, and approved regulatory outcomes. In addition, I provide regulatory guidance and support stakeholder and intervenor engagement related to Integrated Resource Plan ("IRP") and investment planning and monitor regulatory and industry trends to inform management of risks, opportunities, and strategic impacts.

Additionally, I serve as the Electric Supply representative supporting the Company's economic development efforts. In that role, I help evaluate the electric supply

implications of prospective new or expanding customer load, including the resource adequacy, capacity expansion, and energy supply requirements associated with serving such load. I also coordinate with internal teams regarding planning assumptions, customer-specific requirements, and the estimated costs of capacity expansion or other supply-side resources that may be needed to reliably serve large load customers. This work supports the alignment of economic development opportunities with the Company's long-term resource planning and regulatory strategy, while helping ensure that the costs attributable to serving large load customers are appropriately identified and structured so that large load customers are not subsidized by existing customers.

Q. Have you previously testified before the MPSC?

A. Yes. I testified in the Company's general rate cases, Case Nos. U-20650, U-20697, U-21148, U-21224, U-21389, and U-21490; the Company's 2019 and 2020 Demand Response ("DR") Reconciliations, Case Nos. U-20766 and U-21080, respectively; the Company's 2021 IRP, Case No. U-21090; and the Company's 2021 EWR Plan filing, Case No. U-20875. Additionally, I have testified before the MPSC in numerous general rate cases, Gas Cost Recovery cases, EWR cases, and other miscellaneous proceedings on behalf of the MPSC Staff ("Staff") and SEMCO.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to provide an overview of the Company's IRP process and key conclusions as well as a summary of the Company's request for Certificates of Necessity ("CONs") that arise from the findings of the IRP. More specifically, my testimony provides: (i) an overview of the statutory and regulatory requirements that drive the Company's filing; (ii) a summary of the objectives and

principles that drive the evaluation process in the Company's IRP; (iii) an overview of the study process used to complete the IRP; (iv) a summary of the Company's load forecast drivers; (v) a review of the Company's baseline capacity position; (vi) a description of the new resource options considered in the Company's planning process; (vi) an overview of the approach the Company took to evaluate risk and uncertainty; (vii) a summary of the Proposed Course of Action ("PCA") and how the PCA meets key requirements and objectives; and (viii) a description of the Company's request for CONs and related relief in connection to (a) a new Purchase Power Agreement ("PPA") for capacity and energy with Midland Cogeneration Venture Limited Partnership ("MCV") or ("MCV PPA"); (b) a new PPA for capacity and energy with [CONFIDENTIAL] [redacted] [END CONFIDENTIAL]; and (c) construction of a new 456 MW natural gas simple cycle generating facility at the Company's existing D.E. Karn ("Karn") site ("Karn Project") and construction of a new 919 MW natural gas simple cycle generating facility at its existing Thetford site ("Thetford Project"), all of which are collectively referred to as the "Proposed Projects."

Q. Are you sponsoring exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-1 (SQM-1)	IRP Filing Requirements Checklist;
Exhibit A-2 (SQM-2)	Confidential Consumers Energy IRP and Clean Energy Report; and
Exhibit A-118 (SQM-3)	Press Release and Executive Summary of the Company's PCA.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

I. OVERALL TESTIMONY SUMMARY

IRP and CONs – Resource Choices that Proactively Address Customers' Growing Load and the Changing Regulatory Landscape

Q. Why has the Company filed this IRP?

A. The Company is filing this IRP to showcase its planned resource mix that will allow it to continue providing customers with reliable and affordable power for many years to come. The Company proposes a balanced resource portfolio. It includes an additional 8,800 MW of solar and 3,200 MW of wind resources, beyond what it has already committed to; 3,300 MW of 4-hour battery energy storage resources through 2040; an innovative expansion to its virtual power plant ("VPP") capability; the addition of a PPA for clean energy of [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] to help meet the clean energy standard; and an additional 2,615 MW of baseload and peaking Company-built units and PPAs to replace the expiring MCV PPA and retiring Karn units.

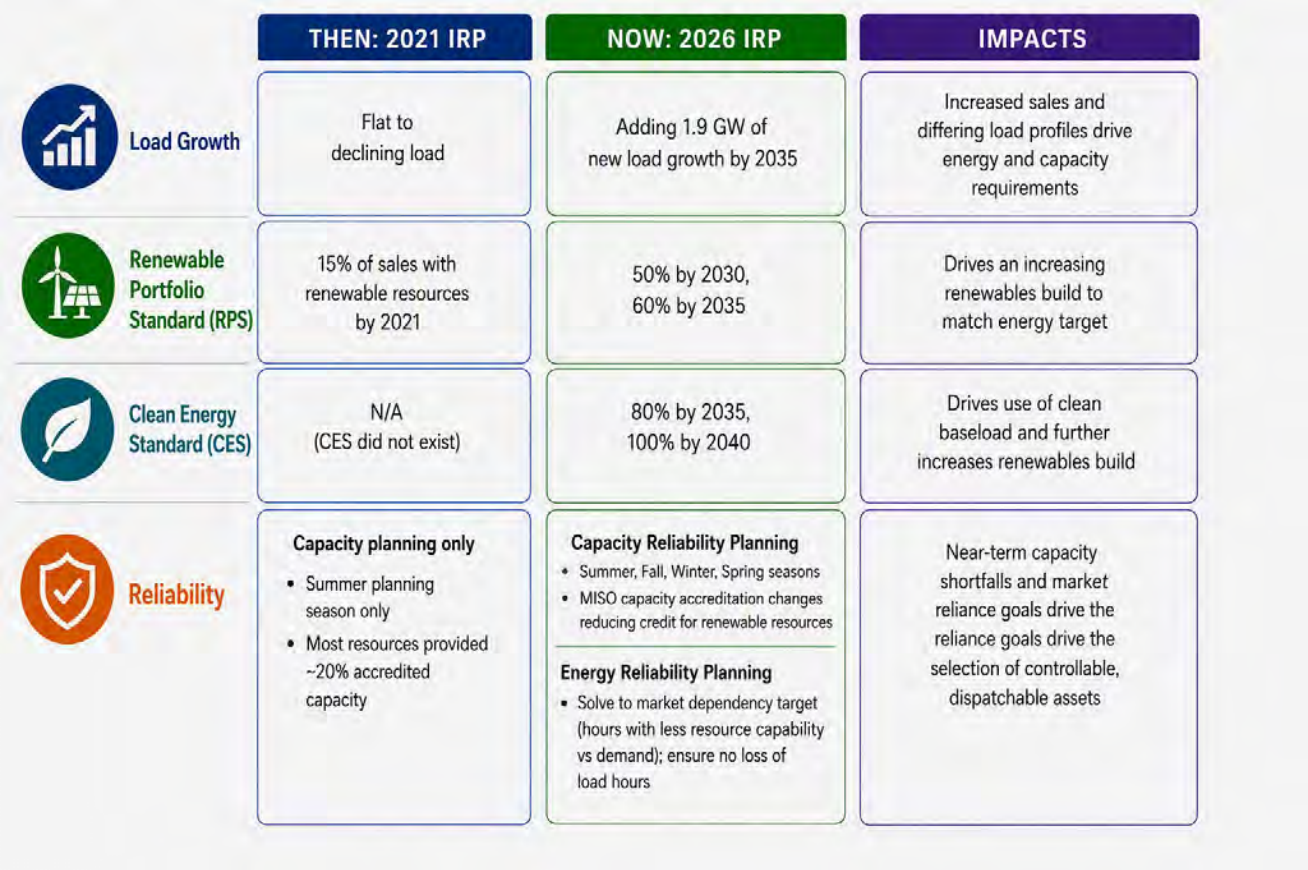
The Company's plan fulfills the State of Michigan's requirement that the Company file a detailed IRP every five years[1]. The IRP provides a plan for how the Company will meet future energy and capacity needs of customers in a prudent manner, adhering to state law and Commission requirements. The PCA from the Company's last IRP filed in 2021 was resolved in June 2022 when the Commission approved a settlement agreement. That plan advanced the Company's clean energy goals via its renewable expansion, the early retirements of all J.H. Campbell ("Campbell") generating Units 1, 2, and 3, acquisition of

[1] A utility is required to file an application for review of its IRP within 5 years after the date of its most recent IRP Order from the MPSC. A utility may choose to file prior to the 5-year requirement (for example, within 3 years of the most-recent Order).

the Covert natural gas fueled generating plant, and an agreement to continue operations at Karn Units 3 and 4, in conjunction with a One-time Solicitation for dispatchable and clean capacity resources.

Since approval of the 2021 IRP, there have been significant changes associated with load growth, market rules, state and federal policy, and technology evolution that all necessitate a significant shift in the Company's PCA. As part of its 2026 IRP, the Company has performed a robust and rigorous set of analyses to identify the most reasonable and prudent path for meeting customers' long-term electric needs in a manner that is safe, reliable, affordable, clean, equitable, and consistent with Michigan energy law. The IRP is the Company's plan for serving both existing customers and load growth in Michigan while complying with applicable clean energy, renewable energy, storage, and EWR requirements. It also provides the Commission, customers, and stakeholders with a transparent record of the Company's planning assumptions, modeling, portfolio evaluation, and recommended resource decisions. Figure 1 below summarizes the major changes and impacts since the 2021 IRP filing.

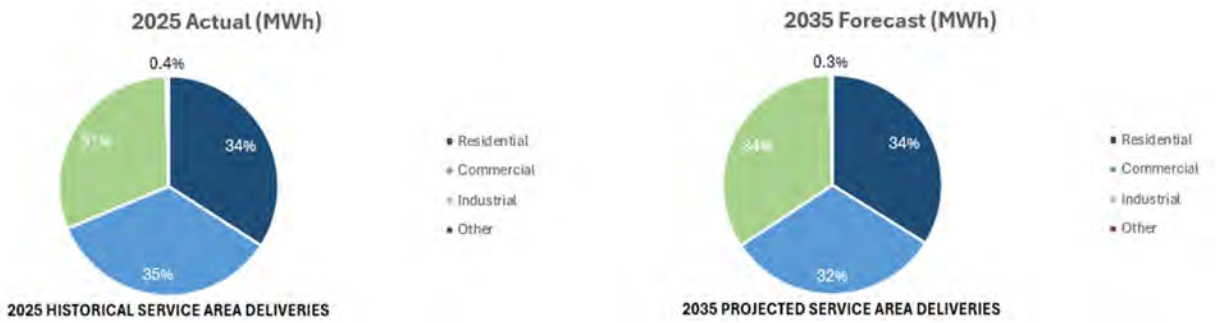
Figure 1: Summary of Changes and Impacts



Q. Please provide a high-level overview of Consumers Energy's electric system.

A. Consumers Energy delivers electricity and gas to 6.8 million customers in all 68 counties of the lower peninsula of Michigan. Our customer base is diverse in type, size, and energy needs. The Company's electric utility customer base consists of a mix of primarily residential, commercial, and diversified industrial customers in the lower peninsula as illustrated in Figure 2 below.

Figure 2: Historical and projected MWh by customer class



Q. What is the planning period evaluated in this IRP?

A. The planning period for the IRP covers the 25-year period beginning January 1, 2026 and ending December 31, 2050.

Q. What has changed since the Company's prior IRP?

A. There have been several significant changes to the electric supply industry, not only within Michigan, but across the country, since the Company's prior IRP. First, the Company has experienced substantial economic development activity including more than 400 MW of new and planned load growth from signed or otherwise committed customer activity, as well as an additional [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] of data center load under an executed Large Load contract as described later in my testimony. In addition, the Company is actively evaluating a broader economic development pipeline that includes significant potential additional growth. This represents a substantial change from the planning environment reflected in the prior IRP, where resource needs were driven primarily by existing customer demand, planned retirements, renewable additions, and replacement capacity. Second, regional resource adequacy conditions across the Midcontinent Independent System Operator, Inc. ("MISO") have tightened, capacity market prices have increased relative to historical levels, and MISO is

implementing reforms that change how capacity reliability is measured and valued. These developments increase the importance of dependable, accredited capacity within the Company's portfolio and reduce the reasonableness of relying on regional market purchases as a primary planning strategy. Third, Michigan's clean energy framework has evolved, including new clean energy and renewable energy requirements, continued EWR obligations, and a statewide energy storage target. Fourth, federal tax policy affecting renewable and clean energy resources has changed materially since the prior IRP. In particular, changes to federal production tax credits and investment tax credits, including accelerated eligibility deadlines, evolving domestic content requirements, and restrictions related to certain foreign ownership or supply-chain participation, can materially affect the modeled and actual cost of renewable resources. These changes create timing, qualification, and execution risks for renewable projects and may increase customer costs if projects are unable to qualify for credits assumed in planning or procurement. Fifth, the Company has gained additional experience implementing the 2021 IRP, including resource procurement, project development, and evolving cost and execution risks, which informed the Company's approach to evaluating the timing, diversity, and flexibility of resources in this IRP.

Q. How has the Company responded to these changed conditions in its 2026 IRP?

A. The Company responded to these changed conditions by enhancing the IRP framework and using that framework to evaluate resource portfolios that could perform under a wider range of future conditions. The Company developed load forecasts that recognize signed large load commitments and evaluate alternative load trajectories, including business-as-usual ("BAU") and higher-load outcomes, to understand how additional economic

development growth could affect resource needs, costs, and customer impacts. The Company also strengthened its reliability assessment by developing market reliance modeling, expanding upon its loss-of-load expectation ("LOLE") modeling, and leveraging third-party experts to assist with and review key modeling assumptions and reliability analyses. The Company also strengthened its reliability assessment by developing market reliance modeling and expanding upon its in-house LOLE modeling to evaluate portfolio performance under tightening regional capacity conditions, evolving MISO accreditation rules, and periods of system stress. In addition, the Company broadened the range of candidate resources evaluated in the IRP, including dispatchable capacity, existing nuclear resources, renewables, storage, VPPs inclusive of EWR, DR, distributed generation, electric vehicle ("EV") load shaping, and conservation voltage reduction ("CVR"), and emerging clean firm technologies such as carbon capture, utilization, and storage. The Company also used a structured analytical process that included a technology screen, consistent assumptions for resource cost, performance, availability, development timing, and build limits, and evaluation of scenarios, sensitivities, and stressors related to load growth, fuel prices, technology costs, resource availability, market conditions, and policy outcomes. The Company further evaluated the potential impact of changing federal tax credits on renewable and storage resource economics, and supply-chain restrictions could increase the delivered cost of solar, wind, and storage resources or alter the relative economics and timing of those resources. Finally, the Company evaluated portfolios against a broader set of planning objectives, including reliability, affordability, resource diversity, clean energy progress, equity, execution risk, and flexibility. Together, these enhancements allowed the Company to evaluate whether

portfolios could meet statutory requirements while reliably and affordably serving existing customers and new large load customers, and to identify a PCA that provides near-term dependable capacity while preserving the ability to add clean and demand-side resources as market, policy, technology, tax, and development conditions continue to evolve.

Q. What additional planning and implementation enhancements did the Company develop to support execution of the PCA?

A. In addition to the modeling and portfolio evaluation enhancements described above, the Company developed several implementation tools and process improvements to support execution of the PCA. First, the Company developed a new rate model that produces a supply rate forecast based on the PCA. This tool allows the Company to translate the resource additions, retirements, fuel and purchased power costs, tax impacts, and other supply-related assumptions reflected in the PCA into projected customer rate impacts over the planning horizon. This additional analysis improves the Company's ability to evaluate affordability, communicate expected customer impacts, and assess how resource decisions affect existing customers and support load growth from economic development. Second, the Company is progressing renewable resource development in the near term where doing so can help capture available federal tax credits and reduce customer costs. Because federal tax credit eligibility for wind and solar resources is increasingly dependent on construction timing, placed-in-service dates, domestic content requirements, and supply-chain eligibility, pursuing near-term renewable additions can preserve tax-credit value and reduce the risk that customers lose the benefit of incentives assumed in planning. Third, the Company has bolstered its collaboration with Michigan Electric Transmission Company ("METC") to better align resource planning, interconnection, and transmission

development considerations. This enhanced coordination supports a more integrated assessment of where resources can be developed, how they can be interconnected, whether transmission constraints or network upgrades may affect cost, and how local generation and transmission planning can work together to support reliability. Finally, the Company updated its solicitation approach from one competitive solicitation per year to two competitive solicitations per year. Moving to a twice-per-year solicitation cadence improves market visibility, provides more opportunities to identify cost-effective resources, supports timely procurement of resources needed to implement the PCA, and gives the Company additional flexibility to respond to changing market prices, interconnection timelines, tax-credit deadlines, and customer load developments.

Summary of Requested Approvals and Rationale for the PCA

Q. Please explain what the Company is seeking approval for in this IRP.

A. In this proceeding, the Company is seeking approval of a PCA which represents the most reasonable and prudent means of meeting the Company's energy and capacity needs over the 5, 10, and 15-year time horizons, consistent with Public Act 341 of 2016 ("Act 341"), MCL 460.6t ("Section 6t"). In order to implement the resource plan in the PCA, the Company also requests approval of CONs under Act 341, MCL 460.6s ("Section 6s") along with the additional approvals necessary to implement the resource plan and related proposals described in the Company's testimony, exhibits, and IRP report.

The PCA provides the best overall balance: a diverse portfolio that delivers safe, reliable, affordable, clean, and equitable power supply. The PCA includes four CONs for a new MCV PPA; a new [CONFIDENTIAL] [redacted]

[redacted] [END CONFIDENTIAL] ; and two peaking natural gas plants that add approximately 1,400 MW of new CT capacity. Beyond these CONs, the Company is adding substantial amounts of solar, wind, storage, and VPP capability over the planning horizon. This portfolio achieves the lowest reasonable cost among feasible alternatives while maintaining reliability, meeting applicable environmental and clean energy requirements, and staying in line with long-term supply rate impacts within inflation. This portfolio provides near-term dependable capacity and operational flexibility needed to maintain reliability as the Company continues to expand renewable, storage, demand-side resources, and emerging clean firm resources over the planning horizon.

The Company selected the PCA because no alternative portfolio outperformed it across the full set of evaluation criteria. The selection of a preferred plan requires assessment of the tradeoffs inherent in any set of resource decisions. No single plan is likely to perform best across each of the primary objectives, but the PCA clearly offers the best balance of performance across *all* objectives and offers the Company a high level of flexibility to respond to future market and industry conditions as they evolve. The PCA provides reliable capacity to serve customers during periods of peak demand, grid stress, low renewable output, and periods of resource unavailability. It supports affordability by achieving the lowest reasonable cost among feasible portfolios that maintain reliability and meet environmental requirements, and by using the new rate model to evaluate projected customer supply rates over the planning horizon. The Company targeted a rate trajectory that remains within inflation, while also recognizing the benefits of load growth on costs per MWh. The PCA promotes resource diversity and reduces technology and execution

risk by relying on commercially mature resources in the near term while preserving optionality for emerging technologies as they reach commercial viability. It advances clean energy progress through [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], continued renewable expansion, growth in energy storage, and scaled VPPs such as EWR, demand-side resources, and distributed generation, with a focus on equitable distribution of clean energy investment.

The Company is seeking:

1. Approval of the PCA. The Company requests approval of the PCA as the most reasonable and prudent plan under Act 341, and consideration of the Alternate and Support Plans as part of the Commission's evaluation of reliability, affordability, and risk. The Alternate, and Support Plans demonstrate why the PCA represents the best balance of system needs across a range of future conditions.

2. Approval of CONs for New Generation Projects. Pursuant to Act 341, Section 6s, the Company is seeking CONs for the following projects identified in the PCA:

    I. Karn CT Project, affirming that:

        (i) the power to be supplied is needed;

        (ii) the size, fuel type, and design characteristics represent the most reasonable and prudent means of meeting that need; and

        (iii) the estimated capital costs and financing plan will be recoverable in rates.

    II. Thetford CT Project, affirming that:

        (i) the power to be supplied is needed;

        (ii) the size, fuel type, and design characteristics represent the most reasonable and prudent means of meeting that need; and

        (iii) the estimated capital costs and financing plan will be recoverable in rates.

    III. MCV PPA, affirming that:

(i) the power to be supplied is needed;

(ii) the terms of the agreement represent the most reasonable and prudent means of meeting that need; and

(iii) the price specified in the agreement will be recoverable in rates.

IV. [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] PPA, affirming that:

(i) the power to be supplied is needed;

(ii) the terms of the agreement represent the most reasonable and prudent means of meeting that need; and

(iii) the price specified in the agreement will be recoverable in rates.

These projects correspond directly to the type, timing, and function of resources selected in the PCA, as supported by the IRP modeling and reliability analysis.

3. Approval of the Company's Clean Energy Plan.

4. Approval of a financial incentive for the new MCV PPA based on the Company's weighted average cost of capital pursuant to MCL 460.6s(6). The financial incentive will be for the duration of the agreement and the financial incentive will be updated based on the most recently approved electric rate case. Approval of a financial incentive for the new [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] based on the Company's pretax weighted average cost of permanent capital pursuant to MCL 460.6t(15) and MCL 460.1028(8). The financial incentive will be for the duration of the agreement and the financial incentive will be updated based on the most recently approved electric rate case.

5. Demand-Side Resource Cost Recovery. Consistent with prior IRPs and Commission practice, the Company seeks approval of EWR, DR, and CVR program costs to be implemented within three years following approval of this IRP, for cost recovery pursuant to MCL 460.6t. These programs remain an integral component of the PCA and are reflected in the Company's modeling assumptions and portfolio selection.

6. Accounting and ratemaking approval to include Construction Work In Progress ("CWIP") in rate base during construction of the Karn and Thetford CT projects and to eliminate the corresponding Allowance for Funds Used During Construction ("AFUDC") offset in general rate case

revenue requirements to the extent financing costs are recovered in rates during the construction period.

7. Approval of accounting treatment related to Karn retention costs. The Company seeks approval of accounting and ratemaking treatment for reasonably and prudently incurred costs associated with retaining Karn Units 3 and 4 through the approved retirement date, with recovery to be addressed consistent with the Company's testimony and applicable future rate proceedings.

8. Public Utility Regulatory Policies Act of 1978 ("PURPA") avoided cost proposal. The Company seeks approval of the PURPA implementation and avoided cost proposal, including continued use of competitive procurement to inform avoided cost values, prospective modifications to capacity-related avoided cost eligibility for qualifying facilities that provide bundled energy, capacity, and renewable energy credits, an annual PURPA capacity-related cap, and annual avoided cost updates.

9. Approval of an ex parte approval process for battery energy storage system ("BESS") projects. The Company requests approval of an ex parte process for future BESS projects selected through competitive solicitations or bilateral negotiations, subject to Commission review and an objective cost benchmark not to exceed 140% of the Planning Year 2029 BESS PCA proxy. This process would allow the Company to timely pursue cost-effective storage resources needed to implement the PCA while preserving customer protections.

In addition to the requested approval of the CONs under MCL 460.6s for the Proposed Projects as described above, the proposed EWR, DR, and CVR costs which will be commenced by the Company within three years following the Commission's expected approval of the Company's IRP as reasonable and prudent for cost recovery purposes pursuant to MCL 460.6t, the Company is seeking approval of the following costs:

a. DR costs for January 1, 2028 to August 31, 2030 ($3,579,375 capital, $69,992,433 Operating and Maintenance ("O&M"), $13,355,590 of incentive, to achieve a total of 549 MW (645 Zonal Resource Credits ("ZRCs")) in 2029);

b. EWR costs for January 1, 2030 to August 31, 2030, ($91,205,607 O&M, 13,680,841 of incentive, 315,226 MWh savings, 1,312 MW savings); and

c. CVR costs for January 1, 2028 to August 31, 2030 ($11,265,239 capital, 136,351 MWh savings, 56.81 MW savings).

Q. Why is the Company seeking approval of CONs and, more specifically, why is it seeking approval as part of this filing?

A. The CONs are a critical component of the Company's overall resource plan that will supply customers with affordable power they can rely on when they need it most. To reliably serve customers, the Company is proposing CONs for two company-built peaking gas plants at existing industrial sites, one CON for a baseload thermal Power Purchase Agreement, and an additional CON for a [CONFIDENTIAL] [END CONFIDENTIAL]that will complement the Company's current generation assets. The Company is seeking approval of these CONs as part of this filing because the Proposed Projects fall within the statutory framework for CON review and approval. Section 6s authorizes an electric utility to seek a CON for the construction of an electric generation facility with investment costs greater than $100 million and for a PPA with a term of six years or longer. Section 6t also requires Commission review of the resources included in an IRP and provides the framework for determining whether the Company's PCA represents the most reasonable and prudent means of meeting customers' energy and capacity needs.

The Karn and Thetford natural gas combustion turbine ("CT") projects each exceed the applicable statutory thresholds for new generation facilities because each project is greater than 225 MW and involves investment costs greater than $100 million. The MCV PPA and [CONFIDENTIAL] [END CONFIDENTIAL] each have terms greater than six years. Because these resources satisfy the statutory categories for CON review, the Company is requesting Commission approval confirming that the power to be supplied by

each resource is needed, that the proposed facilities or PPA terms represent the most reasonable and prudent means of meeting that need, and that the associated costs are eligible for recovery in rates consistent with Michigan law.

As described in greater detail later in my testimony these resources replace aging Karn units with modern, reliable generation that will help ensure dependable service while supporting the Company's clean energy goals. They are needed to maintain reliable service as existing resources retire, demand grows, and regional capacity conditions tighten. The Karn and Thetford projects provide firm, dispatchable capacity; the MCV PPA preserves dependable, firm, and dispatchable capacity and energy from an existing resource; and the [CONFIDENTIAL] [redacted] [END CONFIDENTIAL]energy and capacity that supports clean energy compliance. Together, the Proposed Projects address the capacity, energy, reliability, and compliance needs identified through the IRP process.

Compliance with Commission Requirements and Witness Roadmap

Q. Does this IRP and CON filing meet the Commission's requirements?

A. Yes. This filing meets the requirements set forth by the Commission in Case Nos. U-21867 and U-21570 (Michigan IRP Parameters, Michigan IRP, and Michigan Clean Energy Filing Requirements), Case No. U-15896 (CON Filing Requirements), and Case No. U-20633 (Emissions Reporting). The Company's filing also meets the requirements in Section 6s and 6t of Act 341. Exhibit A-1 (SQM-1) details each IRP filing requirement and the corresponding location of responsive information in the Company's filing. It should be noted that this exhibit is intended to direct a reviewer of the Company's filing to information filed by the Company which addresses a certain filing requirement and does

not provide an exhaustive list of all information which may be applicable to a certain filing requirement.

Q. Has the Company developed a report to supplement this IRP filing?

A. Yes. I am sponsoring the Company's IRP report, which appears as Exhibit A-2 (SQM-2). The IRP report is inclusive of the required Clean Energy Report. The Company's IRP report meets the Commission's filing requirements and provides, among other things, the Company's analysis and decisions in selecting its PCA resource evolution strategy, and Clean Energy Plan

Q. Please provide an overview of the witnesses and the topics for which they will present evidence in support of this IRP filing.

A. There are 25 witnesses presenting evidence in support of this IRP filing and the related CONs requested by the Company.

Several witnesses discuss and document key assumptions that drive key inputs for the Company's overall IRP analysis. These include:

- Company witness Marianne M. Walter presents the existing electric generating resources under the Company's control and operation and the capital and O&M costs associated with those resources and the new generation resources reflected in the PCA. Company witness Walter also describes the retirement dates assumed in the modeling and the treatment of the hydro sale and related PPA assumptions reflected in the IRP.

- Company witness Eugène M. Breuring provides detail regarding how the forecast of electric deliveries, peak demand, and system output is developed for the period 2026 through 2050. Company witness Breuring describes the forecasting methodology and forecast evaluation process, including the treatment of EWR, CVR, and DR impacts, as well as the assumptions related to electric vehicles, large economic development customers, data centers, and the BAU, physical climate change, and aggressive load growth forecast scenarios used in this IRP.

- Company witness Thomas P. Clark describes the proxy unit cost attributes and cost estimates used in the IRP process for new generation resource options. He

also specifically discusses the details of the proposed CT projects at the Karn and Thetford sites in support of the Company's CON applications.

- Company witness James R. McCormick describes the Company's engagement with the local transmission owner, the transmission assumptions used in the IRP modeling, and the studies performed regarding transmission alternatives and constraints. Company witness McCormick also discusses Capacity Import Limit ("CIL") assumptions, transmission network upgrade sensitivities, the Company's consideration of grid-enhancing technologies, storage-related transmission considerations, out-of-state resource considerations, and the interconnection studies supporting the proposed Karn and Thetford projects.

- Company witness Angela K. Rissman describes the Company's fuel procurement strategy and the fuel-related assumptions supporting the PCA. Company witness Rissman discusses the Company's approach to firm gas transportation, supply portfolio design, storage and flexibility for winter reliability, layered hedging strategies, and contract structures intended to support reliability and manage customer cost exposure as gas-fired resources play an increasing role in the Company's supply portfolio.

- Company witness Kenneth D. Johnston addresses the Company's Clean Energy Plan, Renewable Energy Plan, and Voluntary Green Pricing ("VGP") programs. Company witness Johnston describes the Company's existing and projected renewable generating resources, compares the assumptions in the Company's approved 2024 Renewable Energy Plan to the assumptions reflected in this IRP, discusses compliance with Renewable Portfolio Standards and the Clean Energy Standard, explains how the Company's renewable and clean energy resources compare to the statutory clean energy goals, and addresses projected customer demand for VGP products. Additionally, witness Johnston addresses the Company's PURPA proposal.

- Company witness Brian J. VanBlarcum explains the federal renewable and clean-energy tax credits and other tax considerations relevant to the IRP. Mr. VanBlarcum discusses the requirements to qualify for available tax credits, including applicable start-of-construction timing requirements, the calculation of base and bonus credits, and the manner in which tax incentives and related property-tax considerations affect the economics of renewable, storage, and other generation technologies reflected in the Company's resource planning analysis. Company witness VanBlarcum also discusses the property taxes for the proposed Karn and Thetford projects.

- Company witness Alex M. Gast provides a policy overview of the Company's VPP demand-side resources, including EWR, DR, and EV programs. Company witness Gast discusses the Company's EWR and DR portfolios, the relationship between statutory EWR requirements, the Company's EWR planning assumptions, MISO's Load Modifying Resource reforms, and the role of EV

charging programs and charging behavior in shaping load and supporting off-peak system utilization.

- Company witness Dimitry V. Burdjalov, a representative of ICF Resources, L.L.C. ("ICF"), discusses the methodology, assumptions, and results of the Company's EWR and DR potential studies. Mr. Burdjalov explains how those studies inform the Company's IRP, compares the current study outcomes to the prior IRP, describes scenario analysis performed in the studies, and addresses the factors that limit long-term EWR and DR potential.

- Company witness Daniel A. Schmoekel discusses the Company's CVR program and describes the assumptions and results of the CVR analysis reflected in the IRP. Company witness Schmoekel explains the Company's CVR strategy, the expected load-reduction benefits, the associated investment assumptions, and the role of grid modernization efforts in enabling those benefits.

- Company witness Beth A. Skowronski explains the Company's contractual supply arrangements and procurement-related assumptions reflected in the IRP. This witness discusses the 2025 all-source request for proposals, the Company's existing PPA portfolio and related modeling assumptions, the Company's acquisition strategy for new supply-side resources.

Several witnesses sponsor testimony that describes the Company's overall modeling process and key analysis elements, as well as its engagement with stakeholders. These include:

- Company witness Adam J. Moritz discusses economic modeling completed in support of the IRP. In particular, he provides a description of the scenarios, sensitivities, assumptions, and constraints included within the IRP modeling and used to evaluate the Company's need for new resources. Company witness Moritz also explains the modeling results, including energy, capacity, and net present value outcomes, and supports the conclusion that the resources selected in the PCA best satisfy the Company's reliability, affordability, and compliance objectives. His testimony also supports the alternative resource analysis required for the Company's CON requests by comparing feasible portfolio and resource options and demonstrating that the resources for which the Company seeks CON approval represent the most reasonable and prudent means of meeting the identified need.

- Company witness Paul I. Soni describes the risk and reliability assessment methodology utilized in this IRP and the results of that analysis. Company witness Soni explains market reliance metrics, the LOLE study methodology, the multi-metric reliability assessment used in the filing, the reliability

outcomes across the filed plans, and the cost-risk analysis associated with key sensitivities, including gas price volatility.

- Company witness Heidi J. Myers explains the financial assumptions used in the IRP model and provides the estimated customer rate impacts and affordability analysis associated with the PCA and applicable alternative plans. Company witness Myers also supports the filing requirement affordability calculations and addresses the ratemaking mechanics associated with the proposed CWIP treatment for the gas projects.

- Company witness Heather A. Breining describes the environmental regulations applicable to the Company's generating fleet, the emissions outlook associated with the Company's resource plan, and the environmental justice evaluation and analysis performed for this filing. Company witness Breining also addresses the environmental and emissions implications of the PCA, the relationship between the PCA and the Company's clean energy objectives, and environmental considerations associated with the proposed Karn, Thetford, and MCV resources.

- Company witness Jason R. Coker describes the Company's stakeholder engagement efforts for this IRP. Company witness Coker discusses the statutory and settlement-driven stakeholder engagement requirements, the design and execution of the Company's outreach efforts, including public outreach, technical workshops, Environmental Justice community engagement, Tribal engagement, and coordination with Staff and transmission owners, and explains how stakeholder feedback informed modeling assumptions, scenario design, and the development of the PCA.

Finally, several witnesses provide detail on the specific projects and requests being made associated with the CONs the Company is seeking. These include:

- Company witness Nathan J. Washburn describes the capital and operating cost estimates for the proposed Karn and Thetford generating station projects. Company witness Washburn explains the methodology used to develop the cost estimates and presents the proposed capital expenditure and operating expenditure assumptions for each project.

- Company witness Steven A. Sulzman describes the proposed generating technology, major systems, operational characteristics, procurement status, and equipment selection for the proposed Karn and Thetford generating station projects. Company witness Sulzman explains the rationale for the selected equipment and addresses the project design considerations supporting the Company's CON requests.

- Company witness Erin M. Busby describes the development and site-selection support for the proposed new natural gas generation projects for which the

Company seeks CONs. Company witness Busby explains the site selection process and criteria, the characteristics of the proposed sites and surrounding land uses, anticipated off-site transportation and infrastructure considerations, the project development and construction schedule, and the expected construction workforce.

- Company witness Daniel J. Azukas, a representative of Sargent & Lundy ("S&L"), describes the independent owner's engineer work performed in support of the proposed natural gas generation projects. This witness explains the independent site-selection methodology and screening criteria, the comparative evaluation of candidate sites, the suitability of the Karn and Thetford sites for simple-cycle natural gas generation, and the preliminary interconnection analysis supporting the feasibility of the proposed projects.

- Company witness Sang H. Gang, a representative of S&L, describes the independent owner's engineer work performed in support of the proposed natural gas generation projects. This witness explains the transmission studies performed for the Proposed Karn Project ("Karn Replacement Study") and for the Proposed Thetford Project ("Thetford System Impact Study")

- Company witness Marc R. Bleckman explains the Company's request for CWIP in rate base treatment, rather than AFUDC, for the two near-term gas-fired simple-cycle projects. Company witness Bleckman addresses the financial and credit-metric rationale for that request and its relationship to the Company's financing and affordability considerations.

- Company witness Keith G. Troyer discusses the Company's proposed MCV PPA, proposed [CONFIDENTIAL] [END CONFIDENTIAL], and related CON support for each agreement. Company witness Troyer explains the background, procurement, principal terms, and customer benefits of the PPAs, including their role in providing [CONFIDENTIAL] [END CONFIDENTIAL]. He also supports the Company's request for Commission approval of the PPAs, including findings that the power to be supplied is needed, that the size, fuel type, and terms of the agreement represent the most reasonable and prudent means of meeting a portion of the Company's power needs, and that the price specified in the agreements should be recoverable in rates.

For ease of reference, the following table summarizes the primary categories of testimony presented in support of the Company's IRP and related CON requests, identifies the witnesses addressing those topics, and describes each witness's principal role in supporting the filing.

Table 1

Category	Witness	Primary Role
Overall Narrative & CON Justification	Steven Q. McLean	IRP Strategy & Regulatory Narrative
Key Input Assumptions	Eugène M. Breuring	Load Forecast & Demand Growth
	James R. McCormick	Transmission & Deliverability
	Thomas P. Clark	Resource Cost Assumptions
	Angela K. Rissman	Fuel Supply Strategy
	Kenneth D. Johnston	Clean Energy Compliance
	Marianne M. Walter	Existing Generation Fleet & Cost Assumptions
	Brian J. VanBlarcum	Tax Credits & Incentives
	Alex M. Gast	Demand-Side Resource Strategy
	Dimitry V. Burdjalov (ICF)	EWR & DR Potential Studies
	Daniel A. Schmoekel	CVR Planning Strategy
	Beth A. Skowronski	Procurement & Contracting Strategy
	Jason R. Coker	Stakeholder Engagement & Outreach
Core Portfolio Development and PCA Selection	Adam J. Moritz	Portfolio Selection & Economics
Key Portfolio Performance Outcomes	Paul I. Soni	Reliability & Risk Assessment
	Heather A. Breining	Environmental & Emissions Compliance

Category	Witness	Primary Role
	Heidi J. Myers	Affordability & Rate Impacts
CON Leads	Keith G. Troyer	MCV and [CONFIDENTIAL] [redacted] [END CONFIDENTIAL]
	Thomas P. Clark	Karn and Thetford
Specific CON Project Support	Marc R. Bleckman	Financing & CWIP Strategy
	Erin M. Busby	Project Development & Siting
	Daniel J. Azukas (S&L)	Independent Site Evaluation
	Sang H. Gang (S&L)	Interconnection & Grid Studies
	Nathan J. Washburn	Project Cost Estimates
	Steven A. Sulzman	Plant Design & Technology Selection

II. STATUTORY AND REGULATORY BACKGROUND

Michigan IRP and CON Requirements

Q. Were the IRP statutory provisions and CON provisions enacted together?

A. No. The CON statutory provisions, which can be found in Section 6s, came first. They took effect on October 6, 2008 after then Governor Jennifer Granholm approved Public Act 286 of 2008, which added Section 6s to Public Act 3 of 1939. Section 6s was later amended by Act 341 but has not been amended since. Act 341, in addition to amending Section 6s, integrated the CON statutory requirements together with a new IRP framework in Section 6t for electric utilities whose rates are regulated by the Commission.

Q. Did the Commission promulgate rules to carry out the CON statutory provisions?

A. Yes, the Commission adopted CON Application Instructions in its December 23, 2008 Order in Case No. U-15896, and they were updated on May 11, 2017.

Q. What facilities qualify for a CON under the law?

A. Under Section 6s(1), a utility that plans to "construct an electric generation facility . . . or enter into a power purchase agreement for the purchase of electric capacity for a period of 6 years or longer may submit an application to the [C]ommission seeking a certificate of necessity" if the facility or PPA "costs $100,000,000.00 or more and a portion of the costs would be allocable to retail customers in this state."

Q. How and when can a CON be sought and to what end?

A. A CON can be sought as part of a standalone proceeding or together with an IRP filing. When an IRP includes a utility-built facility of 225 megawatts or more, Section 6t(13) requires that the utility file a CON application. When this happens, Section 6s(1) explains that the Commission should consider the requests together in a consolidated proceeding.

A utility may ask the Commission to approve CONs for a project for one or more of the following purposes:

> (a) A certificate of necessity that the power to be supplied as a result of the proposed construction, investment, or purchase is needed.
>
> (b) A certificate of necessity that the size, fuel type, and other design characteristics of the existing or proposed electric generation facility or the terms of the power purchase agreement represent the most reasonable and prudent means of meeting that power need.
>
> (c) A certificate of necessity that the price specified in the power purchase agreement will be recovered in rates from the electric utility's customers.

> (d) A certificate of necessity that the estimated purchase or capital costs of and the financing plan for the existing or proposed electric generation facility, including, but not limited to, the costs of siting and licensing a new facility and the estimated cost of power from the new or proposed electric generation facility, will be recoverable in rates from the electric utility's customers subject to subsection (4)(c). MCL 460.6s(3)**.**

Q. Turning to the IRP framework, please provide an overview of the IRP statutory framework, filing requirements, and planning parameters as they were first enacted and adopted.

A. As already alluded, Section 6t was added to Public Act 3 of 1939 after then Governor Rick Snyder signed Act 341 into law on December 21, 2016. When it took effect on April 20, 2017, Section 6t(1) required electric utilities to file an IRP with the Commission no later than April 20, 2019, and, at a minimum, every five years thereafter. Section 6t(1) also required the Commission, within 120 days of the effective date of the act and at least every four years thereafter, to commence a proceeding that, among other things, establishes modeling scenarios and assumptions that each electric utility should include, in addition to the Company's own scenarios and assumptions, in developing its IRP.

On July 31, 2017, the Commission initiated Case No. U-18418 to implement the provisions of Section 6t(1). In its Order, the Commission directed Staff to file a proposal to establish parameters related to the IRP process and invited the public and stakeholders to submit written comments. The Commission approved Michigan Integrated Resource Planning Parameters ("MIRPP" or "planning parameters") on November 21, 2017, which included scenarios, assumptions, and sensitivities that must be included in each utility's IRP. On February 18, 2021, the Commission issued an Order in Case No. U-20633

directing Consumers Energy to include an additional scenario ("Carbon Reduction Scenario") inclusive of two carbon sensitivities in the Company's 2021 IRP filing.

In addition, Section 6t(3) of Act 341 required the Commission to issue an order establishing filing requirements, including application forms, instructions, and filing deadlines for an IRP filed by an electric utility whose rates are regulated by the Commission. On October 11, 2017, the MPSC issued an Order in Case No. U-18461 requesting comments on draft IRP filing requirements. The Commission issued an Order on December 20, 2017 in Case No. U-18461, which adopted final IRP Filing Requirements.

Q. Have there been changes to the law since 2021?

A. Yes. On December 29, 2023, Governor Gretchen Whitmer signed Public Act 231 of 2023 ("Act 231") into law. Effective February 13, 2024, Act 231 added several new requirements for utilities filing IRPs. For example, it required utilities to file an analysis showing how their IRPs comply with new requirements in Public Act 235 of 2023 ("Act 235"),[2] including clean energy requirements, updated EWR targets, DR targets, and energy storage targets. Act 231 also required utilities to consider how potential electrification affects planning, evaluate how their IRPs will impact affordability, and analyze how the IRPs will impact emissions. Concerning the last point (emissions and environmental compliance), a utility must specifically include in its IRP a long-term forecast estimating the greenhouse gas emissions and other pollutants coming from the power the utility proposes to generate or purchase; a utility must also include an environmental justice analysis for any plan that includes the construction of new natural gas generation.

[2] Act 235 amended the Clean and Renewable Energy and Energy Waste Reduction Act.

Q. Have there been any changes to the filing requirements and planning parameters since 2017?

A. Yes. The Commission revised the IRP filing requirements on October 27, 2022 in Case No. U-18461, and it revised the planning parameters on the same day in Case No. U-21219. More recently, on December 18, 2025, the Commission again revised the IRP filing requirements and planning parameters in Case No. U-21867. IRPs must now incorporate the requirements of Acts 231 and 235, which means utilities must file a Clean Energy Plan together with the IRP; demonstrate progress toward Act 235's clean energy requirements (80% clean energy by 2035 and 100% by 2040); and describe how they intend to meet EWR, DR, and energy storage targets. Electrification must also be considered in various modeling scenarios and sensitivities. As for affordability, utilities must project the customer rate impacts of their PCA over the planning horizon. Finally, concerning environmental requirements, utilities must include a chart with their IRP filing that compares the total projected carbon emissions under each required scenario to the relevant sensitivities and build plans under that scenario, and utilities must perform an environmental justice analysis for any portfolio that includes generation within a three-mile radius of an environmental justice community.

Q. Has the Company filed IRPs in the past?

A. The Company filed its first IRP on June 15, 2018 in Case No. U-20165. This IRP included a historic commitment to add approximately five GW of new solar resources. On June 7, 2019, the Commission approved a settlement agreement which was supported, or not opposed, by 20 intervening parties and showed wide support and alignment from many stakeholders to create the best IRP for Michigan. On June 30, 2021, the Company filed its

second IRP in Case No. U-21090. This IRP built on the previous commitment to new solar resources by pledging to an additional two GW of new solar and a battery storage program. The Company purchased the New Covert Generating Facility as part of its plan because it realized that new solar also required dispatchable baseload units as a reliability backstop. The Company's second IRP was also resolved through a contested settlement, which again garnered support from multiple parties and which the Commission approved on June 23, 2022.

Q. Please provide an overview of the resources which make up the Company's currently approved IRP.

A. The Company's currently approved IRP, also known as the Company's 2021 Clean Energy Plan, contains the following key components:

- Retirement of all three Campbell Units by May 31, 2025.
- Purchase of the Covert Generating Station in 2023, which adds significant natural-gas-fired capacity and additional ZRCs to support reliability in MISO Zone 7.
- Continued operation of Karn Units 3 and 4 through May 2031, rather than accelerating their retirement to 2023.
- Addition of approximately 8,000 MW of solar generation by 2040, with significant solar development occurring throughout the 2020s.
- Accelerated deployment of energy storage, targeting 75 MW by 2027 and 550 MW by 2040.
- Continued reliance on customer demand-side resources—including EWR, DR, CVR, and other emerging technologies—to reduce customer demand and lower peak needs.
- A one-time competitive solicitation for an additional 700 MW of capacity by 2025, sourced from competitive bids.
- Continuation of the annual competitive solicitation process approved in the prior IRP, with added flexibility around the ownership structure for competitively procured resources.

Q. Has the Company successfully implemented the 2021 IRP, as approved by the Commission?

A. Yes. The Company has substantially implemented the 2021 IRP as approved by the Commission. The Company completed the Covert acquisition, continued operation of Karn Units 3 and 4 consistent with the approved plan, pursued the planned retirement of Campbell Units 1, 2, and 3, advanced renewable and storage procurement, implemented demand-side resources, and maintained competitive solicitation processes to support resource additions.

Implementation has been affected by changed external conditions, most notably temporary federal reliability orders requiring Campbell to remain available to support regional reliability. Those orders do not reflect a change in the Company's long-term strategy. Overall, the Company's execution of the 2021 IRP has supported reliability, clean energy progress, and affordability, while informing the resource timing, market reliance, and flexibility reflected in this IRP.

Q. Why has the retirement of the Campbell generating units been delayed?

A. The Company's approved 2021 IRP included the retirement of Campbell Units 1, 2, and 3 by May 31, 2025, and the Company was on track with that retirement. However, before the retirement could occur, the United States Department of Energy issued an emergency order requiring Campbell to remain available to support regional reliability. As a result, Campbell continues to operate only because of temporary federal reliability orders.

Q. How does the Company treat Campbell in this IRP?

A. The Company does not treat Campbell as a long-term Company utility resource for purposes of the PCA. Rather, Campbell is being made available as a MISO reliability

resource pursuant to temporary federal orders. The Company expects that additional temporary orders may continue to be issued while MISO and federal authorities determine that Campbell is needed for regional reliability. However, the Company continues to plan on retiring Campbell when those temporary orders cease and Campbell is no longer required to remain available for MISO reliability purposes.

MISO Market and Federal Environmental Policy Developments

Q. What has changed in the MISO capacity and energy markets?

A. Since the Company's 2021 IRP, the MISO capacity and energy market environment has changed materially. Regional resource adequacy conditions have tightened as load growth expectations have increased, dispatchable resources have continued to retire or face operating constraints, and new resources have experienced development, interconnection, and accreditation uncertainty. These conditions have contributed to higher and more volatile capacity prices and have increased the importance of ensuring that the Company's plan includes sufficient dependable capacity to serve customers during periods of system stress.

MISO has also implemented, or is in the process of implementing, specific market reforms that affect how capacity is valued and how resource adequacy risk is reflected in the market. In 2023, MISO capacity market transitioned to a seasonal capacity construct, which requires resources to demonstrate capacity value across summer, fall, winter, and spring. In 2025, the Reliability Based Demand Curve was implemented, which changes how capacity prices reflect scarcity and tightening reserve margins. The Direct Loss of Load ("DLOL") accreditation framework, approved by FERC and expected to take effect beginning with the 2028/2029 Planning Year, which evaluates resource contributions

during high-risk hours rather than relying only on traditional peak-hour measures. MISO has also advanced reforms related to Load Modifying Resources, including testing, accreditation, performance, and penalty requirements using a phased implementation schedule spanning from 2025 to 2028. Collectively, these reforms increase the importance of resources that are available when the system is most at risk. Notably, MISO accreditation changes reduced the capacity value of intermittent generation and energy-limited resources., These market signals increase the value of dispatchable generation that can be counted on to support system reliability during periods of system stress. These MISO market reforms and their treatment in the Company's modeling are discussed further in the direct testimony of Company witness Moritz.

Recent MISO capacity auctions have cleared at elevated prices relative to historical experience, which reinforces the risk of relying too heavily on short-term market purchases to satisfy long-term customer needs. While the Company will continue to use market purchases when they are economic and available, the changed market environment supports a planning approach that does not depend on the market as the primary source of capacity during stressed system conditions.

These market developments are consistent with broader reliability assessments indicating that supply and demand conditions in MISO are tightening. North American Electric Reliability Corporation ("NERC") and other regional reliability analyses have identified increased resource adequacy risk as load grows, generation retirements continue, and the pace of new capacity additions remains uncertain. MISO and the Organization of MISO States have similarly highlighted the need for sufficient accredited resources to maintain reliability as the region transitions its resource mix.

At the same time, load growth, including data centers and energy-intensive manufacturing, is increasing the need for careful capacity planning. Load growth announcements and interconnection activity across Michigan and the broader MISO footprint demonstrate that incremental demand may emerge faster than traditional utility planning cycles. Some announced load growth may be supported by intermittent resources or by capacity that does not provide the same dependability as dispatchable generation, which increases the importance of evaluating the quality, timing, and deliverability of capacity—not simply the nominal amount of installed generation.

Taken together, these changes mean that market reliance carries greater risk than it did at the time of the 2021 IRP. The Company therefore incorporated enhanced market reliance analysis, expanded reliability modeling, and a broader evaluation of capacity resource accreditation into this IRP. Those analyses support the PCA's inclusion of near-term dependable capacity, continued clean resource additions, demand-side resources, and flexibility to respond as MISO market rules, load growth, and resource accreditation continue to evolve.

Q. What has changed related to state and federal environmental policy ?

A. Since the Company's 2021 IRP, the environmental policy framework applicable to electric resource planning has changed materially at both the state and federal levels. At the state level, Michigan enacted Acts 231 and Act 235, which together significantly expanded the environmental and clean energy requirements that must be addressed in an IRP. Act 231 updated the IRP statute and filing requirements, including new requirements to evaluate affordability, electrification, emissions, and environmental justice impacts. Act 235 established a clean energy standard of 80% by 2035 and 100% by 2040, a renewable energy

standard of 50% by 2030 and 60% by 2035, and a statewide energy storage target of 2,500 MW. These requirements now directly inform the Company's resource planning, emissions analysis, and evaluation of the PCA. The clean and renewable energy standards and compliance are further discussed by Company witness Johnston.

At the federal level, the United States Environmental Protection Agency ("EPA") has finalized, proposed, or reconsidered several major rules affecting fossil-fueled electric generating units. These include updates to the Mercury and Air Toxics Standards ("MATS"), greenhouse gas regulations for fossil fuel-fired power plants under Clean Air Act Section 111, revisions to the Steam Electric Effluent Limitation Guidelines ("ELG"), and updates to Coal Combustion Residuals ("CCR") requirements. The EPA also finalized a Good Neighbor Plan addressing interstate ozone transport, although implementation has been subject to litigation and administrative stays. In addition, the EPA has taken action regarding new source performance standards for CTs and has reconsidered certain greenhouse gas reporting and power-sector greenhouse gas requirements.

Additionally, as described by Company witness VanBlarcum, Public Law 119-21 of 2025 (sometimes referred to as the One Big Beautiful Bill Act) created significant sourcing and supply chain implications by imposing additional restrictions on the use of certain foreign-sourced components, entities, and supply-chain participation for clean energy projects seeking federal tax benefits. These requirements further constrain the development process by increasing diligence obligations, limiting eligible suppliers, and creating greater timing, cost, and qualification risk for renewable and storage resources.

Taken together, these state and federal developments have increased the importance of evaluating environmental compliance, emissions reductions, environmental justice, and

resource flexibility in the IRP process. The Company's 2026 IRP reflects these changes by evaluating the emissions impacts of the PCA and alternative scenarios, considering applicable compliance obligations for existing and proposed generating resources, and demonstrating how the resource plan supports Michigan's clean energy requirements while maintaining reliability and affordability for customers. Environmental regulations and compliance are further discussed by Company witness Breining.

III. IRP OBJECTIVES AND PRINCIPLES

Q. What planning objectives did the Company set as it performed this IRP?

A. Section 6t of Act 341 requires the Commission to approve an IRP if it determines the plan represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs. To make this determination, the Commission shall consider whether the plan appropriately balances all the following factors:

i. Resource adequacy and capacity enough in quantity to serve anticipated peak electric load plus applicable Planning Reserve Margin Requirement ("PRMR") and Local Clearing Requirement ("LCR");

ii. Compliance with applicable state and federal environmental regulations;

iii. Competitive pricing;

iv. Reliability;

v. Commodity price risks;

vi. Diversity of generation supply;

vii. Whether the proposed levels of peak load reduction and EWR are reasonable and cost effective;

viii. Affordability; and

ix Overall cost-effectiveness in providing utility service.

In the context of the factors the law requires the Commission to consider when deciding whether an IRP constitutes the most reasonable and prudent plan, the Company

examined its own planning objectives. Customers expect the lights to stay on, bills to remain affordable, and Michigan's energy system to continue becoming cleaner. The Company's IRP objectives are designed to balance those expectations and deliver a plan that performs well under a wide range of future conditions. To do so, the Company's planning objectives are grounded in its Triple Bottom Line commitment to People, Planet, and Prosperity. Accordingly, the Company's primary planning objectives focus on ensuring a safe and reliable, affordable, clean and equitable, and diverse energy supply. The Commission's and Company's planning objectives are well aligned and, when taken together, result in a better plan for Michigan.

Q. How does the Company define and measure reliability, affordability, clean and equitable outcomes, and resource diversity in this IRP?

A. The Company evaluates the PCA against an integrated set of planning objectives: safe and reliable energy supply, affordability, clean and equitable outcomes, and a diverse resource portfolio. These objectives align with the Company's Triple Bottom Line framework—People, Planet, and Prosperity—and are considered together because a reasonable and prudent plan must balance customer cost, system reliability, clean energy requirements, compliance obligations, equity, resource diversity, execution feasibility, and flexibility over the planning horizon.

As older resources retire and demand grows, maintaining dependable service becomes even more important. A safe and reliable portfolio is therefore a foundational principle of the IRP. Safe and reliable energy supply means the ability to serve customers across expected and stressed system conditions. The Company measures reliability through resource adequacy, including PRMR and LCR obligations, as well as reliability and risk

analyses that evaluate accredited capacity, market reliance, loss-of-load risk, seasonal and all-hours needs, deliverability, import limits, resource availability, and portfolio performance during extreme weather, low renewable output, or tight regional market conditions.

Customers feel the impact of energy decisions through their monthly bills. For that reason, affordability is evaluated alongside reliability and clean throughout the planning process. Affordability, which supports both the People and Prosperity objectives, means providing competitive supply rates and achieving the lowest reasonable customer cost among feasible alternatives while maintaining reliability and meeting environmental and clean energy requirements. The Company measures affordability using system-cost metrics and customer-facing rate impacts, including projected supply rates from the Company's rate model, comparison of those rates to inflation, and additional customer-impact measures such as Share of Wallet and Lifetime Plan Savings.

Keeping our promise to build a cleaner energy future for Michigan remains a core objective of the Company's resource planning process. Before Michigan established its current clean energy requirements, Consumers Energy committed to reducing emissions and expanding clean energy resources through its prior IRPs. Today, Michigan's clean energy laws provide a clear framework that reinforces and accelerates that vision. Clean and equitable outcomes reflect the Company's Planet and People objectives. Clean outcomes means meeting Michigan's renewable and clean energy requirements, complying with applicable environmental regulations, and reducing emissions over time. Equitable outcomes mean evaluating how the plan affects customers, employees, and communities, including environmental justice communities, and ensuring that the benefits and burdens

of the energy transition are considered transparently. These outcomes are measured through clean energy compliance, emissions analysis, environmental review, stakeholder engagement, affordability analysis, and community-impact considerations.

No single resource can meet every customer need in every hour and every season. That is why our planning process begins with a diversified portfolio approach. Resource diversity supports all three objectives by maintaining a portfolio that does not over-rely on any single technology, fuel, market product, location, or customer program. The Company evaluates diversity through the mix of owned and contracted resources, such as CTs, nuclear, solar, wind, storage, EWR, DR, CVR, EV programs, distributed generation, and future clean firm optionality. Resource diversity helps manage fuel, market, technology, execution, environmental compliance, customer participation, and performance risks while preserving the ability to adapt as changing demands and external conditions continue to evolve

Together, these measures provide the framework the Company uses to evaluate potential resource portfolios and determine whether they appropriately balance reliability, affordability, clean energy compliance, resource diversity, flexibility, and execution feasibility. The Company applies these measures throughout the IRP process to assess whether a portfolio can be reliably implemented and represents a reasonable and prudent path for serving customers over the planning horizon. In doing so, the Company pursues an all-of-the-above approach that helps ensure power is available every hour of every day while maintaining affordability for customers.

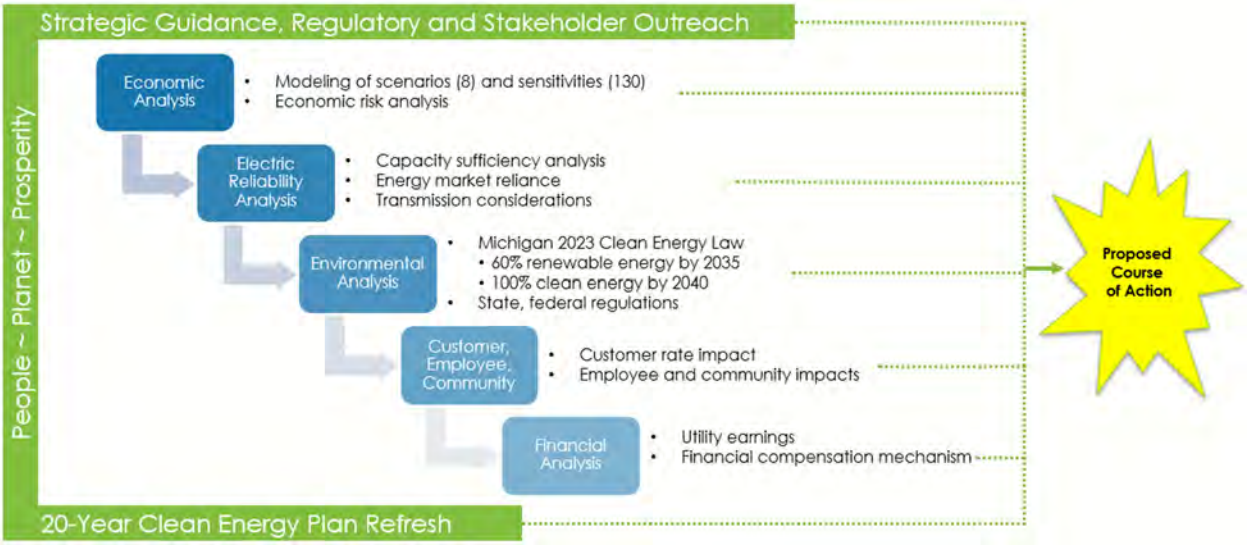
IRP PROCESS

Process Overview

Q. Please summarize the process used by the Company to complete this IRP.

A. The IRP process starts with the identification of the principles and compliance requirements as previously discussed. Traditionally, IRPs have been associated with capacity expansion models able to run probabilistic analysis to determine the lowest cost resources available to meet a utility's coincident peak load requirement plus a reserve margin which equates to a utility's PRMR. The coincident peak load historically occurs during high-demand months like July and August. The capacity expansion models are powerful tools used to stress test future scenarios, sensitivities, and risks to determine cost impacts to customers. At the same time, the Company engages stakeholders inclusive of the general public, interested parties that typically intervene in the Company's electric rate case proceedings and IRPs, and the local transmission owner to discuss development of the IRP, receive feedback, and obtain analysis from the transmission owner to support determining the resources needed to meet future capacity and energy needs. Consumers Energy supplements the stakeholder feedback and the capacity expansion economic analysis by incorporating electric supply reliability analysis, environmental impact analysis, customer-employee-community impacts, and financial analysis. Hundreds of cases and thousands of iterations are conducted to evaluate various options and solutions to determine a balanced PCA. This is further defined in Figure 3.

Figure 3: Integrated Resource Plan Process and Key Analysis



Core Analysis Framework

Q. Please summarize the Capacity Expansion Economic Analysis in the IRP Process.

A. The Capacity Expansion Economic Analysis is a core component of the Company's IRP and is designed to identify a reasonable and prudent long-term resource strategy that balances cost, reliability, and evolving policy requirements. The analysis begins with the establishment of the Company's planning foundation, including forecasts of customer demand, existing and planned resources, and key regulatory and operational requirements. These inputs are used to assess the Company's capacity position and identify the timing of any future resource needs. Building on this foundation, the Company evaluates a broad range of potential supply-side and demand-side resource options and considers how those resources perform across a range of possible future conditions. To reflect uncertainty, the Company develops multiple scenarios and sensitivities that test key variables such as load growth, fuel prices, technology costs, and policy drivers. The Company then utilizes industry-standard modeling tools to evaluate resource portfolios and identify combinations of resources that meet customer energy and capacity needs at the lowest reasonable cost,

comply with State, Federal, and market requirements, and deliver reliability. These tools evaluate both the timing and type of resource additions and compare portfolios on an economic basis, including net present value of long-term costs. The output results of this economic analysis provide the foundation used to develop the strategy reflected in selection of the Company's PCA. The PCA reflects the selection of a balanced portfolio of resources that were proven (through modeling) to meet customer needs under a wide range of future conditions. Subsequently, as discussed next, the Company evaluates risk and reliability considerations to ensure the selected plan remains robust and adaptable in the face of uncertainty.

Q. Please summarize the Electric Reliability Analysis in the IRP Process.

A. The Electric Reliability Analysis is a critical component of the Company's IRP and is designed to evaluate whether a given resource plan can reliably meet customer energy and capacity needs across a wide range of future conditions. The Company evaluates reliability within a broader, integrated risk framework that considers how resource portfolios perform under varying assumptions, including changes in customer demand, resource availability, market conditions, and system constraints. This approach, as supported by Company witness Soni, reflects utility industry best practices for modern integrated resource planning because it evaluates reliability using multiple metrics and stress conditions rather than relying solely on a single deterministic reserve-margin measure. As part of this framework, the Company conducts multiple layers of analysis, including scenario and sensitivity modeling, stochastic assessments, and electric reliability studies. These analyses are designed to evaluate whether portfolios maintain sufficient capacity and energy to serve

customers while mitigating exposure to operational and market risks. Detailed reliability and risk analyses are provided in the testimony of Company witness Soni.

The Company's reliability analysis in this IRP includes significant modeling sophistication enhancements. First, in this IRP the Company has modeled the incorporation of changes in MISO's resource adequacy construct since the Company's 2021 IRP. These changes include the transition to a seasonal capacity market framework, adoption of a reliability-based demand curve, and implementation of DLOL resource accreditation. Collectively, these changes shift planning from a single annual peak framework to an "all-hours" approach that better reflects reliability conditions during high-risk periods and requires more granular evaluation of resource performance across seasons. It also better captures risks associated with increasing levels of intermittent resources like renewables and energy-limited resources like battery storage and DR.

Second, consistent with IRP filing requirements, the Company evaluates reliability under a range of stressed conditions through sensitivities that reflect increased uncertainty and variability in system conditions. This includes evaluation of atypical or extreme weather events, which are explicitly modeled to assess how portfolios perform during periods of elevated system stress and risk. These analyses help ensure that the selected plan remains robust under increasingly variable operating conditions.

Third, the Company evaluates the degree to which resource portfolios rely on market purchases for capacity and energy. Higher levels of reliance may expose customers to risks related to availability, price volatility, and changing market dynamics, particularly in light of tightening regional supply and demand conditions.

Transmission considerations are an integral part of the reliability assessment. The Company coordinates with the local transmission owner, METC, to evaluate transmission system capabilities, including system topology, import and export capability, and the deliverability of new resources. This analysis includes:

- Evaluation of network upgrade and interconnection costs associated with new resources;
- Assessment of transmission constraints that could impact resource deliverability; and
- Consideration of transmission-related revenue requirements associated with potential system upgrades.

These transmission inputs are incorporated directly into the modeling and portfolio evaluation process to ensure resource plans are both feasible and cost-effective. Detailed discussion of these transmission planning assumptions, system constraints, and associated costs is provided in the testimony of Company witness McCormick.

Together, these reliability, market, and transmission evaluations provide a comprehensive assessment of each portfolio's ability to reliably serve customers. The results are considered alongside economic and policy objectives to inform selection of the Company's PCA. At a policy level, this analysis demonstrates that the selected plan provides a balanced and adaptable resource strategy that maintains system reliability, manages exposure to risk, and positions the Company to serve customers under a wide range of future conditions.

Q. Please summarize the Environmental Impact Analysis in the IRP Process.

A. The Company evaluates the environmental impacts of its resource plans by considering applicable environmental regulations for its existing and proposed generating fleet, projected emissions over the planning horizon, and environmental justice considerations.

This analysis includes key air, water, waste, and greenhouse gas requirements applicable to the Company's resources, as well as projected emissions under the PCA and the scenarios and sensitivities analyzed in the IRP. The Company also evaluates environmental justice considerations by screening for potentially vulnerable communities, assessing whether the PCA is expected to materially increase local emissions at identified facilities, and considering environmental impacts associated with proposed new resources.

In addition, the Company's assessment of feasible and prudent alternatives evaluated proposed resources and alternative resource options on a consistent basis, including the reasonably foreseeable environmental impacts associated with the proposed resource and with alternative resources capable of meeting the same underlying reliability, capacity, energy, and clean energy needs. Those environmental impacts were evaluated over comparable planning horizons so that the environmental impacts of the proposed resource and feasible alternatives could be meaningfully compared. Accordingly, the Company's IRP and CON analyses provide a robust assessment of feasible and prudent alternatives from both reliability and environmental perspectives. Company witness Breining further explains the Environmental Impact Analysis, including the emissions outlook, environmental compliance requirements, environmental justice analysis, and environmental considerations associated with the PCA and the proposed CONs for Karn, Thetford, and the PPA resources.

Q. Please summarize the Customer Rate, Employee, and Community Impact Analysis in the IRP Process.

A. Customer rate impacts are evaluated through the Company's affordability analysis, including projected revenue requirements, year-over-year rate impacts, compound annual

growth rate, and potential customer savings over the planning period. This analysis helps determine how each resource plan is expected to affect customer supply rates and is addressed in more detail in the direct testimony of Company witness Myers.

The Company also evaluates employee and community impacts associated with resource additions, retirements, and transitions. This includes consideration of the number of co-workers affected by a resource plan, the time and resources needed to safely and effectively transition employees, impacts to local tax revenues and host communities, and the effects of adding or retiring generation assets. The Company further considers impacts to vulnerable communities and environmental justice communities, including where resource decisions involve fossil resource retirements or the development of new assets. The vulnerable community and environmental justice analysis is addressed in greater detail by Company witness Breining..

Q. Please summarize the Financial Analysis in the IRP Process.

A. The Financial Analysis evaluates how the resource plans may affect utility earnings, credit metrics, and the Company's ability to finance the investments needed to implement the PCA. This analysis considers the treatment of incentives and cost recovery mechanisms, the impact of incremental capital expenditures on earnings and balance sheet measures, and the effect of the plan on credit ratings and financial flexibility. The Financial Analysis complements the economic, reliability, environmental, customer, employee, and community analyses by helping confirm that the selected plan is financially executable. Company witnesses Bleckman, Clark, and Myers provide additional detail on these matters in their direct testimony.

Scenario-Based Development of Resources

Q. Please provide an overview of how the Company utilized scenarios and sensitivities in its IRP analyses.

A. The Company's IRP uses a structured set of scenarios and sensitivities to evaluate how the electric system may evolve under a range of potential future conditions. These analyses are developed consistent with the requirements of MCL 460.6t and the MIRPP, which establish the analytical framework for long-term planning.

Scenarios represent distinct, internally consistent future outlooks that reflect different combinations of key drivers such as customer demand, electrification, resource availability, and environmental considerations. Each scenario describes a plausible "future state" of the system, allowing the Company to evaluate how resource strategies perform under materially different conditions.

Sensitivities are then applied to these scenarios to isolate the impact of uncertainty in key assumptions. These sensitivities vary individual inputs, one at a time—such as demand growth, fuel prices, technology costs, and system constraints—to evaluate how each change influences planning outcomes.

Consistent with IRP filing requirements, the Company also evaluates system performance under stressed conditions, including sensitivities that reflect atypical or extreme weather events, as well as other sources of operational and market uncertainty.

Together, scenarios and sensitivities provide a comprehensive framework to evaluate a broad range of potential outcomes and identify resource strategies that remain reliable, cost-effective, and adaptable over time. This approach supports selection of a PCA

that is robust to uncertainty and represents a reasonable and prudent long-term plan for serving customers.

Q. What is meant by a resource "portfolio"?

A. The term "portfolio" is used throughout this IRP to represent a mix of different resource types and amounts that collectively meet IRP requirements. A portfolio of resources generally always includes existing and planned resources; but one portfolio may differ from another based on the types and amounts of new or incremental resources considered in the long-term planning horizon. For example, one portfolio may be heavily reliant on renewable resources entirely, to meet the 2023 energy law requirements, while a second portfolio may contemplate clean baseload resources in addition to the renewable resources to meet the standards. Another example would be one portfolio that meets reliability needs through a combination of natural gas resources and battery storage, while a second portfolio may consider only natural gas resources to meet reliability needs, and a third portfolio may consider only battery storage resources. Portfolios are often used for comparative purposes, utilizing key metrics like affordability, reliability, feasibility, market reliance and more, on which to judge each portfolio, often against an alternative.

Q. Please summarize the scenarios and sensitivities considered in this IRP.

A. In applying the scenarios and sensitivities framework, the Company evaluated a set of four scenarios designed to assess resource plans across a range of plausible future conditions, consistent with the MIRPP and the requirements of MCL 460.6t. These scenarios include:

- **MIRPP Scenario 1 ("MSO") and the Company's Physical Climate Change ("PCC") scenario**, which represent an accelerated energy transition pathway characterized by higher levels of electrification, stronger demand growth, and more rapid regional decarbonization. The PCC scenario is closely aligned with MSO, with limited differences in specific assumptions such as EWR levels.

- The **BAU scenario**, which reflects a more moderate transition pathway with incremental load growth, moderate electrification and EV adoption, and a moderate pace of regional carbon reduction.

- A **Company-developed load growth scenario**, designed to assess the impact of economic development and large customer demand on future resource needs.

- The **Aggressive Load Growth ("ALG") scenario**, which evaluates a higher-end load growth future and a slower pace of regional carbon reduction.

Taken together, these scenarios allow the Company to evaluate resource strategies across a spectrum ranging from moderate system evolution to more accelerated decarbonization and significant load growth. Across these scenarios, the Company evaluated a comprehensive set of sensitivities to assess how resource plans perform under key uncertainties. As summarized in Table 6-1 of the IRP Report, the Company evaluated a number of sensitivities that vary key planning assumptions to isolate their impact on system outcomes. These sensitivities contemplate, among other categories:

- Variations in economic development load and overall demand growth;

- Changes in fuel prices and resource costs, including natural gas and renewable and storage technologies;

- Differences in renewable availability and build constraints;

- Alternative levels of EWR and distributed generation;

- Variations in transmission-related assumptions, including network upgrade costs and import/export capability; and

- Evaluation of atypical or extreme weather conditions, consistent with IRP filing requirements.

To support these scenarios and sensitivities, the Company developed detailed modeling assumptions, including load forecasts, fuel price outlooks, technology cost and performance characteristics, demand-side program assumptions, environmental requirements, and transmission system inputs. The Company also performed screening analyses to identify the supply-side and demand-side resources evaluated in the portfolio

optimization process. The development and additional descriptions of these scenarios, sensitivities, and modeling assumptions, as well as the resulting resource planning analysis, are described in detail in the direct testimony of Company witness Moritz. Collectively, these scenarios and sensitivities provide the analytical foundation for evaluating the resilience of resource plans and demonstrate that the Company's PCA is robust across a wide range of future conditions and uncertainties.

Q. Does the Company's modeling and analysis effort represent a robust foundation for the IRP?

A. Yes. The modeling and analysis efforts represent a robust foundation across the variables impacting People, Planet, and Prosperity over 182 combinations of scenarios and sensitivities. In total, there were approximately 910 model runs equating to roughly 3,600 hours and computational runs measuring 455 working days (8 hours) or approximately 152 full days (24 hours) and storage space upwards of 20 Terabytes. In addition to the optimal plans generated from these scenarios and sensitivities a set of analysis was also conducted for the environment, rates, financials, community and employee impacts, and risk assessments. Figure 3 and the description above depicts the level of robust analysis used to develop the IRP and the resulting PCA.

Stakeholder and Public Engagement

Q. Please provide an overview of the Company's outreach efforts.

A. The Company conducted a structured stakeholder engagement process that included public outreach, technical conferences, and coordination with Staff and the local transmission owner. These efforts provided transparency into the IRP process, assumptions, scenarios, and timeline, and gave stakeholders multiple opportunities to provide input. Company

witness Coker describes the stakeholder engagement process and supporting exhibits in greater detail.

Q. Please describe the public outreach efforts.

A. The Company's public outreach included community-focused engagement, including the Energizing Equity series in environmental justice communities, a virtual IRP Community Feedback session, and online channels for written comments and questions. These efforts were designed to improve access to information and gather input from customers and communities affected by the Company's long-term energy planning. Company witness Coker provides the detailed description of these outreach efforts and related exhibits. I've also attached an exhibit (Exhibit A-118 (SQM-3)), which is a press release and executive summary of the Company's PCA that presents the supply plan in plain, accessible language intended for a broad public audience. The press release and executive summary are being issued the same day this case is filed.

Q. Please describe the technical workshops.

A. The Company also held technical conferences for stakeholders involved in IRP and electric regulatory matters. These conferences addressed key assumptions, modeling approach, scenarios, sensitivities, resource options, risk assessment, MISO market considerations, and the 2023 clean energy legislation. The conferences allowed stakeholders to ask questions and provide feedback that informed the IRP analysis. Company witness Coker discusses the technical conference process and supporting materials in his testimony and exhibits.

Q. Please describe the collaboration efforts with the local transmission owner.

A. The Company coordinated with METC/International Transmission Company ("ITC") throughout the IRP development process to evaluate transmission-related impacts, including generation additions, retirements, interconnection requirements, and network upgrade costs. Those inputs were incorporated into the Company's evaluation of resource portfolios and the development of the PCA. Company witness McCormick provides additional detail on transmission coordination, while Company witness Coker addresses how this coordination fit within the broader stakeholder process.

Q. Please summarize the results of the stakeholder engagement report.

A. Stakeholder engagement produced feedback on affordability, reliability, clean energy, emissions, resource diversity, modeling transparency, distributed generation, and demand-side resources. The Company considered this feedback in developing assumptions, scenarios, sensitivities, and resource portfolios. Company witness Coker details the stakeholder engagement process and events with summary reports for all events and technical workshops.

Q. Please describe how the Company applied the collaboration and outcomes of its stakeholder engagement into its IRP process.

A. The Company used stakeholder feedback to improve the transparency and robustness of the IRP by refining assumptions, evaluating additional sensitivities and risk considerations, and considering stakeholder perspectives on reliability, affordability, emissions, resource diversity, and customer-side resources. This feedback helped strengthen the IRP while ensuring the PCA remains aligned with statutory requirements, settlement commitments,

and reliability needs. Company witness Coker provides the detailed discussion of how stakeholder input was received, documented, and reflected in the IRP process.

IV. THE COMPANY'S LOAD FORECAST

Managing Demand Forecast Uncertainty

Q. What are the principal assumptions underlying the Company's forecasts of customer demand, energy needs, fuel prices, and market conditions?

A. The Company developed its forecasts using a range of assumptions regarding weather, economic activity, demographics, electrification, large customer growth, demand-side resource adoption, fuel prices, capacity market conditions, and other factors that may influence future energy and capacity requirements. Because these assumptions are inherently uncertain over the long-term planning horizon, the Company evaluated multiple planning scenarios and sensitivities to assess the impacts changes to each of these input assumptions. The resulting forecasts serve as the foundation for evaluating future resource needs and developing a resource plan that remains reliable and flexible under a range of plausible future conditions. Additional detail regarding the development of the Company's energy and peak demand forecasts, including key assumptions and forecasting methodologies, is further described in the direct testimonies of Company witnesses Moritz and Breuring. Detail regarding the development of the Company's fuel price forecasts is included in the direct testimony of Company witness Rissman.

Q. Please describe the levels of customer demand, or load forecasts, evaluated as part of this IRP.

A. Through its scenario- and sensitivity-based economic analysis described in Section IV of this testimony, the Company developed six primary load scenarios, as well as several load

sensitivities. The six load forecast scenarios are described in detail in the testimony of Company witness Breuring and are summarized in Table 2, below.

Table 2 Load Forecast Scenarios

LOAD FORECAST SCENARIO	DESCRIPTION
Business-as-Usual (BAU)	Includes existing, operational, and contracted loads as of mid-2024
BAU Current	Represents BAU load plus an additional manufacturing load (approximately 100 MW) contracted during IRP case development
Probable Load Growth (PLG)	Represents Current load plus 1.5 GW of signed large load commitments and a probability-adjusted view of the broader development pipeline; this is the load forecast included in the Company's PCA
Alternate Plan High Load Growth ("HLG")	Builds upon the PLG forecast, increasing large load growth for a total of 2.2 GW above Current load levels
Aggressive Load Growth (ALG)	Represents a higher bookend of load growth, up to a maximum of 3.5 GW above Current load levels
MIRPP Scenario One (MSO) and Physical Climate Change (PCC)[3]	Corresponds to MIRPP Scenario #1 requirements contemplating increased electrification

Q. How did the Company determine the load levels included in each load forecast scenario presented in Table 2?

A. Described in detail in the testimony of Company witness Breuring, the Company initiated its modeling based on its most up-to-date outlook on customer demand. During development of the IRP, economic growth teams at the Company were responding to significant inquiries to provide electric service to new customers, who were considering

[3] The PCC load forecast differs from that used in the MSO primarily due to differences in assumed levels of EWR.

siting their businesses within the Company's electric service territory. Such inquiries comprise what the Company refers to as its load growth "pipeline," representing potential load growth over the course of the planning horizon.

Given the range of potential outcomes informed by the load growth pipeline, the Company established discrete load forecast scenarios to guide the IRP planning process and resulting resource buildouts.

The first load forecast scenario was the BAU, which included existing or newly contracted load as of mid-2024. The BAU is inclusive of contracted new customer load from data centers and large manufacturing customers increasing system demand by 178 MW in 2026 and growing to approximately 300 MW by 2030. Other relevant load forecast scenarios include the ALG, which added approximately 3.5 GW of economic development load growth to the BAU, and the PCC, which assumed BAU levels of economic development load growth, but included increased EV and heating electrification loads. These three load forecast scenarios provided the foundation on which most of the scenario and sensitivity capacity expansion modeling was conducted.

As described in Section [V], the capacity expansion modeling provides insights into the types and amounts of resources most-widely selected to meet capacity and energy needs at various load levels. The PCA and Alternate Plans were developed based on the resource types and amounts that are most consistently selected by the model and score highest across the Company's metrics to supply reliable, affordable, clean, and equitable power.

However, while the resources that would be included in the PCA and Alternate Plan portfolios were becoming evident, a re-examination of load forecasts was prudent. During development of the IRP, the load growth pipeline was highly active, with load contracts

being signed during the time IRP modeling was taking place. For example, the BAU load forecast became stale, with the execution of a signed contract to serve an additional 91 MW of manufacturing load resulting in approximately 400 MW of contracted new load within the "Current" load forecast. The Company developed the "Current" load forecast to update the baseline outlook of existing and contracted load operational today. That load forecast is included in the Alternate Plan Current portfolio.

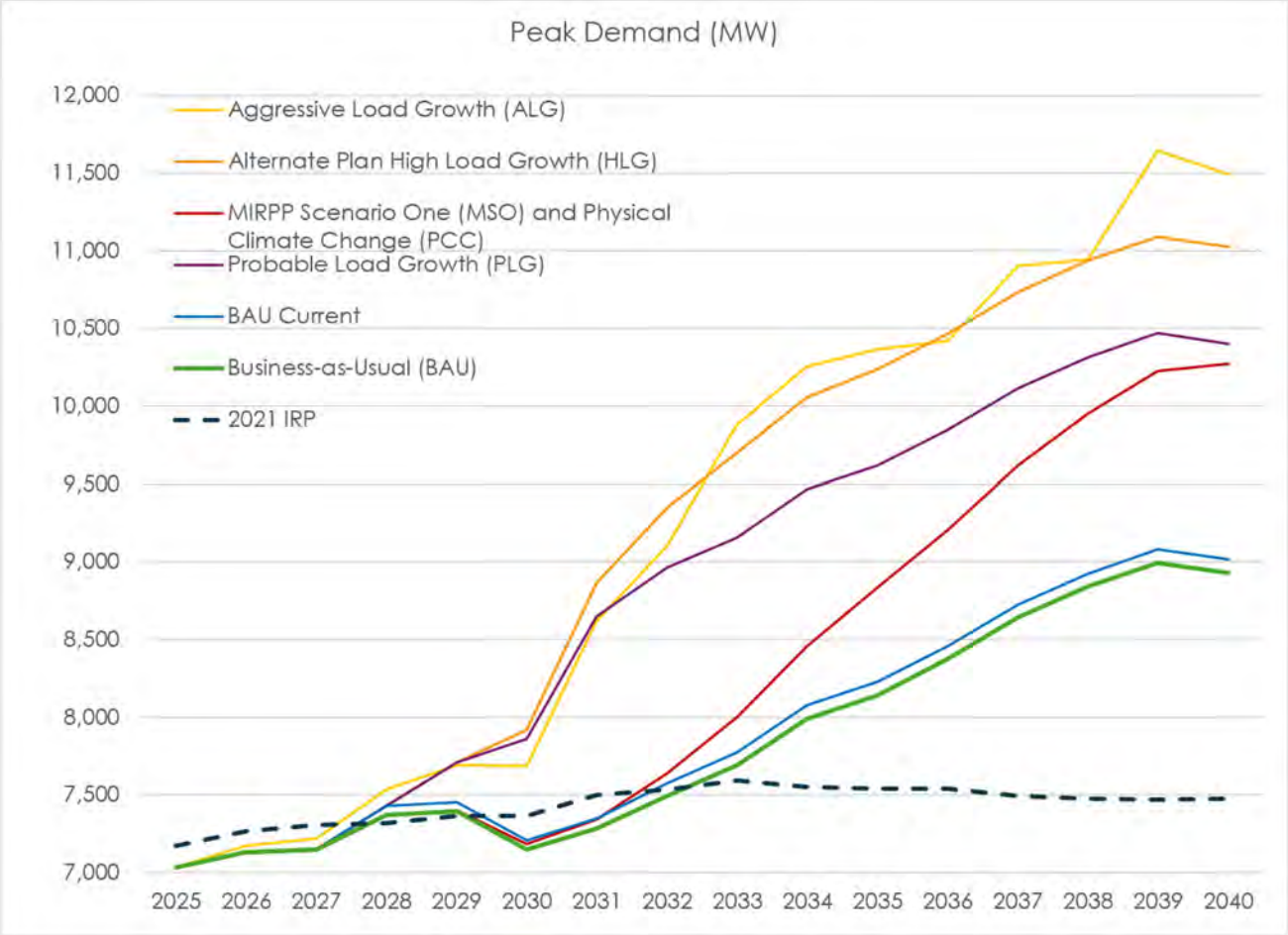
Additionally, the Company executed an agreement [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] to serve a data center as described in greater detail later in my testimony, with additional growth in the development pipeline under active evaluation. Consistent with IRP filing requirements to consider load with and without large load additions, the Company developed a new load forecast that shows growth of 1.5 GW incremental to the Current outlook. The Company refers to this as the "Probable Load Growth" forecast, representing the most-likely load levels expected during the IRP study horizon. This forecast is included in the PCA portfolio.

Finally, a HLG forecast was developed which falls within the range considered between BAU and ALG. Given more recent information and potential within the growth pipeline, the Company determined a probable HLG forecast that includes a total of 2.2 GW above BAU Current load levels. The Alternate Plan HLG portfolio provides details corresponding to that load forecast scenario.

Q. How do the six load forecasts you described compare, relative to each other?

A. Figure 4 presents a visual representation of the range of load forecasts corresponding to those described in Table 2.

Figure 4



Q. What role does economic development play in the Company's IRP?

A. Economic development is an important planning consideration in this IRP because the Company is experiencing material and verifiable load growth from large customers, including data centers and other energy-intensive industries. The PCA is designed to maintain reliability for existing customers while preserving the flexibility needed to serve new customer growth as it materializes. The Company's objective is not simply to accommodate growth, but to do so in a manner that supports reliability, affordability, and compliance with Michigan's clean energy requirements.

Q. Is load growth a key assumption underlying the PCA?

A. Yes. The PCA reflects the Company's PLG outlook, which includes signed large load commitments together with a probability-adjusted assessment of the broader development pipeline. The PCA reflects approximately 1.5 GW of incremental load growth, above the Company's "Current" load forecast, from data centers that meet the criteria of the Company's Large Load Customer tariff provision ("Large Load") growth. This includes an executed Rate Agreement under the Company's Large Load Customer tariff provision as approved by the Commission in Case No. U-21859. [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] The load-growth assumptions used in the PCA are therefore grounded in actual commercial activity rather than speculative forecasts.

Large Load Growth

Q. Please briefly describe the Rate Contract.

A. The Rate Contract is a long-term electric service arrangement under which the customer would develop and take service for a Large Load data center. Under the agreement, the customer will pay standard fully embedded rate charges, currently Rate GPD, as well as incremental capacity, energy, and related resource costs needed to serve its specific load. [CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Under this structure, Large Load customers will pay their fair share. The structure is intended to support significant new load and economic development while protecting existing customers from cost shifting [CONFIDENTIAL] [redacted]

[redacted]

[redacted] [END CONFIDENTIAL]

Q. Why does the PCA treat the Large Load growth as incremental to current load?

A. The PCA treats the Large Load growth as incremental because it is not yet part of the Company's current customer demand. Although the Company has executed a long-term electric service agreement supporting approximately [CONFIDENTIAL] [redacted] [redacted] [END CONFIDENTIAL] of new Large Load growth, the agreement was recently signed, the customer must still complete land-use, permitting, and related development activities, and the Rate Contract remains subject to Commission review and approval.

Treating the growth as incremental allows the Company to separately show the impact of the Large Load forecast on the PCA, including the resources needed to serve that load and the resulting affordability effects. It also provides a transparent comparison between current-load conditions and the PLG forecast, while demonstrating how properly structured Large Load service can support economic development without shifting incremental costs to existing customers.

Q. Is the Company seeking approval of the Rate Contract as part of this filing?

A. No. The Company is not seeking approval of the Rate Contract in this IRP filing. The Company will request approval of the Rate Contract in a separate filing consistent with the Commission's Final Order in Case No. U-21859.

Q. Why is the Company including the Large Load growth in the PCA prior to Commission approval of the Rate Contract?

A. The Company is including the Large Load growth in the PCA because, based on the information known today, it represents the Company's most probable load outlook. The Company has executed a long-term electric service agreement with a customer, which reflects a concrete commercial commitment that is materially different from speculative or uncommitted load growth. Although Commission approval of the Rate Contract is still required, the executed agreement and related development activity provide a reasonable basis to include the associated load in the PLG forecast used for the PCA.

Including the Large Load growth also provides the most comprehensive plan based on what is known at this time. It allows the Company to evaluate the resource, cost, reliability, and affordability impacts of the most probable growth case and compare those results against other load scenarios and alternate plans. This approach gives the Commission and stakeholders a robust analysis of the expected system effects if the executed Large Load Rate Contract proceeds, while preserving transparency regarding the uncertainty that remains until the Rate Contract is approved.

Q. How does the PCA account for uncertainty surrounding future Large Load development?

A. As illustrated in Table 2 and Figure 4, the Company evaluated multiple load-growth trajectories, ranging from no incremental economic development load to significantly higher levels of growth. The PLG forecast is based on executed agreements, active negotiations, and the Company's assessment of the broader economic development

pipeline, while higher-growth scenarios test the implications of additional economic development.

This approach allows the Company to prepare for likely Large Load growth and broader economic development without relying on speculative assumptions. It also preserves flexibility to adjust future resource decisions if actual development is higher or lower than reflected in the PCA.

Q. What happens if additional large load customers are added beyond those included in the PCA?

A. The Company evaluated higher load-growth scenarios to understand the implications of additional economic development and identify the types of incremental resources that may be needed if growth exceeds the PCA forecast. In particular, the Company developed the Alternate Plan HLG portfolio to show a pathway for serving additional large load customers beyond those included in the PCA.

Q. What happens if some anticipated load does not materialize?

A. If some anticipated load does not materialize, the Company retains flexibility to adjust future resource decisions as circumstances evolve. The Company's Rate Contract for Large Load data center agreements also include contractual protections, such as minimum billing obligations, exit fee provisions, and parent guaranty and collateral requirements, that are designed to limit risk to existing customers.

Q. How does the Company ensure affordability if Large Load growth does not materialize as expected?

A. The PCA addresses this risk through flexible resource additions, scenario analysis, and contractual protections for large load service. The Company can adjust the timing and scale

of future resources if load develops differently than expected, while the Rate Contract structure is intended to ensure that Large Load customers bear the incremental costs associated with serving their demand, as well as rate protections for customers if new resources are developed for data centers that exit prior to the term of the Rate Contract. Together, these features help maintain affordability for existing customers if economic development load is lower than forecast.

EV and Broader MISO Market Trends

Q. What EV and electrification assumptions are reflected in the load forecast?

A. The load forecast reflects expected growth in EV adoption and broader electrification over the planning period, including transportation electrification, building electrification, and other customer technologies that may increase electric energy use and alter peak demand patterns. These assumptions are incorporated into the Company's forecast of annual energy requirements, seasonal peak demand, and hourly load shapes so the IRP can evaluate resource needs under changing customer usage patterns.

The Company evaluates these assumptions through the load forecast scenarios described above, including the BAU, PCC, and MSO forecasts. This approach allows the Company to assess a range of potential electrification outcomes, from more moderate adoption to higher levels of EV charging and end-use electrification. Additional detail regarding the methodology, adoption assumptions, and resulting impacts on energy and peak demand is provided in the direct testimony of Company witness Breuring. As discussed later in my testimony, the Company limited the impact of EV load growth on generation resource needs by modeling EV load as a VPP resource so that charging shifts as solar generation grows limiting the need for additional dispatchable generation.

Q. How do broader MISO market conditions inform the Company's load and resource planning?

A. Broader MISO market conditions inform the Company's load and resource planning by increasing the importance of dependable, accredited capacity within the Company's portfolio. Regional resource adequacy conditions have tightened as load growth increases, dispatchable resources retire, and new resource development faces interconnection, accreditation, and execution uncertainty. These conditions make it less prudent to rely primarily on short-term market purchases to meet long-term customer needs.

Accordingly, the Company's IRP evaluates load growth and resource needs in light of evolving MISO resource adequacy requirements, capacity market price signals, seasonal accreditation rules, and tightening regional supply-demand conditions. This planning approach supports the PCA's inclusion of firm, dispatchable resources, existing contracted resources, renewable and storage additions, and demand-side resources so that the Company can reliably serve customers while managing exposure to market availability and price volatility.

Recent market and reliability data support this planning approach. MISO's 2025 Planning Resource Auction reflected tightening summer conditions, with summer capacity clearing at $666.50/MW-day and annualized North/Central capacity prices of approximately $217/MW-day; MISO also explained that the Reliability-Based Demand Curve is intended to better reflect the reliability value of accredited capacity as supply margins tighten. MISO's 2026 Planning Resource Auction continued to show elevated summer capacity value, with Local Resource Zones 1 through 7 clearing at $424.30/MW-day for summer and approximately $126.19/MW-day on an annualized basis. In addition,

the 2025 OMS-MISO Survey identified at least 3.1 GW of additional capacity needed beyond committed capacity to meet the projected planning reserve margin forecast for the 2026/2027 planning year, noted that load growth driven by economic development is outpacing prior forecasts, and identified winter reliability risk as solar penetration grows. NERC's 2025 Long-Term Reliability Assessment similarly highlights increasing resource adequacy risk driven by rapid demand growth, generation retirements, and uncertainty regarding the timing of new resource additions.

V. CURRENT BASELINE CAPACITY POSITION

Q. How does the Company currently meet the capacity and energy needs of its customers?

A. The Company currently meets the capacity and energy needs of its customers pursuant to its approved IRP and through its participation in the MISO markets. The Company's resource strategy is based on a diversified portfolio of supply-side and demand-side resources designed to reliably meet customer needs in a cost-effective and environmentally responsible manner.

The Company owns approximately 6,474 MW of installed generating capacity, located primarily within Michigan and the MISO footprint. These owned resources reflect a diverse mix of generation technologies, including natural gas combined cycle and peaking resources, hydroelectric generation[4], renewable resources such as wind and solar, and energy storage assets including pumped storage and battery systems. This portfolio provides a combination of baseload, intermediate, peaking, intermittent, and storage

[4] The Company is in the process of selling the hydroelectric generation. Approval of the sale is pending in Case No U-21985. When the sale is final the energy and capacity from the facilities will be purchased through a PPA.

capabilities that enable the Company to meet customer demand across a wide range of operating conditions.

In addition to Company-owned resources, the Company maintains a significant portfolio of long-term PPAs. As supported by Ms. Skowronski, the Company has approximately 146 PPA contracts representing approximately 7,744 MW of capacity across a broad range of resource types, including natural gas, wind, solar, hydroelectric, energy storage, and other renewable resources. These contracts include substantial dispatchable capacity, as well as a large portfolio of renewable and smaller distributed resources that contribute to both energy supply and compliance with clean energy requirements.

The Company also incorporates VPPs through distributed generation resources, demand-side resources, including EWR, DR programs, CVR, and EV load shaping, which reduce overall system demand and contribute to meeting peak capacity requirements. These resources are integrated directly into the Company's planning and operations and serve as an important component of the overall resource mix.

To supplement its owned, contracted, and VPP resources, the Company participates in MISO's day-ahead and real-time energy markets, as well as the capacity construct, which together facilitate the efficient balancing of supply and demand and support compliance with regional resource adequacy requirements. Consistent with Michigan's State Reliability Mechanism, the Company ensures that it maintains sufficient capacity, either owned or under contract, to meet today's planning reserve margin and local resource adequacy obligations.

Overall, the Company's current portfolio is an integrated mix of Company-owned generation, long-term contractual resources, customer-side VPP and demand-side resources, and MISO market participation. The portfolio includes dispatchable natural gas and hydro resources, renewable resources, storage capability, PPAs, EWR, DR, CVR, EV load-shaping programs, and distributed generation resources that collectively allow the Company to meet current customer energy and capacity needs. This existing portfolio provides the baseline from which the IRP evaluates future resource needs, including the effect of planned retirements, expiring contracts, load growth, evolving MISO accreditation rules, and the additional resources needed to maintain reliability, affordability, clean energy compliance, and portfolio diversity over the planning horizon.

Q. What were the Company's base capacity outlooks at the onset of the IRP process?

A. The base capacity positions were developed for each scenario evaluated in the IRP. The base capacity position outlooks start from the Company's forecast of electric demand. The capacity position is defined as the total amount of planning resources in ZRCs less the total load forecast plus reserves. The base capacity positions reflect the Company's existing and planned resource portfolio, including generation resources, demand-side programs, and market activity. These outlooks provide the starting point for identifying future capacity needs over the planning horizon.

The base capacity positions are further described in the direct testimony of Company witness Moritz.

Q. Why were different base capacity positions created?

A. The Company created different base capacity positions to: (i) establish a consistent starting point for evaluating resource needs by reflecting only existing and planned resources that

are reasonably certain, while removing longer-term or previously evaluated resources that are not part of the current IRP baseline, and (ii) adjust the load forecast and corresponding capacity needs based upon varying assumptions across scenarios, including differing levels of EWR and load growth.

Q. Please describe how the Company created a base capacity outlook to refresh the Company's currently approved IRP.

A. The Company's base capacity outlook included the following assumptions and adjustments:

- Supply-side resources – Approximately 1,920 MW of solar capacity and 828 MW of energy storage, representing previously approved and committed resource additions, were included based on expected in-service dates. Planned renewable additions beyond these levels were removed to establish a consistent baseline portfolio for evaluation in the IRP;
- DR – DR was included at expected program levels of approximately 350 MW on average, reflecting current program assumptions. Incremental DR beyond these levels was not included in the base capacity outlook and instead evaluated within the IRP modeling;
- EWR – EWR was included consistent with current program assumptions, including savings levels of approximately 1.3% annually through 2029 and 0.8% thereafter. Variations in EWR levels across scenarios were reflected through adjustments to the load forecast as well as made available for model selection; and
- Purchased and contracted resources – Capacity from existing and committed PPAs, including MCV through May 31, 2030, and other contracted resources, were incorporated consistent with contract terms and expected availability.

Figure 5 provides the PCA base capacity outlook to illustrate the Company's approach to establishing a consistent baseline for evaluating future capacity needs relative to the PRMR. Figure 6 provides the BAU Current base capacity outlook to illustrate the Company's approach to establishing a consistent baseline for evaluating future capacity

needs relative to the PRMR excluding the incremental 1.5 GW of Large Load. The base capacity positions are further described in the direct testimony of Company witness Moritz.

Figure 5: PLG Balance of Supply and Demand to Meet PRMR

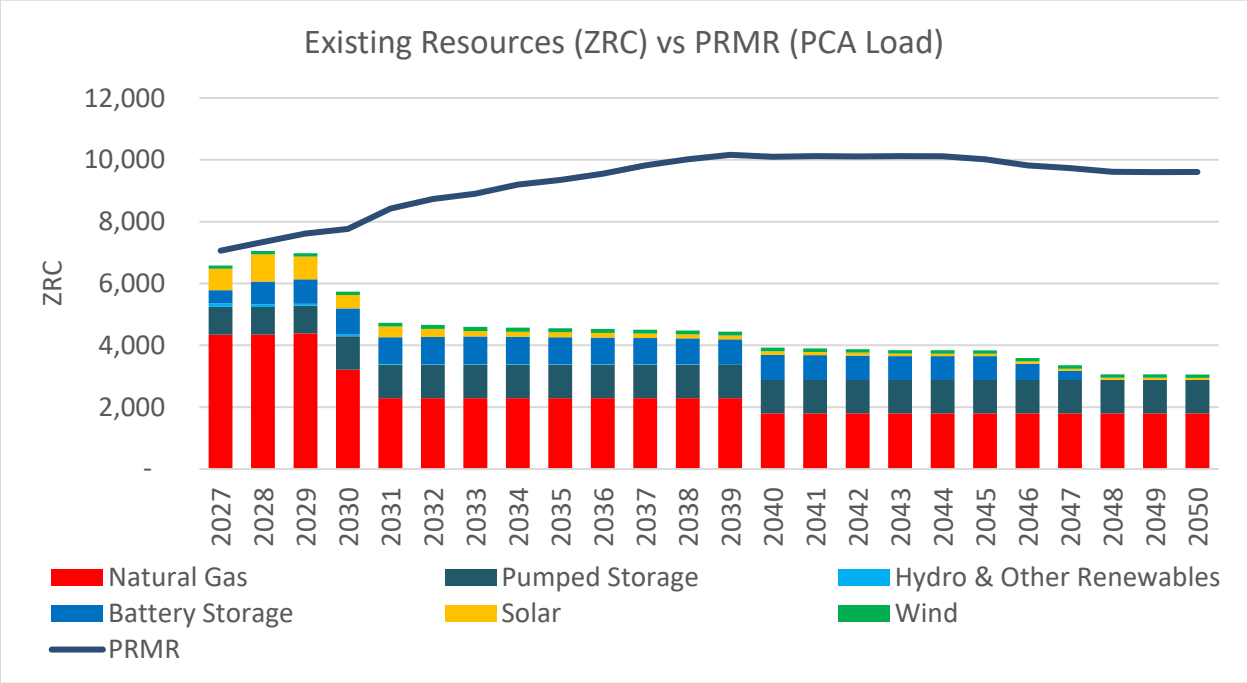
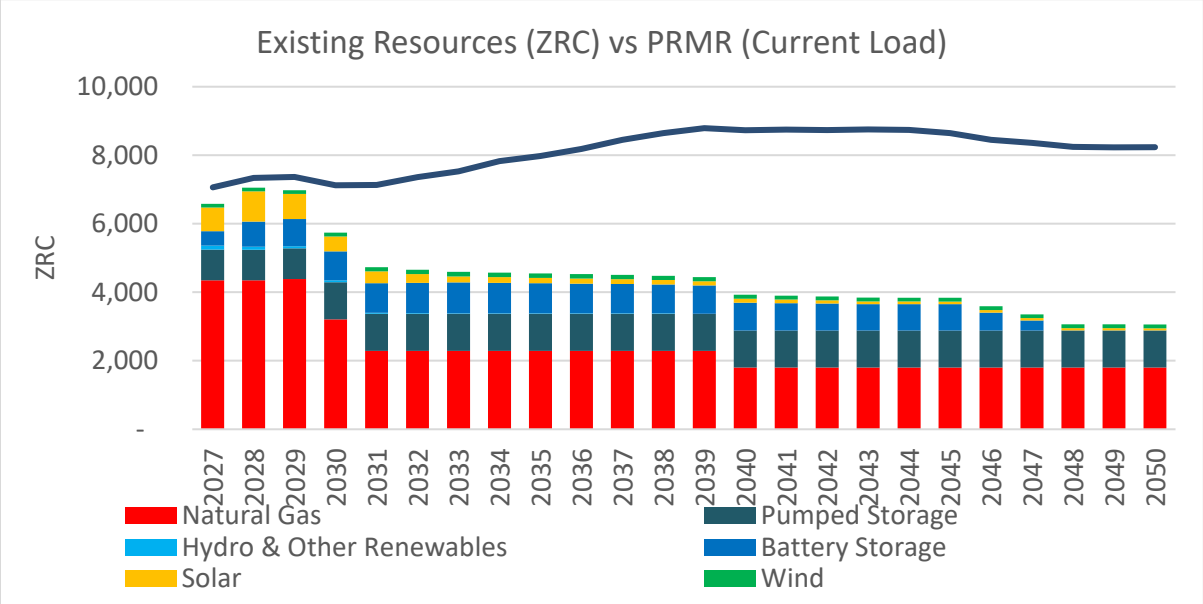


Figure 6: BAU Current Balance of Supply and Demand to Meet PRMR



Other major resources included in the baseline capacity position outlook are:

- Thermal generation fleet – Operation of existing natural gas-fired generation, including the Zeeland, Jackson, and Covert facilities, and planned retirement of Karn Units 3 and 4 in 2031;
- Energy storage resources – Approximately 1,100 MW[5] of pumped storage at the Ludington facility and 828 MW of storage capacity expected to be operational between 2028-2030;
- Renewable resources – Existing wind, solar, and other renewable resources, along with approximately 1,600 MW of additional solar capacity associated with previously approved renewable energy plans; and
- Major PPAs – Continuation of key contracted resources, including MCV through 2030 and other contracted generation resources.

Q. Please describe the major drivers of changes in the Company's capacity position over the planning horizon.

A. As described in the direct testimony of Company witness Moritz, the Company's capacity position changes over the planning horizon based on the interaction of projected customer demand, MISO resource adequacy obligations, resource accreditation, existing and planned supply resources, expiring contracts, and planned retirements. The capacity position is measured in ZRCs and reflects whether the Company has sufficient accredited capacity to serve forecasted peak demand plus applicable PRMR and LCR obligations.

A principal driver is the expiration or retirement of existing resources included in the baseline capacity outlook. The existing MCV PPA is scheduled to expire on May 31, 2030 and does not include a unilateral extension right. Karn Units 3 and 4, which currently provide approximately 1,120 MW of peaking capacity, are expected to retire in 2031.

[5] 1,100 MW represents the Company's approximate 51% share of the Ludington plant.

These changes remove significant accredited capacity from the Company's portfolio at the same time customer demand and MISO reliability requirements are increasing.

The capacity position is also affected by load growth and changes in MISO accreditation. The Company evaluated multiple load forecasts, including the PLG forecast reflected in the PCA and higher-load alternatives. In addition, MISO's transition to a seasonal resource adequacy construct and changes to accreditation, including DLOL accreditation, affect the ZRC value of resources over time. These market-rule changes make it necessary to evaluate not only installed capacity, but also the accredited capacity value that resources provide during higher-risk periods.

Taken together, the expiration of contracted resources, planned retirement of Company-owned generation, load growth, and changes in resource accreditation create a significant need for additional accredited capacity. As summarized by Company witness Moritz, the Company's analysis identifies a need of approximately 4,073 ZRCs by 2032, growing to approximately 6,175 ZRCs by 2040, to continue serving projected peak demand plus PRMR and LCR obligations.

These capacity-position results provide a key foundation for the PCA and the related CON requests. They demonstrate why the Company must add dependable, accredited capacity, preserve existing contracted capacity where reasonable, continue clean and renewable additions, and reduce excessive reliance on short-term market purchases while maintaining flexibility as load, accreditation, and market conditions evolve.

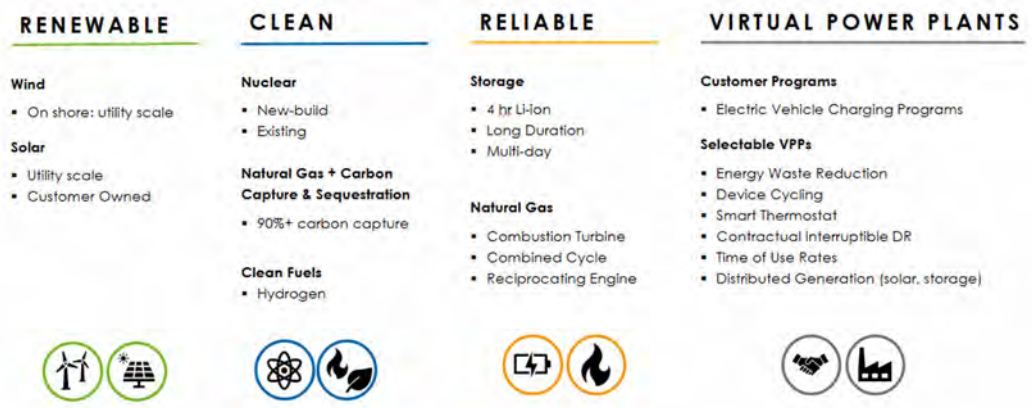
VI. NEW RESOURCE OPTIONS

Supply-Side Resource Options

Q. What supply-side resource options were evaluated in the IRP?

A. As discussed in the direct testimony of Company witness Moritz, the model selects resources based on their ability to deliver one or more of four primary attributes. The modeling conducted by Mr. Moritz represents a co-optimization to deliver the least-cost portfolio that meets energy, capacity, renewable, and clean requirements. The set of supply-side resources considered for selection within the model are presented in Figure 7 below, and discussed in further detail by Mr. Moritz.

Figure 7: New Resource Options



Q. What role do existing assets like MCV and [CONFIDENTIAL] [END CONFIDENTIAL] play in the screening process?

A. Consistent with new-construction supply side resources, the new MCV PPA and the [CONFIDENTIAL] [END CONFIDENTIAL] were offered into the model for selection. These PPAs are recognized for the qualitative benefits provided as [CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

In addition to the qualitative benefits recognized within the screening process, the PPAs offer competitive pricing against other options. The PPA options were compared on a levelized cost of energy ("LCOE") and levelized cost of energy available ("LCOA") basis and determined to pass the economic screen and offered for model selection, competing alongside other resources.

VPPs and Demand-Side Resource Options

Q. How have VPPs been considered in the IRP?

A. The Company's overall strategy is to advance VPPs as part of an integrated portfolio that balances reliability, affordability, and flexibility. The IRP recognizes that many existing customer programs - including DR, EWR, Time-of-Use rates, EV charging programs, and Distributed Generation - already provide the foundational capabilities associated with VPPs and are modeled accordingly. The Company intends to continue building on these capabilities as technologies, customer participation, aggregation platforms, and operational tools mature over time.

Q. Does the Company believe it already has VPP capabilities today?

A. Yes. The Company has numerous customer programs that collectively perform many of the functions commonly associated with VPPs. Existing DR, EWR, Time-of-Use rates, EV charging programs, CVR, and Distributed Generation resources all help reduce, shift, or

supply energy during periods when the electric system is under stress. These impacts are already reflected in IRP modeling and reduce the need for traditional supply-side resources.

Rather than viewing VPPs as a separate resource category, the Company views VPPs as an evolution of customer-side programs, technologies, and distributed resources that become increasingly coordinated, observable, and dispatchable over time. As of 2026, these existing resources reduce the Company's peak demand by approximately 2 GW.

Q. How does the Company assess its current level of VPP maturity?

A. The Company views VPP development as a progression from foundational customer programs to increasingly integrated and dispatchable distributed energy resources. Consumers Energy has already established many of the foundational capabilities associated with VPPs through existing DR programs, energy efficiency resources, time-varying rates, managed EV charging initiatives, distributed generation programs, and advanced metering infrastructure. Together, these programs already provide meaningful peak reduction and load flexibility benefits that are incorporated into the IRP.

The Company therefore views itself as having progressed beyond the foundational stage of VPP development and as actively building toward greater coordination, visibility, and operational integration of customer-side resources over time.

Q. What would characterize a more mature VPP ecosystem?

A. As VPPs mature, customer resources become increasingly observable, controllable, and coordinated across multiple technologies and customer segments. Greater integration of distributed energy resources, improved telemetry, enhanced customer participation, aggregation capabilities, and advanced operational platforms can allow distributed

resources to provide a broader range of grid services and support system operations more directly.

Higher levels of VPP maturity are generally characterized by greater interoperability among customer devices, improved visibility into resource performance, and the ability to coordinate diverse resources in a reliable and scalable manner.

Q. What steps are necessary to advance to higher levels of VPP maturity?

A. Advancing VPP capabilities requires continued growth in distributed energy resource participation, improved visibility into customer resources, enhanced communications and telemetry, greater interoperability among devices, and operational tools that allow distributed resources to be coordinated at scale. It also requires performance validation and operating experience to ensure distributed resources deliver the expected reliability and customer benefits.

The Company is pursuing a measured path that builds experience through existing customer programs, pilots, distributed energy resource initiatives, and ongoing evaluations of emerging technologies and market offerings. As distributed resource participation grows, additional opportunities may emerge to increase coordination and operational integration of customer-side resources.

Q. What role do Distributed Energy Resource Management Systems ("DERMS") and aggregation platforms play in the evolution of VPPs?

A. DERMS, aggregation platforms, and related technologies can provide the visibility, coordination, and operational capabilities needed to manage growing numbers of customer-side resources. These tools can help integrate distributed resources into utility operations and enable increasingly sophisticated grid services as VPP capabilities mature.

The Company has initiated a DERMS Workgroup that has been scheduled to begin on September 22, 2026, consistent with the Commission's March 21, 2025 Order in Case No. U 21585, and March 27, 2026 Order in Case No. U-21870. The goal of the DERMS Workgroup is to engage with stakeholders on the best approach for a comprehensive benefit cost analysis ("BCA") that could be included in a future rate case filing for recovery on a DERMS solution. Additionally, the Company is participating in EPRI's FLEXIT initiative that aims to establish uniform standards for VPP integrations, thus avoiding costly one-off integrations with various vendors.

Q. How are VPPs reflected in the IRP today?

A. VPP-related capabilities are incorporated directly into the IRP through both existing programs and selectable resource options evaluated by the model. Existing customer programs provide measurable demand reduction, load shifting, and customer-sited generation impacts. Additional distributed energy resources, distributed solar, battery resources, DR, and energy efficiency opportunities are also evaluated as selectable resource options within the planning process.

This approach ensures that VPP-related resources compete with traditional alternatives within the same least-cost, reliability-constrained planning framework used throughout the IRP.

Q. How does this approach align with Commission expectations?

A. The Commission has expressed strong interest in the consideration of distributed energy resources, distributed generation, and VPPs within integrated resource planning. The Company's approach is consistent with that direction by explicitly modeling customer-side

resources, evaluating additional distributed resource opportunities, and continuing work to improve future VPP capabilities.

VPPs are a critical component of the Company's long-term resource mix; by 2035 the total VPP inclusive of EWR will reach 3.5 GW – 2.2 GW exclusive of EWR – and will comprise approximately 18% of our peak demand requirements exclusive of EWR. The Company intends to continue advancing those capabilities through ongoing planning, stakeholder engagement, pilots, and future resource evaluations.

Q. Is the Company open to VPP aggregators and third-party VPP solutions?

A. Yes. The Company expects VPP offerings and distributed energy resource aggregations to continue evolving and encourages innovative solutions that can deliver measurable customer and system benefits. As part of its normal resource planning and procurement practices, the Company is already evaluating VPP-related offerings, aggregations, and technologies through existing solicitation and procurement processes alongside other resource alternatives.

Any resource considered for future procurement would be evaluated using the same standards applied to other resource options, including cost, reliability contribution, operational performance, and customer value, with consideration given to non-traditional benefits.

Q. How is the Company preparing for more advanced VPP capabilities in the future?

A. The Company is actively pursuing initiatives that support future VPP development, including the Whole Home Optimization Demand Response Pilot and ongoing work related to distributed energy resource management and customer-side flexibility. These

efforts are intended to improve understanding of resource performance, customer participation, operational capabilities, and long-term scalability.

The objective is to gain practical experience and data that can inform future planning decisions while maintaining affordability and reliability for all customers.

Q. Why is the Company discussing VPP maturity in an IRP focused on current reliability needs?

A. The Company's responsibility is to plan for both current system needs and future opportunities. The IRP provides opportunity to evaluate resources that can reliably serve customers today while identifying pathways that can increase the contribution of emerging technologies such as distributed energy resources, customer flexibility, and VPPs over time.

Q. Does the Company view VPPs as capable to fully displace traditional dispatchable generation resources?

A. Not at this time. The Company views VPPs and traditional generation as complementary resources that provide different benefits to the electric system. VPPs can help reduce peak demand, provide flexibility, improve utilization of existing infrastructure, and support customer participation. Firm generation resources provide sustained, utility-controlled capacity needed to meet the Company's promise to deliver reliability under a broad range of operating conditions.

The IRP is built around an optimized portfolio approach that combines traditional generation, customer-side resources, clean energy resources, storage technologies, and emerging flexibility solutions to achieve reliability, affordability, and environmental objectives.

Q. How will the Company evaluate future VPP opportunities as the market evolves?

A. The Company expects VPP technologies, distributed energy resources, and aggregation models to continue evolving rapidly. As part of its normal resource planning and procurement processes, the Company is already evaluating, and will continue to evaluate, customer-side flexibility resources, aggregated distributed resources, and VPP offerings alongside other resource alternatives based on their demonstrated ability to provide customer value, support affordability, and contribute to system reliability.

Q. Does the PCA include any new or different VPPs?

A. Yes, the Company has modeled a new flatter EV load shape to account for increased solar generation. . The Company has successfully implemented an EV program that promotes charging overnight. As described by Mr. Gast, the program has been very successful with over 90% of residential charging occurring off-peak overnight. As the Company was developing the IRP we determined that the amount of solar development justifies more charging during the day. This allows for charging when there is excess capacity from renewables and prevents the need for additional dispatchable resources beyond what is included in the PCA. Additionally, beginning in 2034 the Company included a new EV load shaping program to further limit the impact of EV charging on the system. By 2035 this new program represents 327 MW of VPP related to EVs which grows to approximately 700GW by 2040.

VII. PROPOSED COURSE OF ACTION

PCA Development and Selection

Q. Please describe how the PCA was developed.

A. The PCA was developed through a process designed not simply to identify the lowest-cost collection of resources, but to identify the portfolio that best serves customers by maintaining reliability in a changing energy landscape, managing long-term customer costs, complying with Michigan's clean energy requirements, and supporting continued economic growth across the state. Through that process, the Company evaluated resource portfolios using the integrated planning framework described above, including the process summarized in Figure 3. That framework evaluated whether each portfolio could maintain reliability, achieve the lowest reasonable customer cost, meet environmental and clean energy requirements, support equitable outcomes, and preserve resource diversity and flexibility over the planning horizon.

The Company utilized its Aurora capacity expansion and production cost modeling framework to evaluate a wide range of scenarios and sensitivities, incorporating updated assumptions regarding load growth, fuel prices, technology costs, resource performance, and reliability and clean energy requirements. Through this process, the Company identified the demand-side and supply-side resources most consistently selected across scenarios as providing the best balance of reliability, affordability, and risk mitigation. Consistent with long-standing Company goals and the 2023 energy law requirements, the PCA includes continued expansion of significant renewable energy resources. The BAU scenario and related sensitivities indicated that firm, dispatchable natural gas resources were an economic selection in the near term that provides a necessary backstop to support

renewables and energy-limited resources. Based on those results, the Company further evaluated the timing, scale, and type of dispatchable capacity needed to support the resource portfolios identified by the modeling. The Company then assessed candidate resources for consistency with planning objectives, operational characteristics, development feasibility, and alignment with statutory requirements, including the need for resources that could provide firm capacity under extreme system conditions. Resources that were supported by reasonable assumptions, demonstrated robust performance across modeled futures, and aligned with the Company's planning objectives were included in the PCA in amounts necessary to meet projected capacity and energy needs. The modeling approach, assumptions, and results that informed the development of the PCA are described in detail in the direct testimony of Company witnesses Moritz and Soni, while the procurement and contractual aspects of the resources reflected in the PCA are addressed by Company witnesses Clark, Troyer, Washburn, Sulzman, Busby, Azukas, and Gang.

Q. How did the Company score the PCA against alternative portfolios?

A. The Company scored the PCA against alternative portfolios using an integrated scorecard that reflects the principal objectives of the IRP: reliability, affordability, clean and equitable outcomes, and resource diversity. The scorecard was not intended to mechanically select a portfolio based on a single metric. Instead, it provided a structured way to compare how each portfolio performed across the full set of objectives that determine whether a plan is reasonable and prudent for customers.

The Company evaluated each portfolio based on whether it could reliably serve customer demand, meet PRMR and LCR obligations, reduce excessive reliance on market purchases, provide the lowest reasonable customer cost, keep projected supply rate impacts

within inflation, comply with renewable and clean energy requirements, support equitable outcomes, and maintain a diverse and flexible mix of resources. The PCA scored strongest overall because it provided the best balance across these measures, even though no portfolio performed best on every individual metric. At its core, the PCA provides the best overall combination of reliability, affordability, clean energy progress, and flexibility for customers. It ensures power is available when customers need it most, supports Michigan's clean energy future, and does so through a portfolio designed to maintain long-term affordability.

Q. What fundamental challenges is the PCA designed to address?

A. The PCA addresses two fundamental challenges facing Consumers Energy and its customers. First, the Company must maintain reliability as existing resources retire, contractual resources expire, and MISO resource adequacy requirements continue to evolve. The need for additional accredited capacity exists even without incremental large load growth because the Company must replace retiring resources and preserve reliable service during the highest-risk hours.

Second, the Company must continue advancing toward Michigan’s statutory clean energy requirements. Meeting those requirements requires substantial additions of renewables, storage, customer-side flexibility, and firm clean energy resources while maintaining affordability and reliability. The PCA is designed to solve both challenges simultaneously, allowing Consumers Energy to continue providing dependable service, regardless of weather conditions, market volatility, or changes occurring across the broader electric industry, while advancing the clean energy future.

Q. Can the Company meet the clean energy requirements while building two natural gas plants, entering a new PPA with MCV, and continuing to operate existing natural gas assets?

A. Yes, the Company can meet all statutory renewable and clean energy standards while still building two dispatchable natural gas plants, entering a new PPA for energy and capacity from MCV, and operating existing natural gas assets to continue reliably serving customers and meeting resource adequacy requirements. This is possible because Michigan's energy laws set a floor for renewable and clean resources but do not set a ceiling for other resources needed to meet reliability and resource adequacy requirements.

Q. Does the need for the PCA exist even without large load growth?

A. Yes. Large load growth affects the ultimate scale and timing of resource additions, but it does not create the core reliability need addressed by the PCA. The Company must replace retiring capacity, address the expiration of existing contractual resources, satisfy resource adequacy requirements, and minimize reliance on increasingly constrained regional capacity and energy markets. Those requirements exist regardless of whether additional large load growth materializes.

Q. What role do Michigan's clean energy requirements play in the PCA?

A. Michigan's clean energy requirements are a central driver of the PCA. The PCA is intentionally structured to provide a credible pathway toward Michigan's Clean Energy and Renewable Energy Standards through substantial renewable additions, significant storage deployment, customer-side flexibility, and [CONFIDENTIAL] [redacted] [redacted] [END CONFIDENTIAL]. The PCA therefore addresses both near-term reliability needs and long-term statutory compliance obligations.

Importantly, the PCA does not rely on a single technology or a single pathway to achieve compliance. Instead, it combines resources in a balanced manner that provides customers with a practical and executable path toward Michigan's Renewable and Clean Energy requirements.

Q. How does the PCA position the Company to comply with Michigan's 2035 and 2040 clean energy requirements?

A. The PCA is intentionally structured around Michigan's statutory Renewable Energy and Clean Energy Standards.

The renewable additions, storage additions, VPP growth, and [CONFIDENTIAL] [END CONFIDENTIAL] each play specific roles in achieving those requirements. Solar and wind provide the primary renewable energy additions needed to satisfy increasing renewable standards. Storage helps integrate those resources and improve operational flexibility. VPP and customer-side resources reduce demand and improve system efficiency. The PPA [CONFIDENTIAL] [END CONFIDENTIAL] that helps bridge the system toward Michigan's 2040 clean energy requirement. Together, these resources create a compliance pathway that remains reliable, affordable, and executable for customers.

Q. Please describe the key components of the PCA.

A. The PCA includes:

- Approximately 1.5 GW of incremental large load growth[6],

[6] The PCA's load growth represents 1.5GW higher load than current load levels that are planned and operational today, which include increased load due to manufacturing growth and EV consumption.

- Approximately 1,400 MW of natural gas CT capacity,
- Approximately [CONFIDENTIAL] [END CONFIDENTIAL],
- Approximately 1,240 MW of natural gas combined cycle capacity via a PPA with MCV,
- Continued renewable expansion, achieving over 17,000 MW of total solar and wind capacity by 2040,
- Over 5,000 MW of total storage capacity by 2040,
- Delayed CCS deployment to 2040, and
- Over 3 GW load shifting and reductions through VPP by 2040.

Together, these resources form a diverse and balanced portfolio that combines fast-starting dispatchable generation, [CONFIDENTIAL] [END CONFIDENTIAL] renewable resources, storage technologies, and customer-focused programs to ensure reliable service during the moments that matter most, support long-term affordability, and achieve Michigan's clean energy objectives. Below I will describe the specific aspects based on the 5, 10, 15, and 25-year plans.

Q. Does each major resource in the PCA serve the same purpose?

A. No. One of the strengths of the PCA is that different resources address different customer and system needs. The Karn and Thetford CTs and the MCV PPA primarily address reliability needs by providing dependable capacity and dispatchable energy. By repowering existing industrial sites at Karn and Thetford with modern, fast-starting generation and securing long-term capacity and energy from MCV, the Company replaces retiring and expiring resources. This helps ensure power is available regardless of market conditions or system stress and establishes the reliability foundation necessary to continue expanding renewable, storage, and other clean energy resources.

By contrast, renewable resources, battery storage, VPP-related resources, and the [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] primarily address the Company's long-term clean energy strategy while also providing significant portfolio diversity and operational benefits. These resources play a critical role in meeting Michigan's Renewable Energy and Clean Energy Standards and supporting the Company's transition toward a cleaner resource portfolio. The PCA is successful because it uses different resource types to solve different planning challenges simultaneously.

Load Growth in the PCA

Q. What role does load growth play in the PCA?

A. The PCA reflects the PLG forecast described in Section V of my testimony. That forecast includes signed Large Load commitments and a probability-adjusted assessment of the broader development pipeline. Including this forecast allows the Company to evaluate the resources, costs, reliability impacts, and affordability effects associated with the most probable load outlook known at the time of the IRP. In doing so, the PCA serves two purposes simultaneously: maintaining reliable and affordable service for existing customers while creating a framework capable of supporting future economic growth opportunities throughout Michigan.

Load growth affects the scale and economics of the PCA, but it does not create the core reliability need addressed by the plan. The Company continues to need dependable resources to replace retiring capacity, address the expiration of existing contractual resources, reduce excessive reliance on short-term market purchases, and maintain reliability under tightening MISO resource adequacy conditions. The PLG forecast informs

the amount and timing of resources needed, while the underlying reliability and compliance needs exist even before considering incremental load growth.

Q. How does the PCA protect existing customers while supporting load growth?

A. The PCA protects existing customers by planning for load growth through an integrated resource portfolio and customer-specific service arrangements that are designed to avoid inappropriate cost shifting. Large Load customers are not assigned ownership of, or responsibility for, individual resources such as the new CTs, the MCV PPA, the [CONFIDENTIAL] [END CONFIDENTIAL], or renewable and storage resources. Rather, they take service from the Company's integrated portfolio and are expected to contribute toward the costs of serving their demand, including firm capacity, energy, renewable and clean attributes, and the system capabilities needed to provide reliable service.

The Company's Large Load data center Rate Contract arrangements are designed so that data center customers bear the incremental costs associated with serving their demand and contribute their fair share of the broader system they use. This structure allows the Company to support economic development and new customer growth while protecting existing customers from subsidizing new Large Load data center customers. When structured properly, incremental load growth can strengthen affordability by contributing to the costs of maintaining the electric system, supporting jobs and investment across Michigan, and spreading fixed costs over a larger sales base.

PCA Implementation Over the Planning Horizon

Q. Please provide an overview of the five-year plan.

A. The five-year plan addresses the Company's most immediate reliability, resource adequacy, market reliance, and compliance needs. It serves as the near-term bridge from the Company's current portfolio to the broader long-term transition by replacing retiring local capacity, retaining dependable existing capacity, adding firm clean energy, continuing major renewable and storage additions, and continuing to expand demand-side and VPP-related resources. This period is particularly critical because it is when the Company must navigate the retirement of aging resources, tightening regional supply-demand conditions, increasing market volatility, and new clean energy requirements while preserving the reliability customers expect and establishing the foundation for continued renewable growth.

The principal objective of the five-year plan is to ensure that the Company can continue to serve customers reliably as Karn Units 3 and 4 retire, the existing MCV arrangement expires, load growth continues to materialize, and MISO resource adequacy conditions continue to tighten. The five-year plan therefore emphasizes executable near-term resources that provide dependable capacity and energy while reducing exposure to increasingly uncertain and costly short-term market purchases and building on the next phase of clean resource additions.

Figure 8: Proposed Course of Action 5-Year Capacity Plan (2027-2031) [CONFIDENTIAL]



[END CONFIDENTIAL]

- **Reliability resources.** The five-year plan replaces retiring Karn Units 3 and 4, which currently provide approximately 1,120 MW of capacity, and repowering the sites with new Karn and Thetford CT capacity replacing what was retired. Approximately 1,375 MW of CT capacity, representing approximately 1,306 ZRCs, is expected to be online by June 1, 2031.

- **Contracted reliability resources.** The MCV PPA adds approximately 1,240 MW of dependable capacity and energy beginning in 2030. Because MCV is an existing Michigan resource, it preserves accredited capacity, supports reliability, reduces reliance on increasingly volatile market purchases, and helps protect customers from capacity and energy market price spikes.

- **Contracted clean baseload resources.** The [CONFIDENTIAL] [END CONFIDENTIAL] strengthens the Company's ability to meet Michigan's Renewable Energy and Clean Energy Standards by securing clean energy from an [CONFIDENTIAL] [END CONFIDENTIAL] at a critical point in the State's energy transition.

- **Renewable resources.** The PCA increases incremental solar additions to 3,000 MW by 2031 and incremental wind additions to approximately

1,200 MW by 2031. These additions support Renewable Portfolio Standard compliance, Clean Energy Standard progress, resource diversity, and the continued transition toward a cleaner supply portfolio.

- **Battery storage.** The PCA increases incremental battery storage additions to approximately 2,000 MW by 2031, supporting renewable integration, intra-day flexibility, capacity value, and reduced reliance on market purchases during higher-risk hours.

- **VPP and demand-side resources.** EWR, DR, CVR, EV programs, distributed generation, and other customer-side resources continue to provide 2.5 GW of load reduction and flexibility through the five-year plan, complementing supply-side additions and supporting affordability and reliability.

Q. Please provide an overview of the 10-year plan.

A. The 10-year plan builds on the five-year foundation by carrying the Company through 2036, when the portfolio must support continued reliability, expanded renewable and storage deployment, growing VPP and demand-side capability, and significant progress toward Michigan's renewable and clean energy requirements. During this period, the PCA preserves the reliability value of the Karn and Thetford CTs, the MCV PPA, and the [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] while materially increasing the clean and flexible resources needed to support the next stage of the transition.

The objective of the 10-year plan is to maintain dependable capacity while scaling resources that support renewable compliance, clean energy progress, affordability, and operational flexibility. Solar and wind additions increase substantially, storage grows to support renewable integration and higher-risk hours, and VPP-related resources continue to provide load reduction and customer-side flexibility. This mix reduces excessive reliance on market purchases and gives the Company multiple resource types that can perform under different system conditions.

Figure 9: Proposed Course of Action 10-Year Capacity Plan through approximately 2036

[CONFIDENTIAL]



[END CONFIDENTIAL]

- **Renewable resources.** The PCA increases incremental solar additions to approximately 7,200 MW by 2036 and incremental wind additions to approximately 3,200 MW by 2036. These additions support Renewable Portfolio Standard compliance, Clean Energy Standard progress, resource diversity, and the continued transition toward a cleaner supply portfolio.

- **Battery storage.** The PCA increases incremental battery storage additions to approximately 3,160 MW by 2036, supporting renewable integration, intra-day flexibility, capacity value, and reduced reliance on market purchases during higher-risk hours.

- **VPP and demand-side resources.** EWR, DR, CVR, EV programs, distributed generation, and other customer-side resources provide.3.2 GW of load reduction and flexibility through the 10-year plan, complementing supply-side additions and supporting affordability and reliability.

- **Reliability and clean baseload resources.** The Karn and Thetford CTs, MCV PPA, and [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] continue to provide the dependable capacity, dispatchable energy, and firm clean energy needed to support reliability and clean energy compliance while renewable, storage, and customer-side resources scale.

Q. Please provide an overview of the 15-year plan.

A. The 15-year plan extends the PCA through 2041, when Michigan's 100% clean energy requirement becomes central to portfolio design. By this point, the PCA reflects a more mature clean energy portfolio that continues to rely on dependable reliability resources while scaling renewable, storage, VPP, and demand-side capability.

The objective of the 15-year plan is to demonstrate that the PCA can meet long-term clean energy requirements without sacrificing reliability, affordability, or flexibility. The plan does this by continuing significant renewable expansion, adding substantial storage, advancing VPP and customer-side resources, maintaining dependable capacity, and preserving optionality for future clean firm technologies. The PCA defers CCS deployment to 2040, allowing additional time for technology, cost, permitting, tax, and execution risks to mature before customers are asked to rely on that resource category.

Figure 10: Proposed Course of Action 15-Year Capacity Plan through approximately 2041

[CONFIDENTIAL]



[END CONFIDENTIAL]

- **Renewable resources.** The PCA continues significant solar and wind expansion through the 15-year plan, reaching over 17,500 MW of total solar and wind capacity by 2041. These additions support renewable energy compliance, clean energy progress, fuel diversity, and long-term customer affordability.

- **Battery storage.** The PCA increases total storage capacity to more than 3,200 MW by 2041, supporting renewable integration, flexibility, peak management, and reliability during higher-risk hours. Storage remains an important complement to, but not a complete substitute for, firm dispatchable resources.

- **VPP and demand-side resources.** EWR, DR, CVR, EV programs, distributed generation, and other customer-side resources provide 3.4 GW of load reduction and flexibility through the 10-year plan, complementing supply-side additions and supporting affordability and reliability.

- **Clean baseload optionality.** The PCA defers CCS deployment to 2040, when approximately 1,200 MW of new clean firm capacity, representing approximately 960 ZRCs, comes online. This preserves long-term optionality while avoiding premature reliance on resources that continue to face technology, cost, permitting, and execution uncertainty.

Overall, the 15-year plan demonstrates that the PCA remains reliable, affordable, clean, diverse, and flexible through 2041. It maintains dependable capacity, scales renewable and storage resources, advances VPP capabilities, supports large load and broader customer growth, and preserves optionality for future clean firm technologies as the market and regulatory environment continue to evolve.

Q. Please provide an overview of the 25-year plan.

A. The 25-year plan extends the PCA through the full IRP planning horizon ending in 2050. This period is not intended to lock the Company into a fixed technology pathway. Instead, it demonstrates that the PCA is an adaptable roadmap that maintains reliability, supports affordability, sustains compliance with Michigan's clean energy requirements, and preserves flexibility as technology, markets, policy, and customer demand evolve.

By 2050, the portfolio is expected to rely on a mature mix of renewable resources, storage, customer-side flexibility, firm clean resources, and dispatchable resources needed to serve customers during peak and stressed conditions. The purpose of the 25-year view is to show that the near-term decisions in the PCA do not foreclose future options. Instead, the PCA preserves the ability to adjust future resource additions as more information becomes available regarding load growth, MISO market rules, transmission availability, tax policy, technology costs, clean firm technologies, long-duration storage, advanced nuclear, hydrogen-capable resources, expanded VPP capabilities, and other commercially viable options.

Overall, the 25-year plan demonstrates that the PCA is not a static resource plan. It is a long-term, adaptable roadmap that maintains reliability, supports affordability, advances clean energy compliance, enables customer and economic growth, and preserves

flexibility to incorporate emerging technologies and market developments through 2050. This long-term flexibility is important because the Company must make executable near-term decisions now while retaining the ability to adapt future resource selections as actual conditions develop.

Figure 11: Proposed Course of Action 25-year Capacity Plan through 2050 [CONFIDENTIAL]



[END CONFIDENTIAL]

Q. Why is a diverse resource mix necessary to support the PCA?

A. The PCA includes a balanced mix of reliability, clean energy, storage, renewable, and customer-side resources because no single resource type can satisfy all of the Company's needs. The Karn and Thetford CTs provide local, dispatchable capacity needed to replace retiring resources and support reliability during peak and stressed conditions. The MCV PPA preserves dependable capacity and energy from an existing resource with lower execution risk than a comparable new-build alternative. The [CONFIDENTIAL]

[END CONFIDENTIAL] Storage, renewables, VPP programs, and distributed generation provide clean energy, flexibility, load reduction, and customer-side

benefits. Together, these resources reduce market reliance, support affordability, advance clean energy requirements, and preserve flexibility as load, technology, market rules, and policy conditions evolve.

Q. Why are the Karn and Thetford CTs necessary?

A. The Karn and Thetford CTs are necessary because the reliability challenges they address are not theoretical or limited to a future where there is load growth; the Company is already seeing these challenges emerge today. As solar production declines later in the day, the higher-risk hours for serving customers are increasingly shifting into the evening, when dependable resources must be available to meet demand. The Company is also seeing stressed system conditions that can last multiple days in various seasons across the year, including events that took place this past winter during Winter Storm Fern and in July 2026, where customers need sustained energy production—not only resources that can shift energy for a limited number of hours. These existing conditions reinforce the importance of fast-starting, controllable, energy-producing resources that can perform during periods of high demand, low renewable output, constrained imports, and stressed market conditions. These same conditions are also when short-term capacity and energy purchases are most likely to be less available and more expensive, so the Karn and Thetford CTs help protect customers by reducing exposure to high-cost market purchases during periods of system stress.

Storage, DR, EWR, CVR, EV programs, distributed generation, and other VPP-related resources are valuable and are included in the PCA, but they are not complete substitutes for firm dispatchable generation. Storage provides important intra-day flexibility but is duration-limited and must be recharged, which limits its ability to address

extended multi-day energy needs or shorter duration periods when renewable production is low. Demand-side resources depend on customer participation, event availability, program limitations, and MISO requirements.

The Karn and Thetford projects replace retiring generation with modern, local capacity resources that provide the dependable, accredited capacity needed to serve customers during periods of peak demand, high system stress, and constrained market conditions.

Q. What role does the MCV PPA play in the PCA?

A. The MCV PPA is primarily a reliability resource. The agreement creates new access to dependable dispatchable energy and accredited capacity from an existing operating facility at a time when regional reserve margins are tightening and market reliance is becoming increasingly costly and uncertain, located right here in Michigan. The MCV PPA ensures the Company can continue serving customers reliably while avoiding many of the permitting, construction, supply chain, interconnection, and execution risks associated with building an equivalent resource from the ground up. The MCV PPA also provides an important hedge against increasingly volatile market purchases and capacity prices, helping protect customers from reliability risks and market uncertainty.

Q. Why is the MCV PPA included in the PCA?

A. The MCV PPA is included because it represents one of the most reliable and executable methods available to preserve accredited capacity and dispatchable energy for customers.

The facility is already operating, already interconnected, and already capable of performing when needed. As a result, the MCV PPA avoids many of the risks associated with developing a comparable new resource while helping maintain reliability as the

Company replaces retiring resources and navigates tightening MISO resource adequacy conditions. The MCV PPA also reduces reliance on short-term market purchases during periods when capacity and energy prices may be elevated. Importantly, by preserving dependable capacity and energy from an existing operating resource, the MCV PPA provides a reliable bridge that allows the Company to continue advancing renewable resources, energy storage, VPPs, and other clean energy investments while maintaining the reliability customers expect. Accordingly, the MCV PPA represents both a reliability strategy and a customer affordability strategy.

Q. Beyond maintaining reliability, what other long-term objectives must the PCA address?

A. In addition to maintaining reliability, the PCA must position the Company to meet Michigan's increasingly stringent Renewable Energy and Clean Energy Standards. As a result, the PCA includes substantial renewable and storage additions, continued investment in customer-side flexibility resources, and [CONFIDENTIAL] [END CONFIDENTIAL]. Together, these resources support a balanced pathway toward the State's 2035 and 2040 clean energy requirements while maintaining affordability and reliability.

Q. What role does the clean PPA with [CONFIDENTIAL] [END CONFIDENTIAL] play in the PCA?

A. The [CONFIDENTIAL] [END CONFIDENTIAL] PPA is primarily a clean energy and compliance resource. [CONFIDENTIAL]

[END CONFIDENTIAL]

Q. Why is the [CONFIDENTIAL] [END CONFIDENTIAL]PPA included in the PCA?

A. The [CONFIDENTIAL] [END CONFIDENTIAL] PPA is included because it provides [CONFIDENTIAL] [END CONFIDENTIAL] carbon-free energy from an [CONFIDENTIAL] [END CONFIDENTIAL]

Q. Why is it important to secure the [CONFIDENTIAL] [END CONFIDENTIAL] PPA now?

A. The [CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Q. Why are demand-side resources, VPP-related resources, and battery storage complements to, rather than substitutes for, firm dispatchable capacity?

A. Demand-side resources, VPP-related resources, and battery storage are important components of the PCA because they reduce demand, provide flexibility, support customer participation, and help integrate renewable resources.

However, VPPs are not substitutes for firm dispatchable capacity. DR, EWR, CVR, EV managed charging, distributed generation, and other customer-side resources depend on customer participation, program rules, event availability, MISO dispatch requirements, and operational limits. Recent events reinforce that point. During Winter Storm Fern, MISO called on Load Modifying Resources and took emergency actions to maintain reliability, and recent summer and winter demand response events have shown that repeated curtailments can create operational and economic impacts for participating customers, particularly large commercial and industrial customers.

Battery storage also provides valuable capacity and flexibility, but it is duration-limited and must be charged before it can discharge. There are moments that matter the most for our customers, and these moments typically occur during long stretches when there is simply not enough energy in the market to charge these batteries. Or when the duration of the event lasts more than four hours.

For that reason, the PCA deploys an all-of-the-above approach to resource diversity, and combines these resources with local dispatchable capacity so the Company can maintain reliability during peak demand, low renewable output, extended weather events, constrained imports, high market prices, and other stressed system conditions in service to our customers.

Scoring the PCA

Q. What role do the alternative plans have in the evaluation of the PCA?

A. As explained by Company witness Adam J. Moritz, the Alternative Plan Current and Alternate Plan High Load Growth were developed to evaluate the PCA against a reasonable range of potential load outcomes. These plans help demonstrate that the PCA is not being selected in isolation, but rather after comparing how different portfolios perform under lower, probable, and higher load-growth assumptions.

The Alternative Plan Current reflects the Company's updated current-load outlook, including existing and contracted load, but excluding the incremental PLG included in the PCA. This plan demonstrates that the need for the Proposed Projects are not solely dependent on the incremental Large Load data center growth reflected in the PCA. Even under the Current load outlook, the modeling supports the need for the proposed Karn CT project, the proposed Thetford CT project, the MCV PPA, and the [CONFIDENTIAL] [END CONFIDENTIAL]. In other words, these resources are needed to maintain reliability, replace retiring or expiring resources, meet capacity and energy needs, and support clean energy compliance even before considering the additional PLG included in the PCA.

The Alternate Plan HLG evaluates a higher-growth outcome than the PCA, reflecting additional economic development load beyond the PLG forecast. The HLG plan demonstrates the magnitude of additional resources that the Company may need to add if customer demand develops more rapidly than reflected in the PCA.

Together, these alternative plans support the Company's evaluation of the PCA by showing how the resource portfolio performs across a range of load outcomes. The

Alternative Plan Current confirms that the Proposed Projects are needed under today's updated load outlook, while the Alternate Plan HLG demonstrates the additional resource implications if load growth exceeds the PCA forecast. This comparison supports the conclusion that the PCA provides the best overall balance of reliability, affordability, clean energy compliance, resource diversity, and flexibility, while the Alternative Plans provide transparency regarding how the Company's resource needs may change if actual load growth is lower or higher than forecast.

Q. Did the Company perform additional alternatives analyses to support the specific resources included in the Company's CON requests?

A. Yes. The Company evaluated a broad range of alternative technologies and resource options before selecting the resources included in the CON requests. Those alternatives included combined-cycle gas generation, combined-cycle generation with carbon capture, battery storage, market purchases and ZRCs, [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], additional wind and solar, distributed generation, demand-side resources, and VPP options. Each alternative was assessed based on cost, timing, reliability, availability, environmental performance, operational characteristics, and ability to meet the Company's identified energy, capacity, renewable, and clean-energy needs.

The modeling and supporting analyses show that the proposed resources are the most reasonable and prudent options available. The MCV PPA was economically selected across the Company's modeling and provides near-term seasonal accredited capacity and energy value. As previously described, the clean PPA with [CONFIDENTIAL] [redacted]

[redacted] [END CONFIDENTIAL] The Karn and Thetford CTs provide needed dispatchable capacity beginning in 2031, improve reliability during stressed system conditions, and were selected as cost-effective resources compared to feasible alternatives.

The Company also performed resource-removal modeling in Confidential Exhibit A-33 (AJM-19) to identify what Aurora would select if each CON resource were excluded. That analysis shows that removing the MCV PPA, Karn CT, or Thetford CT would increase customer costs, while the [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] PPA was included primarily to support Clean Energy Standard compliance and [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] Based on the Company's quantitative modeling, reliability analysis, and qualitative assessment of feasibility and execution risk, the proposed CON resources represent an optimal and prudent set of resources for inclusion in the PCA.

Q. Please summarize the Company's overall rationale for the PCA.

A. The PCA provides the Company's best path to deliver reliable, affordable, and increasingly clean energy for customers. It addresses immediate reliability needs, responds to changing market and industry conditions, supports economic growth opportunities across Michigan, and creates a practical pathway toward compliance with the State's clean energy requirements. No other portfolio evaluated by the Company provided a better overall balance of reliability, affordability, clean energy compliance, resource diversity, and execution certainty. It adds local dispatchable capacity to reduce market reliance and support reliability, preserves dependable existing capacity and energy through the MCV

PPA, [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], and continues substantial investment in renewable, storage, VPP, and demand-side resources. This combination allows the Company to meet customer energy and capacity needs, support Michigan's renewable and clean energy requirements, and maintain flexibility as load growth, MISO market rules, technology costs, tax policy, and resource availability evolve.

The PCA also supports serving new customers through economic development while protecting existing customers. Large Load customers are expected to contribute to the incremental costs of serving their demand and to their fair share of the broader integrated system through the Company's Large Load tariff and related rate contract provisions. Other large customers included in the Company's forecast represent manufacturing, industrial, and other economic development growth occurring across the Company's service territory. Together, these customers contribute to system utilization, economic growth, and the costs of maintaining reliable service. The resources included in the PCA address broader reliability and compliance needs and are not being proposed solely for new large load customers. These assets in the PCA are needed regardless of the incremental Large Load growth; this is shown in the analysis of multiple load trajectories as illustrated in Figure 6 in Section V of my testimony and supported by Company witness Moritz testimony, sections IX through XI.

The PCA is also integrated with the CONs requested in this case. The requested CON approvals provide the foundational dispatchable and contractual resources needed to execute the PCA as modeled. If the Commission modifies or rejects those approvals, the feasibility and internal consistency of the PCA could be materially affected, and the

Company will need to reassess whether the remaining elements of the plan can be implemented as proposed.

VIII. DESCRIPTION OF SIGNIFICANT PROPOSALS AND SUMMARY OF REQUESTED RELIEF

Q. Please explain the Company's request with respect to the proposed construction of the Karn and Thetford CTs.

A. The Company is requesting CONs under MCL 460.6s for the Karn and Thetford CT projects. As discussed above, the Company's IRP modeling, reliability analysis, capacity position, and PCA selection support the statutory findings that the power to be supplied by these projects is needed, that the proposed size, fuel type, and design characteristics are the most reasonable and prudent means of meeting that need, and that the Commission should approve the construction of the projects, the associated capital costs, the financing plan, and recovery of approved costs in rates.

The need for the projects is established by the broader record described in prior sections: retiring Karn Units 3 and 4, load growth, tightening MISO resource adequacy conditions, and the need to reduce reliance on short-term market purchases to protect customer affordability. The Karn and Thetford CTs provide firm, dispatchable, local accredited capacity that complements the renewable, storage, VPP, demand-side, MCV, and [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] resources included in the PCA.

The proposed projects are reasonable and prudent because simple-cycle CTs can provide flexible, utility-controlled capacity on a timeline aligned with the identified reliability need. The existing Karn and Thetford sites also support project execution by using established generation locations, infrastructure, interconnection opportunities, and

development experience. The detailed support for project design, siting, interconnection, costs, operations, and financing is provided in the Company's CON testimony and exhibits.

Accordingly, the Company requests that the Commission approve recovery in rates of the approved capital costs for the Karn Project of $ 1.2 billion and the Thetford Project of $2.4 billion, or a combined total of $3.6 billion. The Company will update the cost approval request at 150 days per MCL 460.6s. As described by Company witness Washburn, these capital costs are inclusive of internal loadings and financing costs. Financing costs, such as AFUDC, are applied by the Company to the Owner's Engineer cost estimates and are included in the total capital costs listed below. None of the projected costs have previously been included in the Company's rate base. As described by Company witness Bleckman, if approved, the Company's requested CWIP treatment would allow recovery of financing costs during construction by including CWIP in rate base. Although CWIP and AFUDC differ in accounting treatment and timing of recovery, the underlying estimate of financing costs during construction is not expected to materially change as a result of the requested CWIP treatment.

Q. What approvals is the Company requesting related to CWIP for the Karn and Thetford CT projects?

A. The Company is requesting accounting and ratemaking approval to include CWIP in rate base during construction of the Karn and Thetford CT projects and to eliminate the corresponding AFUDC offset in general rate case revenue requirements to the extent financing costs are recovered in rates during the construction period. As explained by Company witness Bleckman, this treatment is authorized by MCL 460.6s(12) and is requested only for the two near-term gas-fired projects at this time.

The purpose of the request is to support the Company's ability to finance the projects needed to implement the PCA while maintaining credit quality and customer affordability. Under traditional AFUDC treatment, financing costs incurred during construction would be capitalized and recovered after the projects enter service, which can increase the total capitalized cost of the projects and place pressure on the Company's credit metrics during the construction period. CWIP in rate base provides more timely recovery of financing costs, helps mitigate credit metric deterioration, and reduces the amount of financing costs that would otherwise be capitalized into plant balances.

Accordingly, the Company requests that the Commission approve CWIP in rate base treatment for the Karn and Thetford projects, together with elimination of the AFUDC offset to the extent financing costs are recovered in rates, as part of the financing plan supporting the requested CON approvals. Company witness Bleckman provides the detailed financial, credit-metric, and affordability support for this request.

Q. Please explain the Company's request with respect to the proposed PPA for MCV.

A. The Company is requesting a CON under MCL 460.6s for the proposed MCV PPA. As discussed above, the Company's IRP modeling, reliability analysis, capacity position, and PCA selection support the statutory findings that the power to be supplied under the MCV PPA is needed, that the terms of the PPA represent the most reasonable and prudent means of meeting that need, and that the Commission should approve the PPA, the price specified in the agreement, recovery of approved costs in rates, and the financial incentive authorized under MCL 460.6s.

The need for the MCV PPA is established by the broader record described in prior sections: expiring contractual resources, load growth, tightening MISO resource adequacy

conditions, and the need to reduce reliance on short-term market purchases. The MCV PPA preserves a large, existing, interconnected source of dependable, accredited capacity and dispatchable energy that complements the Karn and Thetford CTs, [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], renewable, storage, VPP, and demand-side resources included in the PCA.

The proposed MCV PPA is reasonable and prudent because it provides near-term reliability value from an existing operating resource while avoiding many of the development, construction, interconnection, permitting, and execution risks associated with building an equivalent new resource on the same timeline. Accordingly, the Company requests that the Commission approve the MCV PPA, approve recovery in rates of the price specified in the agreement, and authorize a financial incentive for the PPA based on the Company's weighted average cost of capital, as permitted under MCL 460.6s and supported by the Company's CON testimony and exhibits.

Q. [CONFIDENTIAL] [redacted]

[redacted] [END CONFIDENTIAL]

Q. What approvals is the Company requesting for Karn retention and separation costs?

A. The Company is requesting accounting approval to defer reasonably and prudently incurred retention and separation costs associated with Karn Units 3 and 4 as a regulatory asset, with recovery of the deferred balance to be addressed in a future electric rate case. As explained by Company witness Myers, these costs are incremental, non-recurring, and necessary to support the safe, reliable, and orderly retirement of Karn Units 3 and 4 by maintaining a qualified workforce through the cessation of operations.

The Company proposes to defer these costs through the closure of the plant in 2031. The amortization period and related expense would be reviewed and approved in a future

rate case, and the deferred unamortized balance would be included in rate base and earn a return at the Company's prevailing authorized rate of return. Company witness Myers estimates that total O&M costs to be deferred for the 2027 through 2031 period will be approximately $15.1 million, subject to adjustment based on actual costs incurred. This proposed treatment preserves the opportunity for future Commission review and recovery if the costs are found to be prudent.

Q. What approvals is the Company requesting with regard to BESS projects?

A. The Company is requesting approval of an ex parte process for future BESS projects selected through competitive solicitations or bilateral negotiations. Under this process, projects would remain subject to Commission review and would need to satisfy an objective cost benchmark not to exceed 140% of the Planning Year 2029 BESS PCA proxy. The benchmark provides a defined customer protection while giving the Company flexibility to act on cost-effective storage opportunities that may arise between IRP filings or outside the normal timing of contested proceedings.

This approval process is important because the PCA includes a significant expansion of BESS resources, and timely procurement will be needed to support reliability, integrate renewable resources, meet Michigan's energy storage objectives, and preserve affordability. The proposed process would allow the Company to pursue storage resources that are consistent with the PCA and market-tested through competitive solicitations or supported by comparable market information, while ensuring that only projects meeting the approved cost parameters would be eligible for ex parte approval. Company witness Skowronski provides additional detail on the proposed BESS approval process.

Q. Please Summarize all relief that the Company is seeking as part of this filing.

A. In this proceeding, the Company requests approval of the PCA as the most reasonable and prudent plan for meeting customer energy and capacity needs over the 5-, 10-, and 15-year planning horizons under MCL 460.6t. The Company also requests CON approvals under MCL 460.6s and the related accounting, ratemaking, cost recovery, and implementation approvals necessary to execute the PCA and related proposals described in the testimony, exhibits, and IRP Report.

The Company is seeking:

1. Approval of the PCA. The Company requests approval of the PCA as the most reasonable and prudent plan under Act 341, and consideration of the Alternate and Support Plans as part of the Commission's evaluation of reliability, affordability, and risk. The Alternate and Support Plans demonstrate why the PCA represents the best balance of system needs across a range of future conditions.

2. CONs for New Generation Projects. Pursuant to Act 341, Section 6s, the Company is seeking CONs for the following projects identified in the PCA:

    I. Karn CT Project, affirming that:
        (i) the power to be supplied is needed;
        (ii) the size, fuel type, and design characteristics represent the most reasonable and prudent means of meeting that need; and
        (iii) the estimated capital costs and financing plan will be recoverable in rates.

    II. Thetford CT Project, affirming that:
        (i) the power to be supplied is needed;
        (ii) the size, fuel type, and design characteristics represent the most reasonable and prudent means of meeting that need; and
        (iii) the estimated capital costs and financing plan will be recoverable in rates.

    III. MCV PPA, affirming that:
        (i) the power to be supplied is needed;
        (ii) the terms of the agreement represent the most reasonable and prudent means of meeting that need; and
        (iii) the price specified in the agreement will be recoverable in rates.

IV. [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], affirming that:
(i) the power to be supplied is needed;
(ii) the terms of the agreement represent the most reasonable and prudent means of meeting that need; and
(iii) the price specified in the agreement will be recoverable in rates.

These projects correspond directly to the type, timing, and function of resources selected in the PCA, as supported by the IRP modeling and reliability analysis.

3. Approval of the Company's Clean Energy Plan.

4. Approval of a financial incentive for the new MCV PPA based on the Company's weighted average cost of capital pursuant to MCL 460.6s(6). The financial incentive will be for the duration of the agreement and the financial incentive will be updated based on the most recently approved electric rate case.

5. Demand-Side Resource Cost Recovery. Consistent with prior IRPs and Commission practice, the Company seeks approval of EWR, DR, and CVR program costs to be implemented within three years following approval of this IRP, for cost recovery pursuant to MCL 460.6t. These programs remain an integral component of the PCA and are reflected in the Company's modeling assumptions and portfolio selection.

6. Accounting and ratemaking approval to include CWIP in rate base during construction of the Karn and Thetford CT projects and to eliminate the corresponding AFUDC offset in general rate case revenue requirements to the extent financing costs are recovered in rates during the construction period.

7. Approval of accounting treatment related to Karn retention costs. The Company seeks approval of accounting and ratemaking treatment for reasonably and prudently incurred costs associated with retaining Karn Units 3 and 4 through the approved retirement date, with recovery to be addressed consistent with the Company's testimony and applicable future rate proceedings.

8. PURPA avoided cost proposal. The Company seeks approval of the PURPA implementation and avoided cost proposal, including continued use of competitive procurement to inform avoided cost values, prospective modifications to capacity-related avoided cost eligibility for qualifying facilities that provide bundled energy, capacity, and renewable energy credits, an annual PURPA capacity-related cap, and annual avoided cost updates.

9. Approval of an ex parte approval process for BESS projects. The Company requests approval of an ex parte process for future BESS projects selected through competitive solicitations or bilateral negotiations, subject to

Commission review and an objective cost benchmark not to exceed 140% of the Planning Year 2029 BESS PCA proxy. This process would allow the Company to timely pursue cost-effective storage resources needed to implement the PCA while preserving customer protections.

In addition to the requested approval of the CONs under MCL 460.6s for the Proposed Projects, as described in parts 2(I)-(IV) of the requested relief summarized above, the Company is requesting approval of the proposed EWR, DR, and CVR costs which will be commenced by the Company within three years following the Commission's expected approval of the Company's IRP. Specifically, the Company is seeking approval of the following costs pursuant to MCL 460.6t as reasonable and prudent for cost recovery purposes:

a. DR costs for January 1, 2028 to August 31, 2030 ($3,579,375 capital, $69,992,433 O&M, $13,355,590 of incentive, to achieve a total of 549 MW (645 ZRC) in 2029);

b. EWR costs for January 1, 2030 to August 31, 2030, ($91,205,607 O&M, $13,680,841 of incentive, 315,226 MWh savings, 1,312 MW savings); and

c. CVR costs for January 1, 2028 to August 31, 2030 ($11,265,239 capital, 136,351 MWh savings, 56.81 MW savings).

Q. Please Summarize your direct testimony.

A. My direct testimony supports approval of the Company's 2026 IRP, the PCA, the requested CONs, and related approvals. It explains the statutory and regulatory framework, the Company's planning objectives, the IRP study process, load forecast, capacity need, resource options, PCA selection, and requested relief.

The testimony demonstrates that the PCA is the most reasonable and prudent plan because it balances reliability, affordability, clean energy compliance, resource diversity, and flexibility. The PCA includes dependable capacity from the Karn and Thetford CTs,

the MCV PPA, and the [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], together with continued renewable, storage, VPP, EWR, DR, and CVR additions.

Finally, my testimony explains why the related approvals are necessary to implement the PCA, including CON approvals for the Proposed Projects, associated cost recovery and accounting approvals, demand-side resource cost recovery, and the Company's PURPA avoided cost proposal.

Q. Does this complete your direct testimony?

A. Yes.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan and Certificates of Necessity under MCL 460.6s and 460.6t, certain accounting approvals, and for other relief.	)))))))	Case No. U-22127

REDACTED

EXHIBITS

OF

STEVEN Q. MCLEAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2026

Line No.	Origin of Requirement	Filing, Testimony, Exhibits, and Workpaper Requirements	Witness	Testimony Section(s)	Exhibit Reference	Work Paper Reference
1		**General Filing Requirements**				
2	MPSC Case Nos. U-21570 & U-21867	These application instructions apply to a standard electric utility application for Michigan Public Service Commission (MPSC or Commission) approval of an Integrated Resource Plan (IRP) under the provisions of MCL 460.6t, as well as an IRP that may be filed under the provisions of MCL 460.6s. The application shall be consistent with these instructions, with each item labeled as set forth below. Any additional information considered relevant by the utility may also be included in the application.	Consumers Energy's application is submitted as an Integrated Resource Plan under MCL 460.6t and includes requests for Certificates of Necessity under MCL 460.6s, as applicable. The filing is organized and labeled consistently with the Commission's filing instructions and includes additional information relevant to the Commission's review, as reflected in Exhibit A-2 (SQM-2), pp. 2 and 27–29 (Sections 1.1 and 4.1–4.3).			
3		**Schedule and Filing Coordination**				
4	MPSC Case Nos. U-21570 & U-21867	A utility shall coordinate with the Commission Staff (Staff) in advance of filing its application to avoid resource challenges with IRP applications being filed at the same time as IRP applications filed by other utilities. A utility may be requested to delay its IRP application to preserve a 21day spacing between IRP applications.	Consumers Energy coordinated its IRP filing date with Commission Staff and will comply with all Commission-directed filing deadlines and future scheduling requirements.			
5	MPSC Case Nos. U-21570 & U-21867	Following the initial IRP applications, the utilities shall comply with all future filing deadlines directed by the Commission and shall continue to coordinate with the Staff to schedule future IRP application filing dates.				
6		**Filing Announcement**				
7	MPSC Case Nos. U-21570 & U-21867	To facilitate the scheduling and preparation of IRP proceedings, a utility shall file a filing announcement in a new docket at least 30 calendar days prior to the expected or scheduled filing date. A utility who intends to file an IRP on a date other than its scheduled filing date, shall file a filing announcement, in a new docket, at least 30 calendar days prior to the proposed filing. The filing announcement, along with proof of service, shall be served on all parties granted intervention in the utility's last IRP case and the utility's last electric rate case. If the IRP described in the filing announcement is not filed within 120 days after filing of the announcement, the filing announcement will be considered withdrawn. The IRP filing announcement will also serve as the CEP filing announcement. If a certificate of necessity (CON) is also being filed; the same filing announcement will serve as the filing announcement Variations from the standard instructions may occur as allowed by MCL 460.6(4) for multistate utilities and those serving fewer than 1 million Michigan customers. required for the CON. The filing announcement shall include:	A filing announcement was made by the Company on 8/4/2026, and corrected on 8/14/2026, announcing the Company's intent to file its 2026 Integrated Resource Plan, Clean Energy Plan and Certificates of Necessity on 9/3/2026 in docket U-22127 with proof of service attached.			
8	MPSC Case Nos. U-21570 & U-21867	a) Statement of intent to file an IRP;				
9	MPSC Case Nos. U-21570 & U-21867	b) Estimated date of filing;				
10	MPSC Case Nos. U-21570 & U-21867	c) Information related to any stakeholder engagement meetings that have already taken place or are scheduled to take place;				
11	MPSC Case Nos. U-21570 & U-21867	d) Information related to any CON application that would be filed with the utility's IRP; and				
12	MPSC Case Nos. U-21570 & U-21867	e) Information related to the CEP that will be filed with the utility's IRP.2 The Commission may, if necessary, order a delay in filing an application to establish a 21-day spacing between filings. The filing announcement shall be submitted at least 30 calendar days prior to the IRP application, thus providing the Commission sufficient time to issue an order regarding the 21-day spacing, if it so chooses.				
13		**Pre-Filing Request for Proposals**				
14	MPSC Case Nos. U-21570 & U-21867	Each electric utility whose rates are regulated by the Commission shall issue a request for proposal (RFP) to provide any new supply-side capacity resources needed to serve the utility's reasonably projected electric load, applicable planning reserve margin, and local clearing requirement for its customers in this state, as well as customers located in other states but served by the utility, during the initial three-year planning period to be considered in each IRP to be filed, as outlined in MCL 460.6t.	Skowronski	Section I – Pre-Filing and Competitive Solicitation Requirements, p. 5	Exhibit A-109 (BAS-1), p. 3	
15	MPSC Case Nos. U-21570 & U-21867	The utility shall comply with the following:	See Lines 16–20			
16	MPSC Case Nos. U-21570 & U-21867	a) The utility shall include documentation demonstrating that the RFP process was completed with the IRP application;	Skowronski	Section I – Pre-Filing and Competitive Solicitation Requirements, p. 5	Exhibit A-109 (BAS-1), p. 4	
17	MPSC Case Nos. U-21570 & U-21867	b) The utility's RFP process is subject to audit by the Staff;	Skowronski	Section I – Staff Audit and Independent Review, p. 7		
18	MPSC Case Nos. U-21570 & U-21867	c) The IRP filing shall include evidence that the pre-filing RFP process was conducted in a manner consistent with the Commission's code of conduct, and applicable state, federal, Utility Clean Energy Plans should follow the guidance outlined in the Clean Energy Plan Filing Requirements. and Commission rules, and any adherence with the competitive procurement guidance in Case No. U-20852;	Skowronski	Section I – Code of Conduct and Competitive Procurement Compliance, p. 7	Exhibit A-109 (BAS-1), p. 23	
19	MPSC Case Nos. U-21570 & U-21867	d) The RFP shall allow for proposals of sizes smaller than the total capacity need such that a combination of projects is needed, including but not limited to distribution connected resources, to provide new supply-side capacity, pursuant to MCL 460.6t(6); and	Skowronski	Section I – Minimum Offer Sizes and Distribution-Connected QFs, p. 8	Exhibit A-109 (BAS-1), pp. 3 and 15–17 Exhibit A-110 (BAS-2), pp. 1–3	
20	MPSC Case Nos. U-21570 & U-21867	e) The RFP shall allow for proposals to provide new supply-side capacity in the form of a Power Purchase Agreement for a period that is the lesser of the study period or the useful life of the resource type proposed.	Skowronski	Section I – PPA Term Lengths, p. 9		
21		**Stakeholder Engagement and Public Outreach**				
22	MPSC Case Nos. U-21570 & U-21867	Participant engagement early in the development of the IRP is strongly encouraged to: (1) educate potential participants on utility plans; (2) utilize a transparent decisionmaking process for resource planning; (3) create opportunity to provide feedback to the utility on its resource plan; (4) encourage robust and informed dialogue on resource decisions; (5) reduce utility regulatory risk by building understanding and support for utility resource decisions; and (6) ensure the inclusion of diverse voices, including environmental justice communities and Tribal Nations. The utility should incorporate some, or all, of the participant input in its analysis and decision-making for the IRP filing. Clean Energy Plan (CEP) participant engagement may be combined with the IRP participant engagement to the extent practical. In the 12 months prior to the IRP filing, each utility is encouraged to host update workshops with interested participants. The purpose of the pre-filing workshop(s) is to ensure that participants have an opportunity to provide input and stay informed regarding: (1) the assumptions, scenarios, and sensitivities; (2) the progress of the utility's IRP process; and (3) plans for the implementation of the proposed IRP. Documentation demonstrating the public outreach process undertaken by the utility shall be included with the IRP filing and the utility is encouraged to share these documents with the public. Documentation should include:	Coker	Sections III–VII – Engagement Requirements, Activities, Feedback, and Plan Influence, pp. 4–30	Exhibit A-99 (JRC-1), pp. 1–10 Exhibit A-100 (JRC-2), pp. 1–18 Exhibit A-101 (JRC-3), pp. 1–6 Exhibit A-102 (JRC-4), pp. 1–9 Exhibit A-103 (JRC-5), pp. 1–17 Exhibit A-104 (JRC-6), pp. 1–26 Exhibit A-105 (JRC-7), pp. 1–16 Exhibit A-106 (JRC-8), pp. 1–24 Exhibit A-107 (JRC-9), pp. 1–19 Exhibit A-108 (JRC-10), pp. 1–11	
23	MPSC Case Nos. U-21570 & U-21867	a) Workshop dates and times, including times outside of the workday;	Coker	Section V – Public Events and Technical Workshop Dates and Times, pp. 9–15	Exhibit A-99 (JRC-1), pp. 1–10 Exhibit A-100 (JRC-2), pp. 1–18 Exhibit A-101 (JRC-3), pp. 1–6 Exhibit A-102 (JRC-4), pp. 1–9 Exhibit A-105 (JRC-7), pp. 1–16 Exhibit A-106 (JRC-8), pp. 1–24 Exhibit A-107 (JRC-9), pp. 1–19 Exhibit A-108 (JRC-10), pp. 1–11	
24	MPSC Case Nos. U-21570 & U-21867	b) Evidence that a notice of the workshops was provided to the public;	Coker	Sections IV–V – Public Invitations, Registration, and Event Promotion, pp. 7–13	Exhibit A-100 (JRC-2), pp. 1–18 Exhibit A-101 (JRC-3), pp. 1–6 Exhibit A-102 (JRC-4), pp. 1–9 Exhibit A-103 (JRC-5), pp. 1–17	
25	MPSC Case Nos. U-21570 & U-21867	c) Meeting minutes;	Coker	Sections V–VII – Stakeholder Engagement Activities Executed, Stakeholder Feedback Results, and Influence on the Final Plan, pp. 9–31	Exhibit A-103 (JRC-5), pp. 16–17	
26	MPSC Case Nos. U-21570 & U-21867	d) Meeting or workshop attendance lists;	Coker	Sections V–VII – Stakeholder Engagement Activities Executed, Stakeholder Feedback Results, and Influence on the Final Plan, pp. 9–31	Exhibit A-99 (JRC-1), pp. 8–10 Exhibit A-100 (JRC-2), pp. 12–18 Exhibit A-101 (JRC-3), pp. 4–6 Exhibit A-103 (JRC-5), pp. 16–17	
27	MPSC Case Nos. U-21570 & U-21867	e) Participant comments on the last approved IRP and/or inputs into the proposed IRP application;	Coker	Sections V–VI – Participant Comments and Stakeholder Feedback, pp. 9–24	Exhibit A-99 (JRC-1), pp. 1–10 Exhibit A-100 (JRC-2), pp. 1–18 Exhibit A-101 (JRC-3), pp. 1–6 Exhibit A-102 (JRC-4), pp. 1–9 Exhibit A-103 (JRC-5), pp. 1–17 Exhibit A-104 (JRC-6), pp. 1–26 Exhibit A-105 (JRC-7), pp. 1–16 Exhibit A-106 (JRC-8), pp. 1–24 Exhibit A-107 (JRC-9), pp. 1–19 Exhibit A-108 (JRC-10), pp. 1–11	
28	MPSC Case Nos. U-21570 & U-21867	f) Description of how the public outreach process influenced the IRP; and	Coker	Section VII – Influence on the Final Plan, pp. 25–30	Exhibit A-106 (JRC-8), pp. 1–24 Exhibit A-107 (JRC-9), pp. 1–19 Exhibit A-108 (JRC-10), pp. 1–11	
29	MPSC Case Nos. U-21570 & U-21867	g) Description of community outreach efforts for environmental justice communities and tribal lands within the Company's service territory. Environmental justice communities should be identified using the MI EJScreen Tool. A minimum of two engagement workshops is recommended. An engagement workshop will give interested persons an opportunity to provide input regarding the utility's assumptions, inputs, and modeling methodologies employed during the development of the IRP. The utility is encouraged to provide basic information regarding the IRP filing process and how interested persons could participate. The utility is encouraged to invite interested persons, including expected intervenors, and the Staff, to its engagement workshops. The utility shall invite all Tribal Nations with tribal lands in their service territory and provide a point of contact with a local utility engagement specialist that can address how the IRP and CEP may impact tribal lands. If the engagement workshops are not open to the public, two additional hybrid public meetings with the option for both virtual and in-person attendance are recommended. If 5% or greater of a utility's residential customers are in communities identified as part of the Environmental Justice (EJ) analysis, it is recommended that at least one of the two additional hybrid public meetings are located in any of the identified communities. The public meetings are intended to educate the public on the utility's planning process as well as provide an opportunity for the public to comment. The utility is encouraged to provide basic information regarding the IRP filing process and how interested persons and members of the public could participate. The public meetings should be offered in the utility's service territory in geographic locations that are convenient for customers, prioritizing accessibility and convenience for customers identified in the EJ analysis. Advanced notice should be provided to customers in the utility's service territory. This should include Tribal governments, local governments, and community-based organizations. The utility is encouraged to consider holding public meetings after normal business hours to encourage attendance. The public meetings should be conducted in a manner accessible to those with disabilities, including those that are hearing and visually impaired. The public meetings should also be available to those whose first language is not English upon request and to the extent practicable.	Coker	Sections IV–V – Environmental Justice and Tribal Outreach, pp. 7–13	Exhibit A-99 (JRC-1), pp. 1–10 Exhibit A-100 (JRC-2), pp. 1–18 Exhibit A-101 (JRC-3), pp. 1–6 Exhibit A-102 (JRC-4), pp. 1–9 Exhibit A-104 (JRC-6), pp. 1–26	
30	MPSC Case Nos. U-21570 & U-21867	If the utility chooses to hold pre-filing workshops, including engagement workshops or public meetings, the utility shall prepare a public outreach report to document the outcomes of any prefiling workshops, and shall file the report with the IRP application. All presentations, recordings, comments, and transcripts from those presentations open to the public should be maintained on a website in a location open to the public for the duration of the outreach process and the duration of the IRP case, until a final commission order is published.	Coker	Section V - Stakeholder Engagement Activities Executed, pp. 9-16	Exhibit A-99 (JRC-1), pp. 1–10 Exhibit A-100 (JRC-2), pp. 1–18 Exhibit A-101 (JRC-3), pp. 1–6 Exhibit A-102 (JRC-4), pp. 1–9 Exhibit A-103 (JRC-5), pp. 1–17 Exhibit A-105 (JRC-7), pp. 1–16 Exhibit A-106 (JRC-8), pp. 1–24 Exhibit A-107 (JRC-9), pp. 1–19 Exhibit A-108 (JRC-10), pp. 1–11	
31		**Risk Assessment Methodology**				
32	MPSC Case Nos. U-21570 & U-21867	The utility's IRP filing shall include a thorough risk assessment of the proposed resource plan and the optimal plans for each of the scenarios specified in the Michigan Integrated Resource Planning Parameters (MIRPP), all additional utility-developed scenarios and utility-developed sensitivities related to early retirement that are filed with the IRP application. The utilitysubmitted alternative build plans should be feasible and differ in generation mix from the proposed resource plan and MIRPP plans. The intent of the risk assessment is to test the optimized resource strategies for each scenario and the proposed course of action (PCA) to determine how each strategy would perform in an unexpected range of possible futures. The utility shall provide detail on how the risk assessment was conducted, including the impact of atypical weather conditions that occur at least as frequently as once in ten years.3,4,5 The utility shall also include all extreme weather events of the last 20 years, identified by State declaration of an emergency. Additionally, the utility should detail any scenario and sensitivity runs conducted with the utility's risk assessment where the PCA or proposed alternative build plan results in unserved load. Utilities are encouraged to link variables that can be shown to have correlations or dependencies with each other. Examples of variables to be considered under weather conditions include but are not Atypical weather conditions are weather events that meet the definition of "catastrophic conditions" from the MPSC Service Quality and Reliability Standards less the periods with a State declaration of emergency limited to changes in load, operations, and resource availability. The IRP shall include a discussion of the methodology used for risk assessment, including the utility's justification for the chosen methodology over other alternatives. Acceptable forms of risk assessment include, but are not limited to, the following: scenario analysis, global sensitivity analysis, stochastic optimization, generating near-optimal solutions, agentbased stochastic optimization, mean-variance portfolio analysis, and Monte Carlo simulation.	Moritz Soni	(Moritz) Section V – Scenario and Sensitivity Development and Section X – Summary of Phase 1 Modeling Results, pp. 23–31 and 77–80. (Soni) Section VIII – Risk Assessment, pp. 55–70	Exhibit A-23 (AMJ-9), pp 1 - 4 Exhibits A-34 (PS-1) through A-41 (PS-8), pp. 1–24	WP-PS-2 through WP-PS-8, pp. 1–26
33	MPSC Case Nos. U-21570 & U-21867	Utilities with one million customers or more, shall include a Local Reliability Requirement (LRR) analysis of the proposed resource plan in the IRP filing. The LRR analysis shall estimate a five-year outlook of the LRR in the local resource zone. The analysis shall be conducted consistently with the resource adequacy construct used by the regional transmission organization (RTO) or independent system operator (ISO). The purpose of this calculation is to estimate the marginal impact of the utility's proposed resource plan on the resource adequacy of the local resource zone during the first five years of the plan.	Soni	Section VI – Local Reliability Requirement Analysis, pp. 34–37		WP-PS-4, Local Reliability Requirement Analysis
34		**Confidential Information**				

Line No.	Origin of Requirement	Filing, Testimony, Exhibits, and Workpaper Requirements	Witness	Testimony Section(s)	Exhibit Reference	Work Paper Reference
35	MPSC Case Nos. U-21570 & U-21867	Transparency and the use of data that can be shared with the Commission, the Staff, and intervenors is encouraged. Proprietary, confidential, and other nonpublic materials used in the development of the forecasts, scenarios, or other aspects of the IRP shall be presented in such a way that the proprietary and confidential nature of the materials is preserved. The use of publicly available data and materials is encouraged in lieu of proprietary and confidential materials and claims that information is proprietary or confidential should be justified by the utility. Inclusion of specific materials in the IRP filing may be contingent upon appropriate confidentiality agreements and protective orders. Proprietary, confidential, and other nonpublic materials filed as part of the IRP shall be clearly designated by the utility as confidential.	Proprietary, confidential, and other nonpublic materials are clearly designated and filed confidentially under the applicable protective order. Publicly available information is used where practicable, and any confidentiality claims are supported by an appropriate justification.			
36		**Definitions**				
37	MPSC Case Nos. U-21570 & U-21867	The following definitions are provided to aid in ensuring consistency across planning processes. Distributed Energy Resources - A source of electric power and its associated facilities that is connected to a distribution system. Distributed Energy Resources (DER) includes both generators and energy storage technologies capable of exporting active power to a distribution system. Non-Wires Alternatives - An electric grid investment or project that uses distribution solutions such as DER, energy waste reduction (EWR), demand response (DR), and grid hardware and software, to defer or replace the need for distribution system upgrades. Environmental Justice Communities – Overburdened, vulnerable, underserved, or disadvantaged communities that are identified, for the purpose of this analysis, by a minimum percentile of 75 in the Michigan Environmental Justice Screening Tool (MiEJScreen). If MiEJScreen tool is not available, the utility should work with and take feedback from Staff, EGLE, and interested parties when determining which other tool or methodology to use. Environmental Justice Analysis – The identification of and assessment of impacts to Environmental Justice Communities, as well as the identification of communities with a minimum percentile of 75 in either the Low Income Population or Black, Indigenous, People of Color population layers in the MiEJScreen tool. Demand-Side Resources - Resources serving resource adequacy needs by reducing or shifting load, which reduces the need for additional generation, including but not limited to EWR, DR, grid and software controls, behind-the-meter distribution connected storage, etc. Co-Benefits – Benefits that are quantified as part of another planning process that are important for the justification of a resource included in the IRP. Examples include a cost reduction to the distribution system or transmission system that has been evaluated in the distribution planning or transmission planning process.	The IRP and Clean Energy Plan use the definitions provided in the Commission's filing requirements, including Distributed Energy Resources, Non-Wires Alternatives, Environmental Justice Communities and Analysis, Demand-Side Resources, and Co-Benefits.			
38		**Approval of Costs**				
39	MPSC Case Nos. U-21570 & U-21867	For the Commission to specify the costs to be approved for the construction of or significant investment in supply or demand-side resources, or contractual agreements, excluding short-term market capacity purchases to meet state reliability mechanism capacity requirements, in accordance with MCL 460.6(11) through (12), the following information, data, and documents shall be provided: For specific supply-side resources (inclusive of storage technologies and clean emerging technologies), that are planned to commence within three years following the approval of the IRP, the following evidence (covering the lifespan of the project) shall be provided:	Not Applicable - Cost Recovery for construction of new generating facilities and PPAs is requested pursuant to MCL 460.6s. Please see Exhibit A-5 (KGT-3), Exhibit A-13 (TPC-8) and Exhibit A-14 (TPC-9) illustrating the filing requirements for the Certificates of Necessity.			
40	MPSC Case Nos. U-21570 & U-21867	a) A description of the plant size, type, and summary of engineering/design specifications. The description shall also include the following: 1. Description of fuel use, both primary and back-up, and provisions for transporting and storing fuel; 2. Projected annual costs, in accordance with the breakdown specified in the Federal Energy Regulatory Commission Uniform System of Accounts; and 3. Annual depreciation on the capital investment.	Not Applicable			
41	MPSC Case Nos. U-21570 & U-21867	b) Projected annual return and income taxes on capital investment;	Not Applicable			
42	MPSC Case Nos. U-21570 & U-21867	c) The operation and maintenance (O&M) costs over the life of the facility described as costs which are variable, in current dollars per kilowatt-hour (kWh), with expenses for fuel and non-fuel items indicated separately; and costs which are fixed, in current dollars per kilowatt (kW);	Not Applicable			
43	MPSC Case Nos. U-21570 & U-21867	d) Projected property taxes;	Not Applicable			
44	MPSC Case Nos. U-21570 & U-21867	e) The rates of escalation of cost, including: 1. Capital costs; 2. O&M costs which are variable and related to fuel; 3. O&M costs which are variable and unrelated to fuel; and 4. O&M costs which are fixed.	Not Applicable			
45	MPSC Case Nos. U-21570 & U-21867	f) The total annual average cost per kWh at projected loads in current dollars for each year of the plan for the proposed facility;	Not Applicable			
46	MPSC Case Nos. U-21570 & U-21867	g) Equivalent availability factors, including both scheduled and forced outage rates;	Not Applicable			
47	MPSC Case Nos. U-21570 & U-21867	h) Capacity factors for each year in the planning period;	Not Applicable			
48	MPSC Case Nos. U-21570 & U-21867	i) Operation cycle (i.e., baseload, intermediate, or peaking), identifying expected hours per year of operation, number of starts per year, and cycling conditions for each year in the planning period;	Not Applicable			
49	MPSC Case Nos. U-21570 & U-21867	j) Heat rates (efficiency) for various levels of operation;	Not Applicable			
50	MPSC Case Nos. U-21570 & U-21867	k) Unit lifetime, both for accounting book purposes and engineering design purposes, with explanations of differences;	Not Applicable			
51	MPSC Case Nos. U-21570 & U-21867	l) Lead time, separately identifying the estimated time required for engineering, permitting and licensing, design, construction and pre–commercial operation date testing;	Not Applicable			
52	MPSC Case Nos. U-21570 & U-21867	m) Potential socioeconomic impacts, such as employment, for the local region of the proposed supply-side resource, construction of or significant investment in an electric generation facility, or the purchase of an existing electric generation facility;	Not Applicable			
53	MPSC Case Nos. U-21570 & U-21867	n) Procurement strategy, including third-party and company owned contracts, and any adherence to the most recent Commission approved Competitive Procurement Guidance that includes a description of how the procurement process will commit to meeting the labor standards set out in PA 231 Section 6(8)(c);	Not Applicable			
54	MPSC Case Nos. U-21570 & U-21867	o) A summary description of the expected decommissioning process, costs, and how the utility intends to provide assurance of proper disposal with consideration of material salvage and recycling for proposed new resources; and	Not Applicable			
55	MPSC Case Nos. U-21570 & U-21867	p) A detailed description of any implementation risks that are specific to each generation technology type.	Not Applicable			
56		**Renewable Resources: The utility shall file data consistent with any approved renewable energy plan. Revenue requirement and incremental costs shall be calculated to include the following:**	Not Applicable			
57	MPSC Case Nos. U-21570 & U-21867	a) Capital, O&M costs for renewable energy systems (including property taxes and insurance for renewable energy systems);	Not Applicable			
58	MPSC Case Nos. U-21570 & U-21867	b) Financing costs;	Not Applicable			
59	MPSC Case Nos. U-21570 & U-21867	c) Costs that are not otherwise recoverable in base rates, including interconnection and substation costs;	Not Applicable			
60	MPSC Case Nos. U-21570 & U-21867	d) Cost of purchased renewable energy credits (RECs) other than those purchased for noncompliance;	Not Applicable			
61	MPSC Case Nos. U-21570 & U-21867	e) Cost of Contracts;	Not Applicable			
62	MPSC Case Nos. U-21570 & U-21867	f) Expenses incurred as a result of governmental action including changes in tax or other laws;	Not Applicable			
63	MPSC Case Nos. U-21570 & U-21867	g) Subtract revenues (i.e., transfer price, environmental attributes, interest on regulatory liability, etc.) through 2029;	Not Applicable			
64	MPSC Case Nos. U-21570 & U-21867	h) Recovery to include the authorized rate of return on equity, which will remain fixed at the rate of return and debt to equity ratio that was in effect in base rates when the renewable plan was approved (only through 2029);	Not Applicable			
65	MPSC Case Nos. U-21570 & U-21867	i) Provide the following information in relation to renewable resource cost recovery: 1. Forecast through the end of the renewable plan period of the non-volumetric surcharge; and 2. Forecast through the end of the renewable plan period of the regulatory liability balance.	Not Applicable			
66	MPSC Case Nos. U-21570 & U-21867	j) Procurement strategy, including third-party and company owned contracts. Address whether the procurement strategy adhered to the most recent Commission-approved Competitive Procurement Guidance that includes a description of how the procurement process will commit to meeting the labor standards set out in PA 231 Section 6a(8)(c); and;	Not Applicable			
67	MPSC Case Nos. U-21570 & U-21867	k) A summary description of the expected decommissioning process, costs, and how the utility intends to provide assurance of proper disposal with consideration of material salvage and recycling for proposed new renewable resources.	Not Applicable			
68		**Energy Storage: The utility shall provide any relevant data, according to its plan to procure its share of the statewide energy storage target, established under MCL 460.1101(1). The following information shall be provided in relation to the energy storage procurement plan:**	Not Applicable			
69	MPSC Case Nos. U-21570 & U-21867	a) If the utility has not yet filed for approval to procure its proportional share of the statewide energy storage target, the utility must seek approval of these storage resources in an IRP filed no later than December 31, 2029;	Not Applicable			
70	MPSC Case Nos. U-21570 & U-21867	b) Capital and O&M costs for energy storage systems;	Not Applicable			
71	MPSC Case Nos. U-21570 & U-21867	c) Financing costs; 1. Procurement strategy, including third-party contracts, build transfer, or company owned. Address how the utility will adhere to the most recent Commission approved Competitive Procurement Guidance; 2. A description of how the procurement process will commit to meeting the labor standards set out in PA 231 Section 6(8)(c); 3. A summary description of the expected decommissioning process, anticipated costs, and how the utility intends to provide safety and assurance of proper disposal, with consideration of material salvage and recycling, for proposed new energy storage resources.	Not Applicable			
72		**EWR: The utility shall provide the following information in relation to EWR programs cost approval and recovery (including utility providers that elect the State Administrator under the alternative compliance program, also known as the Efficiency United or EU program). For each individual program or group of programs, provide:**				
73	MPSC Case Nos. U-21570 & U-21867	a) Total annual cost, energy, and capacity including: 1. Annual O&M cost for each individual portfolio of EWR programs; 2. Annual capital cost for each individual portfolio of EWR; 3. Expected cost-sharing or financial incentive granted to the utility by the Commission; and 4. How the utility included the avoided distribution costs when evaluating the most cost effective EWR amount in all IRP scenarios.	Moritz Burdjalov Gast	(Moritz) Section VIII – EWR Modeling Inputs, pp. 68–70 (Burdjalov) Section I – EWR Potential and Cost Inputs, pp. 4–15 (Gast) Section I – EWR Program Savings, Costs, and PCA Alignment, pp. 4–8	Exhibit A-20 (AJM-6), pp. 1–3 Exhibit A-92 (AMG-1), pp. 1–4 Exhibit A-96 (DVB-1), pp. 1–106	
74	MPSC Case Nos. U-21570 & U-21867	b) Calculated generation savings using annual marginal line loss rates for energy and marginal line loss rates at peak hours for capacity to determine total peak demand (MW) and energy (megawatt-hours (MWh)) reduction potential;	Moritz Burdjalov Gast	(Moritz) Section VIII – EWR Modeling Inputs, pp. 68–70 (Burdjalov) Section V – Potential Modeling Methodology and Marginal Line Losses, pp. 73–88 (Gast) Sections I–II – EWR and DR Peak-Demand and Energy Reductions, pp. 4–18	Exhibit A-20 (AJM-6), pp. 1–3 Exhibit A-93 (AMG-2), p. 1 Exhibit A-96 (DVB-1), pp. 1–106 Exhibit A-98 (DVB-2), pp. 39–41	
75	MPSC Case Nos. U-21570 & U-21867	c) Total resource capacity (MW) and whether or not it is reported/registered to the applicable regional transmission organization (RTO) or independent system operator (ISO). If the resource is registered to an applicable RTO/ISO, then detail the resource type it is registered as.	Gast Moritz		Exhibit A-93 (AMG-2), p. 1	WP-AJM-1, p. 16 of 72
76		**DR, DER Programs, and other demand-side resources: The utility shall provide the following information in relation to DR programs, DER programs, and other demand-side resources cost approval and recovery. For each individual program or group of programs, provide:**				
77	MPSC Case Nos. U-21570 & U-21867	a) Total annual cost including: 1. Annual O&M cost for each individual program of DR, DER, and demand-side programs; 2. Annual capital cost for each individual program of DR, DER, and demand-side programs; and 3. Expected cost-sharing or financial incentive granted to the utility by the Commission.	Gast Burdjalov Moritz McLean Schmoekel	(Burdjalov) Section II – DR Potential, pp. 16–19 (Gast) Section II – DR Program Costs and Performance Incentive, pp. 8–18 (Moritz) Section VIII – DR Modeling Inputs, pp. 67–68 (McLean) Section I – Demand-Side Resource Cost Recovery, pp. 16–17 (Schmoekel) Section II – CVR Program Assumptions, pp. 11–12	Exhibit A-98 (DVB-2), pp. 1–51 Exhibit A-93 (AMG-2), p. 1 Exhibit A-21 (AJM-7), pp. 1–3 Exhibit A-2 (SQM-2), pp. 74–83 (Tables 8-3, 8-6, 8-8, and 8-11) Exhibit A-114 (DAS-2), p. 1 Exhibit A-115 (DAS-3), p. 1 Exhibit A-117 (DAS-5), p. 1	
78	MPSC Case Nos. U-21570 & U-21867	b) Total demand reduction potential (MW), including the amount of load reduction and the expected hours of interruption per day, month, and year for each program, if applicable; 1. Maximum single event demand reduction; 2. Total resource capacity (MW) and whether or not it is reported/registered to an applicable RTO or ISO, then detail the resource type it is registered as;	Burdjalov Gast Moritz	(Burdjalov) Section II – DR Potential, pp. 16–19 (Gast) Section II – DR Program Impacts, MISO Registration, Events, and Testing, pp. 8–17 (Moritz) Section VIII – DR Modeling Inputs, pp. 67–68	Exhibit A-98 (DVB-2), pp. 1–51 Exhibit A-93 (AMG-2), p. 1 Exhibit A-21 (AJM-7), pp. 1–3	
79	MPSC Case Nos. U-21570 & U-21867	c) Total energy reduction achieved (MWh); and	Gast Schmoekel	(Schmoekel) Section III – CVR Results, pp. 16–23 (Gast) Section II – DR Energy Reduction and Program Benefits, pp. 9–10	Exhibit A-116 (DAS-4), pp. 1–3 Exhibit A-93 (AMG-2), p. 1	
80	MPSC Case Nos. U-21570 & U-21867	d) Description of program, including customer enrollment, technology used, and marketing plan.	Burdjalov Gast	(Burdjalov) Section II – DR Potential, pp. 16–19 (Gast) Section II – Residential and Business DR Programs, Enrollment, Technology, and Implementation, pp. 8–18	Exhibit A-98 (DVB-2), pp. 1–51 Exhibit A-93 (AMG-2), p. 1	
81		**Waivers and Process for Smaller and Multistate Utilities**				
82	MPSC Case Nos. U-21570 & U-21867	An electric utility with fewer than 1,000,000 customers in this state may request a waiver to any portion of these IRP filing requirements. Any request for a waiver shall include a discussion and justification outlining why the waiver is warranted and in the best interest of its customers. Discussion and justification for the requested waiver shall include a description of the utility's current and forecasted energy and capacity needs, and its plan for meeting those needs over the upcoming 10 years.	Not applicable. Consumers Energy serves more than 1,000,000 electric customers in Michigan and is not requesting a waiver from the IRP filing requirements.			

Line No.	Origin of Requirement	Filing, Testimony, Exhibits, and Workpaper Requirements	Witness	Testimony Section(s)	Exhibit Reference	Work Paper Reference
83	MPSC Case Nos. U-21570 & U-21867	If the utility requires resolution of a waiver request prior to filing an IRP application, the utility shall file the waiver request no less than 60 days prior to the filing of the IRP application. An electric utility with fewer than 1,000,000 customers in this state may request approval from the Commission to file an IRP jointly with other smaller utilities. Commission approval is required prior to filing a joint IRP. A non-multistate Michigan electric utility serving fewer than 1,000,000 customers may elect to file an IRP, based on its specific circumstances, that deviates from these requirements, but that is subject to the Staff's ability to request supplemental information. The filing shall include an explanation of why the deviations are reasonable under its circumstances. The Commission shall review any such filings under the traditional "just and reasonable" standard. Northern States Power Company-Wisconsin and Indiana Michigan Power Company are utilities located in Michigan that already file multistate IRPs in other jurisdictions. Due to the provisions in MCL 460.6t(4) regarding multistate IRPs, Northern States Power Company-Wisconsin and Indiana Michigan Power Company may utilize the IRP filing requirements of another state in accordance with those provisions. However, the Commission reserves the right to request additional information to facilitate its review of the IRP as it relates to Michigan.	Not applicable. Consumers Energy is not a smaller or multistate utility and is not requesting approval to file a joint or alternative-form IRP.			
84		**IRP Filing, Data, and Documentation**				
85	MPSC Case Nos. U-21570 & U-21867	The utility's IRP filing shall demonstrate compliance with MCL 460.6t and include the following items:	McLean	Section II – Statutory and Regulatory Background, pp. 25–35	Exhibit A-2 (SQM-2), pp. 2–232 (Sections 1 and 4–21) Exhibit A-1 (SQM-1)	
86	MPSC Case Nos. U-21570 & U-21867	a) Letter of transmittal expressing commitment to the approved resource plan and resource acquisition strategy and signed by an officer of the utility having the authority to commit the utility to the resource acquisition strategy, acknowledging that the utility reserves the right to make changes to its resource acquisition strategies as appropriate due to changing circumstances;	The IRP filing includes a letter of transmittal filed in Docket No. U-22127 and signed by an authorized Company officer, confirming the Company's commitment to the proposed resource plan and acquisition strategy while reserving the right to respond appropriately to changing circumstances.			
87	MPSC Case Nos. U-21570 & U-21867	b) Technical volume(s) that fully describe and document the utility's analysis and decisions in selecting its proposed resource plan and resource acquisition strategy;	McLean	Introduction and Purpose of Testimony, pp. 3–4 Section I – Overall Testimony Summary, pp. 5–24	Exhibit A-2 (SQM-2), pp. 2–232 (Sections 1 and 4–21)	
88	MPSC Case Nos. U-21570 & U-21867	c) The data and information requested in the Commission's IRP Filing Requirements included herein;	McLean	Section II – Statutory and Regulatory Background, pp. 25–35	Exhibit A-2 (SQM-2), pp. 2–232 (Sections 1 and 4–21) Exhibit A-1 (SQM-1)	
89	MPSC Case Nos. U-21570 & U-21867	d) Any information that the Commission in its orders regarding the utility's previous IRPs or other dockets required to be provided in this present IRP. This information should also be provided to interested persons at public outreach meetings; and	McLean Coker	(Coker) — Sections III–VII, pp. 4–30	Exhibit A-1 (SQM-1) Exhibits A-99 through A-108 (JRC-1 through JRC-10)	
90	MPSC Case Nos. U-21570 & U-21867	e) Any other information deemed relevant by the utility.	Any additional information the Company considers relevant to the Commission's review is included in the IRP filing in Docket No. U-22127.			
91	MPSC Case Nos. U-21570 & U-21867	The utility's IRP filing shall include an IRP document(s) and application information, including testimony and exhibits, that describes and documents the utility's analysis and decisions in selecting its proposed resource plan and resource acquisition strategy. To facilitate a similar format for each utility's application, the utility is encouraged to align its filing with this provided outline and include at least the following items:	McLean	Introduction and Purpose of Testimony, pp. 3–4 Section I – Overall Testimony Summary, pp. 5–24	Exhibit A-2 (SQM-2), pp. 2–232 (Sections 1 and 4–21)	
92		Executive Summary:	McLean	Introduction and Purpose of Testimony, pp. 3–4 Section I – Overall Testimony Summary, pp. 5–24	Exhibit A-2 (SQM-2), pp. 2–16 (Section 1 Executive Summary)	
93	MPSC Case Nos. U-21570 & U-21867	An IRP shall include an exhibit that serves as an executive summary, suitable for distribution to the public. The executive summary shall be an informative nontechnical description of the resource plan proposed by the utility and resource acquisition strategy. The executive summary shall summarize the contents of the IRP document and shall include the following:	McLean	Introduction and Purpose of Testimony, pp. 3–4 Section I – Overall Testimony Summary, pp. 5–24	Exhibit A-118 (SQM-3)	
94	MPSC Case Nos. U-21570 & U-21867	a) An overview of the planning period examined in the IRP analysis and application;	McLean	Introduction and Purpose of Testimony, pp. 3–4 Section I – Overall Testimony Summary, pp. 5–24	Exhibit A-2 (SQM-2), pp. 2 and 6	
95	MPSC Case Nos. U-21570 & U-21867	b) A brief introduction describing the utility, its existing facilities, new resources being proposed, and implementation strategy;	McLean Walter	(Walter) Direct Testimony, Existing Generation Resources, Retirement Dates, and Expenditure Forecasts, pp. 2–6 (McLean) Introduction and Purpose of Testimony, pp. 3–4 (McLean) Section I – Overall Testimony Summary, pp. 5–24	Exhibit A-2 (SQM-2), pp. 2–16 (Section 1 Executive Summary) Exhibit A-90 (MMW-1), p. 1 Exhibit A-91 (MMW-2), p. 1	WP-MMW-1, Existing Resource In-Service and Retirement Dates, p. 1 WP-MMW-2, Renewable Repowering Estimates, p. 1 WP-MMW-3, Existing Generation Capital Expenditures, p. 1 WP-MMW-4, Existing Generation O&M Expenditures, p. 1
96	MPSC Case Nos. U-21570 & U-21867	c) A summary of the state, federal, ISO, RTO resource adequacy regulations applicable to the utility;	McLean	Section V – Current Baseline Capacity Position, pp. 64–70	Exhibit A-2 (SQM-2), pp. 2–16 (Section 1 Executive Summary)	
97	MPSC Case Nos. U-21570 & U-21867	d) A summary of the analytical approach used in the utility's analysis and the types of new resources considered;	McLean	Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 2–16 (Section 1 Executive Summary)	
98	MPSC Case Nos. U-21570 & U-21867	e) A description of how the analytical approach considered potential resource co-benefits from other planning processes, such as distribution or transmission planning;	McLean	Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), p. 5	
99	MPSC Case Nos. U-21570 & U-21867	f) A summary of any retirement analysis performed;	McLean Walter	(Walter) Direct Testimony, Existing Generation Resources and Retirement Assumptions, pp. 3–6 (McLean) Introduction and Purpose of Testimony, pp. 3–4 (McLean) Section I – Overall Testimony Summary, pp. 5–24	Exhibit A-2 (SQM-2), p. 5 Exhibit A-91 (MMW-2), p. 1	WP-MMW-1, Existing Resource In-Service and Retirement Dates, p. 1 WP-MMW-2, Renewable Repowering Estimates, p. 1
100	MPSC Case Nos. U-21570 & U-21867	g) A description of how the environmental justice (EJ) analysis results influenced the utility's proposed course of action (PCA);	McLean Breining	Section II – Statutory and Regulatory Background, pp. 25–35 (Breining) Section III – Environmental Justice Analyses, pp. 15–23	Exhibit A-2 (SQM-2), pp. 10–11 and 222–231	
101	MPSC Case Nos. U-21570 & U-21867	h) The Company shall include a graph that depicts a stacked bar graph that includes the RTO/ISO capacity credit 6 of all existing resources and PCA resource additions, color designated by resource type, that it will use to serve demand in each year for all planning years. The graph shall have a line representing expected demand over the length of the planning period with the inclusion of the necessary planning reserve margin;	McLean	Section V – Current Baseline Capacity Position, pp. 64–70	Exhibit A-2 (SQM-2), pp. 8 and 14 (Figures 1-2 and 1-5)	WP-AJM-3, pp. 3–7
102	MPSC Case Nos. U-21570 & U-21867	i) The Company shall include a graph that depicts a stacked bar graph that includes the annual energy expected to be produced by all existing resources, PCA resource additions, and market purchases for each year of the planning horizon. The graph shall be color designated by resource type. The graph shall have a line representing expected demand over the length of the planning period;	McLean	Introduction and Purpose of Testimony, pp. 3–4 Section I – Overall Testimony Summary, pp. 5–24	Exhibit A-2 (SQM-2), p. 15 (Figure 1-6)	WP-AJM-3, p. 8
103	MPSC Case Nos. U-21570 & U-21867	j) The Company shall include a graph(s) that summarizes the total of each of the following pollutants projected using the PCA in the MIRPP Scenario 1 for each year of the planning horizon. A graph should be included for nitrogen oxide (NOx), sulfur dioxide (SO2), particulate matter (PM), mercury (Hg), volatile organic compounds (VOC), carbon dioxide (CO2). The graph should also depict the utility's progress toward or achievement of State, Federal and utility announced goals or requirements by including annotations for those goals on the years they apply;	McLean Breining	(McLean) Section III – IRP Objectives and Principles, pp. 40–52 (Breining) Section II – IRP Emissions Outlook, Scenario Comparisons, and Carbon Accounting, pp. 12–15	Exhibit A-2 (SQM-2), pp. 12–13 (Figures 1-3 and 1-4) Exhibit A-49 (HAB-1), pp. 1–9 Exhibit A-50 (HAB-2), pp. 1–64 Exhibit A-51 (HAB-3), pp. 1–2	
104	MPSC Case Nos. U-21570 & U-21867	k) The Company shall include a discussion of the estimated costs of the PCA; and	McLean	Introduction and Purpose of Testimony, pp. 3–4 Section I – Overall Testimony Summary, pp. 5–24	Exhibit A-2 (SQM-2), pp. 10–11 and 207–210 (Figures 19-1 through 19-3)	WP-AJM-3, pp. 1 and 14–21
105	MPSC Case Nos. U-21570 & U-21867	l) Any other information that would aid the public understanding of the utility's proposed resource plan. For example, MISO Zonal Resource Credit.	McLean	Introduction and Purpose of Testimony, pp. 3–4 Section I – Overall Testimony Summary, pp. 5–24	Exhibit A-2 (SQM-2), pp. 2–16 (Section 1 Executive Summary)	
106		Table of Filing Requirements:	McLean	Section II – Statutory and Regulatory Background, pp. 25–35	Exhibit A-1 (SQM-1)	
107	MPSC Case Nos. U-21570 & U-21867	The utility shall provide a table that clearly identifies where in the filing it has met all the filing requirements. It shall include locations in testimony, exhibits, and workpapers.	McLean	Section II – Statutory and Regulatory Background, pp. 25–35	Exhibit A-1 (SQM-1)	
108		Testimony Introduction:	McLean	Introduction and Purpose of Testimony, pp. 3–4 Section I – Overall Testimony Summary, pp. 5–24	Exhibit A-2 (SQM-2), pp. 27–34 (Section 4 Introduction; Figure 4-1 and Figure 4-2)	
109	MPSC Case Nos. U-21570 & U-21867	The utility shall describe resource plans to satisfy at least the objectives and priorities identified in MCL 460.6t. The utility may identify and/or describe additional planning objectives that the resource plan will be designed to meet. The utility shall describe and document its additional planning objectives and its guiding principles to design alternative resource plans that consider the planning objectives and priorities. The introduction shall include the following:	McLean	Section III – IRP Objectives and Principles, pp. 36–39	Exhibit A-2 (SQM-2), pp. 27–34 (Section 4 Introduction; Figure 4-1 and Figure 4-2)	
110	MPSC Case Nos. U-21570 & U-21867	a) General description of the utility's existing energy system, including: 1. Net present value revenue requirements (NPVRR), 7 with and without any financial performance incentives for demand-side resources; 2. Summary of existing generation and PPAs by fuel type; 3. Utility's existing capacity resource mix; 4. Utility's service territory and breakdown of customer class composition; and 5. Description of planning period analyzed;	McLean Walter Moritz Myers	(McLean) Sections I and V – Overall Testimony Summary and Current Baseline Capacity Position, pp. 5–24 and 64–70 (Walter) Direct Testimony, Existing Generation Resources, Retirement Dates, and Expenditure Forecasts, pp. 2–6 (Moritz) Section VI - Existing and Planned Resource Assumptions, pp. 34–36 (McLean) Section VI – New Resource Options, pp. 71–78 (Myers) Section I – PCA Revenue Requirements and Customer-Class Rate Impacts, pp. 4–5	Exhibit A-2 (SQM-2), pp. 27–34 (Section 4 Introduction; Figure 4-1 and Figure 4-2) Exhibit A-90 (MMW-1), p. 1 Exhibit A-91 (MMW-2), p. 1 Exhibit A-17 (AJM-3), pp. 1–21 Exhibit A-42 (HJM-1), p. 1	WP-MMW-1, Existing Resource In-Service and Retirement Dates, p. 1 WP-MMW-2, Renewable Repowering Estimates, p. 1 WP-MMW-3, Existing Generation Capital Expenditures, p. 1 WP-MMW-4, Existing Generation O&M Expenditures, p. 1 WP-HJM-57, p. 1 WP-HJM-31, pp. 1–4
111	MPSC Case Nos. U-21570 & U-21867	b) Statement of power need;	McLean Moritz	Introduction and Purpose of Testimony, pp. 3–4 Section I – Overall Testimony Summary, pp. 5–24 (Moritz) Section VI – Supply and Demand Assessment, pp. 31–46	Exhibit A-2 (SQM-2), pp. 27–34 (Section 4 Introduction; Figure 4-1 and Figure 4-2)	
112	MPSC Case Nos. U-21570 & U-21867	c) Identify and explain the basis for the forecasted price of energy, capacity, fuels, and of peak demand and energy requirements, over the study period used in each scenario and sensitivity evaluated by the utility as part of the IRP process;	Moritz McLean Rissman	(Moritz) Sections IV–VI (Rissman) Sections III–IV – Commodity and Delivered Fuel Price Forecasts, pp. 6–12 (McLean) Section IV – The Company's Load Forecast, pp. 53–63	Exhibit A-2 (SQM-2), pp. 27–34 (Section 4 Introduction; Figure 4-1 and Figure 4-2) Exhibit A-16 (AJM-2), pp. 1–4 Exhibit A-79 (AKR-2), p. 1 Exhibit A-80 (AKR-3), p. 1 Exhibit A-81 (AKR-4), p. 1 Exhibit A-82 (AKR-5), p. 1 Exhibit A-83 (AKR-6), p. 1 Exhibit A-84 (AKR-7), p. 1 Exhibit A-85 (AKR-8), p. 1 Exhibit A-86 (AKR-9), p. 1 Exhibit A-87 (AKR-10), p. 1 Exhibit A-88 (AKR-11), p. 1	WP-AJM-1, pp. 3–20 and 57–64
113	MPSC Case Nos. U-21570 & U-21867	d) Market and regulatory environment influencing resource planning decisions: 1. RTO market and state regulation structure if a multistate utility; 2. Potential changes to RTO capacity market; 3. Electric customer choice; 4. Transmission expansion; 5. Environmental; 6. Renewable portfolio standards; and 7. Other; The assumed discount rate shall be included along with a justification for the assumed discount rate. Results should be presented in nominal dollars.	McLean Breining McCormick Johnston	(McLean) Section II – Statutory and Regulatory Background and MISO Market Developments, pp. 25–35 (McLean) Section III – IRP Objectives and Principles, pp. 40–52 (Breining) Section I – Environmental Regulations and Compliance Strategy, pp. 3–13 (McCormick) Section VI – Transmission Network Upgrade, CIL, and CEL Assumptions and Sensitivities, pp. 31–36 (Johnston) Sections II–III – RE Plan Relationship and RPS Compliance, pp. 13–29	Exhibit A-2 (SQM-2), pp. 27–34 (Section 4 Introduction; Figure 4-1 and Figure 4-2) Exhibit A-54 (KDJ-1), p. 1 Exhibit A-75 (JRM-2), pp. 1–17	WP-JRM-1, MISO GIA Costs and Statistical Summary WP-JRM-2, CIL and CEL Forecasts
114	MPSC Case Nos. U-21570 & U-21867	e) IRP planning process; and	McLean	Introduction and Purpose of Testimony, pp. 3–4 Section I – Overall Testimony Summary, pp. 5–24	Exhibit A-2 (SQM-2), pp. 27–34 (Section 4 Introduction; Figure 4-1 and Figure 4-2)	
115	MPSC Case Nos. U-21570 & U-21867	f) Engagement report.	Coker McLean	(Coker) Sections III–VII – Stakeholder Engagement Report, pp. 4–30 (McLean) Introduction and Purpose of Testimony, pp. 3–4 (McLean) Section I – Overall Testimony Summary, pp. 5–24	Exhibit A-2 (SQM-2), pp. 27–34 (Section 4 Introduction; Figure 4-1 and Figure 4-2) Exhibit A-99 (JRC-1), pp. 1–10 Exhibit A-100 (JRC-2), pp. 1–18 Exhibit A-101 (JRC-3), pp. 1–6 Exhibit A-102 (JRC-4), pp. 1–9 Exhibit A-103 (JRC-5), pp. 1–17 Exhibit A-104 (JRC-6), pp. 1–26 Exhibit A-105 (JRC-7), pp. 1–16 Exhibit A-106 (JRC-8), pp. 1–24 Exhibit A-107 (JRC-9), pp. 1–19 Exhibit A-108 (JRC-10), pp. 1–11	
116		**Analytical Approach**				
117	MPSC Case Nos. U-21570 & U-21867	a) Describe the modeling process, including the duration of the study;	Moritz McLean	(Moritz) Section IV – Process Used in Modeling (McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 35–45 and 173–193 (Sections 5 and 17; Tables 5-1 and 5-2; Figures 5-1, 5-2, and 17-1 through 17-6)	WP-AJM-1, pp. 21–25
118	MPSC Case Nos. U-21570 & U-21867	b) The utility shall describe and identify how its model approach optimizes resources to meet load and demand for all times of the year and for each year of the planning horizons. The utility shall explain how the model considers the seasonal and operational characteristics of all resource types, including generation profiles, forced outages, facility derates, seasonal or limited availability of resources, etc.;	Moritz McLean Soni	(Moritz) Section IV – Process Used in Modeling (Soni) Sections IV and VI – Reliability Methodology and Results, pp. 14–17 and 22–39 (McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 35–45 and 173–193 (Sections 5 and 17; Tables 5-1 and 5-2; Figures 5-1, 5-2, and 17-1 through 17-6)	WP-PS-5, Stochastic Distributions WP-PS-6, Loss-of-Load Dispatch WP-PS-7, Capability versus Demand
119	MPSC Case Nos. U-21570 & U-21867	c) The PCA and Utility Alternative (if applicable) should be evaluated under all scenarios and sensitivities listed in the MIRPP;	Moritz McLean	(Moritz) Sections V and XI (McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 35–45 and 173–193 (Sections 5 and 17; Tables 5-1 and 5-2; Figures 5-1, 5-2, and 17-1 through 17-6) Exhibit A-15 (AJM-1), pp. 1–7 Exhibit A-22 (AJM-8), pp. 1–4	WP-AJM-3, pp. 1–10
120	MPSC Case Nos. U-21570 & U-21867	d) If the utility presents a retirement study as justification for an early resource retirement or to delay the scheduled retirement of a fossil fuel plant, the utility should refer to the minimum scenario and sensitivities in Appendix G of the MIRPP when conducting that analysis. The previously approved retirement dates should also be evaluated under the scenarios and sensitivities indicated in Appendix G. To allow for evaluation over the same time horizons, the portion of the previously approved IRP that does not have resources, should include any new (additional) generic resources as selected by model optimization.	McLean Moritz	(McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 35–45 and 173–193 (Sections 5 and 17; Tables 5-1 and 5-2; Figures 5-1, 5-2, and 17-1 through 17-6) Exhibit A-15 (AJM-1), pp. 1–7 Exhibit A-22 (AJM-8), pp. 1–4 Exhibit A-23 (AJM-9), pp. 1–8	

Line No.	Origin of Requirement	Filing, Testimony, Exhibits, and Workpaper Requirements	Witness	Testimony Section(s)	Exhibit Reference	Work Paper Reference
121	MPSC Case Nos. U-21570 & U-21867	e) If the utility is proposing the retirement of a baseload or intermediate coal or natural gas power plant with a date that differs from the most recently approved IRP: 1. The utility shall share the dates being studied, as well as the criteria that will be analyzed as part of the IRP, with Staff. This information will be provided in the utility's initial IRP filing. 2. To test the optimized resource strategies for the proposed retirement, the utility shall model sensitivities to ensure the retirement dates were stress-tested and the PCA is reasonable and prudent under various conditions. 3. Sensitivities may include, but are not limited to, high load growth, high natural gas prices, and extreme weather conditions. 4. The utility must present the retirement analysis methodology, summarize the results, and demonstrate that the PCA is reasonable and prudent under the conditions tested.	McLean Moritz Breining Rissman	(McLean) Section III – IRP Objectives and Principles, pp. 40–52 (Breining) Section I – Environmental Compliance Costs and Required Controls, pp. 5–13 (Rissman) Sections III–VII – Base, Sensitivity, Delivered Fuel, and PSCR Forecasts, pp. 6–14	Exhibit A-2 (SQM-2), pp. 35–45 and 173–193 (Sections 5 and 17; Tables 5-1 and 5-2; Figures 5-1, 5-2, and 17-1 through 17-6) Exhibit A-15 (AJM-1), pp. 1–7 Exhibit A-22 (AJM-8), pp. 1–4 Exhibit A-23 (AJM-9), pp. 1–8 Exhibit A-79 (AKR-2), p. 1 Exhibit A-89 (AKR-12), p. 1	
122	MPSC Case Nos. U-21570 & U-21867	The utility must also demonstrate that the PCA complies with the renewable energy plan requirements of MCL 460.1028, the clean energy requirements of MCL 460.1051, the energy waste reduction measure in MCL 460.1077, and the energy storage target of MCL 460.1101, unless the retirement analysis is part of a request for extension of compliance with the clean energy plan under MCL 460.1051(b). 5. If the retirement proposed as part of the PCA is not supported under one or more of the conditions or sensitivities assessed, the utility shall include in testimony how the company plans to monitor the risk in advance of retirement as well as a risk mitigation plan.	McLean Moritz Clark Johnston Burdjalov Gast	(Clark) Direct Testimony, PCA Storage Compliance and Procurement, pp. 43–49 (McLean) Section VI – New Resource Options, pp. 71–78 (Johnston) Sections II–IV – RE Plan Relationship, RPS, and Clean Energy Compliance, pp. 13–38 (Burdjalov) Section I – EWR Potential, pp. 4–15 (Gast) Section I – EWR Program, PCA Alignment, Savings, and Costs, pp. 4–8	Exhibit A-2 (SQM-2), pp. 35–45 and 173–193 (Sections 5 and 17; Tables 5-1 and 5-2; Figures 5-1, 5-2, and 17-1 through 17-6) Exhibit A-15 (AJM-1), pp. 1–7 Exhibit A-22 (AJM-8), pp. 1–4 Exhibit A-23 (AJM-9), pp. 1–8 Exhibit A-10 (TPC-5), p. 1 Exhibit A-11 (TPC-6), p. 1 Exhibit A-20 (AJM-6), pp. 1–3 Exhibit A-54 (KDJ-1), p. 1 Exhibit A-55 (KDJ-2), p. 1 Exhibit A-92 (AMG-1), pp. 1–4	
123	MPSC Case Nos. U-21570 & U-21867	f) If the utility is proposing the retirement of a baseload or intermediate coal or natural gas power plant with a date that differs from the most recently approved IRP:	McLean Moritz	(McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 35–45 and 173–193 (Sections 5 and 17; Tables 5-1 and 5-2; Figures 5-1, 5-2, and 17-1 through 17-6) Exhibit A-15 (AJM-1), pp. 1–7 Exhibit A-22 (AJM-8), pp. 1–4 Exhibit A-23 (AJM-9), pp. 1–8	
124	MPSC Case Nos. U-21570 & U-21867	g) Describe and provide a justification for the risk assessment approach adopted from the Risk Assessment Methodology section: 1. The utility shall describe and document its quantification of the risk that affects the evaluation of the various resource plan options; 2. The utility shall provide a tabulation of the key quantitative results of that assessment, and a discussion of how those findings affected its decision on a resource plan; and 3. If multiple forms of risk assessment are presented the utility shall explain why certain risk variables could not be included in or are unsuited for one type of risk assessment or another. Considering a risk variable under multiple forms of risk assessment is not discouraged. 4. The utility shall describe and document the identification of risk variables and/or combinations of risk variables selected, their ranges, probabilities, ranking, and/or weighting that defines the risk quantification which the various resource plan options were judged; describe how these risk variables were judged to be appropriate and explain how these were determined; and describe the modeling tools and data sources employed during the capacity expansion, and other modeling processes; and 5. Interactions between risk variables should be captured to the extent that it is practical. Evaluation of variables in isolation is acceptable so long as there exists a comprehensive evaluation of resource plans risks that captures interactions and shows overall risk of appropriate build plans. A comprehensive risk assessment should at least include optimized build plans from the required MIRPP scenarios, the proposed resource plan, and any alternative resource plans presented by the utility.	McLean Soni Moritz	(Soni) Section VIII – Risk Assessment, pp. 55–70 (McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 35–45 and 173–193 (Sections 5 and 17; Tables 5-1 and 5-2; Figures 5-1, 5-2, and 17-1 through 17-6) Exhibit A-41 (PS-8), pp. 1–2 Exhibit A-15 (AJM-1), pp. 1–7 Exhibit A-22 (AJM-8), pp. 1–4 Exhibit A-23 (AJM-9), pp. 1–8	WP-PS-2, Cost Sensitivity Levels WP-PS-3, Forecast Error Spreads WP-PS-5, Stochastic Distributions WP-PS-8, Risk Assessment
125	MPSC Case Nos. U-21570 & U-21867	h) If the utility includes any new large loads in its PCA (loads that are greater than 300MW with a load factor of greater than 80%) then provide the following information without the inclusion of those large loads: 1. Total system cost; 2. Net present value revenue requirement and; 3. Rate impact of utility's base case scenario.	McLean Moritz	(McLean) Section IV – The Company's Load Forecast, pp. 53–63	Exhibit A-2 (SQM-2), pp. 35–53, 119–120, and 173–193 (Sections 5–6, 12.4.3, and 17; Tables 17-2 through 17-11) Exhibit A-22 (AJM-8), pp. 1–4 Exhibit A-23 (AJM-9), pp. 1–8	WP-SQM-1, p. 1 WP-SQM-2, p. 1 WP-SQM-3, p. 1 WP-SQM-4, p. 1 WP-SQM-5, p. 1 WP-SQM-6, p. 1 WP-SQM-7, p. 1 WP-SQM-8, p. 1 WP-SQM-9, p. 1
126		**IRP Scenarios and Sensitivities**				
127	MPSC Case Nos. U-21570 & U-21867	a) Include a detailed description of all scenarios and sensitivities; and	Moritz McLean Coker McCormick	(Moritz) Section V – Scenario and Sensitivity Development (Coker) Sections V and VII – Scenario Workshops and Feedback-Driven Adjustments, pp. 13–15 and 25–28 (McCormick) Section IV – Transmission Scenarios and Assumptions, pp. 6–25 (McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 46–53 (Section 6; Tables 6-1 through 6-5) Exhibit A-15 (AJM-1), pp. 1–7 Exhibit A-22 (AJM-8), pp. 1–4 Exhibit A-105 (JRC-7), pp. 1–16 Exhibit A-106 (JRC-8), pp. 1–24 Exhibit A-107 (JRC-9), pp. 1–19 Exhibit A-108 (JRC-10), pp. 1–11 Exhibit A-75 (JRM-2), pp. 1–17	WP-JRM-3, Transmission Scenarios, Resource Siting, and Load Forecasts WP-AJM-1, pp. 21–25
128	MPSC Case Nos. U-21570 & U-21867	b) In addition to the utility's own scenarios and assumptions, the inclusion of the established modeling scenarios and assumptions in the MIRPP, approved by the Commission in Case No. U-21867, or as revised by subsequent Commission orders related to IRP modeling parameters and requirements.	Moritz McLean Coker	(Moritz) Section V – Scenario and Sensitivity Development (Coker) Section V – MPSC Scenario and Assumption Workshops, pp. 13–15 (McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 46–53 (Section 6; Tables 6-1 through 6-5) Exhibit A-15 (AJM-1), pp. 1–7 Exhibit A-105 (JRC-7), pp. 1–16 Exhibit A-106 (JRC-8), pp. 1–24	WP-AJM-1, pp. 21–25
129	MPSC Case Nos. U-21570 & U-21867	c) The utility should show how it used the MIRPP-approved Scenarios, or any additional scenarios that the utility decides to include, to develop the PCA and any alternative build plan and to justify any retirement decisions. To the extent that some portion of the MIRPP-approved scenarios is of concern for the utility, the utility can request a waiver, in advance of the filing of the IRP, to deviate from certain aspects of a scenario or sensitivity. Examples may be to request using a different gas price or updated EWR information.	Moritz McLean Coker	(Moritz) Sections V and XI (Coker) Section VII – Use of Stakeholder Feedback in Scenario Design and PCA Development, pp. 25–28 (McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 46–53 (Section 6; Tables 6-1 through 6-5) Exhibit A-15 (AJM-1), pp. 1–7 Exhibit A-22 (AJM-8), pp. 1–4 Exhibit A-23 (AJM-9), pp. 1–8 Exhibit A-106 (JRC-8), pp. 1–24 Exhibit A-107 (JRC-9), pp. 1–19 Exhibit A-108 (JRC-10), pp. 1–11	WP-AJM-1, pp. 21–25
130	MPSC Case Nos. U-21570 & U-21867	d) Consistent with MCL 460.1051(b), if a utiley has requested and been approved for an off-ramp for their REP, the IRP should align and reflect the Commission's approval. If the utility is using the results of its IRP to support a request for an off-ramp, the utility should run Scenario#1 and Scenario#2 with an additional sensitivity (sensitivities) that illustrates the resulting difference in cost and overall build plan as compared to meeting the standard without the use of an off ramp.	Not applicable. Consumers Energy has not requested or received approval for an off-ramp from its Renewable Energy Plan requirements and is not relying on the IRP to support an off-ramp request.			
131	MPSC Case Nos. U-21570 & U-21867	e) The utility should model its PCA, any utility proposed alternative, any additional scenarios the utility decides to include, and previously approved IRP build plan in all scenarios and sensitivities presented in the MIRPP.	Moritz McLean	(Moritz) Sections IX–XI (McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 46–53 (Section 6; Tables 6-1 through 6-5) Exhibit A-15 (AJM-1), pp. 1–7 Exhibit A-22 (AJM-8), pp. 1–4 Exhibit A-23 (AJM-9), pp. 1–8	WP-AJM-1, pp. 21–25 WP-AJM-3, pp. 1–10
132		**Existing Supply-Side Resources**				
133	MPSC Case Nos. U-21570 & U-21867	Detailed account of projected energy and capacity purchased or produced by the utility's owned and contracted resources, including cogeneration resources. Include data regarding the utility's current generation portfolio, including the age, capacity factor, licensing status, and remaining estimated time of operation for each facility in the portfolio:	Skowronski McLean Moritz Walter Rissman Troyer	(Skowronski) Section II – Existing PPAs and Third-Party Contracts, pp. 12–13 (Walter) Direct Testimony, Existing Generation Resources, Retirement Dates, and Expenditure Forecasts, pp. 2–6 (Rissman) Section II – Existing Generating Facilities and Fuel Supply, pp. 4–6 (Troyer) Direct Testimony, Section I-II, pp. 7-15 and 23-31 (McLean) Section V – Current Baseline Capacity Position, pp. 64–70	Exhibit A-2 (SQM-2), pp. 54–67 (Section 7; Tables 7-1 through 7-7) Exhibit A-17 (AJM-3), pp. 1–21 Exhibit A-111 (BAS-3), pp. 1–8 Exhibit A-78 (AKR-1), p. 1 Exhibit A-3 (KGT-1), pp. 1–32 Exhibit A-4 (KGT-2), pp. 1–118	WP-MMW-1, Existing Resource In-Service and Retirement Dates, p. 1 WP-MMW-2, Renewable Repowering Estimates, p. 1 WP-MMW-3, Existing Generation Capital Expenditures, p. 1 WP-MMW-4, Existing Generation O&M Expenditures, p. 1 WP-AJM-1, pp. 28–39 and 54–64
134	MPSC Case Nos. U-21570 & U-21867	a) Overview;	Moritz Walter McLean Rissman	(Moritz) Section VI – Supply and Demand Assessment (Walter) Direct Testimony, Existing Generation Assets and Retirement Dates, pp. 3–6 (Rissman) Section II – Existing Generating Facilities and Fuel Supply, pp. 4–6 (McLean) Section V – Current Baseline Capacity Position, pp. 64–70	Exhibit A-2 (SQM-2), pp. 54–67 (Section 7; Tables 7-1 through 7-7) Exhibit A-17 (AJM-3), pp. 1–21 Exhibit A-90 (MMW-1), p. 1 Exhibit A-91 (MMW-2), p. 1 Exhibit A-78 (AKR-1), p. 1	WP-MMW-1, Existing Resource In-Service and Retirement Dates, p. 1 WP-MMW-2, Renewable Repowering Estimates, p. 1 WP-MMW-3, Existing Generation Capital Expenditures, p. 1 WP-MMW-4, Existing Generation O&M Expenditures, p. 1
135	MPSC Case Nos. U-21570 & U-21867	b) Fossil-fueled generating units;	Walter McLean Moritz Rissman	(Walter) Direct Testimony, Existing Fossil-Fueled Generation Assets and Retirement Dates, pp. 3–6 (Rissman) Section II – Existing Fossil-Fueled Generating Facilities, pp. 4–6 (McLean) Section V – Current Baseline Capacity Position, pp. 64–70	Exhibit A-2 (SQM-2), pp. 54–67 (Section 7; Tables 7-1 through 7-7) Exhibit A-17 (AJM-3), pp. 1–21 Exhibit A-90 (MMW-1), p. 1 Exhibit A-91 (MMW-2), p. 1 Exhibit A-78 (AKR-1), p. 1	WP-MMW-1, Existing Resource In-Service and Retirement Dates, p. 1 WP-MMW-3, Existing Generation Capital Expenditures, p. 1 WP-MMW-4, Existing Generation O&M Expenditures, p. 1
136	MPSC Case Nos. U-21570 & U-21867	c) Nuclear generating units;	McLean Moritz	(McLean) Section V – Current Baseline Capacity Position, pp. 64–70	Exhibit A-2 (SQM-2), pp. 54–67 (Section 7; Tables 7-1 through 7-7) Exhibit A-17 (AJM-3), pp. 1–21	
137	MPSC Case Nos. U-21570 & U-21867	d) Hydroelectric generating units;	Walter McLean Moritz	(Walter) Direct Testimony, Existing Hydroelectric Generation Assets and Modeling Assumptions, pp. 3–6 (McLean) Section V – Current Baseline Capacity Position, pp. 64–70	Exhibit A-2 (SQM-2), pp. 54–67 (Section 7; Tables 7-1 through 7-7) Exhibit A-17 (AJM-3), pp. 1–21 Exhibit A-90 (MMW-1), p. 1	WP-MMW-1, Existing Resource In-Service and Retirement Dates, p. 1 WP-MMW-3, Existing Generation Capital Expenditures, p. 1 WP-MMW-4, Existing Generation O&M Expenditures, p. 1
138	MPSC Case Nos. U-21570 & U-21867	e) Renewable generating units;	Walter McLean Moritz	(Walter) Direct Testimony, Existing Renewable Generation Assets and Modeling Assumptions, pp. 3–6 (McLean) Section V – Current Baseline Capacity Position, pp. 64–70	Exhibit A-2 (SQM-2), pp. 54–67 (Section 7; Tables 7-1 through 7-7) Exhibit A-17 (AJM-3), pp. 1–21 Exhibit A-90 (MMW-1), p. 1	WP-MMW-1, Existing Resource In-Service and Retirement Dates, p. 1 WP-MMW-2, Renewable Repowering Estimates, p. 1 WP-MMW-3, Existing Generation Capital Expenditures, p. 1 WP-MMW-4, Existing Generation O&M Expenditures, p. 1
139	MPSC Case Nos. U-21570 & U-21867	f) Energy storage facilities;	Walter McLean Moritz	(Walter) Direct Testimony, Ludington Pumped Storage Plant Ownership and Capacity, p. 6 (McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 54–67 (Section 7; Tables 7-1 through 7-7) Exhibit A-17 (AJM-3), pp. 1–21 Exhibit A-90 (MMW-1), p. 1	WP-MMW-1, Existing Resource In-Service and Retirement Dates, p. 1 WP-MMW-3, Existing Generation Capital Expenditures, p. 1 WP-MMW-4, Existing Generation O&M Expenditures, p. 1
140	MPSC Case Nos. U-21570 & U-21867	g) Third-party contracts: energy and capacity purchased or produced by the utility from a contracted resource, including any cogeneration resource; and	Skowronski McLean Moritz Troyer	(Skowronski) Section II – Existing PPAs and Third-Party Contracts, pp. 12–13 (Troyer) Direct Testimony, Section I-II, pp. 7-15 and 23-31 (McLean) Section V – Current Baseline Capacity Position, pp. 64–70	Exhibit A-2 (SQM-2), pp. 54–67 (Section 7; Tables 7-1 through 7-7) Exhibit A-17 (AJM-3), pp. 1–21 Exhibit A-111 (BAS-3), pp. 1–8 Exhibit A-3 (KGT-1), pp. 1–32 Exhibit A-4 (KGT-2), pp. 1–118	
141	MPSC Case Nos. U-21570 & U-21867	h) RTO/ISO capacity credits and modeling of existing units (such as capacity factor, heat rate, outage rate, in-service and retirement dates, operating costs, etc.).	Moritz McLean Soni Walter Rissman	(Moritz) Sections IV and VI (Soni) Sections IV and VI – Outage Modeling and Reliability Results, pp. 14–17 and 22–39 (Walter) Direct Testimony, Existing Unit In-Service Dates, Retirement Dates, and Operating-Cost Assumptions, pp. 3–6 (Rissman) Section II – Existing Unit Technology and Fuel Sources, pp. 4–6 (Moritz) Phase 2 Capacity Results and Exhibit Summary, p. 92 (Moritz) Direct Loss of Load Resource Accreditation, pp. 43 and 74 (McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 54–67 (Section 7; Tables 7-1 through 7-7) Exhibit A-17 (AJM-3), pp. 1–21 Exhibit A-26 (AJM-12), pp. 1–116 Exhibit A-31 (AJM-17), pp. 1–5 Exhibit A-90 (MMW-1), p. 1 Exhibit A-91 (MMW-2), p. 1 Exhibit A-78 (AKR-1), p. 1	WP-PS-2, Thermal Generator Outage Distributions WP-MMW-1, Existing Resource In-Service and Retirement Dates, p. 1 WP-MMW-2, Renewable Repowering Estimates, p. 1 WP-MMW-3, Existing Generation Capital Expenditures, p. 1 WP-MMW-4, Existing Generation O&M Expenditures, p. 1 WP-AJM-1, pp. 28–39 and 54–64
142		**Demand-Side Resources**				
143	MPSC Case Nos. U-21570 & U-21867	Historical and projected load management and DR programs for the utility in terms of MW and RTO or ISO Zonal Resource Credits (ZRCs) and the projected costs for those programs.	Burdjalov McLean Moritz Gast	(Burdjalov) Section II – DR Potential, pp. 16–19 (Gast) Section II – Historical and Projected DR Programs, Impacts, Registration, and Costs, pp. 8–18 (McLean) Section V – Current Baseline Capacity Position, pp. 64–70	Exhibit A-2 (SQM-2), pp. 68–90 (Section 8; Tables 8-1 through 8-12; Figures 8-1 through 8-6) Exhibit A-98 (DVB-2), pp. 1–51 Exhibit A-17 (AJM-3), pp. 1–21 Exhibit A-21 (AJM-7), pp. 1–3 Exhibit A-93 (AMG-2), p. 1	WP-AJM-1, pp. 16–17 WP-SQM-10, p. 1

Line No.	Origin of Requirement	Filing, Testimony, Exhibits, and Workpaper Requirements	Witness	Testimony Section(s)	Exhibit Reference	Work Paper Reference
144	MPSC Case Nos. U-21570 & U-21867	a) Provide data on projected enrolled capacity and DR events for each program. The following items are to be included: 1. Description of current DR and load management programs for the IRP study horizon, including the amount of load reductions and the expected hours of interruption per day, month, and year for each program; 2. Review the historic performance of existing demand-side programs in delivering benefits and how the utility used such information in its DR resource decisions; 3. Describe the utility's method for identifying and deciding whether to pursue costeffective and achievable DR, and determining whether to purchase energy rather than relying on DR; and 4. A description of any other programs the utility is considering that could potentially expand DR resources, including expected load reductions and operating parameters.	Burdjalov McLean Moritz Gast	(Burdjalov) Section II – DR Potential, pp. 16–19 (Gast) Section II – DR Capacity, Events, Performance, Testing, and Implementation Risks, pp. 8–18 (McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 68–90 (Section 8; Tables 8-1 through 8-12; Figures 8-1 through 8-6) Exhibit A-98 (DVB-2), pp. 1–51 Exhibit A-21 (AJM-7), pp. 1–3 Exhibit A-93 (AMG-2), p. 1	WP-AJM-1, pp. 16–17 WP-SQM-10, p. 1
145		**Renewables and Renewable Portfolio Standards**				
146	MPSC Case Nos. U-21570 & U-21867	Projected energy purchased or produced by the utility from renewable energy resources.	Johnston McLean	(Johnston) Sections I–III – Renewable Resources and RPS Compliance, pp. 8–29 (McLean) Section V – Current Baseline Capacity Position, pp. 64–70	Exhibit A-2 (SQM-2), pp. 91–99 (Section 9; Figures 9-1 through 9-4) Exhibit A-54 (KDJ-1), p. 1 Exhibit A-55 (KDJ-2), p. 1	WP-KDJ-1, Company-owned Renewable Projects WP-KDJ-4, REC Comparison – Amended RE Plan versus IRP PCA
147	MPSC Case Nos. U-21570 & U-21867	a) Describe how the electric provider will meet existing renewable energy standards. If the level of renewable energy purchased or produced is projected to drop over the planning periods, the utility must demonstrate why the reduction is in the best interest of ratepayers;	Johnston McLean	(Johnston) Section III – Renewable Energy Standard Compliance, pp. 18–29 (McLean) Section II – Statutory and Regulatory Background, pp. 25–35	Exhibit A-2 (SQM-2), pp. 91–99 (Section 9; Figures 9-1 through 9-4) Exhibit A-54 (KDJ-1), p. 1	WP-KDJ-4, REC Comparison – Amended RE Plan versus IRP PCA
148	MPSC Case Nos. U-21570 & U-21867	b) Specify whether the number of MWh of electricity used in the calculation of the REC portfolio will be the previous 12-month period of weather-normalized retail sales or based on the average number of MWh of electricity sold by the electric provider annually during the previous three years to retail customers in this state;	Johnston McLean	(Johnston) Section III – Renewable Energy Standard Compliance, pp. 18–29 (McLean) Section V – Current Baseline Capacity Position, pp. 64–70	Exhibit A-2 (SQM-2), pp. 91–99 (Section 9; Figures 9-1 through 9-4) Exhibit A-54 (KDJ-1), p. 1	WP-KDJ-2, VGP Sales Historical Detail WP-KDJ-3, Distributed Generation Outflow Forecast
149	MPSC Case Nos. U-21570 & U-21867	c) Include the expected incremental cost of compliance with existing renewable energy standards for the required compliance period;	Johnston McLean Myers	(Johnston) Sections III and VII – Renewable Compliance and Incremental Cost Recovery, pp. 18–29 and 64–66 (McLean) Section II – Statutory and Regulatory Background, pp. 25–35	Exhibit A-2 (SQM-2), pp. 91–99 (Section 9; Figures 9-1 through 9-4)	WP-HJM-2, Calculation of REP Surcharge – PCA WP-HJM-5, PCA Incremental Cost (REP)
150	MPSC Case Nos. U-21570 & U-21867	d) A description of how the electric provider's plan is consistent with the renewable energy requirements established by the Michigan Legislature (e.g. 50% renewable energy by 2030 and 60 % by 2035;	Johnston McLean	(Johnston) Sections II–III – RE Plan Relationship and RPS Compliance, pp. 13–29 (McLean) Section V – Current Baseline Capacity Position, pp. 64–70	Exhibit A-2 (SQM-2), pp. 91–99 (Section 9; Figures 9-1 through 9-4) Exhibit A-54 (KDJ-1), p. 1	
151	MPSC Case Nos. U-21570 & U-21867	e) Describe the options for customer-initiated renewable energy that will be offered by the electric provider and forecast sales of customerinitiated renewable energy;	Johnston McLean	(Johnston) Section VI – VGP Customer Programs and Demand, pp. 49–63 (McLean) Section V – Current Baseline Capacity Position, pp. 64–70	Exhibit A-2 (SQM-2), pp. 91–99 (Section 9; Figures 9-1 through 9-4) Exhibit A-56 (KDJ-3), p. 1	WP-KDJ-2, VGP Sales Historical Detail
152	MPSC Case Nos. U-21570 & U-21867	f) Describe how the electric provider will meet the demand for customerinitiated renewable energy, and;	Johnston McLean	(Johnston) Section VI – VGP Customer Programs and Demand, pp. 49–63 (McLean) Section V – Current Baseline Capacity Position, pp. 64–70	Exhibit A-2 (SQM-2), pp. 91–99 (Section 9; Figures 9-1 through 9-4) Exhibit A-56 (KDJ-3), p. 1	WP-KDJ-2, VGP Sales Historical Detail
153	MPSC Case Nos. U-21570 & U-21867	g) Describe how the electric provider has included distributed generation (DG) as a selectable resource within its modeling for both the IRP and CEP, including interconnection to utility distribution as well as behind-the-meter. The utility is required to consider and model aggregated DG, distributed energy resources (DER) and virtual power plants (VPP) as selectable resources in its IRP. The utility should delineate the costs are paid by DG customers to participate in the program and the costs are paid by all rate payers. Only costs to all rate payer should be included when modeling DG resources. Costs paid by the DG customers (program participants) should not be included in the model but should be considered as compared to the applicable bill credit and DG customer savings to analyze expected participation. This analysis should not solely identify solar generation existing within the utility's system, but instead utilize the most up-to-date information about trends and costs to predict uptake and create a forecast of future DER resources. Information about the assumptions that the utility used to create its DER forecast should be included in the filing.	McLean Johnston Gast	(Gast) Section IV – Distributed Generation Forecast and Cost Impacts, pp. 24–26 (McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 91–99 (Section 9; Figures 9-1 through 9-4) Exhibit A-57 (KDJ-4), pp. 1–4 Exhibit A-95 (AMG-4), p. 1	WP-SQM-10, p. 1 WP-KDJ-3, Distributed Generation Outflow Forecast WP-AJM-1, pp. 10 and 19–20
154		**Energy Storage Target**				
155	MPSC Case Nos. U-21570 & U-21867	Description of how the utility will meet its proportional share of the statewide energy storage target required by MCL 460.1101(1).	McLean Clark	(Clark) Direct Testimony, Energy Storage Target Compliance, pp. 43–49 (McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 100–105 (Section 10; Tables 10-1 and 10-2; Figures 10-1 and 10-2) Exhibit A-10 (TPC-5), p. 1 Exhibit A-11 (TPC-6), p. 1	
156	MPSC Case Nos. U-21570 & U-21867	a) If the utility has not yet filed for approval to procure its proportional share of the statewide energy storage target, the utility must seek approval of these storage resource in an IRP filed no later than December 31, 2029;	McLean Clark	(Clark) Direct Testimony, Approved and Planned Storage Resources, pp. 43–49 (McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 100–105 (Section 10; Tables 10-1 and 10-2; Figures 10-1 and 10-2) Exhibit A-10 (TPC-5), p. 1 Exhibit A-11 (TPC-6), p. 1	
157	MPSC Case Nos. U-21570 & U-21867	b) Identification of the utilities proportional share of the statewide energy storage target of 2500 MW, to be calculated using the methodology approved by the Commission in Case No. U-21751;	McLean Clark	(Clark) Direct Testimony, Company Proportional Storage Share, pp. 43–49 (McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 100–105 (Section 10; Tables 10-1 and 10-2; Figures 10-1 and 10-2) Exhibit A-10 (TPC-5), p. 1 Exhibit A-11 (TPC-6), p. 1	
158	MPSC Case Nos. U-21570 & U-21867	c) Describe the Company's storage procurement plan to meet its required share of the statewide target, including providing the following data on an annual basis: 1. Nameplate capacity and energy output of new resource additions; 2. Storage technology/chemistry deployed and in what amounts; 3. Mix of energy storage capacity that is long-duration and multi-day in duration; 4. Project costs; 5. If the utility's energy storage plan differs from the resultant capacity expansion results, the utility should present its analysis on how it determined the optimal mix and timing of different energy storage technologies and duration capabilities to meet its share of the statewide target, including any modeling or description of other analytical approaches taken.	McLean Clark Skowronski	(Clark) Direct Testimony, Storage Portfolio and Procurement Plan, pp. 43–49 (Skowronski) Section III – BESS Procurement and Approval Strategy, pp. 23–25 (McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 100–105 (Section 10; Tables 10-1 and 10-2; Figures 10-1 and 10-2) Exhibit A-10 (TPC-5), p. 1 Exhibit A-11 (TPC-6), p. 1 Exhibit A-110 (BAS-2), pp. 1–3	
159		**Clean and Renewable Energy Standards**				
160	MPSC Case Nos. U-21570 & U-21867	Detailed resource plan that clearly illustrates how the utility has aligned its IRP with its CEP and how the utility will meet the Clean Energy Standards of 80% clean energy by 2035 and 100% clean energy by 2040. The utility must:	Johnston McLean	(Johnston) Sections II–IV – RE Plan, RPS, and Clean Energy Compliance, pp. 13–38 (McLean) Section II – Statutory and Regulatory Background, pp. 25–35	Exhibit A-2 (SQM-2), pp. 106–110 (Section 11; Figures 11-1 and 11-2) Exhibit A-54 (KDJ-1), p. 1 Exhibit A-55 (KDJ-2), p. 1	WP-KDJ-4, REC Comparison – Amended RE Plan versus IRP PCA
161	MPSC Case Nos. U-21570 & U-21867	a) Describe the utility's planned REC portfolio;	Johnston McLean	(Johnston) Sections III–IV – RPS and Clean Energy Compliance, pp. 18–38 (McLean) Section V – Current Baseline Capacity Position, pp. 64–70	Exhibit A-2 (SQM-2), pp. 106–110 (Section 11; Figures 11-1 and 11-2) Exhibit A-54 (KDJ-1), p. 1 Exhibit A-55 (KDJ-2), p. 1	WP-KDJ-4, REC Comparison – Amended RE Plan versus IRP PCA WP-KDJ-5, Incentive REC Calculations
162	MPSC Case Nos. U-21570 & U-21867	b) Forecast RECs obtained via Michigan incentive RECs;	Johnston McLean	(Johnston) Sections III–IV – Incentive RECs and Clean Energy Compliance, pp. 18–38 (McLean) Section V – Current Baseline Capacity Position, pp. 64–70	Exhibit A-2 (SQM-2), pp. 106–110 (Section 11; Figures 11-1 and 11-2) Exhibit A-54 (KDJ-1), p. 1	WP-KDJ-5, Incentive REC Calculations
163	MPSC Case Nos. U-21570 & U-21867	c) Forecast expected compliance levels by year to meet the renewable portfolio targets;	Johnston McLean	(Johnston) Sections III–IV, pp. 18–38 (McLean) Section V – Current Baseline Capacity Position, pp. 64–70	Exhibit A-2 (SQM-2), pp. 106–110 (Section 11; Figures 11-1 and 11-2) Exhibit A-54 (KDJ-1), p. 1 Exhibit A-55 (KDJ-2), p. 1	WP-KDJ-4, REC Comparison – Amended RE Plan versus IRP PCA WP-KDJ-5, Incentive REC Calculations
164	MPSC Case Nos. U-21570 & U-21867	d) Identify key assumptions used in developing these forecasts and the proposed resource portfolio; and	Johnston McLean	(Johnston) Sections III–IV – Compliance Forecast Assumptions, pp. 18–38 (McLean) Section V – Current Baseline Capacity Position, pp. 64–70	Exhibit A-2 (SQM-2), pp. 106–110 (Section 11; Figures 11-1 and 11-2) Exhibit A-54 (KDJ-1), p. 1 Exhibit A-55 (KDJ-2), p. 1	WP-KDJ-4, REC Comparison – Amended RE Plan versus IRP PCA WP-KDJ-5, Incentive REC Calculations
165	MPSC Case Nos. U-21570 & U-21867	e) Identify risks which may drive performance to vary.	Johnston McLean Clark	(Johnston) Sections III–IV – RPS and CPS Compliance Risks, pp. 18–38 (McLean) Section V – Current Baseline Capacity Position, pp. 64–70 (Clark) Parts I–II – IRP Modeling Assumptions and Execution of the PCA (Solar Development), pp. 23–35	Exhibit A-2 (SQM-2), pp. 106–110 (Section 11; Figures 11-1 and 11-2)	WP-KDJ-7, Curtailed Energy
166	MPSC Case Nos. U-21570 & U-21867	f) If the utility is requesting an extension of a renewable energy credit portfolio deadline pursuant to MCL 460.1032, the utility must provide justification for the extension.	Johnston	Sections III–IV – RPS and CPS Compliance, pp. 18–38 Section IV – No RE Plan or Clean Energy Plan Extension Requested, p. 34		
167	MPSC Case Nos. U-21570 & U-21867	g) Model at least one portfolio without an extension (i.e. what it would look like given the renewable energy deadline without the extension).	Johnston	Section IV – No RE Plan or Clean Energy Plan Extension Requested, p. 34	Exhibit A-54 (KDJ-1), p. 1 Exhibit A-55 (KDJ-2), p. 1	
168		**Peak Demand and Energy Forecasts**				
169	MPSC Case Nos. U-21570 & U-21867	A long-term forecast of the utility's sales and peak demand under various reasonable scenarios. Include details regarding the utility's plan to eliminate energy waste, including the total amount of EWR expected to be achieved annually, and the cost of the plan:	Breuring Burdjalov Schmoekel McLean Moritz Gast	(Breuring) Sections I–VI – Forecast Methodology, Deliveries, Peak Demand, and Alternatives, pp. 4–27 (Burdjalov) Sections I–II – EWR and DR Potential, pp. 4–19 (Schmoekel) Sections I–II – CVR Strategy, Forecast Benefits, and Costs, pp. 4–15 (Gast) Sections I–IV – EWR, DR, EV, DG, and Electrification Forecast Impacts, pp. 4–26 (McLean) Section IV – The Company's Load Forecast, pp. 53–63	Exhibit A-2 (SQM-2), pp. 111–128 (Section 12; Tables 12-1 through 12-6; Figures 12-1 through 12-10) Exhibit A-70 (EMB-1), p. 1 Exhibit A-72 (EMB-3), p. 1 Exhibit A-73 (EMB-4), p. 1 Exhibit A-96 (DVB-1), pp. 1–106 Exhibit A-98 (DVB-2), pp. 1–51 Exhibit A-113 (DAS-1), p. 1 Exhibit A-114 (DAS-2), p. 1 Exhibit A-115 (DAS-3), p. 1 Exhibit A-15 (AJM-1), pp. 1–7 Exhibit A-20 (AJM-6), pp. 1–3 Exhibit A-21 (AJM-7), pp. 1–3 Exhibit A-92 (AMG-1), pp. 1–4 Exhibit A-93 (AMG-2), p. 1 Exhibit A-94 (AMG-3), p. 1 Exhibit A-95 (AMG-4), p. 1	WP-AJM-1, pp. 7–20
170	MPSC Case Nos. U-21570 & U-21867	a) A forecast of the utility's peak demand and details regarding the amount of peak demand reduction the utility expects to achieve.	Breuring Burdjalov Schmoekel McLean Moritz Gast	(Breuring) Section IV – Base Case Forecasted Peak Demand, pp. 17–21 (Breuring) Sections IV–V – Peak Demand and Forecast Uncertainty, pp. 17–22 (Burdjalov) Section II – DR Potential, pp. 16–19 (Schmoekel) Sections I–II – CVR Peak-Demand Reduction Forecast, pp. 4–15 (Gast) Sections I–II – EWR and DR Peak-Demand Reductions, pp. 4–18 (McLean) Section IV – The Company's Load Forecast, pp. 53–63	Exhibit A-2 (SQM-2), pp. 111–128 (Section 12; Tables 12-1 through 12-6; Figures 12-1 through 12-10) Exhibit A-71 (EMB-2), p. 1 Exhibit A-72 (EMB-3), p. 1 Exhibit A-98 (DVB-2), pp. 1–51 Exhibit A-113 (DAS-1), p. 1 Exhibit A-21 (AJM-7), pp. 1–3 Exhibit A-92 (AMG-1), pp. 1–4 Exhibit A-93 (AMG-2), p. 1	WP-AJM-1, pp. 7–20
171	MPSC Case Nos. U-21570 & U-21867	b) Subsections: 1. Key variables used to develop forecast; 2. Long-term forecasting methodology; 3. Forecasting uncertainty and risks; 4. Historical growth in electric sales for the previous five years, including a record of its previous load forecasts (can be supplied in workpapers); 5. Base load forecasts should include assumed losses and demand forecast; 6. Base load forecasts should include any contracted large loads and include a description of the load and peak demand characteristics of any large load included in the utility's base or alternative load forecasts. 7. Alternative forecast scenarios and sensitivities in accordance with the Commission's final order in Case No. U-21219, or subsequent Commission orders relating to IRP modeling parameters and requirements; 8. Describe in detail how the forecasts used for IRP modeling align with forecasts used for distribution planning; 9. Detail information about how the Company considered DER and non-wired alternative solutions for the potential to offset future utility-scale resources; 10. Detail electric vehicle adoption assumptions and impacts to overall peak demand and energy forecasts; 11. Detail additional electrification adoption assumptions and impacts to overall peak demand and energy forecasts; and 12. Detail exactly how much EWR is embedded in the utility's load forecasts. 13. Detail the addition of projected large load that are not included in the base load forecast but will be used for Scenario #1 large load sensitivity that includes a description of the total incremental large load in the Company's queue to develop a low, medium and high large load forecast. The low, medium, and high forecasts should be derived using a designation of probability for each project in the customer queue. Please detail any additional methodology about how the utility has determined its low, medium and high large load forecast and how this aligns with publicly disclosed load information.	Breuring Burdjalov McLean Moritz Soni Gast Schmoekel	(Breuring) Sections I–VI – Forecast Methodology, Variables, Deliveries, Peak Demand, Uncertainty, and Alternatives, pp. 4–27 (Burdjalov) Sections I–II – EWR and DR Potential, pp. 4–19 (Soni) Section VIII – Forecast-Error and Risk Variables, pp. 55–70 (Gast) Sections I–IV – EWR, DR, EV, DG, and Electrification Forecast Assumptions and Impacts, pp. 4–26 (McLean) Section IV – The Company's Load Forecast, pp. 53–63 (Schmoekel) Sections I–III – CVR Strategy, Forecast Assumptions, Results, and Variances, pp. 4–22	Exhibit A-2 (SQM-2), pp. 111–128 (Section 12; Tables 12-1 through 12-6; Figures 12-1 through 12-10) Exhibit A-70 (EMB-1), p. 1 Exhibit A-71 (EMB-2), p. 1 Exhibit A-72 (EMB-3), p. 1 Exhibit A-73 (EMB-4), p. 1 Exhibit A-96 (DVB-1), pp. 1–106 Exhibit A-98 (DVB-2), pp. 1–51 Exhibit A-15 (AJM-1), pp. 1–7 Exhibit A-20 (AJM-6), pp. 1–3 Exhibit A-21 (AJM-7), pp. 1–3 Exhibit A-92 (AMG-1), pp. 1–4 Exhibit A-93 (AMG-2), p. 1 Exhibit A-94 (AMG-3), p. 1 Exhibit A-95 (AMG-4), p. 1	WP-PS-3, Forecast Error Spreads
172		**Capacity and Reliability Requirements**				
173	MPSC Case Nos. U-21570 & U-21867	. The utility shall indicate how it complies, and will comply, with all applicable state, federal, ISO, and RTO capacity and reliability regulations, laws, rules, and requirements, (such as planning reserve margins, system reliability and ancillary service requirements) including, where feasible, the projected costs/revenues of complying with those regulations, laws, and rules. The utility shall identify any relevant changes to the applicable state, federal, or local laws, rules, and regulations. The utility shall also identify any major ISO or RTO capacity and reliability requirements that have occurred since its last IRP filing, including narrative that identifies how its PCA satisfies those requirements. The utility shall include data regarding the utility's current generation portfolio, including the age, capacity factor, licensing status, and remaining estimated time of operation for each facility in the portfolio.	McLean Moritz Soni	(Soni) Sections III and VI – Reliability Standards and Results, pp. 9–13 and 22–39 (Moritz) Phase 2 Capacity Results and Exhibit Summary, p. 92 (Moritz) Direct Loss of Load Resource Accreditation, pp. 43 and 74 (McLean) Section V – Current Baseline Capacity Position, pp. 64–70	Exhibit A-2 (SQM-2), pp. 129–140 (Section 13; Table 13-1; Figures 13-3 through 13-5) Exhibit A-26 (AJM-12), pp. 1–116 Exhibit A-31 (AJM-17), pp. 1–5	WP-PS-7, Capability versus Demand
174		**Transmission Analysis**				

Line No.	Origin of Requirement	Filing, Testimony, Exhibits, and Workpaper Requirements	Witness	Testimony Section(s)	Exhibit Reference	Work Paper Reference
175	MPSC Case Nos. U-21570 & U-21867	In accordance with MCL 460.6t(5)(b), the utility shall work with their local transmission owner to include an analysis of potential new or upgraded electric transmission options for the utility. The utility's analysis shall include the following information:	McCormick	Sections III–VIII – Transmission Owner Engagement, Evaluation, Limits, Inputs, Alternatives, and Studies, pp. 5–46	Exhibit A-74 (JRM-1), pp. 1–63 Exhibit A-75 (JRM-2), pp. 1–17 Exhibit A-76 (JRM-3), pp. 1–2 Exhibit A-77 (JRM-4), pp. 1–4	WP-JRM-1, MISO GIA Costs and Statistical Summary WP-JRM-2, CIL and CEL Forecasts WP-JRM-3, Transmission Scenarios, Resource Siting, and Load Forecasts
176	MPSC Case Nos. U-21570 & U-21867	a) The utility shall work with their local transmission owner to assess the need to construct new, or modify existing transmission facilities to interconnect any new generation and shall reflect the estimated costs of those transmission facilities in the analyses of the resource options. The analysis shall include a discussion of how implementation of grid enhancing technologies (GETS) can facilitate, defer, or replace other transmission and resource investments and/or reduce market congestion costs;	McCormick McLean	(McCormick) Sections IV and VII – Interconnection Costs and Grid-Enhancing Technologies, pp. 6–25 and 37–44 (McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 141–149 (Section 14; Table 14-1 and Figure 14-2) Exhibit A-75 (JRM-2), pp. 1–17 Exhibit A-76 (JRM-3), pp. 1–2	WP-JRM-1, MISO GIA Costs and Statistical Summary WP-JRM-3, Transmission Scenarios, Resource Siting, and Load Forecasts
177	MPSC Case Nos. U-21570 & U-21867	b) In collaboration with the local transmission owner, include an analysis of any co-benefits of storage, specifically the transmission system benefits associated with transmission interconnected storage that is not designated as "storage as transmission only asset;"	McCormick McLean	(McCormick) Section VII – Storage and Transmission Co-Benefits, pp. 37–44 (McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 141–149 (Section 14; Table 14-1 and Figure 14-2) Exhibit A-76 (JRM-3), pp. 1–2	
178	MPSC Case Nos. U-21570 & U-21867	c) A detailed description of the utility's efforts to engage local transmission owners throughout the utility's IRP process. In an effort to inform the IRP process and assumptions, a meeting schedule in coordination with the transmission owner should be determined that supports engagement through the process. The filing should include a summary including meeting dates, number of meetings and how the engagement influenced the utility's decisions;	McCormick McLean Coker	(Coker) Section V – Collaboration with METC/ITC, pp. 16–17 (McCormick) Section III – Transmission Owner Engagement and Meeting Schedule, pp. 5–6 (McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 141–149 (Section 14; Table 14-1 and Figure 14-2) Exhibit A-74 (JRM-1), pp. 1-63	
179	MPSC Case Nos. U-21570 & U-21867	d) Detailed meeting minutes for utility/transmission owner meetings should include any requested studies, discussions about assumptions and any conclusions made during the meeting, alternatives that were reviewed, any other pertinent information that can be made public or provided through typical contested case confidentiality agreements;	McCormick	Section III – Transmission Owner Meeting Minutes, pp. 5–6	Exhibit A-74 (JRM-1), pp. 1-63	
180	MPSC Case Nos. U-21570 & U-21867	e) Current transmission system import and export limits as most recently documented by the RTO and any local area constraints or congestion concerns;	McCormick McLean Moritz	(McCormick) Section V – Capacity Import and Export Limits, pp. 26–31 (McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 141–149 (Section 14; Table 14-1 and Figure 14-2) Exhibit A-19 (AJM-5), p. 1 Exhibit A-75 (JRM-2), pp. 1–17	WP-JRM-2, CIL and CEL Forecasts
181	MPSC Case Nos. U-21570 & U-21867	f) To the extent available, any information provided by their local transmission and RTO owner indicating the anticipated effects of fleet changes proposed in the transmission system, including both generation retirements and new generation, subject to confidentiality provisions; Any information provided by their local transmission owner, including cost and timing, indicating potential transmission options that could impact the utility's IRP by: (1) increasing a local resource zone's (LRZ) import or export capability; (2) facilitating PPAs or sales of energy and capacity both within or outside the planning zone or from neighboring RTOs; (3) transmission upgrades resulting in increasing system efficiency and reducing line loss allowing for greater energy delivery and reduced capacity need; and (4) advanced transmission and distribution network technologies affecting supply-side resources or demand-side resources; (5) estimated interconnection costs for new resources (6) potential siting locations that may provide transmission system benefits;	McCormick McLean Moritz	(McCormick) Sections IV, VII, and VIII – Fleet Changes, Transmission Options, Costs, and Siting, pp. 6–25 and 37–46 (McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 141–149 (Section 14; Table 14-1 and Figure 14-2) Exhibit A-19 (AJM-5), p. 1 Exhibit A-75 (JRM-2), pp. 1–17 Exhibit A-76 (JRM-3), pp. 1–2 Exhibit A-77 (JRM-4), pp. 1–4	WP-JRM-1, MISO GIA Costs and Statistical Summary WP-JRM-2, CIL and CEL Forecasts WP-JRM-3, Transmission Scenarios, Resource Siting, and Load Forecasts
182	MPSC Case Nos. U-21570 & U-21867	g) In collaboration with their local transmission owner, to the extent available, any information regarding (1) identification of system locations or regions where energy resources can interconnect to the transmission system with minimal transmission investment, (2) recent studies, to the extent that they are available, that indicate ways in which the capacity import or export capabilities can be increased or may change and the resulting impacts to the local clearing requirement;	McCormick McLean Moritz	(McCormick) Sections VII–VIII – Import Capability, Local Reliability, and Hosting Capacity, pp. 37–46 (McLean) Section V – Current Baseline Capacity Position, pp. 64–70	Exhibit A-2 (SQM-2), pp. 141–149 (Section 14; Table 14-1 and Figure 14-2) Exhibit A-19 (AJM-5), p. 1 Exhibit A-75 (JRM-2), pp. 1–17 Exhibit A-77 (JRM-4), pp. 1–4	WP-JRM-2, CIL and CEL Forecasts WP-JRM-3, Transmission Scenarios, Resource Siting, and Load Forecasts
183	MPSC Case Nos. U-21570 & U-21867	h) Any transmission studies performed by their local transmission owner that support the resource plan proposed by the utility;	McCormick McLean Moritz	(McCormick) Section IV – METC Transmission Evaluation, pp. 6–25 (McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 141–149 (Section 14; Table 14-1 and Figure 14-2) Exhibit A-19 (AJM-5), p. 1 Exhibit A-75 (JRM-2), pp. 1–17	WP-JRM-3, Transmission Scenarios, Resource Siting, and Load Forecasts
184	MPSC Case Nos. U-21570 & U-21867	i) In conjunction with the local transmission owner, provide an analysis of transmission costs for access to out-of-state resources conducted by either the RTO, transmission owner(s), and/or utility in a format that can be made available to public; and	McCormick McLean	(McCormick) Section VII – Transmission Costs for Out-of-State Resources, pp. 37–44 (McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 141–149 (Section 14; Table 14-1 and Figure 14-2) Exhibit A-74 (JRM-1), pp. 1–63 Exhibit A-75 (JRM-2), pp. 1–17	WP-JRM-2, CIL and CEL Forecasts
185	MPSC Case Nos. U-21570 & U-21867	j) Provide RTO reports or web links to report locations that contain information relied upon to support transmission related model assumptions in a format that is conducive to public availability.	McCormick	Sections V–VIII – RTO Reports and Public Transmission Sources, pp. 26–46	Exhibit A-75 (JRM-2), pp. 1–17 Exhibit A-76 (JRM-3), pp. 1–2 Exhibit A-77 (JRM-4), pp. 1–4	WP-JRM-1, MISO GIA Costs and Statistical Summary WP-JRM-2, CIL and CEL Forecasts
186		**Fuel**				
187	MPSC Case Nos. U-21570 & U-21867	The utility shall include the following:	Rissman	Sections I–VII – Fuel Supply, Forecasts, and Strategy, pp. 3–15	Exhibit A-78 (AKR-1), p. 1 Exhibit A-79 (AKR-2), p. 1 Exhibit A-80 (AKR-3), p. 1 Exhibit A-81 (AKR-4), p. 1 Exhibit A-82 (AKR-5), p. 1 Exhibit A-83 (AKR-6), p. 1 Exhibit A-84 (AKR-7), p. 1 Exhibit A-85 (AKR-8), p. 1 Exhibit A-86 (AKR-9), p. 1 Exhibit A-87 (AKR-10), p. 1 Exhibit A-88 (AKR-11), p. 1 Exhibit A-89 (AKR-12), p. 1	
188	MPSC Case Nos. U-21570 & U-21867	a) Overview;	Rissman McLean Moritz	(Rissman) Section I – Overview, pp. 3–4 (McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 150–154 (Section 15; Figures 15-1 and 15-2) Exhibit A-15 (AJM-1), pp. 1–7 Exhibit A-78 (AKR-1), p. 1 Exhibit A-79 (AKR-2), p. 1 Exhibit A-80 (AKR-3), p. 1 Exhibit A-89 (AKR-12), p. 1	WP-AJM-1, pp. 57–60
189	MPSC Case Nos. U-21570 & U-21867	b) Natural gas price forecasts under the various scenarios;	Rissman McLean Moritz	(Rissman) Section III – Natural Gas Price Forecasts, pp. 6–8 (McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 150–154 (Section 15; Figures 15-1 and 15-2) Exhibit A-15 (AJM-1), pp. 1–7 Exhibit A-79 (AKR-2), p. 1	WP-AJM-1, pp. 57 and 59–60
190	MPSC Case Nos. U-21570 & U-21867	c) Oil price forecasts under the various scenarios;	Rissman McLean Moritz	(Rissman) Section III – Oil Price Forecasts, pp. 8–9 (McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 150–154 (Section 15; Figures 15-1 and 15-2) Exhibit A-15 (AJM-1), pp. 1–7 Exhibit A-80 (AKR-3), p. 1 Exhibit A-88 (AKR-11), p. 1	WP-AJM-1, p. 58
191	MPSC Case Nos. U-21570 & U-21867	d) Coal price forecasts under the various scenarios;	McLean Moritz	Not Applicable		
192	MPSC Case Nos. U-21570 & U-21867	e) Delivered natural gas prices to existing and new utility-owned generating plants;	Rissman McLean	(Rissman) Section IV – Delivered Natural Gas Prices, pp. 8–12 (McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 150–154 (Section 15; Figures 15-1 and 15-2) Exhibit A-81 (AKR-4), p. 1 Exhibit A-82 (AKR-5), p. 1 Exhibit A-83 (AKR-6), p. 1 Exhibit A-84 (AKR-7), p. 1 Exhibit A-85 (AKR-8), p. 1 Exhibit A-86 (AKR-9), p. 1 Exhibit A-87 (AKR-10), p. 1	WP-AJM-1, pp. 57 and 59
193	MPSC Case Nos. U-21570 & U-21867	f) Delivered oil prices to existing and new utility-owned generating plants;	Rissman McLean	(Rissman) Sections III–IV – Delivered Oil Price Forecast, pp. 8–9 (McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 150–154 (Section 15; Figures 15-1 and 15-2) Exhibit A-88 (AKR-11), p. 1	WP-AJM-1, p. 58
194	MPSC Case Nos. U-21570 & U-21867	g) Delivered coal prices to existing and new utility-owned generating plants;	McLean Moritz	(McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 150–154 (Section 15; Figures 15-1 and 15-2) Exhibit A-15 (AJM-1), pp. 1–7	
195	MPSC Case Nos. U-21570 & U-21867	h) Projected annual fuel costs under the various scenarios;	McLean Moritz	(Moritz) Scenario and Portfolio Fuel-Cost Projections, p. 93 (McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 150–154 (Section 15; Figures 15-1 and 15-2) Exhibit A-15 (AJM-1), pp. 1–7 Exhibit A-28 (AJM-14), pp. 5 Exhibit A-30 (AJM-16), pp. 1–9	WP-AJM-1, pp. 57–60
196	MPSC Case Nos. U-21570 & U-21867	i) The projected long-term firm gas transportation contracts or natural gas storage the utility will hold to provide an adequate supply of natural gas to any new and existing generation facility; and	Rissman McLean Moritz	(Rissman) Section V – Long-Term Fuel Supply Strategy, pp. 12–13 (McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 150–154 (Section 15; Figures 15-1 and 15-2) Exhibit A-15 (AJM-1), pp. 1–7 Exhibit A-81 (AKR-4), p. 1 Exhibit A-82 (AKR-5), p. 1 Exhibit A-83 (AKR-6), p. 1 Exhibit A-84 (AKR-7), p. 1 Exhibit A-85 (AKR-8), p. 1 Exhibit A-86 (AKR-9), p. 1 Exhibit A-87 (AKR-10), p. 1	
197	MPSC Case Nos. U-21570 & U-21867	j) Any other fuels used for electric generation by the utility.	McLean Moritz Rissman	(Rissman) Sections II–IV – Other Fossil Fuels Used for Generation, pp. 4–12 (McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 150–154 (Section 15; Figures 15-1 and 15-2) Exhibit A-15 (AJM-1), pp. 1–7 Exhibit A-78 (AKR-1), p. 1 Exhibit A-88 (AKR-11), p. 1	WP-AJM-1, p. 60
198	MPSC Case Nos. U-21570 & U-21867	k) New generation or retrofitted generation costs to connect to fuel and store CO2 where applicable.	Not applicable. The proposed generation facilities do not include carbon capture and storage; therefore, no costs to transport or store CO_2 are included. Applicable fuel-interconnection costs are reflected in the project cost estimates			
199		**Resource Screen**				
200	MPSC Case Nos. U-21570 & U-21867	Describe the utility's options of resources, including combinations of resources constructed as a single facility (such as storage combined with a generation source), to serve future electric load such as utilizing existing and planned resources (including future load from the electric provider's voluntary green pricing program and any special contracts), build a new facility, purchasing capacity from the market on a short-term basis, and purchasing capacity through a PPA. The following sections shall discuss each option in detail and options shall be considered in combination to serve future electric load. As described below, workpapers with information on the costs and performance data of each modeled resource option and combination of resource options shall be provided with the utility's filing:	McLean Skowronski Moritz Walter Rissman Troyer	(Skowronski) Sections II–III – PPA, Market-Capacity, and Procurement Options, pp. 10–26 (Walter) Direct Testimony, Existing Generation Resources, Retirement Dates, and Expenditure Forecasts, pp. 2–6 (Rissman) Sections II–V – Existing and New Fuel Supply Options, pp. 4–13 (Troyer) Direct Testimony, PPA Alternatives and Resource Options, pp. 8–15 and 23–43 (McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 155–171 (Section 16; Tables 16-1 through 16-12; Figures 16-1 and 16-2) Exhibit A-15 (AJM-1), pp. 1–7 Exhibit A-18 (AJM-4), pp. 1–8 Exhibit A-20 (AJM-6), pp. 1–3 Exhibit A-21 (AJM-7), pp. 1–3 Exhibit A-24 (AJM-10), pp. 1–14 Exhibit A-110 (BAS-2), pp. 1–3 Exhibit A-111 (BAS-3), pp. 1–8 Exhibit A-90 (MMW-1), p. 1 Exhibit A-91 (MMW-2), p. 1 Exhibit A-78 (AKR-1), p. 1 Exhibit A-81 (AKR-4), p. 1 Exhibit A-82 (AKR-5), p. 1 Exhibit A-83 (AKR-6), p. 1 Exhibit A-84 (AKR-7), p. 1 Exhibit A-85 (AKR-8), p. 1 Exhibit A-86 (AKR-9), p. 1 Exhibit A-87 (AKR-10), p. 1 Exhibit A-88 (AKR-11), p. 1 Exhibit A-3 (KGT-1), pp. 1–32 Exhibit A-4 (KGT-2), pp. 1–118	WP-MMW-1, Existing Resource In-Service and Retirement Dates, p. 1 WP-MMW-2, Renewable Repowering Estimates, p. 1 WP-MMW-3, Existing Generation Capital Expenditures, p. 1 WP-MMW-4, Existing Generation O&M Expenditures, p. 1 WP-AJM-1, pp. 28–49 and 54–64 WP-AJM-2, pp. 1–4

Line No.	Origin of Requirement	Filing, Testimony, Exhibits, and Workpaper Requirements	Witness	Testimony Section(s)	Exhibit Reference	Work Paper Reference
201	MPSC Case Nos. U-21570 & U-21867	a) Existing and approved resources;	Moritz McLean Walter	(Moritz) Section VI – Supply and Demand Assessment (Walter) Direct Testimony, Existing Generation Resources and Modeling Assumptions, pp. 3–6 (McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 155–171 (Section 16; Tables 16-1 through 16-12; Figures 16-1 and 16-2) Exhibit A-17 (AJM-3), pp. 1–21 Exhibit A-90 (MMW-1), p. 1 Exhibit A-91 (MMW-2), p. 1	WP-MMW-1, Existing Resource In-Service and Retirement Dates, p. 1 WP-MMW-2, Renewable Repowering Estimates, p. 1 WP-MMW-3, Existing Generation Capital Expenditures, p. 1 WP-MMW-4, Existing Generation O&M Expenditures, p. 1 WP-AJM-1, pp. 28–39 and 54–64
202	MPSC Case Nos. U-21570 & U-21867	b) New build: 1. New generation technology and operating assumptions; 2. New generation development costs; 3. New storage technology and operating assumptions; 4. New energy storage development costs; and 5. Development costs and operating assumptions for combinations of resources constructed as a single facility;	Moritz McLean Clark	(Moritz) Section VII – Supply-Side Resource Options (Clark) Direct Testimony, IRP Technology Cost and Operating Assumptions, pp. 7–23 (McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 155–171 (Section 16; Tables 16-1 through 16-12; Figures 16-1 and 16-2) Exhibit A-18 (AJM-4), pp. 1–8 Exhibit A-24 (AJM-10), pp. 1–14 Exhibit A-6 (TPC-1), p. 1 Exhibit A-7 (TPC-2), p. 1 Exhibit A-8 (TPC-3), p. 1 Exhibit A-10 (TPC-5), p. 1 Exhibit A-11 (TPC-6), p. 1 Exhibit A-12 (TPC-7), p. 1	WP-AJM-1, pp. 40–49 WP-AJM-2, pp. 1–4
203	MPSC Case Nos. U-21570 & U-21867	c) DERs inclusive of non-wires alternatives (NWA) identified in other planning processes;	McLean Moritz Gast	(Gast) Section IV – Distributed Generation Forecast and Impacts, pp. 24–26 (McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 155–171 (Section 16; Tables 16-1 through 16-12; Figures 16-1 and 16-2) Exhibit A-15 (AJM-1), pp. 1–7 Exhibit A-24 (AJM-10), pp. 1–14 Exhibit A-95 (AMG-4), p. 1	
204	MPSC Case Nos. U-21570 & U-21867	d) Demand-side Resources inclusive of NWAs identified in other planning processes;	McLean Ihrdjalov Moritz Gast Schmoekel	(Gast) Sections I–II – EWR and DR Demand-Side Resources, pp. 4–18 (McLean) Section VI – New Resource Options, pp. 71–78 (Schmoekel) Sections I–III – CVR Strategy, Circuit Selection, and Distribution Upgrade Deferral, pp. 4–18	Exhibit A-2 (SQM-2), pp. 155–171 (Section 16; Tables 16-1 through 16-12; Figures 16-1 and 16-2) Exhibit A-97 (DVB-1A), pp. 1–107 Exhibit A-20 (AJM-6), pp. 1–3 Exhibit A-21 (AJM-7), pp. 1–3 Exhibit A-92 (AMG-1), pp. 1–4 Exhibit A-93 (AMG-2), p. 1	WP-SQM-10, p. 1 WP-AJM-1, pp. 16–17
205	MPSC Case Nos. U-21570 & U-21867	e) Market capacity purchases: 1. Regional market supply outlook; 2. Availability of market capacity; and 3. Market capacity price assumptions;	Moritz Skowronski McLean Soni	(Moritz) Sections IV and VII (Skowronski) Section III – Short-Term Capacity Procurement and 2025 RCA Results, pp. 15–22 (Soni) Section VII – Market Dependency, pp. 40–54 (McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 155–171 (Section 16; Tables 16-1 through 16-12; Figures 16-1 and 16-2) Exhibit A-16 (AJM-2), pp. 1–4	WP-PS-1, Historical Market Dependency WP-PS-2, Cost Sensitivity Levels and Net Market Purchases WP-AJM-1, p. 64
206	MPSC Case Nos. U-21570 & U-21867	f) Long-term PPAs; and	Moritz Skowronski McLean Troyer	(Moritz) Sections VII, XI, and XIII, and 11B–end (Skowronski) Sections II–III – Long-Term PPAs and Procurement Strategy, pp. 12–21 (Troyer) Direct Testimony, New Long-Term MCV and Clean PPAs, pp. 7–23 and 23–44 (McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 155–171 (Section 16; Tables 16-1 through 16-12; Figures 16-1 and 16-2) Exhibit A-15 (AJM-1), pp. 1–7 Exhibit A-24 (AJM-10), pp. 1–14 Exhibit A-110 (BAS-2), pp. 1–3 Exhibit A-111 (BAS-3), pp. 1–8 Exhibit A-3 (KGT-1), pp. 1–32 Exhibit A-4 (KGT-2), pp. 1–118	WP-AJM-1, pp. 61–63
207	MPSC Case Nos. U-21570 & U-21867	g) Transmission resources: 1. Overview; 2. Existing import and export capability; 3. Transmission network upgrade assumptions for the IRP; and 4. Import and export impact on resource strategy.	McCormick Moritz McLean	(Moritz) Section VII – Transmission Options (McCormick) Sections IV–VIII – Transmission Resources, Limits, Alternatives, and Studies, pp. 6–46 (McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 155–171 (Section 16; Tables 16-1 through 16-12; Figures 16-1 and 16-2) Exhibit A-19 (AJM-5), p. 1 Exhibit A-75 (JRM-2), pp. 1–17 Exhibit A-76 (JRM-3), pp. 1–2 Exhibit A-77 (JRM-4), pp. 1–4	WP-JRM-1, MISO GIA Costs and Statistical Summary WP-JRM-2, CIL and CEL Forecasts WP-JRM-3, Transmission Scenarios, Resource Siting, and Load Forecasts WP-AJM-1, pp. 65–69
208		**Modeling Results**				
209	MPSC Case Nos. U-21570 & U-21867	An analysis of the capital costs, energy production, energy production costs, fuel costs, energy served, capacity factor, emissions (levels and costs), and stability of all reasonable options available to meet projected energy and capacity needs, including, but not limited to, existing electric generation facilities in this state. The following suggest specific items to be included. They are not exhaustive.	McLean Moritz Myers Walter Rissman Clark Breining	(Walter) Direct Testimony, Existing Fleet Capital and O&M Expenditures, pp. 2, 4–5 (Rissman) Sections III–VI – Fuel Price and Cost Inputs, pp. 6–13 (Clark) Direct Testimony, Capital, O&M, Performance, and Viability Assumptions, pp. 7–23 (McLean) Section VIII – Description of Significant Proposals and Summary of Requested Relief, pp. 105–114 (Breining) Section II – IRP Emissions Outlook, Scenario Comparisons, and Carbon Accounting, pp. 12–15	Exhibit A-2 (SQM-2), pp. 173–193 (Section 17; Tables 17-1 through 17-11; Figures 17-1 through 17-6) Exhibit A-18 (AJM-4), pp. 1–8; Exhibit A-22 (AJM-8), pp. 1–4; Exhibit A-23 (AJM-9), pp. 1–8; Exhibit A-24 (AJM-10), pp. 1–14 Exhibit A-25 (AJM-11), pp. 1–4 Exhibit A-90 (MMW-1), p. 1 Exhibit A-91 (MMW-2), p. 1 Exhibit A-79 (AKR-2), p. 1 Exhibit A-80 (AKR-3), p. 1 Exhibit A-81 (AKR-4), p. 1 Exhibit A-82 (AKR-5), p. 1 Exhibit A-83 (AKR-6), p. 1 Exhibit A-84 (AKR-7), p. 1 Exhibit A-85 (AKR-8), p. 1 Exhibit A-86 (AKR-9), p. 1 Exhibit A-87 (AKR-10), p. 1 Exhibit A-88 (AKR-11), p. 1 Exhibit A-6 (TPC-1), p. 1 Exhibit A-7 (TPC-2), p. 1 Exhibit A-8 (TPC-3), p. 1 Exhibit A-10 (TPC-5), p. 1 Exhibit A-11 (TPC-6), p. 1 Exhibit A-12 (TPC-7), p. 1 Exhibit A-49 (HAB-1), pp. 1–9 Exhibit A-50 (HAB-2), pp. 1–64 Exhibit A-51 (HAB-3), pp. 1–2	WP-HJM-1, PCA Inputs and Calculations WP-HJM-34 through WP-HJM-43, Existing Resource Revenue Requirements and Rate-Base Projections WP-MMW-3, Existing Generation Capital Expenditures, p. 1 WP-MMW-4, Existing Generation O&M Expenditures, p. 1 WP-AJM-1, pp. 28–69 WP-AJM-2, pp. 1–4 WP-AJM-3, pp. 1–21
210	MPSC Case Nos. U-21570 & U-21867	a) Description of IRP portfolio design strategy (portfolio optimized for least cost, value maximization, reliability, risk minimization, environmental specification, minimization of impacts to communities identified in the EJ analysis, etc., or a particular combination);	Moritz McLean Coker	(Moritz) Sections IX–XI (Coker) Section VII – Stakeholder Influence on Portfolio Design, pp. 25–30 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 173–193 (Section 17; Tables 17-1 through 17-11; Figures 17-1 through 17-6) Exhibit A-22 (AJM-8), pp. 1–4 Exhibit A-106 (JRC-8), pp. 1–24 Exhibit A-107 (JRC-9), pp. 1–19 Exhibit A-108 (JRC-10), pp. 1–11	
211	MPSC Case Nos. U-21570 & U-21867	b) Results for all MIRPP required scenarios and sensitivities, additional utility scenarios and sensitivities, and the proposed resource plan that include annual incremental revenue requirements, incremental present value of annual revenue requirements and net present value of revenue requirements, and portfolio capacity, including additions and retirements. Include monthly and annual energy pricing, and resource capacity and load factors; 1. Base case portfolio options to be selected from; 2. Analysis of IRP results;	McLean Moritz Myers Soni Walter Rissman Clark McCormick	(Soni) Section VIII – Risk Assessment Results, pp. 55–70 (Walter) Direct Testimony, Existing Resource Retirement and Capital Assumptions, pp. 3–6 (Rissman) Sections III–VI – Fuel Forecast Scenarios and Cost Inputs, pp. 6–13 (Clark) Direct Testimony, Base and Sensitivity Resource Assumptions, pp. 7–23 (McCormick) Section IV – Transmission Scenario Results and Costs, pp. 6–25 (Moritz) Phase 2 Capacity Results and Exhibit Summary, p. 92 (Moritz) Phase 2 Energy Results and Exhibit Summary, p. 92 (Moritz) PCA Capital, O&M, Fuel, and Purchased-Power Costs, p. 92 (Moritz) Scenario and Portfolio Fuel-Cost Projections, p. 93 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 173–193 (Section 17; Tables 17-1 through 17-11; Figures 17-1 through 17-6) Exhibit A-23 (AJM-9), pp. 1–8; Exhibit A-24 (AJM-10), pp. 1–14; Exhibit A-25 (AJM-11), pp. 1–4; Exhibit A-26 (AJM-12), pp. 1–116 Exhibit A-27 (AJM-13), pp. 1–29 Exhibit A-29 (AJM-15), pp. 1–3 Exhibit A-30 (AJM-16), pp. 1–9 Exhibit A-90 (MMW-1), p. 1 Exhibit A-91 (MMW-2), p. 1 Exhibit A-79 (AKR-2), p. 1 Exhibit A-80 (AKR-3), p. 1 Exhibit A-81 (AKR-4), p. 1 Exhibit A-82 (AKR-5), p. 1 Exhibit A-83 (AKR-6), p. 1 Exhibit A-84 (AKR-7), p. 1 Exhibit A-85 (AKR-8), p. 1 Exhibit A-86 (AKR-9), p. 1 Exhibit A-87 (AKR-10), p. 1 Exhibit A-88 (AKR-11), p. 1 Exhibit A-6 (TPC-1), p. 1 Exhibit A-7 (TPC-2), p. 1 Exhibit A-8 (TPC-3), p. 1 Exhibit A-10 (TPC-5), p. 1 Exhibit A-11 (TPC-6), p. 1 Exhibit A-12 (TPC-7), p. 1 Exhibit A-75 (JRM-2), pp. 1–17	WP-HJM-1, PCA Inputs and Calculations WP-HJM-11, Alternative Growth Inputs and Calculations WP-HJM-21, Alternative Current Inputs and Calculations WP-PS-2, Cost Sensitivity Levels WP-PS-8, Risk Assessment WP-MMW-1, Existing Resource In-Service and Retirement Dates, p. 1 WP-MMW-2, Renewable Repowering Estimates, p. 1 WP-MMW-3, Existing Generation Capital Expenditures, p. 1 WP-MMW-4, Existing Generation O&M Expenditures, p. 1 WP-JRM-3, Transmission Scenarios, Resource Siting, and Load Forecasts WP-AJM-3, pp. 1–21
212	MPSC Case Nos. U-21570 & U-21867	c) Risk assessment is presented with graphics and data that illustrate the results of any stochastic risk analysis performed such that the probability distributions are clearly defined along with relative positions of the distributions so that plans can be directly compared on a single graph. The use of a box and whisker plot and/or efficient frontier plot is recommended; and	McLean Soni Moritz	(Soni) Section VIII – Stochastic Risk Graphics and Results, pp. 55–70 (McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 173–193 (Section 17; Tables 17-1 through 17-11; Figures 17-1 through 17-6) Exhibit A-35 (PS-2), pp. 1–5 Exhibit A-36 (PS-3), pp. 1–2 Exhibit A-37 (PS-4), pp. 1–2 Exhibit A-41 (PS-8), pp. 1–2 Exhibit A-22 (AJM-8), pp. 1–4 Exhibit A-23 (AJM-9), pp. 1–8	WP-PS-5, Stochastic Distributions WP-PS-8, Risk Assessment
213	MPSC Case Nos. U-21570 & U-21867	d) Impacts on resource adequacy for the resource zone.	Moritz McLean Soni McCormick	(Moritz) Sections VI and XI (Soni) Section VI – Resource Adequacy and Reliability Results, pp. 22–39 (McCormick) Sections V and VII – Import Capability and Local Reliability Impacts, pp. 26–31 and 37–44 (Moritz) Phase 2 Capacity Results and Exhibit Summary, p. 92 (Moritz) Direct Loss of Load Resource Accreditation, pp. 43 and 74 (McLean) Section V – Current Baseline Capacity Position, pp. 64–70	Exhibit A-2 (SQM-2), pp. 173–193 (Section 17; Tables 17-1 through 17-11; Figures 17-1 through 17-6) Exhibit A-34 (PS-1), p. 1 Exhibit A-35 (PS-2), pp. 1–5 Exhibit A-36 (PS-3), pp. 1–2 Exhibit A-37 (PS-4), pp. 1–2 Exhibit A-38 (PS-5), p. 1 Exhibit A-39 (PS-6), pp. 1–5 Exhibit A-40 (PS-7), pp. 1–2 Exhibit A-25 (AJM-11), pp. 1–4 Exhibit A-26 (AJM-12), pp. 1–116 Exhibit A-31 (AJM-17), pp. 1–5 Exhibit A-75 (JRM-2), pp. 1–17	WP-PS-6, Loss-of-Load Dispatch WP-PS-7, Capability versus Demand WP-JRM-2, CIL and CEL Forecasts WP-AJM-1, pp. 54–56 WP-AJM-3, pp. 3–7 and 15–16
214		**Proposed Resource Plan**				
215	MPSC Case Nos. U-21570 & U-21867	Include a detailed description of:	See lines 216-223			

Line No.	Origin of Requirement	Filing, Testimony, Exhibits, and Workpaper Requirements	Witness	Testimony Section(s)	Exhibit Reference	Work Paper Reference
216	MPSC Case Nos. U-21570 & U-21867	a) The type of generation technology proposed for a generation facility or combination of resources constructed as a single facility contained in the plan and the proposed capacity of the generation facility or combination of resources constructed as a single facility, including projected fuel costs under various reasonable scenarios;	Moritz McLean Rissman Clark	(Moritz) Sections XI–XIII–end (Rissman) Sections IV–V – Fuel Prices and Supply for New Generating Plants, pp. 8–13 (Clark) Direct Testimony, PCA Technology, Capacity, and Cost Assumptions, pp. 24–55 (McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 194–206 (Section 18; Table 18-1, Figures 18-1 through 18-3, and Table 18-2) Exhibit A-18 (AJM-4), pp. 1–8 Exhibit A-24 (AJM-10), pp. 1–14 Exhibit A-28 (AJM-14) Exhibit A-85 (AKR-8), p. 1 Exhibit A-86 (AKR-9), p. 1 Exhibit A-87 (AKR-10), p. 1 Exhibit A-6 (TPC-1), p. 1 Exhibit A-8 (TPC-3), p. 1 Exhibit A-10 (TPC-5), p. 1 Exhibit A-11 (TPC-6), p. 1 Exhibit A-12 (TPC-7), p. 1	WP-AJM-1, pp. 40–49 and 54–56 WP-AJM-2, pp. 1–4 WP-AJM-3, pp. 3–7
217	MPSC Case Nos. U-21570 & U-21867	b) Plans for meeting current and future capacity needs with the cost estimates for all proposed construction and major investments, including any transmission or distribution infrastructure that would be required to support the proposed construction or investment, and PPAs;	McLean Moritz Clark McCormick Troyer	(Clark) Direct Testimony, PCA Capacity, Construction, Interconnection, and Procurement Plans, pp. 24–55 (McCormick) Sections IV and VI – Transmission Infrastructure Costs and Modeling Inputs, pp. 6–25 and 31–36 (Moritz) Phase 2 Capacity Results and Exhibit Summary, p. 92 (McLean) Section III – IRP Objectives and Principles, pp. 40–52 (Troyer) Section II, pp. 30–36	Exhibit A-2 (SQM-2), pp. 194–206 (Section 18; Table 18-1, Figures 18-1 through 18-3, and Table 18-2) Exhibit A-18 (AJM-4), pp. 1–8 Exhibit A-19 (AJM-5), p. 1 Exhibit A-24 (AJM-10), pp. 1–14 Exhibit A-25 (AJM-11), pp. 1–4 Exhibit A-26 (AJM-12), pp. 1–116 Exhibit A-28 (AJM-14) Exhibit A-10 (TPC-5), p. 1 Exhibit A-11 (TPC-6), p. 1 Exhibit A-12 (TPC-7), p. 1 Exhibit A-75 (JRM-2), pp. 1–17	WP-JRM-1, MISO GIA Costs and Statistical Summary WP-JRM-3, Transmission Scenarios, Resource Siting, and Load Forecasts WP-AJM-2, pp. 1–4 WP-AJM-3, pp. 1 and 14–21
218	MPSC Case Nos. U-21570 & U-21867	c) The projected long-term firm gas transportation contracts or natural gas storage the utility will hold to provide an adequate supply of natural gas to any new generation facility; and	Rissman McLean Moritz	(Rissman) Sections IV–V – New-Plant Delivered Fuel Prices and Long-Term Supply Strategy, pp. 8–13 (McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 194–206 (Section 18; Table 18-1, Figures 18-1 through 18-3, and Table 18-2) Exhibit A-28 (AJM-14) Exhibit A-85 (AKR-8), p. 1 Exhibit A-86 (AKR-9), p. 1 Exhibit A-87 (AKR-10), p. 1	
219	MPSC Case Nos. U-21570 & U-21867	d) How the utility will meet local, state, and federal laws, rules, and regulations under the PCA;	McLean Johnston Breining Clark	(Breining) Sections I and IV–VI – Environmental Compliance Under the PCA, pp. 3–13 and 24–35 (McLean) Section VII – Proposed Course of Action, pp. 79–104 (Clark) Part II – Execution of the PCA (Energy Storage Development, Target, and Procurement Plan; Michigan Workforce and Labor Standards), pp. 41–49 and 59–60	Exhibit A-2 (SQM-2), pp. 194–206 (Section 18; Table 18-1, Figures 18-1 through 18-3, and Table 18-2)	
220	MPSC Case Nos. U-21570 & U-21867	e) Include a detailed description of the impact of the CEP on the diversity of the utility resource portfolio. Include qualitative and quantitative details that include consideration of the benefit associated with resources that add to generation diversity and provide a monetarily quantifiable benefit that would not be achievable absent the resource in a narrative;	McLean Moritz	(McLean) Section III – IRP Objectives and Principles, pp. 36–39	Exhibit A-2 (SQM-2), pp. 194–206 (Section 18; Table 18-1, Figures 18-1 through 18-3, and Table 18-2) Exhibit A-24 (AJM-10), pp. 1–14 Exhibit A-25 (AJM-11), pp. 1–4 Exhibit A-28 (AJM-14)	WP-AJM-3, pp. 2–8 WP-SQM-11, p. 1
221	MPSC Case Nos. U-21570 & U-21867	f) How the utility's IRP and CEP align with or differ from the Company's most recently filed Renewable Energy Plan (REP). If the IRP and CEP diverge from the REP, describe how they will meet the Renewable Energy Portfolio Standard set out in PA 235 and how these differences will influence future REP filings;	Johnston McLean	(Johnston) Section II – RE Plan and IRP Relationship, pp. 13–17 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 194–206 (Section 18; Table 18-1, Figures 18-1 through 18-3, and Table 18-2)	
222	MPSC Case Nos. U-21570 & U-21867	g) How the utility's IRP storage builds meet the utility's share of the Energy Storage Target as set out in PA 235; and	McLean Moritz Clark	(Clark) Direct Testimony, PCA Storage Build and Statewide Target, pp. 43–49 (McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 194–206 (Section 18; Table 18-1, Figures 18-1 through 18-3, and Table 18-2) Exhibit A-24 (AJM-10), pp. 1–14 Exhibit A-25 (AJM-11), pp. 1–4 Exhibit A-10 (TPC-5), p. 1 Exhibit A-11 (TPC-6), p. 1	
223	MPSC Case Nos. U-21570 & U-21867	h) How the utility's IRP aligns with or differs from the utility's most recent EWR plan and how the EWR in the PCA complies with PA 295 as amended.	Burdjalov McLean Moritz Gast	(Burdjalov) Section I – EWR Potential, pp. 4–15 (Gast) Section I – EWR Program, PCA Alignment, Savings, and Costs, pp. 4–8 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 194–206 (Section 18; Table 18-1, Figures 18-1 through 18-3, and Table 18-2) Exhibit A-20 (AJM-6), pp. 1–3 Exhibit A-92 (AMG-1), p. 1–4	
224		**Resource Plan Selection**				
225	MPSC Case Nos. U-21570 & U-21867	The utility shall describe the process used to select the proposed resource plan, including the planning principles used to judge appropriate tradeoffs between competing planning objectives and between expected performance and risk. The utility shall describe how its proposed resource plan satisfies the specified requirements.	Moritz McLean Coker	(Moritz) Sections IV, X, and XI (Coker) Section VII – Stakeholder Influence and Planning Tradeoffs, pp. 25–30 (Moritz) CON Removal Analysis and Replacement Resources, pp. 103–104 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 194–199 (Section 18.1; Figures 18-1 and 18-2) Exhibit A-22 (AJM-8), pp. 1–4 Exhibit A-23 (AJM-9), pp. 1–8 Exhibit A-33 (AJM-19), pp. 1–2 Exhibit A-106 (JRC-8), pp. 1–24 Exhibit A-107 (JRC-9), pp. 1–19 Exhibit A-108 (JRC-10), pp. 1–11	
226	MPSC Case Nos. U-21570 & U-21867	a) Strike an appropriate balance between the various planning objectives specified;	Moritz McLean Coker	(Moritz) Section XI – Proposed Course of Action (Coker) Sections VI-VII – Stakeholder Tradeoffs and Plan Influence, pp. 19–30 (Moritz) CON Removal Analysis and Replacement Resources, pp. 103–104 (McLean) Section III – IRP Objectives and Principles, pp. 36–39	Exhibit A-2 (SQM-2), pp. 194–199 (Section 18.1; Figures 18-1 and 18-2) Exhibit A-22 (AJM-8), pp. 1–4 Exhibit A-23 (AJM-9), pp. 1–8 Exhibit A-33 (AJM-19), pp. 1–2 Exhibit A-104 (JRC-6), pp. 1–26 Exhibit A-106 (JRC-8), pp. 1–24 Exhibit A-107 (JRC-9), pp. 1–19 Exhibit A-108 (JRC-10), pp. 1–11	
227	MPSC Case Nos. U-21570 & U-21867	b) Utilize renewable and demand-side resources to comply with existing laws, goals and, in the judgment of the utility, are consistent with the public interest to achieve state energy policies;	Moritz McLean Coker Gast Schmoekel	(Moritz) Sections VIII and XI (Coker) Sections VI-VII – Clean-Energy and Demand-Side Stakeholder Priorities, pp. 19–30 (McLean) Section VI – New Resource Options, pp. 71–78 (Gast) Sections I–II – EWR and DR Programs, pp. 5–18 (Schmoekel) Sections I-III – CVR Program Overview, Assumptions, and Results, pp. 4–18	Exhibit A-2 (SQM-2), pp. 194–199 (Section 18.1; Figures 18-1 and 18-2) Exhibit A-20 (AJM-6), pp. 1–3 Exhibit A-21 (AJM-7), pp. 1–3 Exhibit A-22 (AJM-8), pp. 1–4 Exhibit A-23 (AJM-9), pp. 1–8 Exhibit A-104 (JRC-6), pp. 1–26 Exhibit A-106 (JRC-8), pp. 1–24 Exhibit A-107 (JRC-9), pp. 1–19 Exhibit A-108 (JRC-10), pp. 1–11	
228	MPSC Case Nos. U-21570 & U-21867	c) In the judgment of the utility, the proposed resource plan, in conjunction with the deployment of DR measures, has sufficient resources to serve load forecasted for the implementation period; 1. A NPVRR comparison of its proposal and reasonable alternatives over the planning period utilized in the analysis. It shall also include the calculation and comparison of the NPVRR of the utility's proposed resource plan and any alternative resource plans, including the alternative resource plans resulting from the Commission-approved modeling scenarios. 2. A detailed analysis of any benefits from resources that provide co-benefits to distribution or transmission planning (such as reliability and resiliency benefits), when those benefits are unable to be captured through capacity expansion modeling runs, to the extent that the co-benefits were relied upon for justification of resource decisions;	McLean Soni Moritz Myers Coker McCormick Gast Breuring Burdjalov	(Soni) Sections VI–VIII – Reliability, Market Dependency, and Risk Assessment, pp. 22–70 (Coker) Section VII – Reliability, Demand Forecast, and Co-Benefit Feedback, pp. 25–30 (McCormick) Section VII – Transmission and Storage Co-Benefits, pp. 37–44 (Gast) Section II – DR Capacity and PCA Implementation, pp. 8–18 (Moritz) Phase 2 Capacity Results and Exhibit Summary, p. 92 (Moritz) Phase 2 Energy Results and Exhibit Summary, p. 92 (Moritz) CON Removal Analysis and Replacement Resources, pp. 103–104 (McLean) Section VII – Proposed Course of Action, pp. 79–104 (Breuring) Sections I–VI – Forecast Methodology, Deliveries, Peak Demand, and Alternatives, pp. 4–27 (Burdjalov) Section II – DR Potential, pp. 16–19	Exhibit A-2 (SQM-2), pp. 194–199 (Section 18.1; Figures 18-1 and 18-2) Exhibit A-34 (PS-1), p. 1 Exhibit A-38 (PS-5), p. 1 Exhibit A-40 (PS-7), pp. 1–2 Exhibit A-22 (AJM-8), pp. 1–4 Exhibit A-23 (AJM-9), pp. 1–8 Exhibit A-25 (AJM-11), pp. 1–4 Exhibit A-26 (AJM-12), pp. 1–116 Exhibit A-27 (AJM-13), pp. 1–29 Exhibit A-33 (AJM-19), pp. 1–2 Exhibit A-106 (JRC-8), pp. 1–24 Exhibit A-107 (JRC-9), pp. 1–19 Exhibit A-108 (JRC-10), pp. 1–11 Exhibit A-76 (JRM-3), pp. 1–2 Exhibit A-93 (AMG-2), p. 1 Exhibit A-70 (EMB-1), p. 1 Exhibit A-71 (EMB-2), p. 1 Exhibit A-72 (EMB-3), p. 1 Exhibit A-73 (EMB-4), p. 1 Exhibit A-98 (DVB-2), pp. 1–51	WP-HJM-57, NPV of PCA Excluding Demand Response Incentive WP-HJM-58, PCA and Alternative 2 Revenue Requirement Comparison WP-PS-5, Stochastic Distributions WP-PS-6, Loss-of-Load Dispatch WP-PS-7, Capability versus Demand WP-PS-8, Risk Assessment WP-SQM-9, p. 1 WP-AJM-3, p. 1
229	MPSC Case Nos. U-21570 & U-21867	d) Include a detailed analysis for any resource type that the utility utilized an analysis outside of the integrated resource model to determine net-cost, external benefits, and additional value streams; 1. Detail the net-cost method used when modeling any resource, where presumed benefits are netted against the costs of a resource to account for benefits outside of the model. A complete account of costs and assumed benefits should be provided such that the metrics and value given to achieving those metrics is clear and transparent; 2. Detail benefits and value streams that are outside of the model that are included in the utility justification for a resource. A detailed analysis should be transparent and included in the utility filing; and 3. Detail how the utility considered whether benefits applied to one resource type are or are not also attributable to other resources.	McLean Moritz	(Moritz) Section XIII – Resource Alternatives Analysis, pp. 94–104 (McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 194–199 (Section 18.1; Figures 18-1 and 18-2) Exhibit A-18 (AJM-4), pp. 1–8 Exhibit A-22 (AJM-8), pp. 1–4 Exhibit A-23 (AJM-9), pp. 1–8 Exhibit A-28 (AJM-14) Exhibit A-33 (AJM-19), pp. 1–2	WP-AJM-2, pp. 1–4
230		**Implementation Plan**				
231	MPSC Case Nos. U-21570 & U-21867	The utility shall develop an implementation plan that specifies the major tasks, schedules, and milestones necessary to implement the proposed resource plan over the implementation period. The utility shall describe and document its implementation plan.	McLean Schmoekel Moritz Clark Troyer Johnston	(Schmoekel) Sections I-II – CVR Deployment and Program Forecast, pp. 4–15 (McLean) Section VII – Proposed Course of Action, pp. 79–104 (Clark) Part II - Supply-Side Development, Engineering, Permitting, Procurement, and Construction, pp. 24–55 (Troyer) Section I, pp. 7–20 and Section II, pp. 23–43	Exhibit A-2 (SQM-2), pp. 203–206 (Section 18.4; Table 18-2) Exhibit A-113 (DAS-1), p. 1 Exhibit A-114 (DAS-2), p. 1 Exhibit A-115 (DAS-3), p. 1 Exhibit A-116 (DAS-4), pp. 1–3 Exhibit A-117 (DAS-5), p. 1 Exhibit A-24 (AJM-10), pp. 1–14 Exhibit A-25 (AJM-11), pp. 1–4 Exhibit A-12 (TPC-7), p. 1 Exhibit A-54 (KDJ-1), p. 1 Exhibit A-55 (KDJ-2), p. 1 Exhibit A-3 (KGT-1), pp. 1–32 Exhibit A-4 (KGT-2), pp. 1–118	
232	MPSC Case Nos. U-21570 & U-21867	a) A schedule to report the status of an approved plan in accordance with MCL 460.6r(14);	Company will file report annually from the date of Commission approval.			

Line No.	Origin of Requirement	Filing, Testimony, Exhibits, and Workpaper Requirements	Witness	Testimony Section(s)	Exhibit Reference	Work Paper Reference
233	MPSC Case Nos. U-21570 & U-21867	b) A schedule and description of actions to implement ongoing and planned demand-side programs and demand-side rates;	Schmoekel McLean Moritz Gast Burdjalov	(Schmoekel) Sections I-II – CVR Deployment and Program Forecast, pp. 4–15 (Gast) Sections I–II – EWR and DR Program Implementation, pp. 4–18 (McLean) Section VII – Proposed Course of Action, pp. 79–104 (Burdjalov) Sections I–II – EWR and DR Potential, pp. 4–19	Exhibit A-2 (SQM-2), pp. 203–206 (Section 18.4; Table 18-2) Exhibit A-113 (DAS-1), p. 1 Exhibit A-114 (DAS-2), p. 1 Exhibit A-115 (DAS-3), p. 1 Exhibit A-116 (DAS-4), pp. 1–3 Exhibit A-117 (DAS-5), p. 1 Exhibit A-20 (AJM-6), pp. 1–3 Exhibit A-21 (AJM-7), pp. 1–3 Exhibit A-24 (AJM-10), pp. 1–14 Exhibit A-92 (AMG-1), pp. 1–4 Exhibit A-93 (AMG-2), p. 1 Exhibit A-96 (DVB-1), pp. 1–106 Exhibit A-98 (DVB-2), pp. 1–51	WP-SQM-10, p. 1
234	MPSC Case Nos. U-21570 & U-21867	c) A schedule and description of relevant supply-side resource research, engineering, retirement, acquisition, and construction;	McLean Moritz Clark	(Clark) Direct Testimony, Supply-Side Development, Engineering, Permitting, Procurement, and Construction, pp. 24–55 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 203–206 (Section 18.4; Table 18-2) Exhibit A-24 (AJM-10), pp. 1–14 Exhibit A-25 (AJM-11), pp. 1–4 Exhibit A-10 (TPC-5), p. 1 Exhibit A-11 (TPC-6), p. 1 Exhibit A-12 (TPC-7), p. 1	
235	MPSC Case Nos. U-21570 & U-21867	d) A description of how, to the extent practical, the construction or investment in new resources in this state will be completed using a workforce composed of residents of this state;	McLean Clark	(Clark) Direct Testimony, Michigan Workforce and Economic Benefits, pp. 56–59 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 203–206 (Section 18.4; Table 18-2)	
236	MPSC Case Nos. U-21570 & U-21867	e) A description of, to the extent practical, the construction of new resources in this state will be completed using materials sourced from this state; and	McLean Clark	(Clark) Direct Testimony, Michigan Labor and Material Sourcing, p. 59 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 203–206 (Section 18.4; Table 18-2)	
237	MPSC Case Nos. U-21570 & U-21867	f) A description of how the utility plans meet the labor standards set out in PA 231 Section 6a(8)(c) for the construction of new generation capacity and rehabilitation of existing capacity resources.	Skowronski McLean Clark	(Skowronski) Section III – PPA Labor-Standards Compliance, pp. 25–26 (Clark) Direct Testimony, PA 231 Labor Standards, pp. 59–60 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 203–206 (Section 18.4; Table 18-2)	
238		**Rate Impact and Affordability**				
239	MPSC Case Nos. U-21570 & U-21867	PCA only rate and affordability impact.	Myers McLean Moritz	(Myers) Sections I-II – PCA Rate and Affordability Impacts, pp. 4–9 (Moritz) PCA Capital, O&M, Fuel, and Purchased-Power Costs, p. 92 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 207–210 (Section 19; Figures 19-1 through 19-3) Exhibit A-42 (HJM-1), p. 1 Exhibit A-43 (HJM-2), p. 1 Exhibit A-44 (HJM-3), p. 1 Exhibit A-29 (AJM-15), pp. 1–3	WP-HJM-1 through WP-HJM-10, PCA Rate Impact Supporting Workpapers WP-HJM-31, PCA Customer-Class Allocations
240	MPSC Case Nos. U-21570 & U-21867	a) The average rate impact by customer class (i.e., residential, C&I, etc.). The analysis shall include the Utility's most recently approved base rate revenue requirement for fullservice customers, a forecast of the revenue requirement growth based on a projected inflation factor, the percentage of the production cost allocations assignable to each customer class, based on the prior approved rate case, and the estimated delta revenue requirement of the PCA to determine the average rate impact. 1. The Utility shall identify the class allocation of the incremental revenue requirement, the class sales forecast and compare it to the current average rate, and class allocation of the incremental revenue requirement shown as a percentage. 2. This rate impact analysis should also include the impact to customers as a result of PCA resources that are cost recovered using the PA 235, Section 22 revenue recovery mechanism.	Myers McLean Moritz	(Myers) Section II – Customer-Class Filing Requirement Rate Impact, pp. 6–9 (Moritz) PCA Capital, O&M, Fuel, and Purchased-Power Costs, p. 92 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 207–210 (Section 19; Figures 19-1 through 19-3) Exhibit A-45 (HJM-4), pp. 1–4 Exhibit A-46 (HJM-5), pp. 1–4 Exhibit A-29 (AJM-15), pp. 1–3	WP-HJM-31, PCA Customer-Class Allocations WP-HJM-55, Existing Power Supply Rates per kWh WP-HJM-56, General Rate Case Power Supply Revenue Requirement
241	MPSC Case Nos. U-21570 & U-21867	b) The utility shall show the affordability impact of the PCA as compared to its previously approved build plan. The utility shall describe its methodology and data sources including but not limited to income-based segmentation, publicly available data used, any limitations of data availability, proxies such as demographics or housing data, etc. Example methodology is in Appendix 2. If any identified income range is expected to increase an energy burden at or above 6%, the utility shall provide a discussion of available assistance, EWR programs and measures, or other options that could aid in mitigating the expected increased energy burden for the areas identified.	Myers McLean	(Myers) Section II – Residential Energy Burden and Affordability, pp. 6–9 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 207–210 (Section 19; Figures 19-1 through 19-3) Exhibit A-47 (HJM-6), pp. 1–101 Exhibit A-48 (HJM-7), pp. 1–102	
242		**Financial Information**				
243	MPSC Case Nos. U-21570 & U-21867	The utility shall describe the financial assumptions and models used in the plan. The resource plan shall include, at a minimum, the specified financial information, together with supporting documentation and justification.	Bleckman McLean Myers Walter	(Bleckman) Sections I-VIII – Financial Treatment, Credit Metrics, and Capitalization, pp. 5–15 (Walter) Direct Testimony, Existing Generation Financial Inputs, pp. 2, 4–5 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 207–210 (Section 19; Figures 19-1 through 19-3) Exhibit A-58 (MRB-1), pp. 1–13 Exhibit A-59 (MRB-2), pp. 1–5 Exhibit A-60 (MRB-3), pp. 1–18 Exhibit A-90 (MMW-1), p. 1 Exhibit A-91 (MMW-2), p. 1	WP-HJM-59, Financial Assumptions WP-MMW-2, Renewable Repowering Estimates, p. 1 WP-MMW-3, Existing Generation Capital Expenditures, p. 1 WP-MMW-4, Existing Generation O&M Expenditures, p. 1 WP-AJM-1, pp. 3–6
244	MPSC Case Nos. U-21570 & U-21867	a) The general rate of inflation;	McLean Myers	(McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 207–210 (Section 19; Figures 19-1 through 19-3)	WP-HJM-59, Financial Assumptions
245	MPSC Case Nos. U-21570 & U-21867	b) The allowance for funds used during construction rates used in the plan;	Myers			WP-HJM-59, Financial Assumptions
246	MPSC Case Nos. U-21570 & U-21867	c) The cost of capital rates used in the plan (debt, equity, and weighted) and the assumed capital structure;	Myers			WP-HJM-59, Financial Assumptions
247	MPSC Case Nos. U-21570 & U-21867	d) The discount rates used in the calculations to determine present worth;	Myers			WP-HJM-59, Financial Assumptions
248	MPSC Case Nos. U-21570 & U-21867	e) The tax rates used in the plan;	Myers			WP-HJM-59, Financial Assumptions
249	MPSC Case Nos. U-21570 & U-21867	f) NPVRR for the plan;	Myers McLean Moritz	(Myers) Section I – Net Present Value of Revenue Requirements, pp. 4–5 (Moritz) PCA Capital, O&M, Fuel, and Purchased-Power Costs, p. 92 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 207–210 (Section 19; Figures 19-1 through 19-3) Exhibit A-42 (HJM-1), p. 1 Exhibit A-43 (HJM-2), p. 1 Exhibit A-44 (HJM-3), p. 1 Exhibit A-23 (AJM-9), pp. 1–8 Exhibit A-29 (AJM-15), pp. 1–3	WP-HJM-57, NPV of PCA Excluding Demand Response Incentive WP-AJM-3, p. 1
250	MPSC Case Nos. U-21570 & U-21867	g) Nominal incremental revenue requirements by year; and	Myers McLean Moritz	(Myers) Section I – Annual Revenue Requirements, pp. 4–5 (Moritz) PCA Capital, O&M, Fuel, and Purchased-Power Costs, p. 92 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 207–210 (Section 19; Figures 19-1 through 19-3) Exhibit A-42 (HJM-1), p. 1 Exhibit A-43 (HJM-2), p. 1 Exhibit A-44 (HJM-3), p. 1 Exhibit A-23 (AJM-9), pp. 1–8 Exhibit A-29 (AJM-15), pp. 1–3	WP-HJM-1, PCA Inputs and Calculations WP-HJM-11, Alternative Growth Inputs and Calculations WP-HJM-21, Alternative Current Inputs and Calculations WP-HJM-58, PCA and Alternative 2 Revenue Requirement Comparison WP-AJM-3, pp. 1 and 14–21
251	MPSC Case Nos. U-21570 & U-21867	h) Average system rates per kWh by year.	Myers McLean Moritz	(Myers) Section I – Customer-Class and System Rates, pp. 4–5 (Moritz) PCA Capital, O&M, Fuel, and Purchased-Power Costs, p. 92 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 207–210 (Section 19; Figures 19-1 through 19-3) Exhibit A-42 (HJM-1), p. 1 Exhibit A-43 (HJM-2), p. 1 Exhibit A-44 (HJM-3), p. 1 Exhibit A-29 (AJM-15), pp. 1–3	
252		**Environmental Considerations and Emissions Analysis**				
253	MPSC Case Nos. U-21570 & U-21867	Describe how the utility's resource plan and any alternative resource plans presented in the application will comply with all applicable local, state, and federal environmental regulations, laws, and rules.	Breining McLean	(Breining) Section I – Environmental Regulations and Compliance Strategy (Breining) Section I – Environmental Regulations and Compliance Strategy, pp. 3–13 (McLean) Section II – Statutory and Regulatory Background, pp. 25–35	Exhibit A-2 (SQM-2), pp. 212–220 (Section 20; Tables 20-1 through 20-4; Figures 20-1 through 20-4)	
254	MPSC Case Nos. U-21570 & U-21867	a) Include a list of all environmental regulations that are applicable to the utility fleet. Identify which regulations apply to which resources;	Breining McLean	(Breining) Section I – Environmental Regulations Applicable to the Generating Fleet (Breining) Section I – Environmental Regulations Applicable to the Generating Fleet, pp. 3–13 (McLean) Section II – Statutory and Regulatory Background, pp. 25–35	Exhibit A-2 (SQM-2), pp. 212–220 (Section 20; Tables 20-1 through 20-4; Figures 20-1 through 20-4)	
255	MPSC Case Nos. U-21570 & U-21867	b) Include all capital costs for compliance with new and reasonably expected environmental regulations for existing fleet assets in the utility IRP;	McLean Breining	(Breining) Section I – Environmental Compliance Costs and Required Controls, pp. 5–13 (McLean) Section VIII – Description of Significant Proposals and Summary of Requested Relief, pp. 105–114	Exhibit A-2 (SQM-2), pp. 212–220 (Section 20; Tables 20-1 through 20-4; Figures 20-1 through 20-4)	WP-AJM-1, pp. 26 and 31
256	MPSC Case Nos. U-21570 & U-21867	c) Include a chart that compares the total projected carbon emissions under each scenario analyzed (no sensitivities applied), including quantifying the carbon emissions projected in each sensitivity as a percentage of the carbon emissions presented in the base scenario associated with that sensitivity. The utility shall identify and justify its use of a carbon accounting methodology, identified in Electric Power Research Institute, Methods to account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases or other Commission approved methodology;	Breining	Section II – IRP Emissions Outlook, Scenario Comparisons, and Carbon Accounting, pp. 12–15	Exhibit A-50 (HAB-2), pp. 1–64 Exhibit A-51 (HAB-3), pp. 1–2	
257	MPSC Case Nos. U-21570 & U-21867	d) If the Company is proposing retirement of an existing resource due to an environmental regulation, clearly identify the future capital cost for environmental regulations and other capital investments in the facility. If costs are identified as avoided capital costs, provide Embedded in Wholesale Power Purchases, https://ghginstitute.org/wpcontent/uploads/2019/04/EPRI-Wholesale-Power-Report-Published-2019.pdf, March 2019. sufficient detail to support the capital cost as avoidable, meaning dollars will never be spent, or capital cost will simply be transferred to another cost category. For example, becoming cost of removal, or fully avoidable capital costs;	McLean	Section VIII – Description of Significant Proposals and Summary of Requested Relief, pp. 105–114	Exhibit A-2 (SQM-2), pp. 212–220 (Section 20; Tables 20-1 through 20-4; Figures 20-1 through 20-4)	
258	MPSC Case Nos. U-21570 & U-21867	e) Hold a technical conference with MPSC and Department of Environment, Great Lakes, and Energy (EGLE) staff within 30 days after the filing to discuss the environmental and emission related data included in the filing testimony, exhibits, and workpapers; and	The Company has scheduled a technical conference with MPSC and EGLE Staff for September 29, 2026, within 30 days after filing, to discuss the environmental- and emissions-related data included in the filing testimony, exhibits, and workpapers.			
259	MPSC Case Nos. U-21570 & U-21867	f) Identify, quantify, and provide evidence in the filing that show's progress in meeting any state, federal or utility announced carbon reduction goals. Illustrate how each optimized build plan for each MIRPP scenario (no sensitivities applied), the proposed resource plan, and the previously approved plan perform in meeting those goals throughout the planning period. 1112	Breining	Sections I-II – Clean-Energy Compliance and Carbon-Emissions Progress, pp. 6–15	Exhibit A-49 (HAB-1), pp. 1–9 Exhibit A-50 (HAB-2), pp. 1–64 Exhibit A-51 (HAB-3), pp. 1–2	
260		**EGLE Advisory Opinion and Environmental Justice Analysis**				
261	MPSC Case Nos. U-21570 & U-21867	Ensure the advisory opinion of EGLE in utility IRP cases is supported by a comprehensive health and environmental impact analysis in support of the State's environmental justice goals and Governor Whitmer's September 2020 Executive Directive 2020-10 and the Public Act 231 Section 6t.	McLean Breining	(Breining) Section III – Comprehensive Environmental Justice and Health Analysis, pp. 15–23 (McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 222–231 (Section 21; Tables 21-1 through 21-4; Figures 21-1 through 21-3) Exhibit A-52 (HAB-4), p. 1 Exhibit A-53 (HAB-5), p. 1	WP-HAB-1A, COBRA 2040 Fleet Emissions – Bay County, pp. 1–6 WP-HAB-1B, COBRA 2040 Fleet Emissions – Genesee County, pp. 1–6 WP-HAB-1C, COBRA 2040 Fleet Emissions – Jackson County, pp. 1–6 WP-HAB-1D, COBRA 2040 Fleet Emissions – Ottawa County, pp. 1–6 WP-HAB-1E, COBRA 2040 Fleet Emissions – PCA, pp. 1–6 WP-HAB-1F, COBRA 2040 Fleet Emissions – Van Buren County, pp. 1–6 WP-HAB-2A, COBRA 2040 Fleet Emissions – Portfolio 1, pp. 1–6 WP-HAB-2B, COBRA 2040 Fleet Emissions – Portfolio 2, pp. 1–6 WP-HAB-2C, COBRA 2040 Fleet Emissions – Portfolio 5, pp. 1–6 WP-HAB-3A, Covert MiEJScreen 3-Mile Radius, pp. 1–3 WP-HAB-3B, DE Karn MiEJScreen 3-Mile Radius, pp. 1–5 WP-HAB-3C, Jackson MiEJScreen 3-Mile Radius, pp. 1–13 WP-HAB-3D, Thetford MiEJScreen 3-Mile Radius, pp. 1–4 WP-HAB-3E, Zeeland MiEJScreen 3-Mile Radius, pp. 1–5
262	MPSC Case Nos. U-21570 & U-21867	a) Scope of portfolio build plans (herein referred to collectively as portfolios) evaluated as follows: 1. Portfolio 1: Previously approved portfolio (status quo; PCA in previously approved IRP) run in the MIRPP Scenario 1 (optimized through the current study period); 2. Portfolio 2: Utility PCA portfolio run in MIRPP Scenario 1; the urgent threat to the environment, economy, and the health and well-being of Michigan's residents posed by climate change and its implications. ED 2020-10 committed Michigan to pursuing a reduction of at least 26 to 28 percent in Greenhouse Gas (GHG) emissions below 2005 levels by 2025 and economy-wide carbon neutrality to be achieved no later than 2050 and maintained thereafter. States building upon carbon reductions to date. The new targets call for an economy-wide net GHG reduction of 50 to 52 percent from 2005 levels by 2030 and net zero GHG emissions economy-wide by no later than 2050. 3. Portfolio 3: Optimized portfolio in MIRPP Scenario 1; 4. Portfolio 4: Optimized portfolio in MIRPP Scenario 1 with high load sensitivity; and 5. Portfolio 5: If applicable a utility's reasonable alternative(s) to the PCA presented by the utility in MIRPP Scenario 1.	McLean Breining	(Breining) Section III – Portfolio Scope and Comparative Environmental Analysis, pp. 15–23 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 222–231 (Section 21; Tables 21-1 through 21-4; Figures 21-1 through 21-3) Exhibit A-50 (HAB-2), pp. 1–64 Exhibit A-51 (HAB-3), pp. 1–2 Exhibit A-53 (HAB-5), p. 1	WP-HAB-2A, COBRA 2040 Fleet Emissions – Portfolio 1, pp. 1–6 WP-HAB-2B, COBRA 2040 Fleet Emissions – Portfolio 2, pp. 1–6 WP-HAB-2C, COBRA 2040 Fleet Emissions – Portfolio 5, pp. 1–6

Line No.	Origin of Requirement	Filing, Testimony, Exhibits, and Workpaper Requirements	Witness	Testimony Section(s)	Exhibit Reference	Work Paper Reference
263	MPSC Case Nos. U-21570 & U-21867	b) The utility will provide the following facility/unit level data and total annual fleet data, in an Excel spreadsheet(s) expressed in total tons, to EGLE for the following pollutants: 1. Nitrogen oxides (NO x) 2. Carbon monoxide (CO) 3. Particulate matter (PM) 4. Lead (Pb) 5. Mercury (Hg) 6. Volatile organic compounds (VOC) 7. Carbon dioxide (CO2) 8. Sulfur dioxide (SO2)	Breining McLean	(Breining) Section II – Annual Facility, Unit, and Fleet Emissions (Breining) Section II – Annual Facility, Unit, and Fleet Emissions, pp. 13–15 (McLean) Section II – Statutory and Regulatory Background, pp. 25–35	Exhibit A-2 (SQM-2), pp. 222–231 (Section 21; Tables 21-1 through 21-4; Figures 21-1 through 21-3) Exhibit A-49 (HAB-1), pp. 1–9 Exhibit A-50 (HAB-2), pp. 1–64	
264	MPSC Case Nos. U-21570 & U-21867	c) For each portfolio, identify existing facilities and potential future facilities with known locations, including peaking units, that are within 3 miles of communities specified for the Environmental Justice Analysis. Analyze all portfolios to quantitatively assess the projected emissions of identified facilities for each respective portfolio, and the differences in each portfolio's projected emissions for that unit relative to portfolio #2. Emissions should be reported in the appropriate unit of measure. If a utility does not have generation within a 3-mile radius of a community identified by the Environmental Justice Analysis, then an assessment is not required.	Breining McLean	(Breining) Section III – Three-Mile EJ Screening and Portfolio Emissions (Breining) Section III – Three-Mile EJ Screening and Portfolio Emissions, pp. 15–19 (McLean) Section II – Statutory and Regulatory Background, pp. 25–35	Exhibit A-2 (SQM-2), pp. 222–231 (Section 21; Tables 21-1 through 21-4; Figures 21-1 through 21-3) Exhibit A-52 (HAB-4), p. 1 Exhibit A-50 (HAB-2), pp. 1–64	WP-HAB-3A, Covert MiEJScreen 3-Mile Radius, pp. 1–3 WP-HAB-3B, DE Karn MiEJScreen 3-Mile Radius, pp. 1–5 WP-HAB-3C, Jackson MiEJScreen 3-Mile Radius, pp. 1–13 WP-HAB-3D, Therford MiEJScreen 3-Mile Radius, pp. 1–4 WP-HAB-3E, Zeeland MiEJScreen 3-Mile Radius, pp. 1–5
265	MPSC Case Nos. U-21570 & U-21867	d) Using the facilities identified in (c), above, quantitatively assess changes to air emissions from early retirement and/or conversion of fossil fuel-fired facilities to the extent the plan includes either conversion or retirement.	Breining McLean	(Breining) Sections II–III – Portfolio Emissions and Retirement Effects (Breining) Sections II–III – Portfolio Emissions and Retirement Effects, pp. 13–20 (McLean) Section II – Statutory and Regulatory Background, pp. 25–35	Exhibit A-2 (SQM-2), pp. 222–231 (Section 21; Tables 21-1 through 21-4; Figures 21-1 through 21-3) Exhibit A-50 (HAB-2), pp. 1–64	
266	MPSC Case Nos. U-21570 & U-21867	e) Using the facilities identified in (c) above, qualitatively assess the potential impacts of all portfolios including utility proposed early retirements, retained, or converted fossil fuelfired facilities. The assessment should address water quality, waste disposal, and expected changes in land use for new or retiring resources to the extent known at the time of filing. The assessment should evaluate whether the utility 's proposed PCA reduces harm to the health and safety of individuals in Environmental Justice Analysis communities in comparison to the alternatives considered;	Breining McLean	(Breining) Section III – Water, Waste, Land-Use, Siting, and EJ Considerations (Breining) Section III – Water, Waste, Land-Use, Siting, and EJ Considerations, pp. 15–18 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 222–231 (Section 21; Tables 21-1 through 21-4; Figures 21-1 through 21-3)	
267	MPSC Case Nos. U-21570 & U-21867	f) To determine health impact estimates for air emissions, the utility will use the environmental Benefits Mapping and Analysis Program–Community Edition (BenMAPCE), or the Co-Benefits Risk Assessment (COBRA) Health Impacts Screening and Mapping Tool. Based on the pollutant parameters compatible with the chosen tool, this air emissions data analysis will be performed to provide health impact estimates. This includes: 1. Assessment of annual fleetwide health impacts or benefits of any of the following: early retirement of fossil fuel-fired units, conversions to a different fuel source(s), and newly constructed/acquired generation units (to the extent the location is known and including renewable energy adoption, new fossil fuel-powered generation, nuclear, etc.). Using emission projections from section XXIII subsection b), compare results for all portfolios with a focus on a comparison of portfolio #2 and #5 (if applicable) to portfolio #1; and 2. County-level results (or finer) for any county that contains retired, new (if location is known), or converted fossil fuel-fired units in or within 3 miles of communities specified for the Environmental Justice Analysis.	Breining McLean	(Breining) Section III – COBRA Health Impact Analysis (Breining) Section III – COBRA Health Impact Analysis, pp. 20–23 (McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 222–231 (Section 21; Tables 21-1 through 21-4; Figures 21-1 through 21-3) Exhibit A-53 (HAB-5), p. 1	WP-HAB-1A, COBRA 2040 Fleet Emissions – Bay County, pp. 1–6 WP-HAB-1B, COBRA 2040 Fleet Emissions – Genesee County, pp. 1–6 WP-HAB-1C, COBRA 2040 Fleet Emissions – Jackson County, pp. 1–6 WP-HAB-1D, COBRA 2040 Fleet Emissions – Ottawa County, pp. 1–6 WP-HAB-1E, COBRA 2040 Fleet Emissions – PCA, pp. 1–6 WP-HAB-1F, COBRA 2040 Fleet Emissions – Van Buren County, pp. 1–6 WP-HAB-2A, COBRA 2040 Fleet Emissions – Portfolio 1, pp. 1-6 WP-HAB-2B, COBRA 2040 Fleet Emissions – Portfolio 2, pp. 1-6 WP-HAB-2C, COBRA 2040 Fleet Emissions – Portfolio 5, pp. 1-6
268	MPSC Case Nos. U-21570 & U-21867	g) Assess PM2.5 and NOx emissions from each individual electric generating unit in portfolio #2 located within 6 miles of communities specified for the Environmental Justice Analysis. If existing unit emissions for either pollutant increase above the historic variability of the unit, conduct emissions impact analyses for those units. The current emissions should be used to establish a baseline by which to compare the future impacts of portfolio #2 units. Any analysis conducted pursuant to this item should include other emissions impacts on the area, as appropriate. The goal of this analysis is to assess how the PM2.5 and NOx emissions may change in communities specified for the If the online version of an analytical tool does not have the data needed for analyzing a year where noteworthy emission changes are expected to occur, impacts can be estimated using emission changes from a year as near as possible to the year of noteworthy emissions change. A desktop version of the analytical tool may also be used. Environmental Justice Analysis, and to encourage consideration of these impacts in the utility's decision on the PCA.	Breining McLean	(Breining) Section III – Six-Mile PM2.5 and NOx Variability Analysis (Breining) Section III – Six-Mile PM2.5 and NOx Variability Analysis, pp. 16–23 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 222–231 (Section 21; Tables 21-1 through 21-4; Figures 21-1 through 21-3) Exhibit A-49 (HAB-1), pp. 1–9 Exhibit A-50 (HAB-2), pp. 1–64 Exhibit A-52 (HAB-4), p. 1	
269	MPSC Case Nos. U-21570 & U-21867	h) For resources located within the nonattainment areas (or an area that may be designated nonattainment based on reasonably known information at the time of filing) in the electric utility service territory, identify and assess their impact to the nonattainment status for portfolio #2, listed above, as compared to portfolio #1, and qualitatively support in testimony. The assessment should consider all nonattainment pollutants (i.e., SO 2 and ozone), as well as their precursors (i.e., NOx and VOCs); and	Breining McLean	(Breining) Section III – Nonattainment Area Assessment (Breining) Section III – Nonattainment Area Assessment, pp. 22–23 (McLean) Section II – Statutory and Regulatory Background, pp. 25–35	Exhibit A-2 (SQM-2), pp. 222–231 (Section 21; Tables 21-1 through 21-4; Figures 21-1 through 21-3)	
270	MPSC Case Nos. U-21570 & U-21867	i) Narrative discussion of the quantitative and qualitative health and environmental impacts, based on the analysis above, methodologies, data sources, and related observations. Explain how these considerations were taken into account in the utility's decision. Discuss changes in health, safety, and welfare of individuals in environmental justice communities from the PCA as compared to the alternatives considered, including siting considerations for any proposed new generation.	Breining McLean	(Breining) Sections III–VI – Environmental, Health, Siting, and Facility Impacts (Breining) Sections III–VI – Environmental, Health, Siting, and Facility Impacts, pp. 15–35 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 222–231 (Section 21; Tables 21-1 through 21-4; Figures 21-1 through 21-3) Exhibit A-52 (HAB-4), p. 1 Exhibit A-53 (HAB-5), p. 1	WP-HAB-1A, COBRA 2040 Fleet Emissions – Bay County, pp. 1–6 WP-HAB-1B, COBRA 2040 Fleet Emissions – Genesee County, pp. 1–6 WP-HAB-1C, COBRA 2040 Fleet Emissions – Jackson County, pp. 1–6 WP-HAB-1D, COBRA 2040 Fleet Emissions – Ottawa County, pp. 1–6 WP-HAB-1E, COBRA 2040 Fleet Emissions – PCA, pp. 1–6 WP-HAB-1F, COBRA 2040 Fleet Emissions – Van Buren County, pp. 1–6 WP-HAB-2A, COBRA 2040 Fleet Emissions – Portfolio 1, pp. 1-6 WP-HAB-2B, COBRA 2040 Fleet Emissions – Portfolio 2, pp. 1-6 WP-HAB-2C, COBRA 2040 Fleet Emissions – Portfolio 5, pp. 1-6 WP-HAB-3A, Covert MiEJScreen 3-Mile Radius, pp. 1–3 WP-HAB-3B, DE Karn MiEJScreen 3-Mile Radius, pp. 1–5 WP-HAB-3C, Jackson MiEJScreen 3-Mile Radius, pp. 1–13 WP-HAB-3D, Therford MiEJScreen 3-Mile Radius, pp. 1–4 WP-HAB-3E, Zeeland MiEJScreen 3-Mile Radius, pp. 1–5
271		**Exhibits and Workpapers**				
272	MPSC Case Nos. U-21570 & U-21867	The filing shall include exhibits and workpapers as outlined below, subject to any license or other confidentiality restrictions that are unable to be resolved by issuance of a protective order.	See lines 273-281			
273	MPSC Case Nos. U-21570 & U-21867	a) The Company shall include an exhibit containing a table that designates where each filing requirement is included within its testimony, exhibits, and workpapers, with appropriate page and section numbers;	McLean	Section II – Statutory and Regulatory Background, pp. 25–35	Exhibit A-1 (SQM-1)	
274	MPSC Case Nos. U-21570 & U-21867	b) The Company shall include an exhibit that depicts a stacked bar graph that includes the RTO capacity credit of all existing resources and new resources for all required scenarios, sensitivities, and any pertinent utility-proposed scenarios, color designated by resource type, in each of the planning years. The graph shall have a line representing expected demand over the length of the planning period with the inclusion of the necessary planning reserve margin;	Moritz Soni	(Soni) Section VII – Capability and Demand During Market Dependency, pp. 40–54 (Moritz) Phase 2 Capacity Results and Exhibit Summary, p. 92	Exhibit A-26 (AJM-12), pp. 1–116	WP-PS-7, Capability versus Demand WP-AJM-3, pp. 3–7
275	MPSC Case Nos. U-21570 & U-21867	c) The Company shall include an exhibit of stacked bar graphs that include the energy expected to be produced by all existing resources, new resources, and market purchases for each planning year and for all MIRPP required scenarios and sensitivities. Each graph shall be color designated by resource type. Each graph shall have a line representing expected demand over the length of the planning period;	Moritz	Phase 2 Energy Results and Exhibit Summary, p. 92	Exhibit A-27 (AJM-13), pp. 1–29	WP-AJM-3, p. 8
276	MPSC Case Nos. U-21570 & U-21867	d) Include a chart that compares the total projected carbon emissions under each required scenario to the relevant sensitivities and build plans under that scenario, including quantifying the carbon emissions projected in each sensitivity as a percentage of the carbon emissions presented in the base scenario associated with that sensitivity. The utility shall identify and justify which of the carbon accounting methodologies it used for all scenarios and sensitivities. The methodology should be one identified in Electric Power Research Institute, Methods to account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases or other Commission approved methodology; 1. Any workpapers used in developing the application, supporting testimony, and IRP. Such workpapers shall, when possible, be provided in electronic format with formulas intact;	Breining	Section II – Carbon Emissions by Scenario and Senstivity, pp. 12–15	Exhibit A-50 (HAB-2), pp. 1–64 Exhibit A-51 (HAB-3), pp. 1–2	
277	MPSC Case Nos. U-21570 & U-21867	e) Any modeling input and output files used in developing the application, supporting testimony, resource plan, and any alternative plans. Such modeling input and output files shall, when possible, be provided in electronic format with formulas intact. The utility shall also identify each modeling program used and provide information for how interested parties can obtain access to such modeling program. Modeling inputs and outputs in the model-dependent binary format should be made available to parties that obtain a license;	Moritz All Witnesses	(Moritz) Sections IV, V, IX, and X – IRP Modeling Process, Scenario and Sensitivity Development, Optimization Portfolios, and Phase 1 Modeling Results, pp. 16–31 and 71–85.		WP-AJM-1, pp. 3–72 WP-AJM-2, pp. 1–4 WP-AJM-3, pp. 1–21 WP-SQM-1, p. 1 WP-SQM-2, p. 1 WP-SQM-3, p. 1 WP-SQM-4, p. 1 WP-SQM-5, p. 1 WP-SQM-6, p. 1 WP-SQM-7, p. 1 WP-SQM-8, p. 1 WP-SQM-9, p. 1 WP-SQM-10, p. 1 WP-SQM-11, p. 1
278		1. Cost data, estimates, and co-benefit analyses that were used in the resource screening process or in any other way to determine resource selection of each resource that was considered either individually or in combination with other resources constructed as a single facility, including DERs, storage, and renewable energy resources;	Clark	Part I – IRP Modeling Assumptions, including Gas-Fueled Technology, Nuclear, Solar, Wind, Energy Storage, and Sensitivity Analysis Assumptions, pp. 6–24	Exhibit A-6 (TPC-1), p. 1 Exhibit A-7 (TPC-2), p. 1 Exhibit A-8 (TPC-3), p. 1 Exhibit A-9 (TPC-4), p. 1 Exhibit A-10 (TPC-5), p. 1 Exhibit A-11 (TPC-6), p. 1 Exhibit A-12 (TPC-7), p. 1	WP-AJM-1, pp. 40–49 WP-AJM-2, pp. 1–4
279	MPSC Case Nos. U-21570 & U-21867	f) A description, including estimated costs, of each alternative proposal received by the utility;	Not applicable - The Company interprets this requirement as applying to alternative proposals submitted directly to the Commission from other existing suppliers under MCL 460.6a(6)).			
280	MPSC Case Nos. U-21570 & U-21867	g) A discussion of any differences between its short-term fuel price forecasts and capacity price curve in the IRP filing, and the short-term fuel price forecasts and capacity price curve in its last power supply cost recovery plan proceeding;	Moritz Rissman	(Moritz) Sections IV–V and Exhibit AJM-18 (Rissman) Section VII – Comparison of IRP and 2026 PSCR Natural Gas Forecasts, pp. 13–14 (Moritz) Short-Term Fuel and Capacity Comparison to PSCR, p. 10	Exhibit A-32 (AJM-18), p. 1 Exhibit A-89 (AKR-12), p. 1	
281	MPSC Case Nos. U-21570 & U-21867	h) Identification and justification of the forecasted price of energy, capacity, and fuels, and of peak demand and energy requirements used in the IRP. The utility shall identify its base case forecasts and a range of sensitivities for each such factor and explain how those sensitivities were identified. If the base case forecast(s) differs from recent previous forecasts submitted by the utility to the Commission in other cases, the utility shall provide an explanation for such differences; 1. Present an environmental compliance strategy which demonstrates how the utility will comply with all applicable federal and state environmental regulations, laws, and rules. Included with this information, the utility shall analyze the cost of compliance on its existing generation fleet going forward, including existing projects being undertaken on the utility's generation fleet; 2. Estimated annual emissions of CO 2 and greenhouse gases, particulates, SO2, NOx, and Hg per year and over the study period of the facilities included in their IRP; 3. The assumed retirement dates of the facilities included in the IRP, with justification provided for the assumed retirement dates; and 4. Other documents and data underlying the IRP and CEP analysis.	Breuring Moritz Soni Rissman McCormick Breining McLean	(Breuring) Section III–VI – Deliveries, Peak Demand, Uncertainty, and Alternative Forecasts, pp. 11–27 (Soni) Section VIII – Cost and Forecast Sensitivities, pp. 55–70 (Rissman) Sections III–VI – Base, Sensitivity, Delivered Fuel, and PSCR Forecasts, pp. 6–14 (McCormick) Section VI – Transmission Network Upgrade, CIL, and CEL Assumptions and Sensitivities, pp. 31–36 (Moritz) Short-Term Fuel and Capacity Comparison to PSCR, p. 10 (Breining) Sections I–II – Environmental Compliance Strategy, Compliance Costs, and Emissions Outlook, pp. 3–15 (McLean) Section VIII – Significant Proposals and Requested Relief, pp. 105–114	Exhibit A-2 (SQM-2), pp. 111–140, 150–154, and 165–167 (Sections 12–16; Figures 12-1 through 12-10, 15-1, 15-2, 16-1, and 16-2) Exhibit A-72 (EMB-3), p. 1 Exhibit A-73 (EMB-4), p. 1 Exhibit A-70 (EMB-1), p. 1 Exhibit A-71 (EMB-2), p. 1 Exhibit A-15 (AJM-1), pp. 1–7 Exhibit A-16 (AJM-2), pp. 1–4 Exhibit A-32 (AJM-18), p. 1 Exhibit A-79 (AKR-2), p. 1 Exhibit A-80 (AKR-3), p. 1 Exhibit A-81 (AKR-4), p. 1 Exhibit A-82 (AKR-5), p. 1 Exhibit A-83 (AKR-6), p. 1 Exhibit A-84 (AKR-7), p. 1 Exhibit A-85 (AKR-8), p. 1 Exhibit A-86 (AKR-9), p. 1 Exhibit A-87 (AKR-10), p. 1 Exhibit A-88 (AKR-11), p. 1 Exhibit A-89 (AKR-12), p. 1 Exhibit A-75 (JRM-2), pp. 1–17 Exhibit A-49 (HAB-1), pp. 1–9 Exhibit A-50 (HAB-2), pp. 1–64 Exhibit A-51 (HAB-3), pp. 1–2	WP-PS-2, Cost Sensitivity Levels WP-PS-3, Forecast Error Spreads WP-JRM-1, MISO GIA Costs and Statistical Summary WP-JRM-2, CIL and CEL Forecasts WP-JRM-3, Transmission Scenarios, Resource Siting, and Load Forecasts WP-AJM-1, pp. 7–10 and 57–69
282		**Affordability Methodology**				

Line No.	Origin of Requirement	Filing, Testimony, Exhibits, and Workpaper Requirements	Witness	Testimony Section(s)	Exhibit Reference	Work Paper Reference
283	MPSC Case Nos. U-21570 & U-21867	1. Calculate the projected rate and expected annual bill impact for the residential customer class for each year of the PCA using the most recently approved cost of service study. Annual cost adjustments shall reflect a rate of inflation at the time of filing. 2. Calculate the expected average annual energy cost for residential customers by household using publicly available data such as the U.S. Energy Information Administration's Residential Energy Consumption Survey and forecast in nominal dollars for the first five years of the PCA. Annual cost adjustments shall reflect a rate of inflation at the time of filing. 3. Create an income distribution of the utility's service territory using publicly available data, such as B19001 Household Income in the Past Months census data. Incomes for the first five years of the plan will be presented in nominal dollars and shall reflect a rate of inflation at the time of filing. 4. Calculate the expected impact of the PCA on Michigan households within the utility service territory by adding the annual bill impact of the PCA in (1), to a residential household's expected average annual energy cost in (2), for the first five years of the plan. 5. Based on the results of (4), calculate the expected energy burden percentage for each income range of the income distribution in (3) for the first five years of the plan.	Myers McLean	(Myers) Section II – Residential Rate, Bill, Income, and Energy-Burden Methodology, pp. 6–9 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 207–210 (Section 19; Figures 19-1 through 19-3) Exhibit A-45 (HJM-4), pp. 1–4 Exhibit A-46 (HJM-5), pp. 1–4 Exhibit A-47 (HJM-6), pp. 1–101 Exhibit A-48 (HJM-7), pp. 1–102	WP-HJM-31, PCA Customer-Class Allocations WP-HJM-55, Existing Power Supply Rates per kWh WP-HJM-56, General Rate Case Power Supply Revenue Requirement
284		**Clean Energy Plan Filing Requirements**				
285		**CEP Statutory Requirements**				
286	MPSC Case No. U-21867 / CEP Filing Requirements	PA 235 of 2023 was signed into law by Governor Whitmer on November 21, 2023. Section 51 directs the following: 1) As a clean energy standard, an electric provider shall achieve a clean energy portfolio of at least the following: (a) In 2035 through 2039, 80%. (b) In 2040 and each year thereafter, 100%. An electric provider whose rates are regulated by the commission shall include a clean energy plan (CEP) illustration of how it intends to comply with the clean energy standard as part of that electric provider's integrated resource plan.	Johnston	Section IV – Clean Energy Portfolio Standard Compliance, pp. 30–38	Exhibit A-55 (KDJ-2), p. 1	
287		**CEP General Filing Requirements**				
288	MPSC Case No. U-21867 / CEP Filing Requirements	These application instructions apply to an investor-owned rate-regulated electric utility application for Michigan Public Service Commission (MPSC or Commission) approval of a Clean Energy Plan (CEP) under the provisions of MCL 460.1051. The application shall be consistent with these instructions, with each item labeled as set forth below. Any additional information considered relevant by the utility may also be included in the application.	The Company's CEP is included with its IRP application in Docket No. U-22127, is organized and labeled consistently with the Commission's CEP filing requirements under MCL 460.1051, and includes any additional information the Company considers relevant to the Commission's review.			
289		**CEP Filing Announcement**				
290	MPSC Case No. U-21867 / CEP Filing Requirements	To facilitate the scheduling and preparation of CEP filings, a rate regulated utility who intends to file a CEP, shall combine its CEP filing announcement with its IRP filing announcement necessary for its integrated resource plan filing. The CEP portion of the filing announcement shall include:	A filing announcement was made by the Company on 8/4/2026, and corrected on 8/14/2026, announcing the Company's intent to file its 2026 Integrated Resource Plan, Clean Energy Plan and Certificates of Necessity on 9/3/2026 in docket U-22127 with proof of service attached.			
291	MPSC Case No. U-21867 / CEP Filing Requirements	a) Statement of intent to file a CEP;				
292	MPSC Case No. U-21867 / CEP Filing Requirements	b) Estimated date of filing;				
293	MPSC Case No. U-21867 / CEP Filing Requirements	c) Any information related to any public engagement that has already taken place or is scheduled to take place.				
294		**CEP Participant Engagement and Public Outreach**				
295	MPSC Case No. U-21867 / CEP Filing Requirements	Participant engagement early in the development of the CEP is strongly encouraged to: (1) educate potential participants on utility plans; (2) utilize a transparent decision-making process for resource planning; (3) create opportunity to provide feedback to the utility on its resource plan; (4) encourage robust and informed dialogue on resource decisions; and (5) reduce utility regulatory risk by building understanding and support for utility resource decisions. Utilities should engage participants in the development of the CEP and IRP simultaneously. The utility may choose to incorporate some, or all, of the participant input in its analysis and decision making for the CEP filing.	The Company conducted stakeholder engagement for the CEP and IRP as a coordinated process. The engagement activities educated participants on the Company's plans, provided opportunities for informed feedback and dialogue, and informed the Company's analysis and decision-making. See Lines 22–30 for the workshop activities and notices, meeting records and attendance, participant feedback, explanation of how outreach influenced the final plan, community and Tribal outreach, and the filed public outreach report.			
296		**CEP Definitions**				
297	MPSC Case No. U-21867 / CEP Filing Requirements	The following definitions are provided to aid in ensuring consistency across planning processes. Many of these definitions are taken directly from Public Act 235 of 2023. Distributed Energy Resources - A source of electric power and its associated facilities that is connected to a distribution system. Distributed Energy Resources (DER) includes both generators and energy storage technologies capable of exporting active power to a distribution system. Environmental Justice Communities – Refers to overburdened, vulnerable, underserved or disadvantaged communities that are identified, for the purpose of this analysis, by a minimum percentile of 75 in the Michigan Environmental Justice Screening Tool (MiEJScreen) or a minimum percentile of 75 in either the Low-Income Population or Black, Indigenous, People of Color population layer. If MiEJScreen tool is not available, the utility should work with and take feedback from Staff, EGLE, and interested parties when determining which other tool or methodology to use. Greenhouse Gas Emissions - carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, or sulfur hexafluride Carbon Capture and Storage - A process that involves collecting carbon dioxide at its source and storing, or sequestering, it to prevent its release into the atmosphere.1 Public Act 295 of 2008 as amended by Public Act 235 of 2023. Direct Air Capture and Storage – A process that involves removing CO2 directly from the atmosphere and storing or sequestering it. Clean Energy - electricity or steam generated using a clean energy system. Clean Energy Plan - An electric provider's plan to meet the clean energy standard approved under section 51.3 Clean Energy Portfolio - The percentage of an electric provider's total retail electric sales consisting of clean energy or renewable energy.4 Clean Energy Standard - The clean energy portfolio required in Public Act 295 as amended by Public Act 341 under section 51(1).5 Clean Energy System - An electricity generation facility or system or set of electricity generation systems that meets any of the following requirements:	The CEP uses the definitions established in Public Act 295, as amended by Public Act 235 of 2023, and the Commission's filing requirements, including Distributed Energy Resources, Environmental Justice Communities, greenhouse gas emissions, carbon capture and storage, clean energy, Clean Energy Plan, Clean Energy Portfolio, Clean Energy Standard, and Clean Energy System. See also Line 37 for common IRP and CEP definitions and Lines 156–163 for application of the clean and renewable energy standards.			
298	MPSC Case No. U-21867 / CEP Filing Requirements	i) Generates electricity or steam without emitting greenhouse gas, including nuclear generation. ii) Is fueled by natural gas and uses carbon capture and storage that is at least 90% effective in capturing and permanently storing carbon dioxide. If the department of Environment, Great Lakes, and Energy determines, through a facility-specific major source permitting analysis consistent with applicable United States Environmental Protection Agency rules, that a capture rate higher than 90% meets the best available control technology standard, as applicable, the higher percentage shall be used instead of 90% for facilities permitted after the effective date of the amendatory act that added section 51. Using carbon dioxide for enhanced oil recovery is not considered to be permanent storage for the purposes of this subparagraph. iii) Is an independently owned combined cycle power plant fueled by natural gas that has a power purchase agreement with an electric provider as of the effective date of the amendatory act that added this subparagraph and that by 2030 receives approval from the commission for a plan that achieves functional equivalence with the clean energy standard in section 51(1)(b) through reduction of greenhouse gas emissions using Public Act 295 of 2008 as amended by Public Act 235 of 2023. Et al. Et al. Et al. Et al. carbon capture and sequestration and other available applications, including, but not limited to, carbon removal technologies. In reviewing and approving a plan submitted under this subparagraph, the commission shall consider best available technology and applications as well as rate affordability, resource adequacy, and grid reliability. iv) Is defined as a clean energy system in rules adopted by the commission consistent with the purposes of this subdivision.	The Company applies the statutory definition of a Clean Energy System, including the qualifying criteria listed in this requirement, when identifying resources eligible to satisfy the Clean Energy Standard. The Company's clean-energy portfolio and compliance approach are addressed at Lines 156–163 and in the supporting testimony, exhibits, and workpapers identified in those rows. Troyer			
299		**CEP Filing, Data, and Documentation**				
300	MPSC Case No. U-21867 / CEP Filing Requirements	The utility's CEP filing shall demonstrate compliance with MCL 460.1051. All assumptions and inputs shall be applied consistently in both CEP and IRP plans. The statute requires that rate regulated utilities file a CEP with its IRP. Rate-regulated utilities need not duplicate information that is contained within the IRP. Both CEPs and IRPs are expected to be filed in the same filing and therefore, information should simply be identified as applying to both plans. CEP filings shall include the following items:	McLean	Section VII – Proposed Course of Action and Clean Energy Compliance, pp. 79–104 Section II – Statutory and Regulatory Background, pp. 25–35	Exhibit A-2 (SQM-2), pp. 106–110 and 202–203 (Sections 11 and 18.3)	
301	MPSC Case No. U-21867 / CEP Filing Requirements	a) Letter of transmittal expressing commitment to the approved clean energy plan signed by an officer of the utility having the authority to commit the utility to the clean energy plan, acknowledging that the utility reserves the right to make changes to its clean energy plan as appropriate due to changing circumstances;	The CEP filing includes a letter of transmittal filed in Docket No. U-22127 and signed by an authorized Company officer, confirming the Company's commitment to the Clean Energy Plan while reserving the right to respond appropriately to changing circumstances.			
302	MPSC Case No. U-21867 / CEP Filing Requirements	b) Any technical volume(s) that are necessary to fully describe and document the utility's analysis and decisions in selecting its clean energy plan and resources therein;	The Company complies by including Exhibit A-2 (SQM-2) as the technical volume that fully describes and documents the analyses, modeling approach, resource alternatives, portfolio evaluation, and decisions used to select the Clean Energy Plan and its resources.			
303	MPSC Case No. U-21867 / CEP Filing Requirements	c) The data and information requested in the Commission's CEP Filing Requirements included herein;	The Company complies by providing the data and information requested in the Commission's CEP Filing Requirements throughout the combined IRP and CEP filing. Exhibit A-1 (SQM-1) identifies where each requirement is addressed, and Exhibit A-2 (SQM-2) provides the supporting technical information.			
304	MPSC Case No. U-21867 / CEP Filing Requirements	d) Any request for an extension pursuant to MCL 460.1051 (2)(b); and	Not applicable. Consumers Energy is not requesting an extension under MCL 460.1051(2)(b).			
305	MPSC Case No. U-21867 / CEP Filing Requirements	e) Any other information deemed relevant by the utility.	Any additional information the Company considers relevant to the Commission's review of the Clean Energy Plan is included in the combined IRP and CEP filing in Docket No. U-22127.			
306		**CEP Summary**				
307	MPSC Case No. U-21867 / CEP Filing Requirements	To facilitate a similar format for each utility's application, the utility is encouraged to align its filing with the provided outline and include at least the following items:	See lines 308-314			
308	MPSC Case No. U-21867 / CEP Filing Requirements	A CEP shall include an exhibit that serves as an executive summary, suitable for distribution to the public. The summary shall include the following:	McLean	Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 2–16 (Section 1; Figures 1-2 through 1-6)	
309	MPSC Case No. U-21867 / CEP Filing Requirements	a) An overview of the planning period examined in the CEP application;	McLean	Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 2–16 (Section 1; Figures 1-2 through 1-6)	
310	MPSC Case No. U-21867 / CEP Filing Requirements	b) A brief introduction describing the utility, its existing facilities, new resources being proposed, and implementation strategy;	McLean	Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 2–16 (Section 1; Figures 1-2 through 1-6)	
311	MPSC Case No. U-21867 / CEP Filing Requirements	c) A summary of any analytical approach used in the utility's analysis and the types of new resources considered;	McLean Moritz	Section III – IRP Objectives and Principles, pp. 40–52 (Moritz) Section IV – Process Used in Modeling, pp. 6–22	Exhibit A-2 (SQM-2), pp. 2–16 (Section 1; Figures 1-2 through 1-6)	
312	MPSC Case No. U-21867 / CEP Filing Requirements	d) A description of how environmental justice (EJ), and overall affordability were considered when selecting the proposed clean energy systems that will be used to meet the clean energy standard;	McLean Breining Myers	(McLean) Section III – IRP Objectives and Principles, pp. 36–39 (Breining) Sections III–VI – Environmental, Health, Siting, and Facility Impacts, pp. 15–35 (Myers) Section II – Residential Energy Burden and Affordability, pp. 6–9	Exhibit A-2 (SQM-2), pp. 2–16 (Section 1; Figures 1-2 through 1-6) Exhibit A-47 (HJM-6), pp. 1–101 Exhibit A-48 (HJM-7), pp. 1–102 Exhibit A-52 (HAB-4), p. 1 Exhibit A-53 (HAB-5), p. 1	
313	MPSC Case No. U-21867 / CEP Filing Requirements	e) The Company shall include a figure that depicts a stacked bar graph that includes the annual energy expected to be produced by all resources used for compliance for each year of the planning horizon as compared to its sales forecast for each corresponding year over the planning period. The graph shall be color designated by resource type. The graph shall have a line representing expected demand over the length of the planning period. The graph should also depict the utility's progress toward or achievement of State goals of 80% clean energy in 2035-2039 and 100% clean energy in 2040 and each year thereafter; and	McLean Johnston Moritz	(McLean) Section IV – The Company's Load Forecast, pp. 53–63 (Johnston) Section IV – Clean Energy Portfolio Standard Compliance, pp. 30–38	Exhibit A-2 (SQM-2), pp. 2–16 (Section 1; Figures 1-2 through 1-6); pp. 108 (Figure 11-2) Exhibit A-55 (KDJ-2), p. 1 Exhibit A-27 (AJM-13)	WP-AJM-3, p. 8
314	MPSC Case No. U-21867 / CEP Filing Requirements	f) Any other information that would aid the public understanding of the utility's proposed plan.	McLean	Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 2–16 (Section 1; Figures 1-2 through 1-6)	
315		**Clean Energy Plan Details**				
316	MPSC Case No. U-21867 / CEP Filing Requirements	The utility shall describe resource plans that it intends to use to satisfy at least the objectives and priorities identified in MCL 460.1051, its CEP planning process, and any public engagement. If a utility is proposing to include a natural gas generation facility that includes carbon capture and storage as a CES, the utility shall provide sufficient evidence to demonstrate that the facility meets the requirements of MCL 460.1003(4)(a).	McLean Johnston Moritz	(McLean) Section VI – New Resource Options, pp. 71–78	Exhibit A-2 (SQM-2), pp. 106–110 and 202–203 (Sections 11 and 18.3) Exhibit A-55 (KDJ-2), p. 1 Exhibit A-15 (AJM-1), pp. 1–7 Exhibit A-24 (AJM-10), pp. 1–14 Exhibit A-25 (AJM-11), pp. 1–4	WP-AJM-1, pp. 21–27, 40–49, and 54–69 WP-AJM-2, pp. 1–4 WP-AJM-3, pp. 1–21
317		**CEP Renewables and Renewable Portfolio Standards**				
318	MPSC Case No. U-21867 / CEP Filing Requirements	Projected energy purchased or produced by the utility from renewable energy resources. Describe how the utility will meet existing renewable energy standards including evidence that illustrates consistency with the utility's REP. The utility shall also discuss any key differences between its REP and CEP.7,8	Johnston McLean	(Johnston) Sections II–IV – Renewable Energy and Clean Energy Compliance, pp. 13–38 (McLean) Section II – Statutory and Regulatory Background, pp. 25–35	Exhibit A-2 (SQM-2), pp. 91–110 (Sections 9–11; Figures 9-1 through 9-4 and 11-1 through 11-2) Exhibit A-54 (KDJ-1), p. 1 Exhibit A-55 (KDJ-2), p. 1	WP-KDJ-1, Company-owned Renewable Projects WP-KDJ-4, REC Comparison – Amended RE Plan versus IRP PCA
319		**CEP Total Electric Sales Forecast**				
320	MPSC Case No. U-21867 / CEP Filing Requirements	A long-term forecast of the electric provider's total electric sales. To ensure compliance with the CEP the electric provider should consider the following when developing its forecast:	Breuring McLean Johnston Gast	(Breuring) Section III – Historical and Forecasted Electric Deliveries, pp. 11–16 (Gast) Sections I–IV – EWR, DR, EV, DG, and Electrification Effects on Sales, pp. 4–26 (McLean) Section IV – The Company's Load Forecast, pp. 53–63	Exhibit A-2 (SQM-2), pp. 111–128 (Section 12; Figures 12-1 through 12-10) Exhibit A-70 (EMB-1), p. 1 Exhibit A-54 (KDJ-1), p. 1 Exhibit A-55 (KDJ-2), p. 1 Exhibit A-92 (AMG-1), pp. 1–4 Exhibit A-94 (AMG-3), p. 1 Exhibit A-95 (AMG-4), p. 1	WP-KDJ-2, VGP Sales Historical Detail WP-KDJ-3, Distributed Generation Outflow Forecast
321	MPSC Case No. U-21867 / CEP Filing Requirements	a) DER adoption and impacts to the overall electric sales in the electric provider's service territory;	Gast McLean Breuring	(Gast) Section IV – Distributed Generation Adoption and Sales Impacts, pp. 24–26 (McLean) Section VI – New Resource Options, pp. 71–78 (Breuring) Sections I–III – Forecasting Methodology, Key Electric Delivery and Demand Variables, and Historical and Forecasted Electric Deliveries, pp. 5–17	Exhibit A-2 (SQM-2), pp. 111–128 (Section 12; Figures 12-1 through 12-10) Exhibit A-95 (AMG-4), p. 1 Exhibit A-70 (EMB-1), p. 1 Exhibit A-73 (EMB-4), p. 1	
322	MPSC Case No. U-21867 / CEP Filing Requirements	b) Electric vehicle adoption assumptions and impacts to overall total electric sales;	Breuring Gast McLean	(Breuring) Section III – Historical and Forecasted Electric Deliveries, pp. 11–16 (Gast) Section III – EV Adoption, Charging Energy, Peak Demand, and Load Flexibility, pp. 18–23 (McLean) Section IV – The Company's Load Forecast, pp. 53–63	Exhibit A-2 (SQM-2), pp. 111–128 (Section 12; Figures 12-1 through 12-10) Exhibit A-94 (AMG-3), p. 1	
323	MPSC Case No. U-21867 / CEP Filing Requirements	c) Electrification adoption assumptions and impacts to overall electric sales forecasts.	Gast McLean Breuring	(Gast) Section IV – Electrification Adoption and Electric Sales Forecast Impacts, pp. 24–26 (McLean) Section IV – The Company's Load Forecast, pp. 53–63 (Breuring) Sections I, II, and III – Forecasting Methodology, Key Electric Delivery and Demand Variables, and Historical and Forecasted Electric Deliveries, pp. 5–17; specifically EV adoption assumptions and projected EV load impacts, pp. 13–15	Exhibit A-2 (SQM-2), pp. 111–128 (Section 12; Figures 12-1 through 12-10) Exhibit A-70 (EMB-1), p. 1	
324		**Proposed Clean Resource Plan**				
325	MPSC Case No. U-21867 / CEP Filing Requirements	Include a detailed description of:	See lines 326-327			
326	MPSC Case No. U-21867 / CEP Filing Requirements	a) The type of clean generation technologies being used to meet compliance.	Johnston McLean Moritz	(Johnston) Section IV – Clean Energy Portfolio Standard Compliance, pp. 30–38 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 194–203 (Sections 18.1–18.3; Table 18-1 and Figures 18-1 through 18-3) Exhibit A-24 (AJM-10), pp. 1–14 Exhibit A-25 (AJM-11), pp. 1–4	WP-AJM-1, pp. 40–49 and 54–56 WP-AJM-2, pp. 1–4 WP-AJM-3, pp. 2–8
327	MPSC Case No. U-21867 / CEP Filing Requirements	b) The impact of the CEP on the diversity of the utility resource portfolio. Include details in a qualitative discussion.	McLean	Section III – IRP Objectives and Principles, pp. 36–39	Exhibit A-2 (SQM-2), pp. 194–203 (Sections 18.1–18.3; Table 18-1 and Figures 18-1 through 18-3)	WP-SQM-11, p. 1
328		**CEP Extension Request**				
329	MPSC Case No. U-21867 / CEP Filing Requirements	If the utility requests an extension of its plan pursuant to MCL 460.1051(2)(b), provide detailed information and supporting data explaining the reason for the requested extension.	Not applicable. Consumers Energy is not requesting an extension under MCL 460.1051(2)(b)			

Line No.	Origin of Requirement	Filing, Testimony, Exhibits, and Workpaper Requirements	Witness	Testimony Section(s)	Exhibit Reference	Work Paper Reference
330		CEP Resource Plan Selection	See line 331			
331	MPSC Case No. U-21867 / CEP Filing Requirements	The utility shall describe the process used to select the proposed resource plan, including the planning principles used to judge appropriate tradeoffs between competing planning objectives and between expected performance and risk.	McLean Moritz	(Moritz) CON Removal Analysis and Replacement Resources, pp. 103–104 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 194–199 (Section 18.1; Figures 18-1 and 18-2) Exhibit A-22 (AJM-8), pp. 1–4 Exhibit A-23 (AJM-9), pp. 1–8 Exhibit A-33 (AJM-19), pp. 1–2	WP-AJM-3, p. 1
332		**CEP Compliance Template**				
333	MPSC Case No. U-21867 / CEP Filing Requirements	Include a completed template consistent with the example in Appendix A of the CEP Filing Requirements.	Johnston		Exhibit A-55 (KDJ-2)	
334		**CEP Implementation Plan**				
335	MPSC Case No. U-21867 / CEP Filing Requirements	The utility shall develop an implementation plan that specifies the major tasks, schedules, and milestones necessary to implement the proposed resource plan over the implementation period. The utility shall describe and document its implementation plan.	McLean Moritz Clark	(McLean) Section VII – Proposed Course of Action, pp. 79–104 (Clark) Direct Testimony, Supply-Side Development, Engineering, Permitting, Procurement, and Construction, pp. 24–55	Exhibit A-2 (SQM-2), pp. 203–206 (Section 18.4; Table 18-2) Exhibit A-24 (AJM-10), pp. 1–14 Exhibit A-25 (AJM-11), pp. 1–4	
336	MPSC Case No. U-21867 / CEP Filing Requirements	a) A schedule and description of actions to implement ongoing and planned demandside programs;	Schmoekel McLean Moritz Gast	(Schmoekel) Sections I–II – CVR Deployment and Program Forecast, pp. 4–15 (Gast) Sections I–II – EWR and DR Program Implementation, pp. 4–18 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 203–206 (Section 18.4; Table 18-2) Exhibit A-113 (DAS-1), p. 1 Exhibit A-114 (DAS-2), p. 1 Exhibit A-115 (DAS-3), p. 1 Exhibit A-116 (DAS-4), pp. 1–3 Exhibit A-117 (DAS-5), p. 1 Exhibit A-20 (AJM-6), pp. 1–3 Exhibit A-21 (AJM-7), pp. 1–3 Exhibit A-24 (AJM-10), pp. 1–14 Exhibit A-92 (AMG-1), pp. 1–4 Exhibit A-93 (AMG-2), p. 1	WP-SQM-10, p. 1
337	MPSC Case No. U-21867 / CEP Filing Requirements	b) A schedule and description of relevant supply-side resource research, engineering, retirement, acquisition, and construction.	McLean Moritz Clark	(Clark) Direct Testimony, Supply-Side Development, Engineering, Permitting, Procurement, and Construction, pp. 24–55 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 203–206 (Section 18.4; Table 18-2) Exhibit A-24 (AJM-10), pp. 1–14 Exhibit A-25 (AJM-11), pp. 1–4 Exhibit A-10 (TPC-5), p. 1 Exhibit A-11 (TPC-6), p. 1 Exhibit A-12 (TPC-7), p. 1	
338		**U-21090 Settlement Agreement**				
339	U-21090 Settlement Agreement - Settlement Items	The parties agree that the Company will file its next IRP consistent with the requirements of MCL 460.6t.	Consumers Energy's 2026 IRP is filed pursuant to MCL 460.6t and is organized to address the applicable statutory and Commission filing requirements.			
340	U-21090 Settlement Agreement - Settlement Items	11. The parties agree to the extension of the Company's PURPA avoided cost construct, as approved in Case No. U-20165 (based on the Company's Annual Solicitations), with certain modifications included below:	Johnston	Section V – PURPA Implementation and Avoided Cost Proposal, pp. 39–48	Exhibit A-57 (KDJ-4), pp. 1–4	
341	U-21090 Settlement Agreement - Settlement Items	a. The Company's PURPA avoided cost construct will be subject to review in the Company's future IRP filings, as opposed to separate biennial filings;	Johnston	Section V – PURPA Implementation and Avoided Cost Proposal, pp. 46–48	Exhibit A-57 (KDJ-4), pp. 1–4	
342	U-21090 Settlement Agreement - Settlement Items	b. QFs 150kWac and below are eligible to receive full avoided cost rates regardless of the Company's capacity needs;	Johnston	Section V – PURPA Implementation and Avoided Cost Proposal, pp. 43–44	Exhibit A-57 (KDJ-4), p. 1	
343	U-21090 Settlement Agreement - Settlement Items	14. In future IRPs, beginning with its next IRP, the Company will (i) collect the necessary data to compute marginal line losses and report these with average line losses and (ii) include marginal line losses and avoided transmission and distribution costs in its evaluation of all distributed resources, including residential DR potential.	Burdjalov Gast	(Burdjalov) Sections I, II, and V – EWR Potential, DR Potential, and Potential Modeling Methodology, pp. 5–29 and 73–88	Exhibit A-96 (DVB-1); Section II – DR Potential, pp. 17–21 Exhibit A-98 (DVB-2), pp. 39–41 Exhibit A-93 (AMG-2), p. 1	
344	U-21090 Settlement Agreement - Settlement Items	15. Consumers Energy agrees to develop a distributed generation as a resource model approach that considers economic distribution connected solar to be modeled by bundling resources installed at the customer level to compare the total economic costs to the utility of distributed generation as a resource to other selectable supply-side resources, consistent with the methodology used for EWR. The Company will develop a model that accounts for all utility costs and/or incentives associated with participating and non-participating distributed generation customers. The Company agrees to present the model approach for stakeholder review and feedback prior to the next IRP. The model approach, including any incorporated stakeholder feedback, will be included into the Company's next IRP.	Moritz McLean Coker Burdjalov Gast	(Moritz) Section VIII – Virtual Power Plant Options Considered in the IRP, pp. 65–71 (McLean) Sections IV, VI, and Stakeholder Engagement, pp. 52–53 and 72–79 (Coker) Sections III–VII – Engagement Requirements, Activities, Feedback, and Plan Influence, pp. 4–30 (Burdjalov) Sections I, II, and V – EWR Potential, DR Potential, and Potential Modeling Methodology, pp. 5–29 and 73–88 (Gast) Section IV – Distributed Generation Adoption and Sales Impacts, pp. 24–26	Exhibit A-15 (AJM-1) Exhibit A-22 (AJM-8) Exhibit A-95 (AMG-4), p. 1 Exhibit A-96 (DVB-1), pp. 1–106 Exhibit A-98 (DVB-2), pp. 1–51 Exhibit A-105 (JRC-7), pp. 1–16 Exhibit A-106 (JRC-8), pp. 1–24	WP-AJM-1, pp. 10 and 19–20 WP-SQM-10, p. 1
345	U-21090 Setlement Agreement - Setlement Items	16. The parties agree that Consumers Energy's IRP set forth a proposal to be Carbon Neutral by 2040 and retire all coal generation by 2025, 14 years ahead of the original timeline. These retirements include two substantial coal and gas units totaling approximately 2,000 MW. To replace the capacity, Consumers Energy has proposed adding existing natural gas-fired generation and plans to add about 8,000 MW of solar generation by 2040, to dramatically reduce the use of fossil fuel resources. The next IRP should consider transmission and how it can facilitate the mitigation of reliability and economic impacts to the electric system. The parties also agree that strategic investment in electric transmission needs continual assessment to understand the role of transmission in allowing for the most economic path to meeting the state's energy goals while complementing Michigan's Load Serving Entities' ("LSE") objectives. Michigan is transitioning its generation portfolio and must take the appropriate steps to increase system reliability, resiliency, flexibility, and affordability. Michigan will be better positioned by taking a forward-looking approach regarding resource adequacy. The state should continue to recognize and support the value of a multitude of resources such as Solar, Wind, DR, and Distributed Energy Resources which assist in an "all of the above" approach. Transmission is essential in delivering the reliability of these resources. The value of transmission can be even further realized by leveraging those transmission resources to better assist the Consumers Energy IRP. This will allow MISO LRZ 7 to access broader pools of generation resources, be better situated for future demands placed on the system, mitigate unnecessary risks, and increase performance of those "all of the above" resources to serve the demands of Michigan's customers reliably and economically.	The current IRP addresses this settlement item through the Commission's revised requirements concerning capacity and reliability, transmission analysis, resource planning, and implementation. See Lines 168–181, 210–233, and the supporting testimony, exhibits, and workpapers identified in those rows.			
346	U-21090 Setlement Agreement - Setlement Items	17. The parties agree that the Company will include the following analysis in its next IRP:	The Commission subsequently adopted revised IRP Filing Requirements that address the environmental-emissions, health-impact, and environmental-justice analyses described in Paragraph 17. The Company responds to those superseding requirements at Lines 248–266.			
347	U-21090 Setlement Agreement - Setlement Items	a. The Company will provide total emissions, in lbs or tons, and rate of emissions, in lbs or tons per MWh and per MMBtu, for each owned power plant unit, or units that that the Company has a power purchase agreement with, for the last 5 years of operation (for existing units) and projected for the next 5 years (for all units) for the following pollutants: carbon dioxide, nitrogen oxides, sulfur dioxide, volatile organic compounds ("VOCs"), and primary particulate matter ("PM2.5");	Breining McLean	(Breining) Section II – Annual Facility, Unit, and Fleet Emissions, pp. 13–15 (McLean) Section II – Statutory and Regulatory Background, pp. 25–35	Exhibit A-2 (SQM-2), pp. 222–231 (Section 21; Tables 21-1 through 21-4; Figures 21-1 through 21-3) Exhibit A-49 (HAB-1), pp. 1–9 Exhibit A-50 (HAB-2), pp. 1–64	
348	U-21090 Setlement Agreement - Setlement Items	b. The Company will calculate the annual PM2.5-related health impacts associated with each power plant's emissions. The modeling will include the impacts from primary PM2.5 emissions and PM2.5 precursors emissions (nitrogen oxides, sulfur dioxide, VOCs). The Company will use one model to evaluate the number and economic value of PM2.5-related health impacts of these emissions. The Company may use COBRA or BenMAP (which will require pollutant change inputs from another model such as InMAP) for these calculations, or models that are of equal or greater complexity and accuracy. The Company will report the total number and economic value of PM2.5-related health impacts across the US for the chosen model and spatially by Michigan county or at a higher resolution;	Breining McLean	(Breining) Section III – COBRA Health Impact Analysis, pp. 20–23 (McLean) Section III – IRP Objectives and Principles, pp. 40–52	Exhibit A-2 (SQM-2), pp. 222–231 (Section 21; Tables 21-1 through 21-4; Figures 21-1 through 21-3) Exhibit A-53 (HAB-5), p. 1	WP-HAB-1A through WP-HAB-1F, COBRA 2040 Fleet Emissions WP-HAB-2A through WP-HAB-2C, COBRA 2040 Portfolio Emissions
349	U-21090 Setlement Agreement - Setlement Items	c. The Company will use the MiEJScreen mapping and screening tool, or, if the MiEJScreen tool is not yet finalized, the EPA Environmental Justice Screening and Mapping Tool ("EJSCREEN"), to assess populations in a 1-mile and 3-mile buffer around each power plant location, including reporting total populations and any indicators and total index results above the 75th percentile;	Breining McLean	(Breining) Section III – Three-Mile EJ Screening and Portfolio Emissions, pp. 15–19 (McLean) Section II – Statutory and Regulatory Background, pp. 25–35	Exhibit A-2 (SQM-2), pp. 222–231 (Section 21; Tables 21-1 through 21-4; Figures 21-1 through 21-3) Exhibit A-52 (HAB-4), p. 1	WP-HAB-3A through WP-HAB-3E, MiEJScreen Three-Mile Radius Analyses
350	U-21090 Setlement Agreement - Setlement Items	d. The Company will report projected low-income energy efficiency participation levels, low-income load-reduction data, and publicly available rooftop solar adoption rates. If available, information on rooftop solar adoption by low-income customers will be provided;	Myers Gast Burdjalov	(Myers) Section II – Residential Energy Burden and Affordability, pp. 6–9 (Gast) Section IV – Distributed Generation Adoption and Sales Impacts, pp. 24–26 (Burdjalov) Sections I–II – EWR and DR Potential, pp. 4–19	Exhibit A-47 (HJM-6), pp. 1–101 Exhibit A-48 (HJM-7), pp. 1–102 Exhibit A-95 (AMG-4), p. 1 Exhibit A-96 (DVB-1), pp. 1–106 Exhibit A-98 (DVB-2), pp. 1–51	
351	U-21090 Setlement Agreement - Setlement Items	e. The Company will include a narrative discussion of how the data obtained in a-d were considered by the utility; and	Breining McLean	(Breining) Sections III–VI – Environmental, Health, Siting, and Facility Impacts, pp. 15–35 (McLean) Section VII – Proposed Course of Action, pp. 79–104	Exhibit A-2 (SQM-2), pp. 222–231 (Section 21; Tables 21-1 through 21-4; Figures 21-1 through 21-3) Exhibit A-52 (HAB-4), p. 1 Exhibit A-53 (HAB-5), p. 1	WP-HAB-1A through WP-HAB-1F, COBRA 2040 Fleet Emissions WP-HAB-2A through WP-HAB-2C, COBRA 2040 Portfolio Emissions WP-HAB-3A through WP-HAB-3E, MiEJScreen Three-Mile Radius Analyses
352	U-21090 Setlement Agreement - Setlement Items	f. To the extent that the Commission formally adopts revised Integrated Resource Plan Filing Requirements and/or revised Michigan Integrated Resource Planning Parameters that address environmental emissions, health impacts from emissions, or environmental justice, such filing requirements will supersede the terms of this Paragraph 17.	The Commission formally adopted revised IRP Filing Requirements in Case Nos. U-21570 and U-21867 addressing environmental emissions, health impacts, and environmental justice. Consistent with this provision, those revised requirements supersede Paragraph 17 of the U-21090 Settlement Agreement; the Company's responses are provided at Lines 248–266.			
353	U-21090 Setlement Agreement - Setlement Items	18. The parties agree that the Company will take the following steps to engage and gather input from the public prior to the filing of its next IRP with the Commission:	See Line 354			
354	U-21090 Setlement Agreement - Setlement Items	i. Include in its filings a concise general statement of the basis and purpose of the comments received by the Company and how the Company considered, addressed, or rejected the issues raised in those comments in the IRP (as practicable); and	Coker	Sections VI and VII – Stakeholder Feedback Results and Influence on the Final Plan, pp. 19–30	Exhibit A-99 (JRC-1), pp. 1–10 Exhibit A-100 (JRC-2), pp. 1–18 Exhibit A-101 (JRC-3), pp. 1–6 Exhibit A-102 (JRC-4), pp. 1–9 Exhibit A-103 (JRC-5), pp. 1–17 Exhibit A-104 (JRC-6), pp. 1–26	
355	U-21090 Setlement Agreement - Setlement Items	19. The parties agree that the Company will do the following with respect to combined heat and power ("CHP") resources:				
356	U-21090 Setlement Agreement - Setlement Items	c. In its next IRP proceeding, the Company will model behind-the-meter CHP representative of a demand-side resource based upon the results from the CHP survey as appropriate; and	Consumers Energy filed the CHP survey in Docket No. U-21090 on June 20, 2023. The survey results did not provide sufficient data to support modeling either behind-the-meter CHP as a demand-side resource or front-of-the-meter CHP configurations in this IRP.			
357	U-21090 Setlement Agreement - Setlement Items	d. In its next IRP proceeding, the Company will model front-of-the-meter CHP configurations based upon the results from the CHP survey as appropriate.				

CMS 2026 IRP
Executive Summary

September 2026

CMS ENERGY

Consumers Energy
Count on Us®

1 Executive Summary

1.1 Purpose, Context, and Approach

1.1.1 A Continued Commitment Under New Conditions

Consumers Energy Company (CE or the Company) has served Michigan customers for nearly 140 years, and the commitment that has guided the Company throughout that period — the safe, reliable, affordable, and increasingly clean provision of electric service, consistent with state policy — remains unchanged. The conditions under which the Company meets that commitment, however, have changed materially since the prior Integrated Resource Plan (IRP). This filing reflects a consistent commitment to customers in a significantly altered planning environment. As both CE's IRP and Clean Energy Plan (CEP), it establishes a roadmap for the 2026-2050 planning period that balances customer growth, reliability, affordability, and compliance with Michigan's evolving clean energy requirements.

In this IRP, CE charts a path to serving new customers while maintaining its core commitment to existing residential, commercial and industrial (C&I) customers. The Company proposes a resource strategy that balances reliability, affordability, clean energy progress, equitable outcomes, and flexibility. By investing in a broad and balanced set of technologies in the near term — including combustion turbines (CTs), [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] resources, renewables, battery storage, virtual power plants (VPPs), and distributed energy resources — while preserving a longer-term pathway to incorporate emerging technologies such as carbon capture, utilization, and storage (CCS), the Preferred Course of Action (PCA) delivers the best blend of performance across CE's primary metrics. It does so while preserving the flexibility to serve higher load growth and minimizing cost and technology risk for customers.

1.1.2 New and Emerging Challenges

The key driver of change since CE's last IRP filing is the shift in the balance between supply and demand. Primary contributors include thermal unit retirements and large-load growth, primarily driven by new data center customers and energy-intensive manufacturers. This growth in Michigan has become both material and verifiable. CE has executed agreements representing approximately 1.6 gigawatts (GW) of new load, with a substantially larger development pipeline under active evaluation. DTE Electric has likewise signed significant new large-load commitments, approximately 2.4 GW at the time of writing[1] within its own service territory.[2]

This phenomenon is not limited to Michigan alone. Across the Midcontinent Independent System Operator, Inc. (MISO) footprint — the regional electricity market in which CE operates — demand is rising, driven by data centers, energy-intensive

[1] Utility Dive, (May 2026), *DTE seeks up to 8.4 GW data center opportunity,* accessible at: https://www.utilitydive.com/news/dte-energy-data-center-earnings-reliability/819052/
[2] DTE Energy, (Apr 2026), *1Q 2026 Earnings Conference Call,* accessible at: https://s24.q4cdn.com/970999156/files/doc_financials/2026/q1/Q1-26-presentation-FINAL.pdf

manufacturing, electric vehicles (EVs), and the electrification of heating.[3] Despite this rising demand, new resource additions are facing pressure to keep pace on an accredited basis — that is, after accounting for the portion of each resource's nameplate capacity that can be relied upon during periods of grid stress — even as legacy coal generation retires and is replaced by new resources.[4] Recent MISO capacity auctions have reflected these evolving market dynamics. Capacity prices increased significantly in the 2025/26 Planning Resource Auction (PRA) as reserve margins tightened and market reforms, including the Reliability-Based Demand Curve, increased the value placed on accredited capacity. Prices moderated slightly in the 2026/27 auction, reflecting additional accredited capacity from new resource additions under current market rules, increased imports, and delayed retirements of several thermal units. However, clearing prices remain elevated relative to historical levels, suggesting that resource adequacy concerns persist and that underlying supply-demand conditions remain structurally tight.[5]

Resource adequacy requirements are a key consideration throughout the IRP process. CE evaluates portfolios against applicable Michigan resource adequacy requirements, MISO planning reserve obligations, and evolving resource accreditation rules to ensure sufficient accredited capacity is available to meet future customer demand. These considerations are particularly important as MISO continues implementing reliability reforms and updating its capacity accreditation framework.

In response, MISO has advanced a series of reforms under its Reliability Imperative,[6] initiated in 2020. These include the transition to a seasonal capacity construct, a reform that was implemented several years ago, and the adoption of a new capacity accreditation methodology known as Direct Loss of Load (DLOL), which will be applicable beginning in 2028.[7] Under DLOL, the capacity value assigned to each resource is determined by that resource's contribution to reliability during the specific hours when the system is most likely to experience a loss of load. The DLOL framework remains under active development, as MISO continues to refine the methodology for certain resource classes — storage, in particular.[8] In addition, because the timing and severity of grid stress events depend on the composition of the regional resource mix,

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[3] MISO, (Apr 2026), *2026 Long-Term Load Forecasting (LTLF) Results Summary,* accessible at: https://cdn.misoenergy.org/20260413%20LTLF%20Workshop%202026%20Long%20Term%20Load%20Forecast%20Summary_UPDATED750524.pdf

[4] Utility Dive, (Jun 2026), *MISO's resource outlook improves as forecast generation additions outpace demand growth,* accessible at: https://www.utilitydive.com/news/oms-miso-survey-resource-outlook-generation/821973/

[5] MISO, (Apr 2026), *Planning Resource Auction Results for Planning Year 2026/27*, accessible at: https://cdn.misoenergy.org/2026%20PRA%20Results%20Posting%2020260522%20-%20Corrections754715.pdf

[6] MISO, (Feb 2026), *2026 Reliability Imperative Report,* accessible at: https://cdn.misoenergy.org/2026%20Reliability%20Imperative%20Report744320.pdf

[7] MISO, (Mar 2024), *Resource Accreditation White Paper Version 2.1*, accessible at: https://cdn.misoenergy.org/Resource%20Accreditation%20White%20Paper%20Version%202.1630728.pdf

[8] MISO, (Apr 2025), *LOLE Modeling Enhancement Storage Modeling*, accessible at: https://cdn.misoenergy.org/20250409%20RASC%20Item%2008%20LOLE%20Modeling%20Enhancements%20Storage%20Modeling689245.pdf

the DLOL values assigned to individual resources can evolve as that mix changes. Taken together, this means that MISO's DLOL values for future years, the resulting supply-demand conditions, and overall resource adequacy outlooks remain uncertain. These are important dynamics for CE to consider in its IRP planning to ensure that the selected resource mix remains robust amidst a range of MISO-wide conditions.

In addition to MISO-wide changes, CE is closely tracking shifting dynamics within Michigan, particularly conditions in MISO Local Resource Zone (LRZ) 7, which is comprised almost entirely of CE and DTE Electric and within which the two utilities share access to the broader regional market. Because resource adequacy and import capability in LRZ 7 depend on the combined position of both utilities, CE must carefully account for conditions across the full zone to capture the reliability risks and benefits of its investment decisions.

Resource adequacy is not the only dynamic shaping the Company's IRP process. Since the prior IRP filing, Michigan's clean energy framework has also evolved, as have the obligations facing other utilities across the footprint. The Michigan Clean Energy Standard (CES) and associated Renewable Energy requirements establish binding clean energy and emissions targets; the Energy Waste Reduction (EWR) statute (Public Act 229 of 2023) requires continued pursuit of cost-effective efficiency savings; and Public Act 235 of 2023 (Act 235) establishes a state energy storage target that the PCA satisfies and exceeds. These requirements are central inputs to the IRP planning process, ensuring that CE makes steady progress toward Michigan's clean energy objectives while balancing its broader commitments to reliability, affordability, and equitable outcomes.

Energy providers across the country are evaluating how to meet rising load while advancing clean energy and emissions objectives. This includes both currently available firm dispatchable resources, such as existing generation and new CTs, and emerging clean firm technologies, including CCS, advanced nuclear, long-duration storage, and clean fuels. Existing and new dispatchable capacity can provide dependable support during periods of peak demand, low renewable output, extended weather-driven reliability events, plant outages, and other conditions where energy-limited resources may be constrained. Emerging technologies could ultimately provide similar firm capacity with lower or zero emissions, but their costs, performance, and deployment timelines remain uncertain. Consistent with peer utilities, CE has evaluated these options in its IRP and sequenced potential deployment of emerging technologies to incorporate lessons from first-of-a-kind projects as they become available.

1.1.3 How the Company Has Responded in Its Modeling Approach

Given the emerging challenges and changing dynamics described above, CE has materially strengthened the analytical foundation underlying this IRP.

The load forecast has been expanded to incorporate large-load customer growth — reflecting significant development pipeline, with greater weight placed on signed commitments than on prospective additions — alongside updated treatment of EV adoption, broader economic development, distributed generation (DG), and energy efficiency savings. The forecast was further evaluated under specific scenarios

reflecting higher and lower data center growth, allowing the Company to plan for the range of plausible outcomes while protecting legacy customers and building flexibility into the plan from the outset.

The Company has identified ambitious goals for VPP deployment, anchored by a next-generation approach to incentivizing EV charging. VPPs remain an emerging resource class in Michigan, where penetration of distributed energy resources (DERs) and EVs is lower than in some other states. Nevertheless, CE has identified EV load-shaping as a powerful lever given forecasted EV adoption levels and the Company's proven track record of incentivizing charging behavior in a manner that minimizes system impacts. While traditional programs have encouraged EV charging at night, evolving system dynamics — including increasing solar penetration and shifting hours of peak stress — warrant a different approach. CE therefore proposes an innovative program to shift EV charging toward daytime hours, aligning load with periods of high solar output and supporting system reliability during evolving peak conditions. With this approach, CE can onboard new EV load while minimizing its impact on peak system conditions.

The Company has continued in-house loss-of-load expectation (LOLE) modeling to assess the reliability risks associated with alternative portfolio mixes. This capability hedges against MISO accreditation uncertainty and positions CE to plan independently as conditions in LRZ 7 continue to tighten.

The Company has broadened the range of technologies we are considering, including emerging resources, to ensure that the candidate portfolios reflect the full set of options realistically available to serve customers over the planning horizon. These resource types include nuclear, CCS, and long-duration energy storage (LDES).

The Company has continued to assess existing resource options to inform long-term resource planning. As part of the IRP process, CE evaluated the timing and implications of existing resource operations to ensure compliance with reliability, affordability, and clean energy objectives. The Company evaluated sensitivities examining the end of operations of the Zeeland generating units and the Covert generating units beginning in 2040 to understand the impact of accelerated retirement decisions on portfolio costs and resource requirements. These evaluations informed the Company's assessment of long-term resource needs and helped ensure that the PCA appropriately balances the benefits of existing generation with the costs and risks associated with replacement resources.

The Company considered co-benefits from other planning processes when selecting the PCA. The Company has incorporated insights from local and regional transmission planning into the IRP, including network upgrade costs, transfer capability, import limits, hosting capacity, and planned transmission expansions. These analyses informed resource siting, portfolio costs, reliability, and implementation feasibility. CE also evaluated whether transmission upgrades and Grid Enhancing Technologies (GETs) could cost-effectively increase import capability and defer or replace new resource investments. The results helped inform selection of the PCA.

1.2 Analytical Approach

This IRP and CEP evaluate resource decisions and compliance pathways across the 2026–2050 planning period, providing a long-term roadmap for meeting growing customer demand while maintaining reliability, affordability, and compliance with Michigan law.

At the heart of the IRP, CE identifies a range of candidate resource mixes across a range of possible outcomes for load growth, prices, and technology availability. This enables the Company to evaluate the risks and benefits of alternative resource mixes and to assess the impact of market outcomes that could evolve over the planning horizon. The process proceeds in four steps, as illustrated in Figure 1-1.

Figure 1-1: IRP analytical approach



1. **Screen technologies.** CE conducts a resource screen based on levelized cost of energy (LCOE), market value, and technology maturation to identify the candidate technologies eligible for selection, including natural gas CTs, combined cycles (CCs) with and without CCS, reciprocating internal combustion engines, nuclear, wind, solar, and battery storage.

2. **Define assumptions.** For each eligible technology, CE develops a consistent set of assumptions covering capital and operating costs, performance characteristics, commercial availability dates, and annual build limits reflecting realistic deployment constraints such as supply chain capacity, interconnection timelines, siting, and workforce availability.

3. **Set evaluation metrics.** CE evaluates portfolios against reliability, affordability, and progress toward Michigan's clean energy and renewable energy requirements. The metrics used to assess the risks and benefits of resource decisions (with bolded metrics representing those in CE's final scorecard) include:
    - *Reliable:* **LOLE**, loss-of-load hours (LOLH), and normalized expected unserved energy (EUE)
    - *Affordable:* net present value (NPV) of revenue requirements (NPVRR) and **average rate per kWh**
    - *Clean:* clean energy percentage, renewable energy percentage, and **CO_2 emissions**
    - *Equitable:* clean energy share delivered within Environmental Justice (EJ) communities

- *Resource Diverse:* maintain a balanced mix of resources, measured by the **Herfindahl-Hirschman Index (HHI Index)**
- *Technology risk:* qualitative assessment of first-of-a-kind deployment exposure for emerging resources

4. **Identify scenarios, sensitivities, and stressors.** CE evaluates portfolios across a structured set of thematic scenarios, sensitivities, and stressors. The uncertainty analysis varies major drivers of portfolio composition (i.e., large-load growth, fuel prices, technology costs, and policy outcomes) to inform key decisions and isolate their impacts. Three themes emerged as central to the analysis: (i) large-load growth remains dynamic and could materialize at higher or lower levels than currently projected; (ii) legacy customers must be protected as new large loads are integrated; and (iii) the timing, balance, and benefits associated with alternative large-scale technology postures – CCS, additional CTs, and nuclear – have material implications for both technology risk and clean energy progress.

Core to CE's uncertainty analysis is the development of three outlooks for load growth. Portfolio outcomes are not directly comparable across load trajectories, as CE would adjust its resource decisions if additional large-load customer agreements materialized. The load scenarios are instead used to evaluate the impact of large-load growth on legacy customers and to understand how outcomes would shift if load growth materialized above currently expected levels. The three load trajectories are summarized below:

Table 1-1: Key load scenarios

LOAD TRAJECTORY	LOAD ASSUMPTION	PURPOSE
Probable Load Growth (PLG)	Signed large-load commitments plus a probability-adjusted view of the broader pipeline	Central planning case from which the PCA is selected
Business-as-Usual (BAU)	No incremental economic development; legacy load only	Informational counterfactual; isolates resource decisions attributable to new large load and confirms cost protection for legacy customers
High Economic Development	Full development pipeline materializes; load grows above PLG	Identifies the directional resource additions required under accelerated growth

Within each scenario, CE uses Aurora – an industry-standard long-term capacity expansion (LTCE) model – to construct a least-cost candidate portfolio that satisfies capacity, energy, and policy requirements and reflects resource-specific operating characteristics, including forced outage rates, seasonal availability, and accredited capacity contributions.[9] Each candidate portfolio is evaluated through production cost

[9] Note that across load trajectories, CE performed optimization analysis that allows the model to select the least-cost portfolio of resources needed to meet system requirements. CE also evaluated the [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] to assess its effect on the overall resource mix, system costs, and the selection of other technologies.

simulation to assess dispatch behavior, energy market interactions, and NPVRR. The resulting portfolios are then compared against the scorecard of metrics described above to identify the portfolio that delivers the most balanced set of outcomes for customers.

1.3 The Preferred Course of Action

The PCA emerges from this structured comparison. As shown in Confidential Figure 1-2, by 2050 the PCA would add 9.8 GW of solar, 3.2 GW of wind, 3.3 GW of storage, 1.4 GW of demand response (DR), 3.5 GW of new CT capacity, a new PPA at the existing Midland Cogeneration Venture Limited Partnership (MCV) plant, a [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], and a 1.2 GW CCS resource entering service in 2040. The PCA also pursues an aggressive expansion of VPP capability through innovative load-shaping of EV charging. The portfolio's renewable, storage, and dispatchable resources are designed to work together. Renewable generation and storage supply increasing amounts of clean energy, while firm dispatchable resources such as the CTs provide operational flexibility and reliability support during periods of low renewable production and extended system stress.

Figure 1-2: Projected installed capacity mix under the PCA (MW) [CONFIDENTIAL]



[END CONFIDENTIAL]

The PCA builds on CE's existing portfolio of owned generation, PPAs, demand-side resources, and transmission assets. As part of the IRP process, the Company first evaluated the capability, expected performance, and ongoing contribution of existing resources to reliability, affordability, and clean energy objectives before identifying the

need for incremental resource additions. This assessment recognizes the value of [CONFIDENTIAL] [END CONFIDENTIAL], and customer-focused demand-side programs, which help satisfy future capacity needs, support emissions reduction goals, and moderate customer costs. By leveraging these resources, the PCA is able to defer or reduce certain new investments while maintaining a reliable and balanced path toward meeting future customer needs.

1.3.1 Four Central Resource Decisions

In addition to CE's continued commitment to new wind, solar, storage, and demand side measures, the PCA reflects four central integrated resource decisions: a new PPA with the MCV facility, securing the [CONFIDENTIAL] [END CONFIDENTIAL], building 1,400 MW of new CT capacity, and [CONFIDENTIAL] [END CONFIDENTIAL]. These decisions capture CE's strategic decision-making to serve growing load in a reliable, equitable, clean, and balanced manner. Each is briefly explained below.

MCV (1,240 MW): MCV is a natural gas-fired cogeneration facility located within CE's service territory and represents one of the Company's largest sources of dispatchable capacity. MCV avoids the development, permitting, construction, and technology risks associated with new-build generation while providing proven operational performance and reliability. MCV supplies accredited capacity across MISO's seasonal resource adequacy framework and provides operational flexibility to respond to changing system conditions, periods of peak demand, and variability from renewable generation. Retaining and optimizing the value of MCV allows the Company to leverage an existing, well-understood generating resource while supporting reliability and affordability during the transition to a cleaner resource portfolio. As a mature facility with established infrastructure and fuel supply arrangements, MCV provides a known and dependable resource that complements the PCA's broader clean energy strategy.

[CONFIDENTIAL] [END CONFIDENTIAL]

New CTs (1,375 MW): The new CTs replace the retiring Karn 3 and 4 units and provide firm, dispatchable capacity during periods of peak demand and system stress, forming the reliability foundation of the PCA. CTs perform reliably under MISO's evolving seasonal and DLOL accreditation framework, can be sited and brought online on timelines aligned with customer needs, and preserve flexibility to scale the portfolio to serve incremental large-load growth as it materializes. They also reduce CE's exposure

to the MISO energy market and high-priced emergency purchases during peak conditions. As a commercially mature, well-understood technology with limited deployment risk, CTs provide an effective near-term complement to longer-duration clean firm resources. Locating a CT within LRZ 7 would also help hedge against uncertainty associated with importing capacity from the broader MISO market. CTs also serve as a reliability anchor for a portfolio with growing levels of renewable generation and energy-limited resources, providing dispatchable capacity during periods of low renewable output and extended system stress when storage resources may be constrained.

CCS (built in 2040): CCS is selected as a long-term clean firm resource across all load trajectories, but the timing of its deployment differs across portfolios. The PCA builds CCS in 2040, by which time CE expects to incorporate cost and performance learnings from first-of-a-kind CCS projects deployed elsewhere in the industry, reducing capital cost risk and increasing confidence in deliverability. Earlier deployment (as soon as 2035) is feasible in modeling and can appear lower-cost on a deterministic basis, but it would require CE to commit to a first-of-a-kind technology before industry learnings are available, and, under the PLG trajectory, without a sufficiently large new-customer base over which to defray the associated first-of-a-kind risk. The PCA's approach captures CCS as a long-term clean firm resource while limiting CE's exposure to first-of-a-kind technology and construction risk.

1.4 Why the PCA

The PCA was selected because it delivers the most balanced performance across CE's evaluation criteria, and because no alternative portfolio outperforms it across all four. The key reasons supporting selection are summarized below.

- **Offers balanced performance across metrics.** The PCA performs at or near the top across the full scorecard. Modeling under stressor combinations, including high load, low resource availability, and adverse weather, confirms that the PCA performs robustly relative to alternatives that rely more heavily on market purchases or non-firm capacity.
- **Preserves reliability for existing customers.** Securing dispatchable, energy-dense resources with the CTs, MCV PPA, and [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], the PCA preserves reliability outcomes at the lowest cost, even without data center growth. Although unlikely given signed large-load interconnection agreements, the analysis under the BAU load trajectory demonstrates that these investments are prudent from a cost and reliability perspective, regardless of large load outcomes. These resources provide dependable capacity and energy during periods when renewable output is reduced or energy-limited resources are unable to sustain extended reliability events.
- **Delivers lowest cost at equivalent reliability.** The PCA delivers the lowest customer rates among the portfolios that meet CE's reliability standard, projected to track at or below the alternatives across the planning horizon. The PCA secures the CTs, the MCV PPA and the [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] at comparable or lower cost than storage-heavy

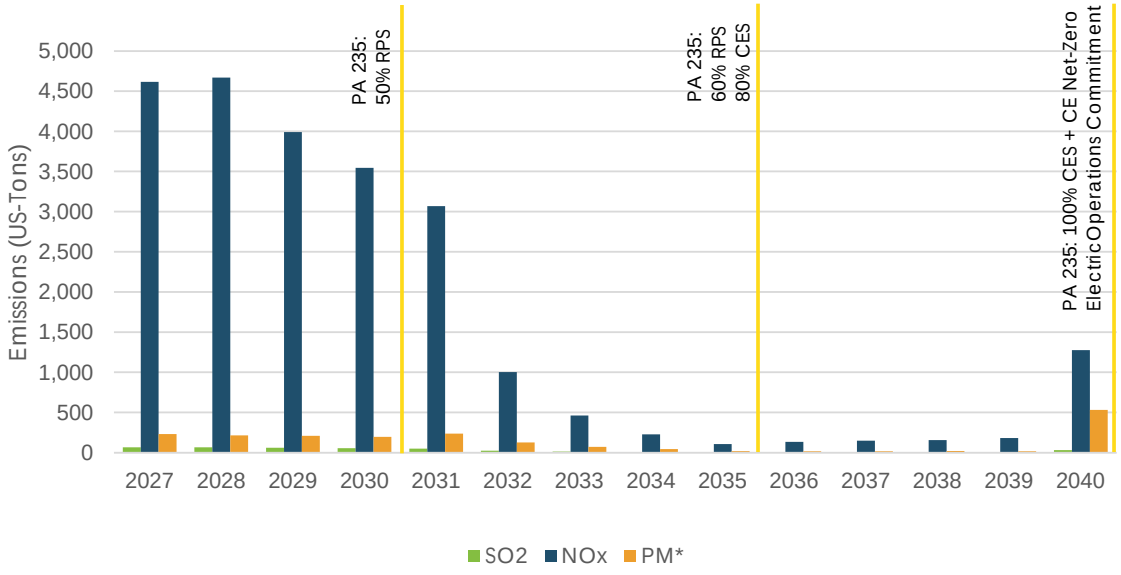
alternatives, with materially lower reliability risk. CE's reliability and market exposure analysis demonstrates that incremental storage alone is insufficient to maintain reliability under current conditions, particularly given DLOL uncertainty for storage and tightening conditions in LRZ 7.

- **Maintains portfolio diversity.** Consistent with Michigan Public Service Commission (MPSC or the Commission)values, the plan maintains a balanced and adaptable resource portfolio across multiple dimensions, including fuel type, resource attributes, ownership structure, geography, development status, and exposure to EJ communities. Rather than relying on a single technology or development pathway, CE combines existing and near-term resources with renewable, dispatchable, and emerging clean firm options. This reduces concentration, timing, and execution risk while preserving flexibility to respond to changing load, market, and technology conditions.
- **Protects customers through structured large-load contracts.** Service arrangements with new large-load customers are structured such that those customers bear the cost of the resources required to serve their demand and contribute their share of the existing portfolio, limiting cost impacts on existing residential, commercial and industrial customers. The PCA's resource mix also continues to reduce emissions intensity for the customer base as a whole. The Rate Contract enables service to a large data center while protecting existing customers by requiring the customer to pay standard rates and the incremental costs of serving its load, supported by minimum billing, exit-fee, guaranty, and collateral protections.
- **Builds local generation in LRZ 7.** The new CTs, together with local renewable and storage additions, contribute firm, energy-dense capacity within CE's own footprint, hedging against uncertainty in DTE Electric's resource decisions and local reserve margin requirements.
- **Ensures equitable outcomes.** The PCA expands clean generation serving EJ communities and manages rate-impact pressures on those customers. The new CTs are sited in energy communities that have hosted CE facilities historically, with established stakeholder engagement, demonstrated local support, and continued local tax revenue contributions.
- **Demonstrates resource value to customers.** The resources needed to match new large-load growth expand upon, rather than displace, the resources CE would otherwise have built, and supports the conclusion that large-load customers help defray costs that benefit the broader customer base. Notably, in the BAU case, deterministic modeling can show earlier CCS deployment (as soon as 2035) appearing lower-cost on paper (Support 1c/2021 IRP); however, that pathway would require CE to commit to a first-of-a-kind technology in 2035 without a large-customer base to absorb the associated cost and technology risk — an exposure CE does not consider prudent for legacy customers to bear. While currently expected to be added in 2040, the Company recognizes potential for the CCS to be deployed flexibly, with the CC element of the resources added as early as 2035, while the CCS elements are added later.
- **Expands VPP capability through next-generation EV load-shaping.** The PCA scales CE's demand-side portfolio through an innovative VPP program that shifts EV charging toward daytime hours to align with periods of high solar output and evolving peak conditions. This approach enables CE to onboard new EV load while minimizing its impact on peak system stress conditions, capturing distributed

resource value in advance of broader DER adoption in Michigan, and providing a flexibility lever that can scale with adoption over time.

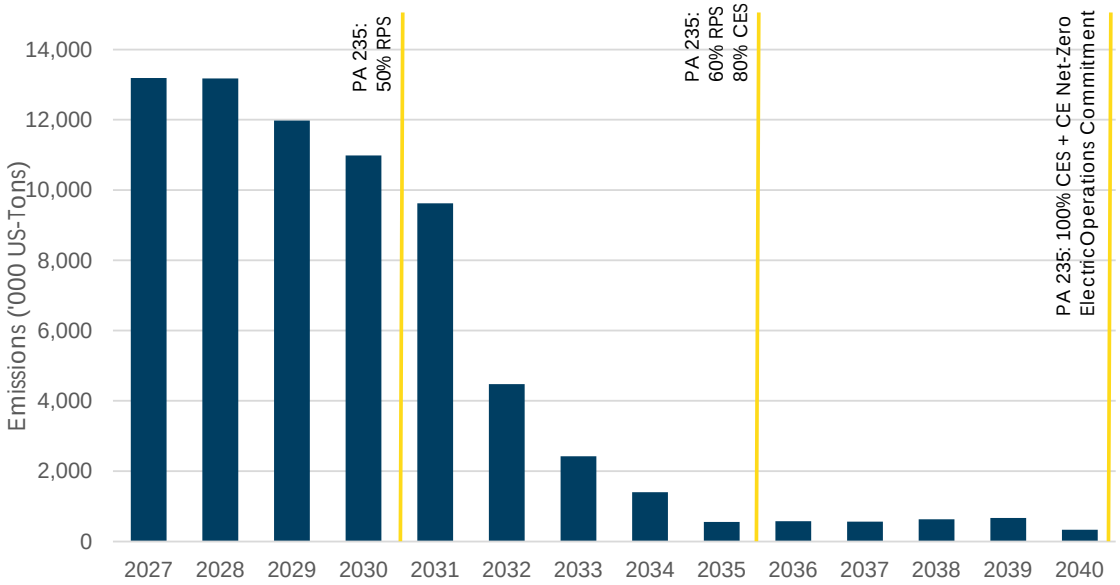
- **Advances clean energy progress.** The PCA continues CE's trajectory toward a cleaner resource portfolio, achieving 100% clean energy and 72% renewable energy by 2040, and reducing CO_2 emissions by approximately 99% by 2040 relative to 2005, as shown in Figure 1-3 and Figure 1-4. These outcomes meet or exceed the Company's obligations under the Michigan CES, the associated Renewable Energy requirements, and Act 235's energy storage target. Clean energy progress is delivered through a combination of continued retirement of legacy generation, [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], the substantial buildout of an additional 9.8 GW of solar and 3.2 GW of wind, the 3.3 GW of storage that enables higher renewable utilization, sustained investment in EWR and DR, and [CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. The PCA achieves this trajectory without taking on first-of-a-kind technology risk in the near term.

Figure 1-3: Annual SO2, NOx, and PM emissions of the PCA portfolio under MSO conditions



*CE-only emissions. PM emission rates not available for PPAs.

Figure 1-4: Annual CO2 emissions of the PCA portfolio under MSO conditions



The PCA represents the most reasonable and prudent path forward during a period of significant uncertainty and change. CE's structured comparison of optimized portfolios across a range of plausible load outcomes confirms that no alternative portfolio outperforms the PCA across all four evaluation criteria. As shown in Figure 1-5 and Figure 1-6Figure 1-6,[10] the PCA maintains resource adequacy and energy sufficiency throughout the planning horizon, with accredited capacity remaining above projected peak demand and sufficient annual energy available to serve growing customer requirements. The portfolio combines existing generation resources with incremental additions of renewable generation, storage, dispatchable capacity, virtual power plant capability, and clean firm resources, creating a diverse and balanced resource mix that minimizes stranded asset risk while preserving flexibility to adapt to future load growth and evolving technology and policy conditions. Accordingly, CE respectfully requests Commission approval of the PCA and the associated near-term resource commitments set forth in this filing.

s energy from the MISO market when doing so is lower cost for customers. Thus, in some years, total generation from CE resources may be below total demand requirements, with the balance met by energy purchases.

Figure 1-5: Summer season accredited capacity relative to peak load under the PCA
[CONFIDENTIAL]



[END CONFIDENTIAL]

Figure 1-6: Annual energy supply and demand under the PCA [CONFIDENTIAL]



[END CONFIDENTIAL]

The PCA will be implemented through a phased approach that combines continued use of existing resources with targeted investments in new generation, renewable and clean resources, energy storage, and demand-side programs. Near-term actions include securing key capacity resources and advancing planned generation projects, while preserving flexibility to adapt to changes in load growth, market conditions, technology costs, and regulatory requirements. This approach supports reliability, affordability, and compliance with Michigan's clean energy objectives.

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Introduction

Section 4

4 Introduction

4.1 Purpose of the Integrated Resource Plan

CE submits this IRP and CEP to establish a long-term strategy for serving customers' electricity needs while maintaining reliability, affordability, environmental stewardship, and compliance with Michigan law. This filing evaluates resource needs and alternatives across the 2029 through 2045 planning period and identifies a PCA that balances customer interests under a wide range of future operating conditions. The IRP serves as the Company's roadmap for resource planning and investment, demonstrating how CE intends to meet projected energy and capacity requirements while advancing Michigan's evolving clean energy objectives.

Integrated resource planning requires utilities to evaluate a broad range of supply-side and demand-side options, including utility-owned generation, purchased power, renewable resources, energy storage, DR, VPPs, DERs, and energy efficiency programs. Through this process, the Company evaluates the relative costs, benefits, risks, and reliability contributions of competing resource alternatives to identify a resource strategy that is reasonable, prudent, and in the public interest. The selected PCA reflects CE's assessment of how best to balance reliability, affordability, clean energy progress, equity, and flexibility while continuing to meet the needs of existing and future customers.

4.2 An Evolving Planning Environment

The electric industry is undergoing a period of significant transformation. Since the Company's previous IRP filing, planning assumptions regarding customer demand growth, resource adequacy, clean energy requirements, and emerging technologies have shifted substantially. These changes require utilities to make resource decisions under a greater degree of uncertainty while continuing to provide safe, reliable, and affordable service to customers.

One of the most significant developments affecting resource planning is the emergence of unprecedented large-load growth. Economic development opportunities, particularly those associated with data centers and energy-intensive manufacturing facilities, are creating the potential for substantial increases in electricity demand throughout Michigan. CE has already executed agreements representing significant new load additions and continues to evaluate a broader pipeline of prospective customers. At the same time, increasing EV adoption and broader electrification trends are expected to contribute to future demand growth. These developments create opportunities for economic growth while also requiring careful planning to ensure that infrastructure investments are made in a manner that protects existing customers from unnecessary cost exposure.

Resource adequacy considerations have also become increasingly important. Across the MISO region, growing demand, generator retirements, evolving accreditation methodologies, and changing market conditions have increased focus on maintaining

reliable electric service during periods of system stress. MISO's ongoing implementation of seasonal resource accreditation and DLOL methodologies introduces additional uncertainty regarding the future capacity value of various resource types. As a result, utilities must evaluate not only the cost and environmental attributes of potential resources, but also their ability to contribute to reliability under evolving market rules and operating conditions.

At the same time, Michigan's policy framework continues to evolve. Recent clean energy legislation establishes ambitious renewable energy, clean energy, energy storage, and energy efficiency requirements that must be incorporated into utility resource planning efforts. CE's resource strategy must therefore satisfy multiple objectives simultaneously: maintaining reliable service, supporting affordability, enabling economic growth, and advancing compliance with Michigan's clean energy policies. The Company's planning process reflects a commitment to achieving each of these objectives in a balanced and cost-effective manner.

4.3 Planning Objectives and Guiding Principles

The Company's planning objectives are grounded in the requirements of Public Act 341 of 2016 (Act 341) and MCL 460.6t, which requires the Commission to evaluate whether an IRP represents a reasonable and prudent means of meeting customers' long-term energy and capacity needs. Consistent with these statutory requirements, CE developed and evaluated resource plans using a framework that balances reliability, affordability, environmental performance, risk management, and compliance with state energy policy objectives.

While the specific planning environment facing the Company has evolved significantly since its previous IRP filing, the fundamental objectives that guide resource planning remain unchanged. The Company evaluated potential resource portfolios against the following core planning considerations.

Resource Adequacy and Capacity Requirements (MCL 460.6t(8)(a)(i))
CE must ensure that sufficient resources are available to satisfy customer demand and applicable reserve requirements under the MISO resource adequacy framework. The Company's resource strategy must meet forecasted energy and peak demand requirements while satisfying planning reserve margin obligations, local resource adequacy requirements, and evolving MISO accreditation rules. Reliable electric service remains a foundational obligation of the Company and a central objective of this IRP.

Compliance with Environmental Regulations and Clean Energy Requirements (MCL 460.6t(8)(a)(ii))
The Company must comply with applicable federal and state environmental requirements, Michigan's Renewable Energy Standard, Clean Energy Standard, Energy Waste Reduction requirements, and energy storage obligations established under Act 235. These requirements are incorporated directly into the IRP modeling framework and inform both resource selection and portfolio evaluation. The Company also recognizes that future environmental regulations and clean energy policies may continue to

evolve over the planning horizon and therefore seeks to maintain flexibility while making continued progress toward Michigan's clean energy objectives.

Competitive Pricing and Customer Affordability (MCL 460.6t(8)(a)(iii) and (viii))
Providing reliable electric service at the lowest reasonable cost remains a core planning objective. Resource alternatives were evaluated based on their impact on customer costs, NPVRR, and long-term affordability. Given the emergence of substantial large-load demand, the Company also evaluated resource strategies with a focus on protecting existing residential and commercial customers from bearing costs associated with serving new customer growth. The PCA reflects the Company's assessment of the most cost-effective portfolio capable of balancing reliability, clean energy progress, and affordability objectives.

Reliability (MCL 460.6t(8)(a)(iv))
In addition to meeting planning reserve requirements, CE evaluated resource portfolios based on their ability to maintain reliable service during periods of peak demand, extreme weather, low renewable output, generator outages, and other system stress conditions. The Company also assessed reliability using probabilistic tools, including LOLE analysis, to better understand the resilience of alternative portfolios under uncertain future conditions. These analyses are intended to ensure that the selected resource strategy can continue to provide reliable service as the electric system evolves.

Commodity Price Risk (MCL 460.6t(8)(a)(v))
Long-term resource planning requires consideration of uncertainty related to natural gas prices, energy market prices, capacity market outcomes, technology costs, and broader economic conditions. CE evaluated these uncertainties through multiple scenarios, sensitivities, and stress tests designed to assess the performance of alternative resource portfolios under a range of plausible futures. Maintaining a diversified portfolio of resources helps moderate customer exposure to commodity price volatility and changing market conditions over the planning horizon.

Diversity of Generation Portfolio (MCL 460.6t(8)(a)(vi))
Portfolio diversity remains an important risk-management consideration. CE evaluated a broad range of supply-side and demand-side resources, including existing generation, renewable energy, battery storage, DR, VPPs, DERs, market purchases, and new dispatchable generation technologies. The PCA reflects a balanced resource strategy that leverages multiple technologies and resource types, reducing reliance on any single fuel source, technology pathway, or market outcome while preserving flexibility to adapt as conditions change.

Cost-Effective Energy Waste Reduction, Demand-Side Resources, and Renewables and overall cost effectiveness (MCL 460.6t(8)(a)(vii) and (ix))
CE recognizes the important role that EWR programs, DR, VPP, DERs, renewable generation, and energy storage play in meeting customer needs. These resources can reduce peak demand, avoid or defer infrastructure investments, support clean energy compliance, and improve overall system efficiency. Accordingly, the Company evaluated demand-side and renewable resources alongside traditional supply-side

resources throughout the IRP process and incorporated them as integral components of the PCA.

Additional Planning Considerations
While the factors identified in MCL 460.6t(8) remain the foundation of the Company's planning framework, CE also considered a number of emerging issues that have become increasingly important since its prior IRP filing. These include large-load growth associated with data centers and economic development, evolving MISO accreditation methodologies, equitable customer outcomes, EJ considerations, technology maturity and deployment risk, and the need to maintain flexibility under uncertain long-term conditions. These considerations informed both portfolio design and selection of the PCA and are discussed throughout this filing.

4.4 Consumers Energy System Overview

4.4.1 Service Territory and Customer Base

CE provides electric service to residential, commercial, and industrial customers across a large portion of Michigan's Lower Peninsula. The Company serves a diverse customer base that includes households, small businesses, large commercial customers, manufacturers, and an increasing number of energy-intensive facilities. This diverse customer mix creates a range of load characteristics and planning needs that must be considered throughout the IRP process. As discussed in Section 12, future demand growth is expected to be driven by both traditional customer growth and emerging end uses, including transportation electrification, data centers, and advanced manufacturing facilities.

4.4.2 Existing Resource Portfolio

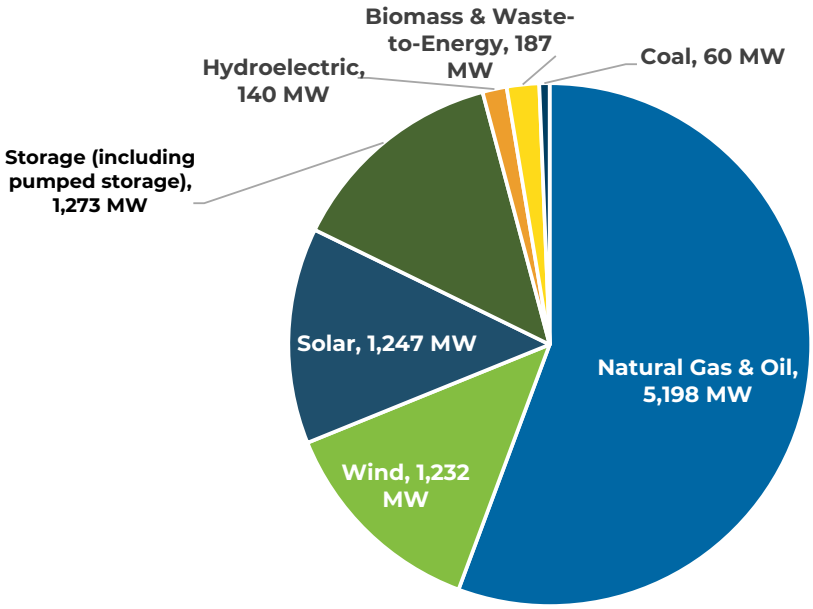
Consumers Energy's existing resource portfolio provides the foundation for the resource planning analyses presented in this IRP. The portfolio reflects decades of investment in generation, storage, and purchased power resources designed to provide reliable and affordable electric service across Michigan. Today, the Company's resource mix includes dispatchable natural gas generation, hydroelectric facilities, utility-scale wind and solar resources, energy storage, and a diverse portfolio of PPAs.

Owned generation resources such as the Covert, Zeeland, Jackson, and Karn facilities provide dispatchable energy and accredited capacity that support system reliability, while renewable resources including Lake Winds, Cross Winds, Gratiot Wind Farm, Crescent Wind, Heartland Wind, and Muskegon Solar contribute to compliance with Michigan's clean energy requirements. Energy storage resources, including the Ludington Pumped Storage Facility and utility-scale battery storage projects, provide additional operational flexibility and resource adequacy benefits.

In addition to Company-owned resources, Consumers Energy maintains an extensive portfolio of PPAs that provide energy, capacity, and renewable energy credits (RECs) from natural gas, renewable, hydroelectric, and storage facilities located throughout Michigan. Long-term contracts such as the MCV PPA continue to play a significant role in supporting reliability and affordability. Together, these owned and contracted

resources form a diverse portfolio that serves as the starting point for the IRP's evaluation of future resource needs.

Figure 4-1: Existing resource portfolio mix



4.4.3 Demand-Side Resources and Virtual Power Plants

Demand-side resources are an integral component of CE's resource strategy. Through EWR, DR, CVR, DG, managed EV charging, and time-varying rates, the Company can reduce energy consumption, lower peak demand, and improve system flexibility. These programs are evaluated alongside traditional supply-side resources throughout the IRP process.

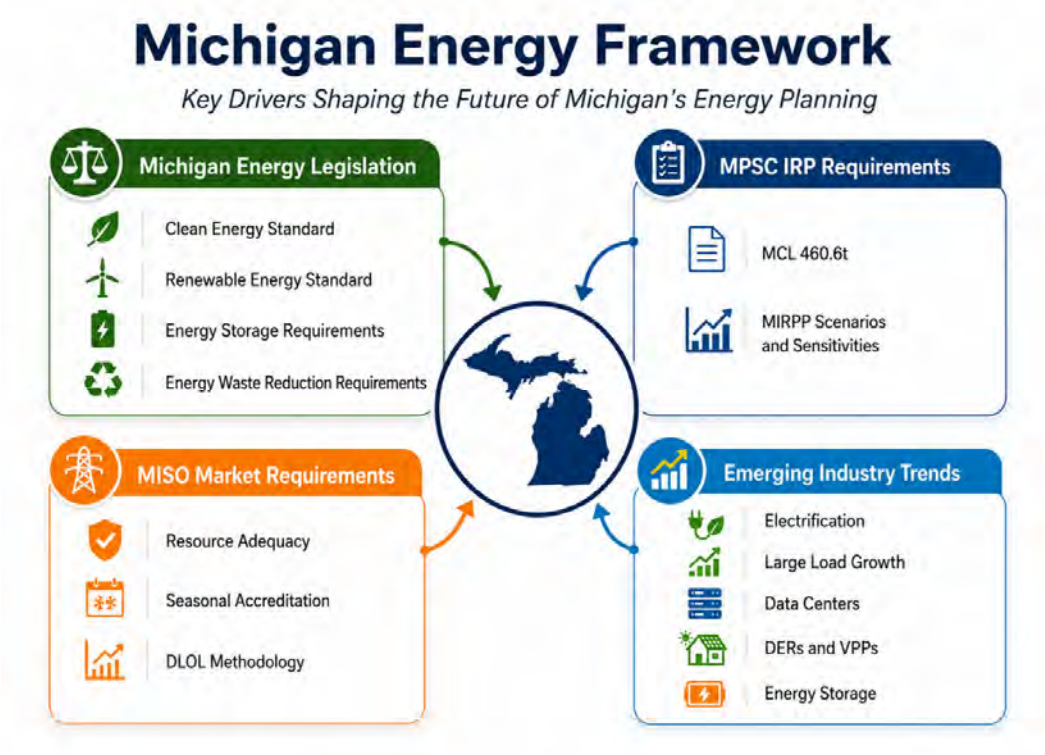
CE also recognizes that many of these programs provide capabilities commonly associated with VPPs. DR, managed EV charging, DG, and customer-sited technologies can collectively reduce demand, shift load, and provide distributed energy services during periods of system need. Rather than representing a distinct resource category, VPPs provide a framework for coordinating customer-side resources to support reliability, affordability, and system flexibility.

4.4.4 Peak Demand and Energy Forecast

An accurate load forecast is the foundation of the IRP. The forecast determines whether existing resources are sufficient to meet customer demand and identifies when additional resources may be required over the planning horizon. CE develops electric energy and peak demand forecasts using econometric models supplemented by assumptions regarding EVs, large-load customers, DG, EWR, Conservation Voltage Reduction (CVR), DR, and Retail Open Access (ROA) participation.

While historical load growth within the service territory has been relatively modest, future growth is expected to be influenced by several emerging drivers. Most notably, transportation electrification and large-load customers, including data centers and advanced manufacturing facilities, are expected to contribute significantly to future energy consumption and peak demand requirements. To capture this uncertainty, the Company evaluated multiple demand scenarios reflecting different assumptions regarding economic development, electrification, and large-load growth.

4.5 Market and Regulatory Environment



CE develops its IRP within a dynamic market and regulatory environment that influences resource planning, reliability requirements, and customer costs. The Company's planning process considers requirements established by the MPSC, Michigan energy legislation, federal environmental regulations, and market rules administered by MISO.

As a load-serving entity within MISO, CE must maintain sufficient accredited capacity to satisfy resource adequacy requirements. Recent changes to MISO's resource adequacy framework, including seasonal accreditation and DLOL methodologies, have increased the importance of evaluating resource performance across all seasons and resource types. These changes influence how generation, storage, and demand-side resources are valued within the IRP.

Michigan's energy policy framework has also evolved since the Company's previous IRP. Recent legislation established enhanced clean energy, renewable energy, energy storage, and EWR requirements that must be incorporated into long-term planning. Accordingly, CE evaluates resource portfolios capable of maintaining reliability and affordability while supporting compliance with applicable state energy policies.

At the same time, increasing electrification, DERs, demand-side programs, VPP capabilities, and growing interest from large-load customers are reshaping future energy and capacity needs. To address these evolving conditions, the Company evaluates multiple scenarios and sensitivities designed to assess portfolio performance under a range of potential futures.

4.6 IRP Planning Process

CE developed this IRP through a structured planning process designed to identify a resource strategy that reliably and cost-effectively meets customers' long-term energy and capacity needs. The process incorporated forecasts of future demand, evaluation of existing resources, assessment of potential resource options, and analysis of multiple future scenarios to address key planning uncertainties.

The Company evaluated a broad range of supply-side and demand-side resources, including generation, energy storage, EWR programs, DR, DERs, and market-based solutions. Alternative resource portfolios were assessed using established planning models and supporting analyses to evaluate reliability, affordability, risk, environmental performance, and compliance with applicable regulatory requirements.

Stakeholder engagement was an important component of the planning process. Feedback from stakeholders helped inform the development of assumptions, scenarios, and planning considerations evaluated throughout this IRP. The results of these analyses informed the selection of the Company's PCA.

Figure 4-2: Consumers Energy's IRP development process



Analytical Approach

Section 5

5 Analytical Approach

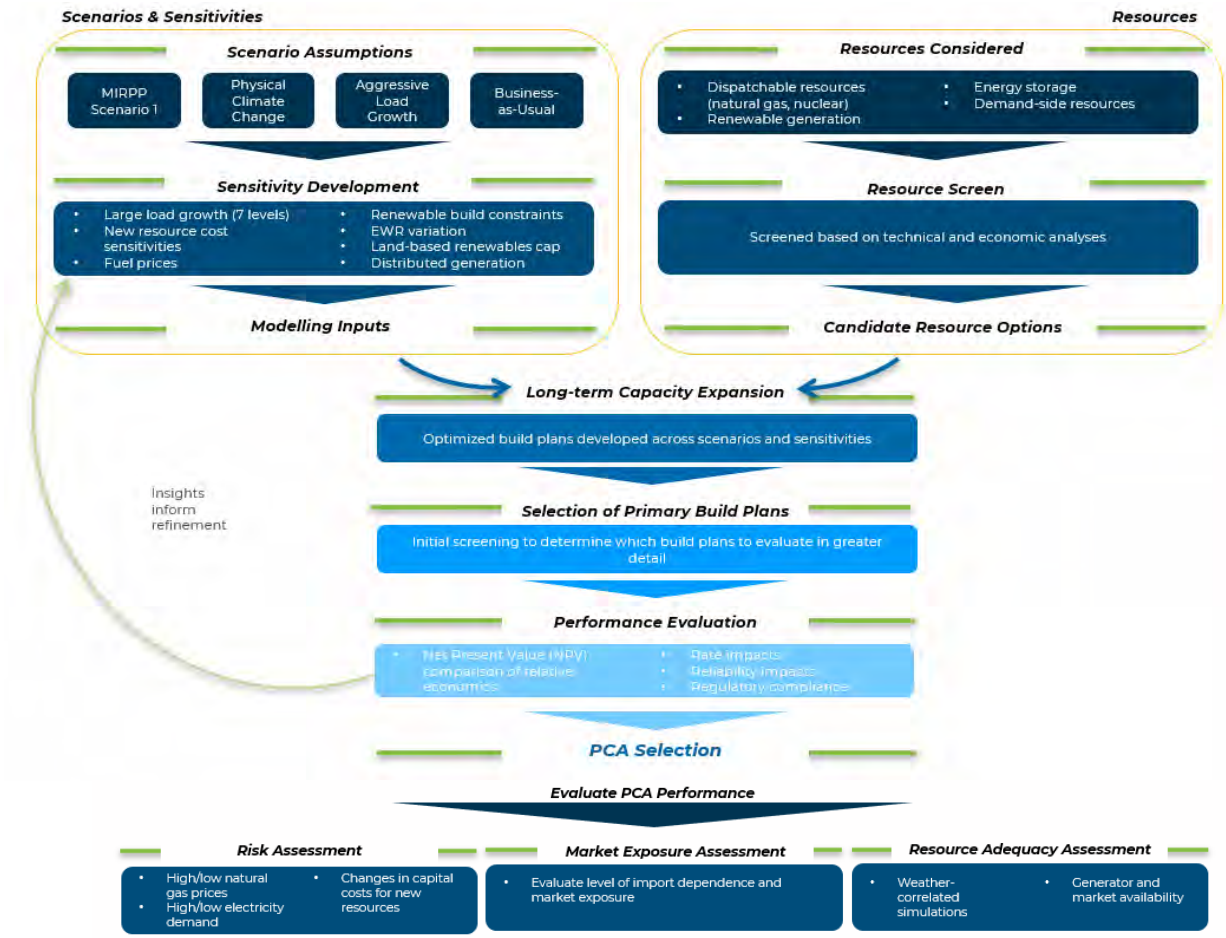
5.1 Modeling Process

The goal of the IRP modeling process is to generate an optimal resource portfolio to serve customers' electricity needs over the next 5-25 years at the lowest reasonable cost and risk, while meeting policy and reliability requirements. The optimal resource portfolios or resulting build plans are developed to meet capacity, energy, and regulatory needs while taking portfolio costs into account. This IRP evaluated capacity needs from 2026 through 2050. Under the base load forecast, given major changes to MISO's resource adequacy capacity market, the Company predicts a capacity shortfall beginning in 2028 and growing thereafter further exacerbated by contracted load growth and existing resource retirements. Alternative load growth trajectories were considered in the scenario and sensitivity development process. Modeling under these alternatives provided insight into how the Company can best position itself for flexibility and reliability as load conditions evolve.

Based on the identified supply and demand imbalance, least-cost capacity expansion optimizations are performed using generic candidate resources determined in a resource screen. The Company conducted a resource screening based on LCOE, levelized cost of available energy (LCOA), market value, and technology maturation and feasibility. This screening identifies the technologies that are viable for the model to consider when addressing the projected capacity shortfall and regulatory mandates. Using the Michigan Integrated Resource Planning Parameters (MIRPP) along with CE scenarios and sensitivities, and aligning with the IRP's principles and objectives, the model produces a long-term resource plan that performs robustly across a range of conditions, such as varying natural gas prices and declining capital costs.

To inform the long-term resource strategy, the Company undertook an extensive modeling analysis to examine which flexible resource options, and what mix of those options, could reliably serve customers' future electricity demand. An overview of the modeling and evaluation approach is provided in Figure 5-1 and discussed further in this section.

Figure 5-1: IRP modelling and assessment process



5.2 Modeling Methodology

5.2.1 Scenario Assumptions

Guided by the planning principles and objectives, scenarios are developed using distinct sets of underlying assumptions to evaluate resource needs and alternatives under uncertain future conditions. For each scenario, the model identifies the least-cost portfolio of resources that meets projected customer energy and capacity needs within the specified assumptions. Scenario analysis helps the Company and stakeholders assess which resource mixes remain resilient under changes affecting affordability, reliability, and market conditions.

CE developed four primary scenarios: BAU, Aggressive Load Growth (ALG), Physical Climate Change (PCC), and MIRPP Scenario 1 (MSO), as described in Section 6, Scenarios and Sensitivities. As discussed in Section 12, Peak Demand and Energy Forecasts, the Company subsequently refined its assessment of future customer demand as additional information regarding potential large-load customers became

available. This led to the development of the PLG and High Load Growth (HLG) forecasts, which were incorporated into the portfolio evaluation process to assess resource needs under a broader range of future demand outcomes.

5.2.2 Resource Screen

A broad range of resource technologies was considered in the modeling process to meet the Company's projected future capacity and energy needs. These resources were evaluated through both technical screening and an economic assessment using LCOE and market value metrics. The purpose of the resource screen is to identify technologies that are commercially feasible and economically competitive for inclusion in the modeling process. Because the model is designed to select least-cost resource portfolios, including options that are uneconomic or provide limited system value would not affect the outcome and would reduce modeling efficiency. The resource screen therefore focuses the analysis on viable alternatives under a consistent set of assumptions.

Table 5-1 lists the resources considered and the determination of the resource screen.

Table 5-1: Resources considered and screening determination

CATEGORY	TECHNOLOGIES CONSIDERED	DETERMINATION	REASONING
Dispatchable Firm Generation	2x1 H-Class CC	Include	Moderate cost, high accreditation resource
	1x1 H-Class CC	Include	Moderate cost, high accreditation resource
	1x0 F-class CT	Include	Low cost, high accreditation, flexible resource
	5x0 Reciprocating Engine	Include	Moderate cost, high accreditation, flexible resource
	2x1 H-Class CC + CCS	Include	High cost, high accreditation, clean baseload resource
	New Large-scale Nuclear	Include	High cost resource with elevated upside cost risk, long lead time
	SMR Nuclear	Exclude	Limited commercial maturity and long development timeline
	Fuel Cell	Exclude	Uncertain fuel availability, limited scalability
	Micro Turbine	Exclude	Limited scalability and unfavorable economics relative to alternatives
	Home Generators	Exclude	High cost, lack of coordinated dispatch
Renewable Generation	In-State Wind	Include	Moderate cost, energy rich resource, with good regional suitability
	Offshore Wind	Exclude	High cost resource with limited regional suitability in the Great Lakes
	Solar Photovoltaic (PV)	Include	Low cost, energy rich resource with moderate regional suitability
	Biomass	Exclude	Limited fuel supply and scalability
	Behind the Meter Biogas	Exclude	Limited methane available and scalability
	Landfill Gas	Exclude	Limited methane capture available and scalability
	Combined Heat and Power	Exclude	Requirement for site-specific opportunities, cannot be modeled generically
	Geothermal	Exclude	Limited regional viability, lack of commercially proven advanced geothermal options

CATEGORY	TECHNOLOGIES CONSIDERED	DETERMINATION	REASONING
Energy Storage	4-Hour	Include	Low cost, capacity rich resource, enables better round-the-clock renewable target compliance
	10-Hour	Include	Moderate cost, capacity rich resource, enables better round-the-clock renewable target compliance
	100-Hour	Include	Moderate cost, capacity rich resource, enables better round-the-clock renewable target compliance
	Compressed Air	Exclude	Low commercial maturity
	Flywheel	Exclude	Low commercial maturity
	Thermal	Exclude	Low commercial maturity
	Pumped Hydro	Exclude	Limited siting available for generic expansion
Existing Resource / Procurement Options	MCV PPA 2030-2040	Include	Existing operational resource providing capacity and energy benefits without new-build development risk
Demand-Side Resources & VPPs	EWR	Include (modeled separately)	Evaluated through demand-side potential studies and incorporated directly into modeling assumptions
	Demand Response	Include (modeled separately)	Provides capacity value and load flexibility; evaluated separately from supply-side resources
	CVR	Include (modeled separately)	Reduces system demand through voltage optimization
	Distributed Generation	Include (load forecast adjustment)	Reflected in load forecast rather than modeled as a selectable supply-side resource
	EV Charging / Managed Charging	Include (modeled separately)	Evaluated through demand-side modeling assumptions
	Behind-the-Meter Batteries / VPPs	Include (modeled separately)	Evaluated separately as distributed demand-side resources

The resource screening process evaluated a broad range of existing and new supply-side, procurement, and demand-side options that could help meet the Company's future capacity, energy, clean energy, and reliability needs. These included existing generating assets, contractual resources, potential contract extensions or replacements, and new-build technologies. Demand-side resources, including EWR, DR, distribution efficiency measures, DG, managed EV charging, and other DERs, were incorporated through separate forecasting and modeling assumptions. Together, these options formed the set of viable alternatives considered in the portfolio optimization analysis.

Additional details on the screening methodology are provided in Section 16, Resource Screen.

5.2.3 Sensitivity Development

Sensitivities are modeling variations that differ from the foundational assumptions defining each scenario. Unlike scenarios, which represent distinct future conditions based on a consistent set of underlying assumptions, sensitivities modify a single assumption within a given scenario to assess its impact on outcomes. They serve as a form of risk assessment by evaluating how uncertainty in individual variables affects resource planning outcomes. The resulting resource portfolios and NPVs illustrate how changes in key inputs affect planning results. For example, if a modeled portfolio includes natural gas generation, adjusting the natural gas price forecast tests how resource decisions could shift under different fuel cost conditions. Both required and

Company-specific sensitivity analyses were applied to the base portfolios of each scenario.

The following sensitivities were included in the analysis:

- High/low natural gas prices
- High/low capital cost
- High/low load incremental large load steps
- Extreme weather / outage sensitivities
- Federal, state, and regional policy changes
- Transmission cost and capabilities
- DG
- EWR
- Renewable availability/build constraints

Additional details on the scenarios and sensitivities included in the analysis are provided in Section 6, Scenarios and Sensitivities. The impacts of large load assumptions on total system costs, NPVRR, and customer rate impacts are evaluated in Section 17, Modeling Results, and Section 19, Rate Impact, Financial Information, and Affordability.

5.2.4 Stressor Development

Stressors are developed as part of the risk assessment, and are similar to sensitivities in that they modify individual input assumptions. Some of the same variables were modified but applied to stress portfolio performance rather than development. Rather than analyzing how build decisions change under different input assumptions, stressors analyze how a portfolio, once established, varies in dispatch, cost, and other performance metrics under modified assumptions.

The following stressors were included in the risk assessment:

- High/low natural gas prices
- High/low capital cost
- High/low load incremental large load steps

5.2.5 Modeling Tools

CE relies upon the Aurora LTCE module to evaluate various combinations of available demand-side and supply-side alternatives to meet future resource requirements. The data associated with the supply-side and demand-side alternatives is inputted into Aurora to evaluate each of the alternatives equally. The resource alternatives considered for the demand-side and supply-side integration were the resources remaining after the initial resource screening. The screening process considered not only levelized cost metrics but also resource availability and reliability characteristics. Technologies that provide firm capacity value were evaluated based on their ability to contribute to resource adequacy and system reliability in addition to energy production costs. The outcome of the resource screen is presented in Table 5-1. The alternatives were assumed to be available by the beginning of a planning year (PY) that follows the capacity and reliability requirements of MISO. The resulting build plans were tested for robustness using sensitivity analyses and NPV comparisons.

Aurora's LTCE module develops resource portfolios by co-optimizing capacity additions and system operations across the planning horizon. The model evaluates candidate resources over all years of the study period and simulates system operations on an hourly basis to identify the least-cost portfolio capable of meeting projected customer needs. In doing so, the model simultaneously evaluates hourly energy requirements, seasonal capacity obligations, renewable and clean energy standards, operational constraints, and resource economics. This approach allows the optimization to identify resource portfolios that meet customer demand at all times of the year while satisfying applicable planning and regulatory requirements

The optimization model incorporates resource-specific characteristics such as forced outage rates, maintenance schedules, seasonal availability, and zonal resource credits (ZRCs) generation profiles, operational constraints, and resource availability. Seasonal accreditation values and associated ZRC assumptions are aligned with MISO's DLOL framework and reflect how resource performance varies across the summer, fall, winter, and spring planning seasons. Hourly load forecasts and resource production profiles are used to evaluate each resource's contribution to meeting energy and capacity requirements throughout the planning horizon. These assumptions allow the optimization to capture the differing operational characteristics of dispatchable generation, renewable resources, energy storage, contractual resources, and demand-side resources when selecting resource portfolios.

To maintain resource adequacy, the model ensures that the accredited capacity of selected resources meets the capacity obligation determined by the load forecast and reserve margin applied. The resulting build plans are subsequently evaluated through sensitivity analyses, stress testing, and reliability assessments to confirm portfolio robustness under a range of future conditions

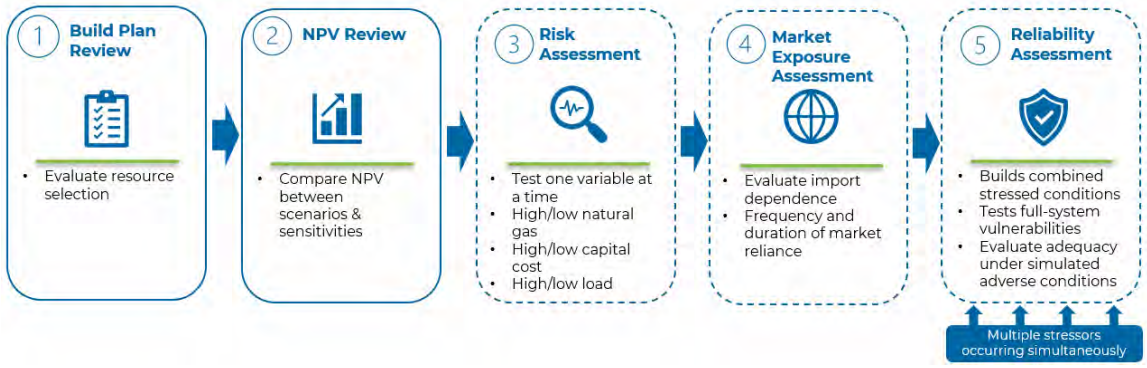
Portfolio optimization is carried out beginning with the five scenarios of load and market conditions. These scenarios described further in Section 5.26 define the load trajectory (further discussed in Section 12), MISO market prices, and commodity prices against which the Company's resources are dispatched. Under each scenario, capacity expansion modeling is performed iteratively using resource eligibility assumptions defined by each sensitivity. The PLG scenario served as the primary optimization case for developing CE's PCA, with capacity expansions selected on a least-cost basis to serve CE's most probable load environment. The same resource eligibility combinations are also used under BAU, ALG, and PCC scenarios to evaluate how different system conditions could affect portfolio performance and resource needs. While these scenario cases did not independently determine the PCA, the results provided important insights into risks, tradeoffs, and resource needs across a broader range of futures. These insights were then used to inform the development and evaluation of BAU-optimized portfolios, with the final PCA selected based on the BAU optimization results and consideration of risks identified across the broader scenario analysis.

5.3 Results Analysis Methodology

The IRP process aims to select a resource portfolio that minimizes risk to customers across several key areas. The economic evaluation process involves four steps including build plan review, NPV review, cost risk assessment, market exposure assessment, and reliability assessment. Together, these analyses provide insight into portfolio performance across a range of future conditions and support selection of the PCA. These steps are shown in Figure 5-2.

In addition to the resource portfolios developed through optimization, the PCA and Utility Alternative were evaluated under the applicable MIRPP-required scenarios and sensitivities to assess the robustness of each portfolio under varying assumptions regarding load growth, fuel prices, resource availability, policy conditions, and other key drivers.

Figure 5-2: Results analysis process



5.3.1 Build Plan Reviews

The build plan review process involves an evaluation of the annual capacity selection of each resource type over the modeling horizon. Performing many capacity expansion iterations under various scenario and sensitivity combinations defines a range of optimal outcomes. Understanding the range and trends in resource selection is essential to selecting a PCA that is well-positioned to respond to the various market conditions and resource availability options explored in scenario and sensitivity development. It bolsters understanding of the tradeoffs between resources as elements such as load growth, availability of EWR measures, and gas prices are modified. The build plan review and resource selection outcomes are presented in Section 17, Modeling Results.

5.3.2 NPV Review of Build Plans

Evaluating the NPV of the resulting build plans is an important step in understanding the implications of resource selection for customer affordability. NPV outcomes are compared across build plans to ensure that the PCA maintains affordability. The NPV of each portfolio is further used in a model that forecasts rate impact across customer classes.

5.3.3 Risk Assessment

Following resource selection, candidate portfolios were evaluated under a series of stressors and sensitivity analyses to assess the potential impacts of uncertainty on portfolio cost, resource utilization, and overall performance. Whereas capacity expansion modeling identifies resource portfolios that satisfy planning requirements under a defined set of assumptions, risk assessment evaluates how portfolio outcomes change when key assumptions vary.

The risk assessment focuses on the affordability and robustness of resource plans by examining the effects of changes in key planning variables, including electric demand, natural gas prices, capital costs, renewable resource performance, and other factors that may influence future system costs. Sensitivity analysis serves as a form of risk assessment by isolating individual variables and evaluating their effect on planning outcomes while holding other assumptions constant. This approach helps identify the factors that have the greatest influence on customer costs and portfolio performance across a range of plausible future conditions.

5.3.4 Market Exposure Analysis

In addition to evaluating portfolio cost and reliability, the Company evaluated the degree to which resource portfolios rely upon energy and capacity from external markets. Market exposure is an important planning consideration because resource portfolios may exhibit similar reliability performance while relying on different levels of external market support. Portfolios with greater capability within the CE portfolio generally require fewer imports during periods of system stress, while portfolios with greater dependence on energy-limited or weather-dependent resources may rely more heavily on market purchases during certain operating conditions.

The market exposure assessment evaluated the frequency, duration, timing, and magnitude of import dependence that are representative of a wide range of operating conditions. These assessments were used in conjunction with reliability and economic analyses to better understand portfolio robustness under a range of future market and system conditions.
The findings from the market exposure assessment provided additional insight into the tradeoffs among resource portfolios and supported evaluation of reliability, affordability, and system resilience objectives.

5.3.5 Resource Adequacy Analysis

The electric resource adequacy analysis evaluates the ability of candidate resource portfolios to reliably serve customer demand under a broad range of operating conditions. While capacity expansion modeling ensures compliance with resource adequacy requirements and planning constraints, additional analysis is required to assess portfolio performance under uncertainty and to quantify reliability risks at the Company level. Reliability assessment therefore provides a complementary evaluation of portfolio performance beyond the capacity expansion model results.

The Company's resource adequacy analysis evaluates portfolio performance using a probabilistic, Monte Carlo-based simulation framework implemented within the Aurora production cost model. The analysis incorporates uncertainty in electric load,

renewable generation output, thermal generator availability, and market availability using weather-correlated simulations and stochastic outage modeling. These inputs are evaluated jointly to capture conditions that can contribute to system stress, including periods of high load, low renewable output, resource outages, and limitations on external market support.

Reliability risk was evaluated using three complementary metrics:

- **LOLE**, measured in event-days per year, which quantifies how frequently resource shortfalls occur;
- **Loss of Load Hours (LOLH)**, measured in hours per year, which quantifies the duration of resource shortfall events; and
- **Normalized Expected Unserved Energy (nEUE)**, measured in parts per million, which quantifies the magnitude of unserved energy relative to total customer demand.

Together, these metrics capture distinct dimensions of risk, how often shortfalls occur, how long they persist, and how severe they are, consistent with current industry best practices and evolving guidance from MISO, North American Electric Reliability Corporation (NERC), and other reliability organizations. These metrics are used to evaluate whether additional capacity resources are required beyond the initial capacity expansion model results to satisfy the Company's reliability criteria. LOLE evaluates the frequency of resource shortfalls, LOLH evaluates the duration of those events, and nEUE evaluates their severity. Evaluating all three metrics allows the Company to assess not only whether shortfalls occur, but also the customer impacts associated with those events.

5.4 Summary of Evaluation Metrics

The findings from these assessments informed resource plan selection by identifying resource portfolios that maintained acceptable cost, reliability, and compliance performance across a broad range of future conditions. The PCA was selected because it demonstrated robust performance across scenario, sensitivity, reliability, and risk assessments while maintaining compliance with applicable planning objectives, as described in Table 5-2.

Table 5-2: Risk assessment evaluation metrics

ASSESSMENT	PRIMARY METRIC	KEY FINDING	IMPACT ON PCA
LTCE Optimization	NPV	Resource selections consistently favored storage, renewables, CTs, MCV PPA, and [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] under multiple futures	Informed PCA resource mix
Scenario Analysis	Portfolio cost and build plan	PCA performed robustly across required scenarios	Supported PCA selection
Sensitivity Analysis	Delta NPV / resource selections	Load growth, fuel prices, and capital costs were major drivers of portfolio outcomes	Supported flexible resource strategy
Risk Assessment	Risk metrics from stochastic analysis	PCA maintained acceptable cost and reliability performance across modeled futures	Supported final PCA recommendation
Market Exposure Assessment	Import dependency, duration, and magnitude of market reliance	Portfolios exhibited varying levels of dependence on external market purchases during periods of system stress.	Informed evaluation of resilience and resource adequacy tradeoffs
Reliability Assessment	LOLE, LOLH, nEUE	Additional accredited capacity was required beyond LTCE outputs in some cases	Influenced final capacity additions

Scenarios & Sensitivities

Section 6

6 Scenarios & Sensitivities

6.1 Scenarios

The IRP evaluates a set of core planning scenarios and BAU-based load-growth refinements designed to capture a range of plausible future conditions under which CE may operate. They are also intended to evaluate the Company's current CEP in compliance with the MIRPP. The MIRPP establishes two core modeling scenarios for utilities in the Michigan portion of MISO Zone 2 and Zone 7 applicable to CE. Scenario 1 is required. Scenario 2 is optional and may be replaced by a utility-created scenario where the MIRPP assumptions are no longer applicable.

In compliance with MCL 460.6t(1)(f), CE evaluated MIRPP scenarios, modeling MSO consistent with the prescribed assumptions, and, exercising the utility option provided under the MIRPP, replaced Scenario 2 with CE's BAU scenario. Additional CE scenarios, ALG, and PCC are included to better understand the optimal utility response to a future involving more significant Economic Development Load, or more aggressive Decarbonization within the Company and regional systems.

The scenarios can be viewed as two complementary dimensions of uncertainty. The first dimension evaluates alternative decarbonization pathways through MSO and PCC. The second evaluates alternative economic development load trajectories through BAU, PLG, and ALG. Together these scenarios allow CE to evaluate resource needs across a broad range of future conditions.

Table 6-1: Summary of CE scenarios

FUTURE TYPE	SCENARIO	DESCRIPTION
Decarbonization Futures	MSO	MPSC IRP planning scenario that represents an accelerated energy transition future, with significant electrification, strong load growth, widespread decarbonization, high renewable deployment, and 80% MISO-wide carbon reduction by 2042. It is aligned with MISO Future 3a.
	PCC	Nearly identical to MSO, differing primarily in its EWR assumptions.
Economic Development Load Futures	BAU: Base Planning Outlook	CE's utility-specific replacement for MIRPP Scenario 2. Aligned with MISO Future 2a, it represents a moderate transition pathway with more modest load growth, electrification, and decarbonization while still achieving state clean energy requirements.
	ALG: BAU + Upside Economic Development	ALG evaluates a future characterized by substantial economic development load growth both within CE's service territory and across the broader MISO region. In addition to higher customer demand, the scenario reflects a corresponding expansion of regional resource development and market conditions needed to support that growth. ALG is intended to evaluate portfolio flexibility and resource needs under an accelerated economic development future. ALG is aligned with MISO Future 1a.

6.1.1 Decarbonization Futures

CE's PCC scenario is modeled consistently with MSO, with the only difference being the assumed level of EWR. Because the scenarios are otherwise nearly identical, they are discussed together in this summary. For compliance purposes, however, MSO is modeled and presented separately to ensure all MIRPP requirements are addressed.

The PCC and MSO represent a more aggressive transition case. Both scenarios are aligned with MISO Future 3a and assume full achievement of announced utility and state goals across the MISO region, significant electrification, stronger load growth, and a high level of carbon reduction over time. It also assumes continued progress on clean energy, storage, EV adoption, and EWR, and is meant to test portfolios under a future with faster decarbonization and stronger demand growth.

Table 6-2: Physical climate change variables and assumptions

VARIABLE	MSO ASSUMPTION	PCC ASSUMPTION
Natural Gas Price Forecast	Prices are consistent with U.S. Energy Information Administration's (EIA) 2025 Annual Energy Outlook (AEO) Reference Case	
Demand and Energy Forecast	Baseline level of demand growth plus additional accelerated electrification	
Technological Advancement	Greater implementation of advanced tech including long-duration storage, CCS, etc. due to potential opposition to new thermal development	
Existing Resources in MISO	Widespread retirement of fossil-fuel capacity	
Planned New Construction in MISO	Significant increase in wind and solar capacity, moderate increase in battery and CCS capacity	
MISO Decarbonization	80% decarbonization of MISO system by 2042	
Generic New Resources (Market & Company Owned)	Consistent with scenario descriptions and considering anticipated new resources currently in the MISO generation interconnection queue	
Renewable and Clean Targets	CE meets 2035 renewable and 2040 clean targets	
Energy Waste Reduction	Assumed to be implemented in compliance with 2.17% level required by MIRPP	EWR savings at 1.3% through 2029 and dropping to 0.8% for years 2030-2050
Existing Public Utility Regulatory Policies Act of 1978 (PURPA) Contracts	Assumed to be renewed throughout study period, unless contract terms indicate an agreement to decommission by a certain date	

6.1.2 Economic Development Load Futures

CE evaluated economic development load uncertainty through a common BAU-based framework. BAU serves as the Company's base planning outlook and reflects a moderate transition pathway aligned with MISO Future 2a. ALG was developed to evaluate the resource implications of significant economic development load growth and is aligned with MISO Future 1a.

Business-as-Usual

CE's BAU scenario represents a more moderate transition case. Rather than directly adopting MIRPP Scenario 2, CE developed its own utility-specific scenario that is broadly similar to MIRPP Scenario 2 and aligned with MISO Future 2a. The scenario assumes more modest load growth, moderate electrification and EV adoption, and a

slower pace of regional carbon reductions. While it still reflects substantial achievement of state and utility plans, it is less aggressive than the PCC Scenario and provides a lower-growth, more incremental transition pathway against which resource plans can be evaluated.

Table 6-3 summarizes the key assumptions of the BAU scenario alongside the corresponding MIRPP Scenario 2 assumptions to demonstrate their overall alignment.

Table 6-3: Business-as-usual variables and assumptions

VARIABLE	CE ASSUMPTION	MIRPP SCENARIO 2
Natural Gas Price Forecast	Prices are consistent with EIA's 2025 AEO Reference Case	
Demand and Energy Forecast	Baseline level of demand growth informed by historic load patterns by customer class. Also includes contracted new large loads	Assumes annual energy growth of 0.22%, driven by existing economic factors, with moderate EV adoption and customer electrification
Technological Advancement	Strategic deployment of advanced tech where economically selected	N/A
Existing Resources in MISO	Widespread retirement of coal capacity consistent with MISO Future 2a	Existing thermal and nuclear resource retirement assumptions should be consistent with MISO Future 1a
Planned New Construction in MISO	Significant increase in wind and solar capacity, moderate increase in gas, battery, and CCS capacity	Specific new units should be modeled if under construction or with regulatory approval, including Certificate of Necessity (CON), IRP cost pre-approval, or signed Generator Interconnect Agreement (GIA)
MISO Decarbonization	60% decarbonization of MISO system by 2042	40% decarbonization of MISO system by 2042
Generic New Resources (Market & Company Owned)	Consistent with scenario descriptions and considering anticipated new resources currently in the MISO generation interconnection queue	
Renewable and Clean Targets	CE 2035 renewable and 2040 clean targets	
EWR	EWR savings at 1.3% through 2029 and dropping to 0.8% for years 2030-2050	Utility load should be modeled based on maintaining a minimum 1.5% EWR savings throughout the study period
Existing PURPA Contracts	Assumed to be renewed throughout study period, unless contract terms indicate an agreement to decommission by a certain date	

Aggressive Load Growth

The ALG scenario represents a future with significant economic development load growth within CE's service territory and throughout the broader MISO region. The scenario is intended to capture the potential upside associated with large industrial facilities, data centers, and other high-load-factor customers. Consistent with this higher-demand future, ALG assumes a regional market environment that supports

additional resource development and system expansion relative to the Company's base planning outlook. By evaluating resource needs under these conditions, ALG provides insight into the flexibility and adaptability of the resource plan should economic development materialize at levels significantly above the Company's most likely forecast.

Table 6-4: Aggressive load growth variables and assumptions

VARIABLE	ASSUMPTION
Natural Gas Price Forecast	Prices are consistent with EIA's 2025 AEO Reference Case
Demand and Energy Forecast	Significant economic development load, characterized by high load factors and limited diurnal, seasonal shaping
Technological Advancement	Strategic deployment of advanced tech where economically selected
Existing Resources in MISO	Existing resource retirements and additions reflect a higher-growth MISO system and support increased regional energy and capacity requirements
Planned New Construction in MISO	Increased buildout of generation and storage resources relative to BAU, including renewable, storage, natural gas, and other technologies needed to support higher regional demand growth
MISO Decarbonization	40% decarbonization of MISO system by 2042
Generic New Resources (Market & Company Owned)	Consistent with scenario descriptions and considering anticipated new resources currently in the MISO generation interconnection queue
Renewable and Clean Targets	CE meets 2035 renewable and 2040 clean targets
EWR	Assumed to be implemented at level consistent with BAU
Existing PURPA Contracts	Assumed to be renewed throughout study period, unless contract terms indicate an agreement to decommission by a certain date

6.2 Sensitivities

Sensitivity analysis evaluates how changes in individual planning assumptions affect the resources selected through the long-term capacity expansion analysis. Unlike scenarios, which represent distinct future states, sensitivities vary specific inputs such as load growth, fuel prices, transmission capability, technology costs, DG, and energy efficiency.

The sensitivities evaluated include both MIRPP-required and CE-developed cases. They are grouped into the following themes, each of which provides a different perspective on portfolio cost, reliability, flexibility, and resilience:

- **Load Growth and Customer Demand:** Assesses how different levels and sources of demand growth change the timing, quantity, and mix of new resources selected.
- **Energy Efficiency and Distributed Resources:** Shows how higher energy efficiency and DG reduce or defer utility-scale resource needs and change the build plan.
- **Renewable Availability and Compliance:** Identifies how renewable build constraints affect the resources needed to meet clean energy requirements.

- **Transmission Capability and Interconnection Costs:** Evaluates how import and export capability and transmission upgrade costs affect the balance between local resource additions, imports, and exports.
- **Resource End of Operations and Retrofits:** Tests how changes in retirement timing, continued operation, or retrofit requirements affect replacement needs, resource timing, and the overall build plan.
- **Resource Cost and Fuel Price Uncertainty:** Shows how changes in technology and fuel costs affect which resources are selected and the overall cost of the build plan.
- **Weather and Climate:** Tests how atypical weather conditions affect demand, reliability needs, and the amount and type of capacity selected.

Table 6-5 summarizes all the sensitivities modeled and the scenarios CE applied them to.

Table 6-5: Modeled sensitivities

CATEGORY	SENSITIVITY	DESCRIPTION	MSO	PCC	BAU	ALG
Load Growth and Customer Demand	High Large Load	Assumes 3,500 MW of incremental large load, based on a probabilistic weighting of known interested projects.	X		X	X*
	Medium Large Load	Assumes 2,000 MW of incremental large load, based on a probabilistic weighting of known interested projects.	X	X	X	X*
	Low Large Load	Assumes 500 MW of incremental large load, based on a probabilistic weighting of known interested projects.	X	X	X	X*
	500 MW Economic Development Increments	Adds a ramping curve of large customer demand from 500 MW to 3,000 MW reaching full demand by 2041 beyond what is included in the base demand forecast of each scenario, in addition to the low, medium, and high large load sensitivities.		X	X	X*
	High Load	Increases demand based on expected large load growth. Demand is increased by 0.5%.			X	
	Low Load	EV adoption and electrification are slower than expected.			X	

CATEGORY	SENSITIVITY	DESCRIPTION	MSO	PCC	BAU	ALG
Energy Efficiency and Distributed Resources	EWR 2%	Increases embedded EWR to 2.0%[11] annual growth.			X	
	EWR 2.5%	Increases embedded EWR to 2.5% annual growth.	X		X	
	DG 10%	Increases embedded DG to the statutory 10% level under MCL 460.1173.	X			
	DG 15%	Increases embedded DG to 15%.	X			
	DG 20%	Increases embedded DG to 20%.	X			
	DG Solar Outflow Cost	Changes DG costing from NREL-based assumptions to outflow cost assumptions.		X	X	X
Renewable Availability and Compliance	Land-Based Renewable Cap	Caps land-based new build renewables to 60% of the CES portfolio. This also assumes no new solar resource builds after 2040.	X			
	Renewable Build Constraint Reduced by 20%	Assumes a 20% reduction in available new build renewables capacity.	X			
Transmission Capability and Interconnection Costs	Capacity Import & Export Limit (CIL & CEL) Low Sensitivity	Represents conservative values based on PY 2025/26 CIL/CEL.		X	X	X
	CIL & CEL High Sensitivity	Reflects anticipated Long Range Transmission Planning (LRTP)-driven increases plus an additional 2,000 MW. Applicable beginning in 2035 after LRTP projects are in service.		X	X	X
	Michigan Electric Transmission Company (METC) Network Upgrade Costs	Applies METC network upgrade cost assumptions to new transmission-connected resources.		X	X	X
Resource Retirements and Retrofits	Zeeland Plant Early (2040) Retirement	Retirement of the Zeeland plant in 2040		X	X	X
	Covert Plant Early (2040) Retirement	Retirement of the Covert plant in 2040		X	X	X

[11]The 2.0% level was used instead of the 2.17% level specified in the MIRPP because the EWR prototype was not designed with a distinct 2.17% block. The available blocks were 2.0%, evaluated in this sensitivity, and 2.5% evaluated in the following sensitivity.

CATEGORY	SENSITIVITY	DESCRIPTION	MSO	PCC	BAU	ALG
	Zeeland Plant + CCS Retrofit	Retrofit of the Zeeland plant to CCS		X	X	X
Resource Cost and Fuel Price Uncertainty	AEO High Gas Price	Uses the EIA AEO high gas price forecast from the EIA 2025 AEO outlook.	X		X	
	Increased Renewable and Storage Costs	Increases the cost of new build renewable and storage resources by 140%.		X	X	X
	Increased Natural Gas-Fueled Capital Cost	Increases the cost of new build natural gas-fueled resources by 20%.		X	X	X
Weather and Climate	Atypical Weather Events	Simulates the impact of increased atypical weather events.	X		X	

* In ALG, economic development load sensitivities were modeled as load reductions because the base ALG forecast already includes significantly higher economic development load than BAU and PCC.

The Company used the MIRPP-approved scenarios and sensitivities, together with Company-developed scenarios, to evaluate portfolio robustness. The PCA was selected because it consistently performed well across the evaluated futures, including BAU, MSO, PCC, ALG, and the applicable sensitivities. Alternative plans were developed to test specific planning risks, including higher levels of large-load growth. Retirement decisions were retained because the economic and reliability analyses demonstrated that they remained reasonable across the evaluated futures.

Existing Supply-Side Resources

Section 7

7 Existing Supply-Side Resources

7.1 Overview

Since the early 1900s, CE has generated the electricity needed to serve its customers reliably and affordably. The size and composition of the Company's generating fleet have changed over time in response to shifts in demand, technology, fuel availability, environmental requirements, and customer expectations. This evolution reflects Michigan's transition from a heavily industrial economy to a more diverse economy and an increasing emphasis on cleaner energy resources.

As of 2026 and this filing, the Company's generating portfolio is diverse, flexible, and continuing to transition toward lower-emitting resources. The fleet includes long-operating hydroelectric facilities, modern natural gas units that provide dispatchable capacity, natural gas and oil peaking plants, pumped storage and energy storage that support grid reliability, various renewable and clean resources like landfill gas, anaerobic digesters, and biomass, and a growing portfolio of wind and solar resources. Existing resources form the foundation of the Company's resource portfolio and serve as the starting point for the IRP modeling process. Future resource needs identified in the IRP are evaluated relative to the capabilities, expected operating lives, and planned retirements of these existing resources. The portfolio and key characteristics of each resource are summarized in the tables that follow.

7.1.1 Fossil-Fueled Generating Units

Table 7-1 includes a summary of the Company's owned operating fossil-fuel generating units. All units are currently operational and authorized for service.

Table 7-1: Owned fossil-fueled generating unit key characteristics

RESOURCE	LOCATION	IN-SERVICE DATE	AGE (YRS FROM COD)	RETIREMENT DATE	REMAINING YEARS OF OPERATION	CAPACITY FACTOR	GENERATING CAPACITY (MW)	
OIL or GAS FIRED							**SUMMER**	**WINTER**
DE Karn 3	Essexville, MI	1975	51	2031	5	0%	593	602
DE Karn 4	Essexville, MI	1977	49	2031	5	0%	526	526
Zeeland 1 (CT)	Zeeland, MI	2007	24	2051	25	20%	179	206
Zeeland 2 (CC)	Zeeland, MI	2007	24	2051	25	70%	179	206
Jackson	Jackson, MI	2015	24	2040	25	45%	534	540
Covert 1	Covert Township, MI	2023	22	2051	25	80%	383	443
Covert 2	Covert Township, MI	2023	22	2051	25	80%	381	435
Covert 3	Covert Township, MI	2023	22	2051	25	80%	385	438

7.1.2 Nuclear Generating Units

CE does not own or operate any nuclear generating units as of the filing of this IRP.

7.1.3 Hydroelectric Generating Units

Table 7-2 includes a summary of the Company's operating hydroelectric generating units. All units are currently operational and authorized for service.

Table 7-2: Owned hydroelectric generating unit key characteristics

RESOURCE	LOCATION	IN-SERVICE DATE	AGE (YRS FROM COD)	RETIREMENT DATE*	CAPACITY FACTOR	GENERATING CAPACITY (MW)	
HYDROELECTRIC						**SUMMER**	**WINTER**
Alcona	Alcona County, MI	1924	102	n/a	38%	8	8
Allegan	Genesee County, MI	1936	90	n/a	53%	2.55	2.55
Cooke	Iosco County, MI	1911	115	n/a	33%	9	9
Croton	Newaygo County, MI	1907	119	n/a	35%	8.85	8.85
Five Channels	Iosco County, MI	1912	114	n/a	42%	6	6
Foote	Iosco County, MI	1918	108	n/a	36%	9	9
Hardy	Newaygo County, MI	1931	95	n/a	29%	30	30
Hodenpyl	Wexford County, MI	1925	101	n/a	27%	17	17
Loud	Iosco County, MI	1913	113	n/a	45%	4	4
Mio	Oscoda County, MI	1916	110	n/a	31%	4.9	4.9
Rogers	Mecosta County, MI	1906	120	n/a	42%	6.75	6.75
Tippy	Manistee County, MI	1908	118	n/a	31%	21	21
Webber	Ionia County, MI	1907	119	n/a	40%	3.23	3.23

*The Company is currently in the process of selling its hydroelectric assets and will retain the output through a PPA.

7.1.4 Renewable Generating Units

Table 7-3 includes a summary of the Company's owned operating renewable generating units.

Table 7-3: Owned renewable generating unit key characteristics

RESOURCE	LOCATION	IN-SERVICE DATE	AGE (YRS FROM COD)	RETIREMENT DATE *	REMAINING YEARS OF OPERATION	CAPACITY FACTOR	GENERATING CAPACITY (MW)
WIND							
Lake Winds	Mason County, MI	2012	14	n/a	n/a	28%	100.8
Cross Winds Phase 1	Tuscola County, MI	2015	12	n/a	n/a	29%	110.98
Cross Winds Phase 2	Tuscola County, MI	2018	8	n/a	n/a	37%	43.7
Cross Winds Phase 3	Tuscola County, MI	2020	6	n/a	n/a	37%	75.9
Gratiot Wind Farm	Gratiot County, MI	2020	6	n/a	n/a	28%	150
Crescent Wind	Hillsdale County, MI	2021	6	n/a	n/a	24%	166
Heartland Wind	Gratiot County, MI	2023	3	n/a	n/a	28%	200.94
SOLAR							
Muskegon Solar	Muskegon County, MI	2025	1	n/a	n/a	22%	250
Sunfish Solar	Calhoun County, MI	2026	0	n/a	n/a	22%	309
Spring Creek Solar	Calhoun County, MI	2026	0	n/a	n/a	22%	140
Solar Gardens - GVSU	Grand Rapids, MI	2016	10	n/a	n/a	11%	3
Solar Gardens - Cadillac	Cadillac, MI	2021	5	n/a	n/a	11%	0.45
Solar Gardens - WMU	Kalamazoo, MI	2016	10	n/a	n/a	11%	1
Blackman Solar Garden	Jackson County, MI	2026	0	n/a	n/a	22%	2.5
Circuit West	Kent County, MI	2018	8	n/a	n/a	11%	0.528

*Renewable resources are not assigned fixed retirement dates because their assumed end-of-life dates fall beyond the study period and the resources are assumed to be eligible for repowering or life extension.

7.1.5 Energy Storage Facilities

Table 7-4 includes a summary of the Company's owned operating utility-scale energy storage units. Ludington is a pumped storage resource, while the remaining resources are lithium-ion. Additional distributed and pilot resources are discussed in Section 10, Energy Storage Target Requirements.

Table 7-4: Owned energy storage unit key characteristics

RESOURCE	LOCATION	IN-SERVICE DATE	AGE (YEARS)	RETIREMENT DATE	REMAINING YEARS OF OPERATION	CAPACITY FACTOR	GENERATING CAPACITY
ENERGY STORAGE							
Ludington Units 1-6	Ludington, MI	1973	53	n/a	43	n/a	1,170 MW/8,000 MWh*
Airpark Battery	Arenac County, MI	2021	5	2040	14	n/a	2 MW/ 8 MWh
Parkview Battery	Kalamazoo County, MI	2018	8	n/a	n/a	n/a	0.3 MW/ 0.3 MWh
Circuit West Battery	Kent County, MI	2018	8	n/a	n/a	n/a	0.16 MW/ 0.16 MWh
Armstrong Battery	Calhoun County, MI	2026	0	n/a	n/a	n/a	2.5 MW/ 10 MWh

*CE owns 51% of Ludington Units 1-6 and DTE owns the remaining 49%. The generating capacity shown reflects the Company's share of ownership.

7.2 Power Purchase Agreements

In addition to electricity generated from Company-owned resources, CE maintains a portfolio of PPAs with independent power producers across Michigan. Under these contracts, the Company agrees to purchase specified amounts of energy, capacity, and RECs at predetermined prices. These agreements help ensure a reliable supply of energy and capacity at prudent and reasonable cost to support Michigan's economy and residents. A summary of the Company's current PPAs is provided in Table 7-5 below.

Table 7-5: Power purchase agreements characteristics

RESOURCE	LOCATION	CURRENT CONTRACT EXPIRATION	REMAINING TIME OF CONTRACT (YEARS)	CAPACITY FACTOR	GENERATING CAPACITY PURCHASED (MW)
NATURAL GAS					
Michigan Power LP 1	Ludington, MI	2030	4	50%	123
MCV LP	Midland, MI	2030	4	50%	1,240
COAL					
TES Filer City Station LP	Filer City, MI	2027	1	50%	60
HYDROELECTRIC					
Commonwealth Power Company (Irving)	Irving, MI	2030	4	37%	0.24
Commonwealth Power Company (LaBarge)	LaBarge, MI	2039	13	37%	0.7

RESOURCE	LOCATION	CURRENT CONTRACT EXPIRATION	REMAINING TIME OF CONTRACT (YEARS)	CAPACITY FACTOR	GENERATING CAPACITY PURCHASED (MW)
Commonwealth Power Company (Middleville)	Middleville, MI	2031	5	71%	0.2
Grenfell Hydro, Inc	Belding, MI	2039	13	37%	0.36
City of Beaverton	Gladwin County, MI	2039	13	37%	0.5
Black River Power	Cheboygan County, MI	2039	13	37%	0.84
Elk Rapids Hydroelectric Power, LLC	Antrim County, MI	2039	13	37%	0.7
STS Hydropower Ltd (Cascade)	Kent County, MI	2039	13	35%	1.4
STS Hydropower Ltd (Fallasburg)	Kent County, MI	2039	13	7%	0.85
STS Hydropower Ltd (Morrow)	Mecosta County, MI	2027	1	8%	1
White's Bridge Hydro Company	Ionia County, MI	2039	13	37%	0.817
Tower Hydro	Cheboygan County, MI	2039	13	34%	0.56
Kleber Hydro	Cheboygan County, MI	2039	13	34%	1.2
ENERGY STORAGE					
Century Oaks	Huron County, MI	2046	20	0%	200
Tibbits Energy Storage	Branch County, MI	2046	20	0%	100
WIND*					
Beebe Renewable Energy	Gratiot County, MI	n/a	n/a	26%	81.6
Geronimo Huron Wind LLC (Apple Blossom)	Huron County, MI	n/a	n/a	29%	100
Harvest II Windfarm, LLC	Pigeon, MI	n/a	n/a	33%	59.4
Heritage Garden Wind Farm I, LLC (Wind Portion)	Gardon, MI	n/a	n/a	27%	20
Heritage Stoney Corners Wind Farm I, LLC (Phase 2)	McBain, MI	n/a	n/a	25%	12.25

RESOURCE	LOCATION	CURRENT CONTRACT EXPIRATION	REMAINING TIME OF CONTRACT (YEARS)	CAPACITY FACTOR	GENERATING CAPACITY PURCHASED (MW)
Heritage Stoney Corners Wind Farm I, LLC (Phase 3)	McBain, MI	n/a	n/a	24%	8.35
Michigan Wind 1, LLC	Ubly, MI	n/a	n/a	33%	12
Michigan Wind 2, LLC	Bad Axe, MI	n/a	n/a	33%	90
SOLAR					
River Fork Solar	Calhoun County, MI	2044	18	22%	100
EARP Solar (Expansion)	Various	2029	3	22%	4
Heritage Garden Wind Farm I, LLC (Solar Portion)	Gardon, MI	2032	6	35%	2.35
Superior Sales Solar	Hudsonville, MI	2037	11	22%	0.121
Calhoun Solar Energy	Calhoun County, MI	2050	24	22%	140
Cereal City	Calhoun County, MI	2048	22	22%	100
South Christian High School	Byron Center, MI	2032	6	22%	0.7
Jackson County Solar	Jackson County, MI	2043	17	22%	125
Heartwood Solar	Hillsdale County, MI	2049	23	22%	150
Michigan Apple Packers Cooperative	Sparta, MI	2030	4	22%	1
DCS Corp Center Solar	Sterling Heights, MI	2032	6	22%	1
Sunfish 1 Solar	Calhoun County, MI	2059	31	22%	309
Solar PURPA	Various	Various	n/a	Various	368
OTHER RENEWABLES					
Adrian Energy Associates, LLC	Adrian, MI	2029	3	46%	2.5
Cadillac Renewable Energy, LLC	Wexford County, MI	2028	2	46%	34
Fremont Community Digester, LLC	Newaygo County, MI	2032	6	44%	2.85
Gas Recovery 1 (C&C 1)	Kent County, MI	2030	4	18%	2.75

RESOURCE	LOCATION	CURRENT CONTRACT EXPIRATION	REMAINING TIME OF CONTRACT (YEARS)	CAPACITY FACTOR	GENERATING CAPACITY PURCHASED (MW)
Gas Recovery 2 (C&C 2)	Kent County, MI	2027	1	18%	2.5
Genesee Power Station LP	Genesee County, MI	2030	4	46%	35
Energy Developments (Grand Blanc), LLC	Genesee County, MI	2029	3	43%	3.812
Energy Developments (Ottawa), LLC	Coopersville, MI	2039	13	43%	4.57
Energy Developments (Seymour), LLC	Kent County, MI	2030	4	43%	0.752
Energy Developments (Pinconning), LLC	Bay County, MI	2028	2	43%	1.842
Energy Developments (Byron Center), LLC	Kent County, MI	2026	0	43%	4.2
Grayling Generating Station LP	Crawford County, MI	2027	1	46%	36.17
North American Natural Resources (Lennon), Inc	Shiawassee County, MI	2030	4	68%	1.6
North American Natural Resources (Rathbun), Inc	Bay County, MI	2039	13	42%	1.6
North American Natural Resources (Peoples), Inc	Ottawa County, MI	2030	4	43%	3.061
Viking Energy of McBain A LP	McBain, MI	2027	1	46%	18
WM Renewable Energy (Northern Oaks)	Oscoda County, MI	2030	4	38%	1.6
WM Renewable Energy (Pine Tree Acres)	Macomb County, MI	2032	6	58%	12.8
WM Renewable Energy (Venice)	Shiawassee County, MI	2027	1	82%	1.5
Kent County Solid Waste	Kent County, MI	2039	13	43%	15.68

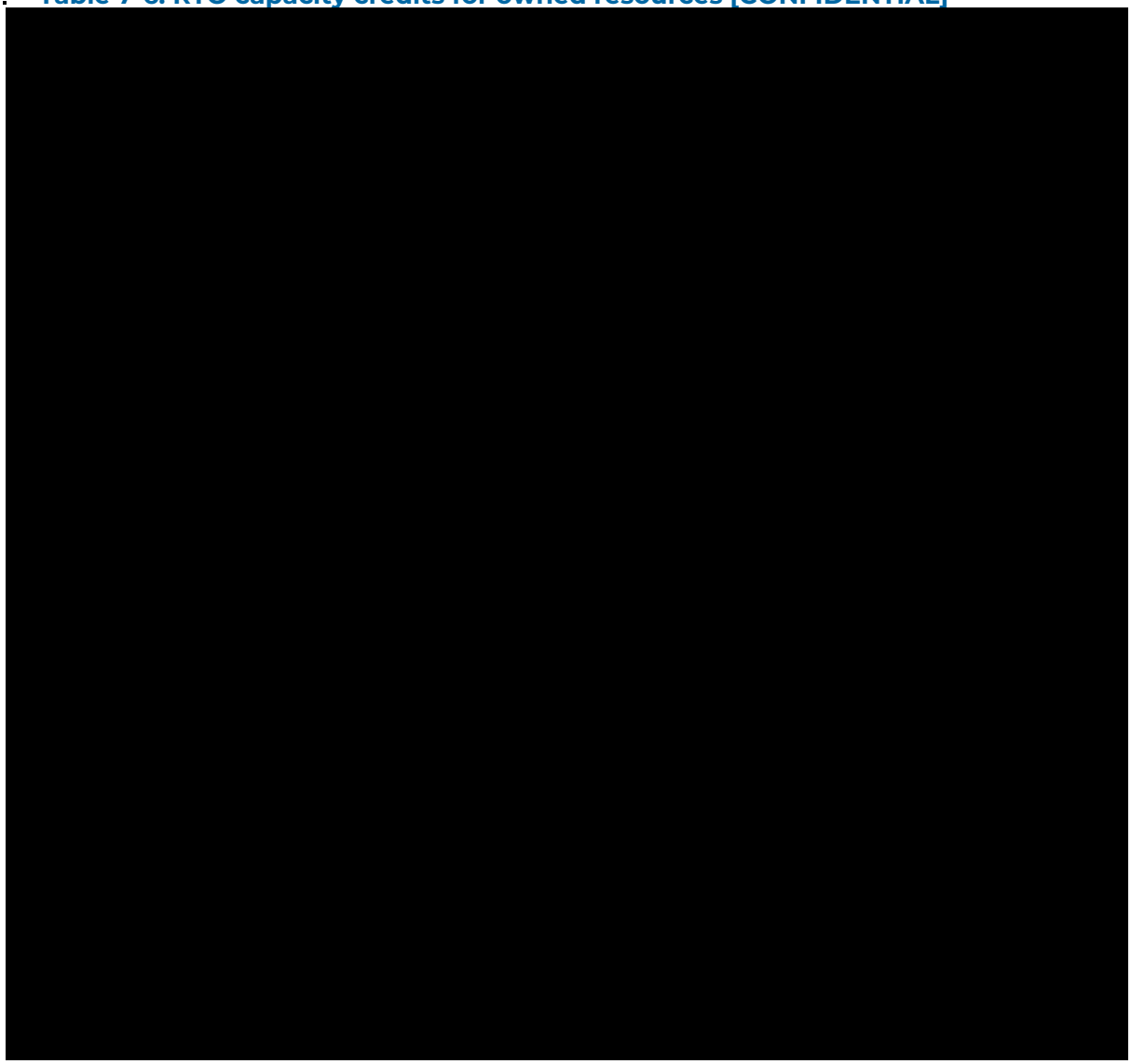
*For modeling purposes, existing wind contracts are assumed to be extended beyond their current expiration dates. The Company will evaluate any contract extensions on a project-by-project basis.

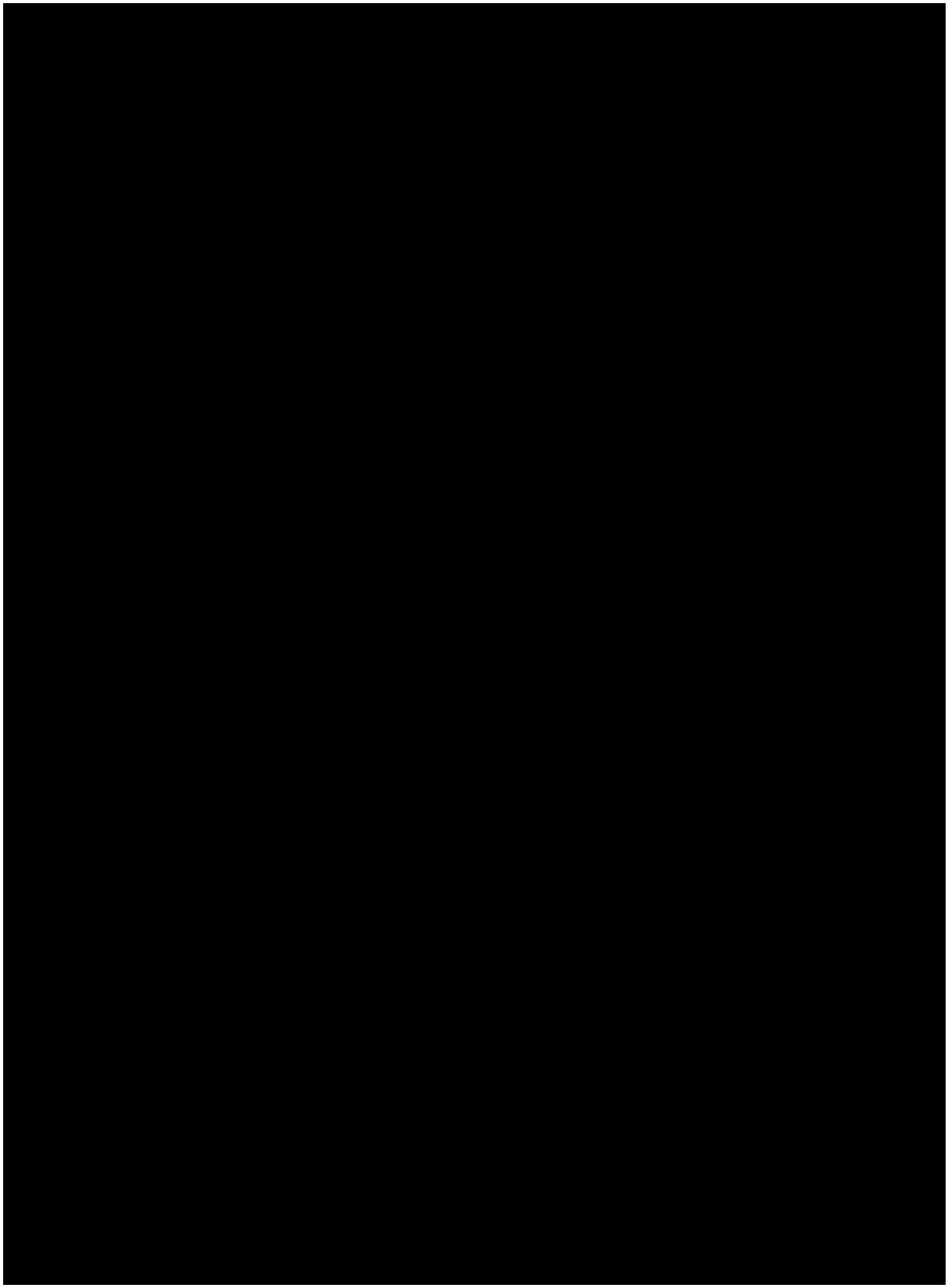
7.3 RTO Capacity Credits and Modeling of Existing Units

One of the primary benefits of the Company's generating units and PPAs is the accredited capacity they provide for resource adequacy planning. MISO, the regional transmission organization, assigns capacity credits to these resources, referred to as ZRCs. A summary of the current capacity credits for the Company's owned and contracted generating units is shown in Table 7-6 and Table 7-7, respectively, below.

In addition to owned and contracted resources, the Company includes bilateral capacity purchases of 170 MW in 2026 and 100 MW in 2027 to support near-term resource adequacy needs. No bilateral capacity purchases are included beginning in 2028.

Table 7-6: RTO capacity credits for owned resources [CONFIDENTIAL]



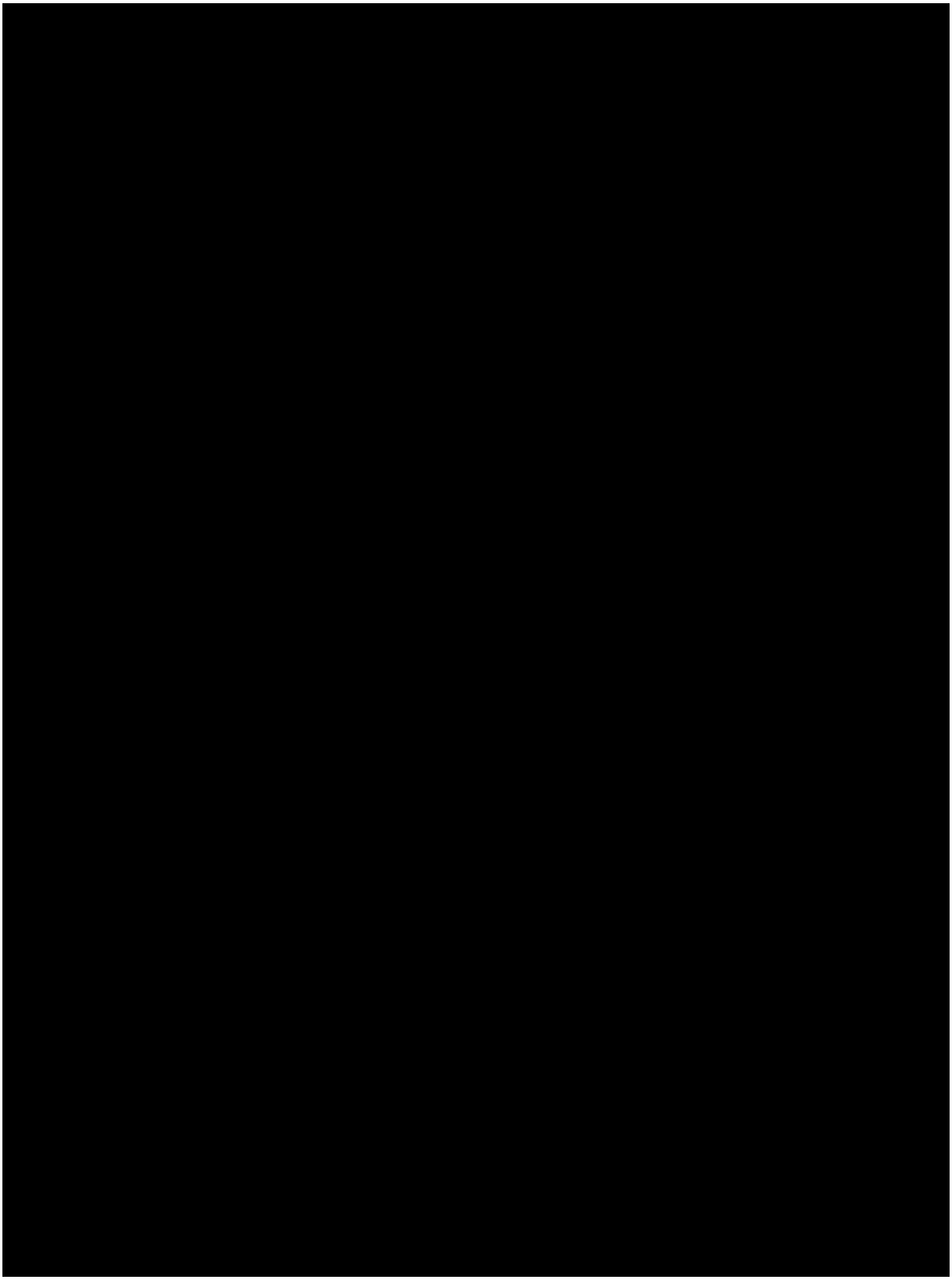


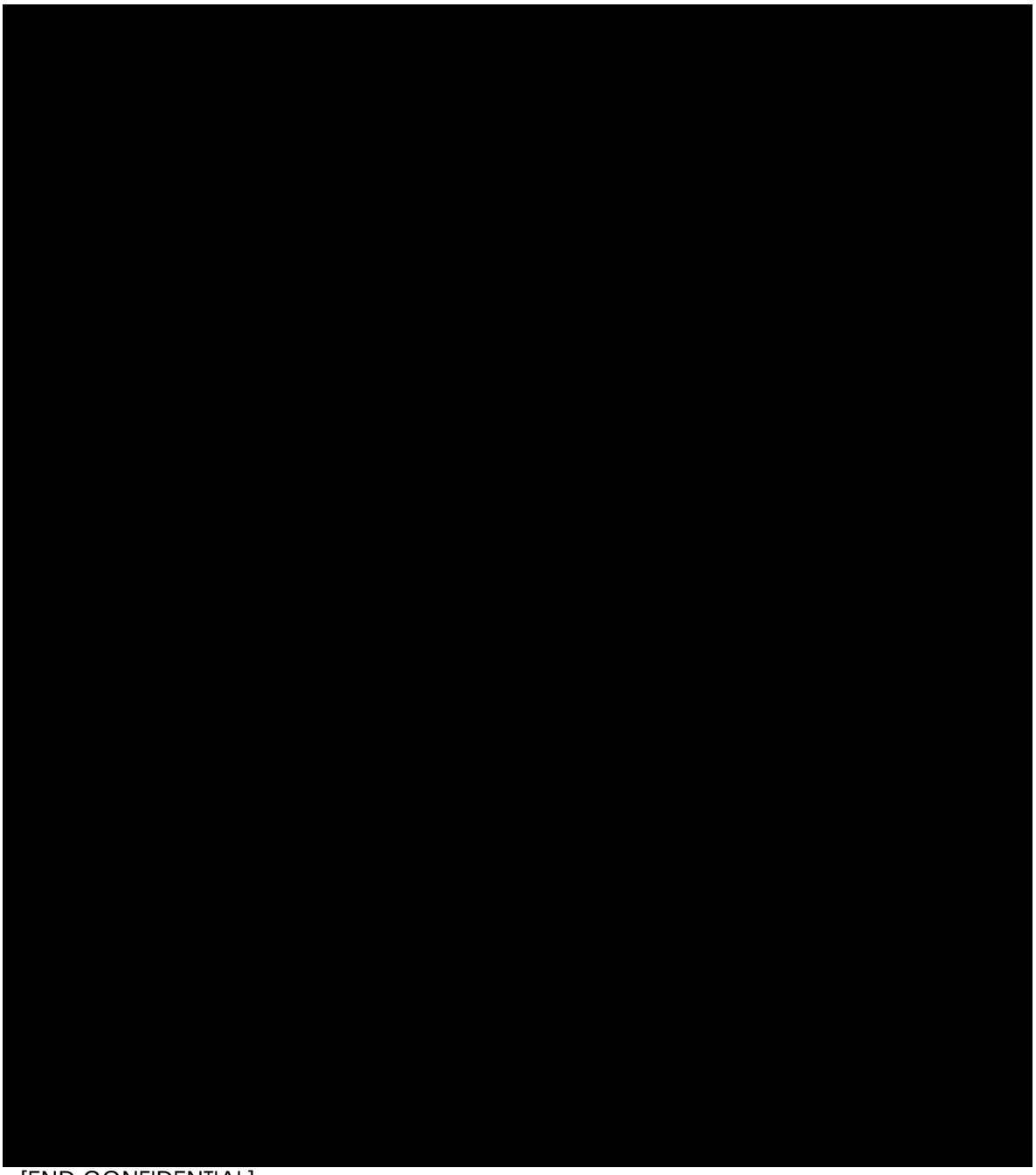
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Table 7-7: RTO capacity credits for contracted resources [CONFIDENTIAL]

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7.4 Spot Market Purchases and Off-System Sales

CE participates in the MISO energy market as a Load Serving Entity (LSE) in LRZ 7. The Company buys and sells energy through MISO based on economic conditions, selling generation from its owned resources and purchasing energy when market prices are more cost-effective for serving customers. This results in both spot market purchases and off-system sales. In 2025, the Company purchased 15.28% of its energy demand

(5,484,678 MWh) from the MISO energy market and sold 16.66% (5,980,935 MWh) of generation into the market. These transactions reflect routine economic dispatch and market participation and do not indicate a reliance on spot market purchases to meet planning reserve requirements.

Demand-Side Resources

Section 8

8 Demand-Side Resources

CE's demand-side resource strategy is built around programs that reduce energy consumption, lower peak demand, improve system flexibility, and support reliable electric service. Through energy waste reduction (EWR), demand response (DR), conservation voltage reduction (CVR), time-varying rates, managed electric vehicle (EV) charging, distributed generation (DG), and other customer-side initiatives, the Company is able to reduce the amount of energy and capacity that must be supplied by traditional generation resources while continuing to meet customer needs. Combined these resources represent the foundation for the Company's growing VPP capabilities and are an important component of the Company's integrated resource portfolio and are evaluated alongside generation, storage, and market purchases in the IRP.

Demand-side management (DSM) programs provide multiple customer and system benefits, including:

- Incentives and technical assistance to encourage efficient energy use and load flexibility;
- Lower customer energy bills and total system costs;
- Improved grid reliability and resilience through peak demand reduction and load management; and
- Support for integration of DERs, electrification, and emerging technologies such as EVs and behind-the-meter (BTM) storage.

Table 8-1 describes the functions and broader system value supported by each type of demand-side resource. As of year-end 2025, CE's DR portfolio included approximately 356,000 enrolled residential and business customers and 693 MW of accumulated demand reduction capability, exceeding the 641 MW projected in the Company's prior IRP. The portfolio has also evolved from a primarily summer-focused offering to a year-round resource through expansion of C&I programs, increasing its contribution to reliability across all seasons.

Table 8-1: Demand-side resource system value

RESOURCE TYPE	PRIMARY FUNCTION	SYSTEM BENEFIT
EWR	Reduce energy use	Lower load and long-term costs
DR	Reduce demand during peak hours	Reliability and capacity value
CVR	Optimize voltage	System efficiency
Time-Varying Rates	Shift customer usage	Peak reduction
EV Load Management	Shift charging load	Load flexibility
DG	Customer-sited supply	Resource diversity

The Company also recognizes that many demand-side resources provide capabilities commonly associated with VPPs. Programs such as DR, time-varying rates, managed EV charging, DG, and other customer-sited technologies can reduce demand, shift customer consumption patterns, or provide energy during periods of system need. These resources serve as the foundation upon which VPP capabilities are built. DR provides dispatchable load reductions, time-varying rates and managed charging create load flexibility, and customer-sited generation and storage contributes distributed energy supply. When viewed collectively, these programs demonstrate how customer-side resources can work together to provide system value beyond the contribution of any single program. From this perspective, VPPs are not a separate resource category, but rather a framework for understanding how demand-side resources collectively contribute to reliability, affordability, and system flexibility. The impacts of these resources are already reflected in the Company's planning assumptions and resource evaluations.

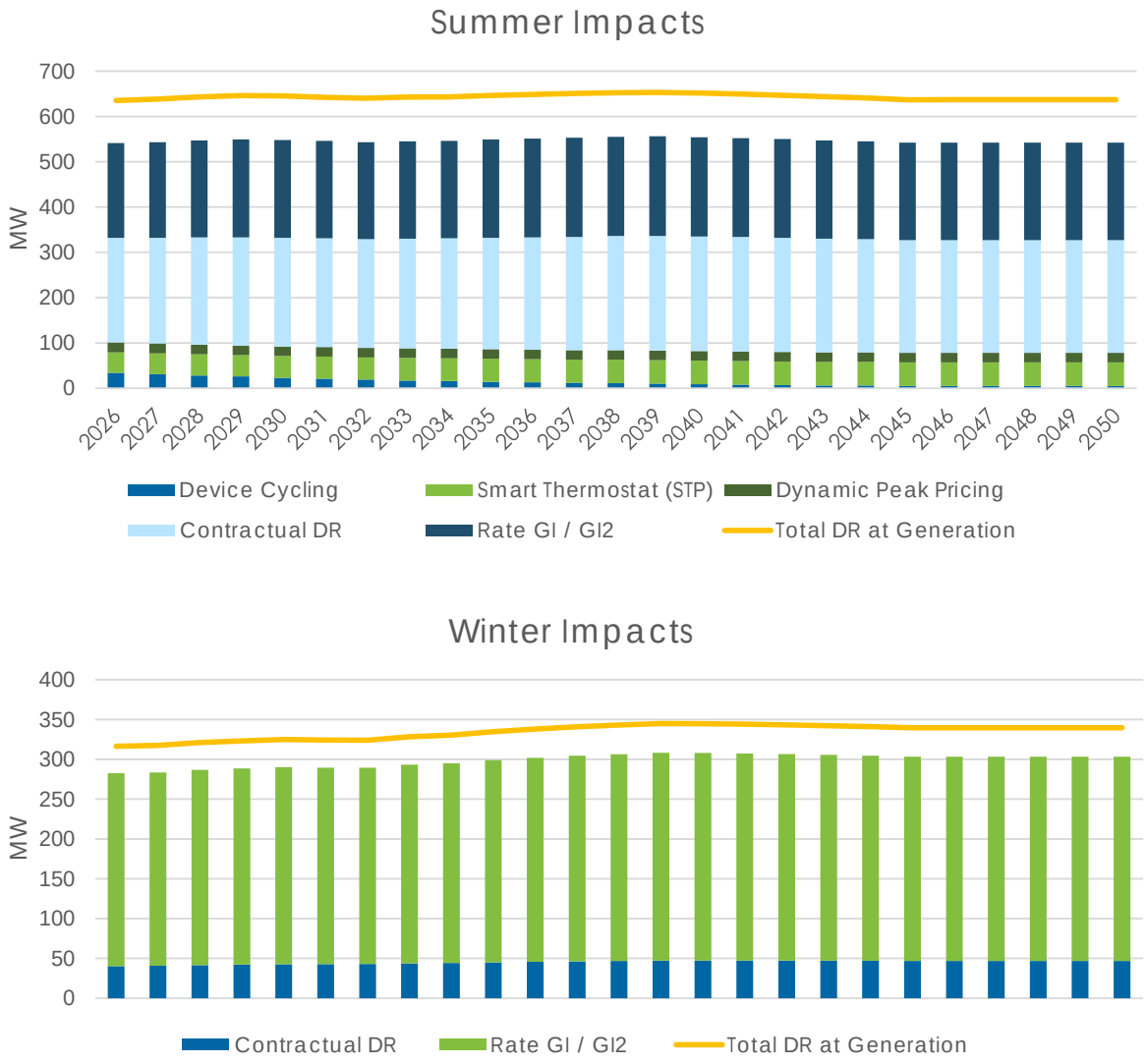
CE's demand-side strategy focuses on deploying and expanding cost-effective customer programs that provide measurable system benefits. Some programs permanently reduce energy consumption, others provide dispatchable peak-demand reductions during critical system conditions, and others shift customer usage away from periods of peak demand. Together, these resources reduce pressure on the electric system and complement traditional supply-side investments. As discussed throughout this section, each program serves a distinct purpose, but collectively they contribute to a more flexible and resilient resource portfolio.

8.1 Demand-Side Resource Portfolio Summary

Consumers Energy's DR portfolio includes a diverse set of residential, commercial, and industrial programs designed to reduce electricity demand during periods of system stress. Residential programs include Device Cycling, Dynamic Peak Pricing (DPP), and the Smart Thermostat Program, which encourage or automate reductions in customer electricity consumption during peak periods. C&I programs include interruptible tariffs (GI and GI2) and contractual DR programs, which provide capacity value by allowing participating customers to curtail load when needed. Together, these programs provide a flexible, scalable demand-side resource that reduces peak demand, supports system reliability, and can defer the need for additional supply-side capacity investments.

Figure 8-1 provides a holistic view of forecasted DR capacity across the Company's full portfolio of DR programs. This summary is intended to orient the reader to the overall scale and composition of the Company's demand-side resources before presenting program-specific detail in the sections that follow. Additional discussion of these projects is included below.

Figure 8-1: Forecasted DR capability, 2026-2050



8.2 Demand Response Programs

The company's DR programs are designed to provide dispatchable, event-based reductions in electricity demand during peak system conditions. These programs are deployed selectively in response to system conditions or market signals to provide flexibility in resource portfolio by temporarily reducing or shifting customer load. This flexibility ultimately supports grid reliability, resource adequacy, and efficient grid operations.

The Company continues to offer residential, commercial, and industrial DR programs to help customers reduce electric use during peak hours to assist with aligning supply and demand of resources throughout the year. These offerings include both direct load control programs and price- or behavior-based offerings that enable the Company to

temporarily reduce or shift customer load, while balancing customer impacts and program reliability. DR events are typically called in response to high forecasted system load, elevated wholesale market prices, or reliability events.

DR resources are identified as a form of flexible capacity within the IRP and are used to reduce peak demand, mitigate exposure to short-term market purchases, and support resource adequacy targets. The DR levels reflected in this IRP are based on demonstrated program performance, achievable program participation assumptions, and independent DR studies. Assumptions are calibrated to existing program design, historical enrollment, and regulatory filings, ensuring projected impacts are realistic.

8.3 Residential Demand Response Programs

Table 8-2 summarizes Consumers Energy's residential DR programs included in this IRP. The table provides a high-level comparison of program design, enrolled capacity, and planning assumptions used in the Company's resource analysis. Values shown reflect current program characteristics and planning inputs, rather than performance targets or guarantees.

Table 8-2: Residential demand response program summary

	PEAK POWER SAVERS® AC PEAK CYCLING	PEAK POWER SAVERS® DYNAMIC PEAK PRICING PROGRAM	SMART THERMOSTAT PROGRAM
Brief Description	On peak "Energy Savings Events," the Company cycles central AC units at 50% to reduce customer electricity use during the event.	Price signal and customer outreach programs (Peak Time Rewards (PTR) and Critical Peak Pricing (CPP))	During "Energy Savings Events," the Company adjusts the enrolled internet-connected thermostats enrolled in a DR platform by up to four degrees
Technology	Utility-controlled AC switch integrated with Advanced Metering Infrastructure (AMI) + DR Management System (DRMS);	Rate-based + behavioral DR (CPP + PTR)	Direct load control is delivered through a cloud-based vendor platform that communicates via APIs to manage customer Wi-Fi thermostat
Incentive	A bill credit of $5.00 per month during the peak event season of June through August	**CPP** - charge of $1 per kWh if the customer does not shift their energy use during Energy Savings Events **PTR** - credit of $1 per kWh shifted during on-peak energy use on Energy Savings Events	$50 at enrollment, plus $25 for each summer of participation
Current Enrollment (participants)*	82,229	208,698	62,609
Current Enrolled Capacity (MW)*	49.3 MW	44.9 MW	57.6 MW

	PEAK POWER SAVERS® AC PEAK CYCLING	PEAK POWER SAVERS® DYNAMIC PEAK PRICING PROGRAM	SMART THERMOSTAT PROGRAM
Operating Season	June through September	Year-round	Year-round
Historic Performance (contextual)	A two-hour event was called on 7/15 calling for 35.0 MW of load reduction. The program delivered 27.2 MW.	The most recent event for DPP was called in 2022. PTR customers provided load reduction of 9.2 MW and CPP customers provided load reduction of 1.9 MW.	In 2025, the Smart Thermostat program called for 44.0 MW of peak load reduction on 7/15. The program delivered 52.4 MW of load reduction.
2045 Projected Enrollment (MW)	7.2 MW	29.3 MW	74.5 MW

* End of year, 2025 See Case No. U-20628.

8.3.1 Program Descriptions

Peak Power Savers® AC Peak Cycling



The Peak Power Savers® AC Peak Cycling program is available to residential customers with central air conditioning systems who agree to allow CE to cycle their air conditioner compressor during peak demand events. The program uses a utility-installed load control switch connected to the customer's air conditioning unit, enabling the Company to cycle the compressor during DR events. Customers enroll through the Company's website or customer service channels and schedule installation of the load control device. The program is marketed through bill inserts, digital communications, and targeted seasonal outreach prior to the summer peak season. The program typically operates during the summer months, when system demand is highest. During Energy Savings Days or other peak events, the air conditioning compressor is cycled on and off according to a predefined strategy to reduce peak demand while maintaining customer comfort.

Beginning in 2025, the Peak Power Savers® AC Peak Cycling program transitioned to maintenance mode following Company evaluations indicating that additional program expansion was no longer cost-effective. As a result, the Company is no longer actively marketing the program or installing new load control switches. Enrollment has gradually declined over time as existing participants leave the program. However, the Company continues to capture value from previously installed equipment through periodic move-in/move-out initiatives that automatically enroll customers who move into homes where program switches remain installed on central air conditioning units.

These efforts help maintain participation levels and maximize the value of existing program infrastructure while limiting new program investment

Key Accomplishments

- **Single Energy Saving Event** – Included all 87,400 enrolled customers and delivered an average demand reduction of .3111 kW per participant, or a total of 27.2 MW in aggregate savings.

Peak Power Savers® Dynamic Peak Pricing Program



The Peak Power Savers® Dynamic Peak Pricing program is available to residential customers who voluntarily enroll in a time-varying rate designed to encourage reductions in electricity use during peak demand periods. The program relies on AMI to apply dynamic pricing signals and notify customers of peak events. Customers enroll through the Company's website or customer service channels and are transitioned to the dynamic pricing rate structure. The program is marketed through customer communications, digital outreach, and education campaigns highlighting opportunities to lower bills by shifting electricity usage outside peak periods. The program primarily operates during the summer peak season. During designated peak pricing events, customers receive advance notice of higher electricity prices and may respond by reducing or shifting their consumption.

Key Accomplishments

- **DPP Maintained Strong Customer Engagement** - At the end of 2025, the Dynamic Peak Pricing portfolio included nearly 209,000 participants and represented approximately 45 MW of enrolled capacity, making it the largest residential DR offering by participation.

Smart Thermostat Program



The Smart Thermostat program is available to residential customers with central air conditioning systems who enroll an eligible internet-connected thermostat in the DR platform. The program uses smart thermostat technology to enable automated adjustments to cooling settings during peak demand events. Customers enroll by registering a compatible thermostat through Energy Hub's partner portal or through participating device providers. The program is marketed through partnerships with thermostat manufacturers, utility communications, and customer incentives that encourage enrollment of eligible devices. The program operates primarily during the summer peak season, between June 1 and August 31. During DR events, participating thermostats automatically adjust temperature setpoints by up to four degrees or temporarily reduce cooling load for up to four hours to help reduce system peak demand while maintaining customer comfort.

Key Accomplishments

- **Smart Thermostat Program Achieved Record Load Curtailment and Exceeded Registered Capacity** – Delivered a record 52.4 MW of aggregate load relief, exceeding the 2025 MISO registered capacity value of 44 MW. The average demand reduction reached 0.871 kW per customer across ~60,000 enrolled participants.

8.3.2 Cost and Investment

Residential DR programs require a combination of customer incentives, enabling technologies, vendor services, and internal program administration to deliver peak demand reductions. Program costs reflected in this IRP include ongoing operations and maintenance expenses, customer participation and performance incentives, and, where applicable, capital expenditures associated with program marketing, platform services, and enabling equipment.

The capital, operating and maintenance (O&M), and customer incentive costs for each of CE's residential DR programs are included in Table 8-3.

Table 8-3: Planning year residential DR expenditures

2026 COST PARAMETERS	PEAK POWER SAVERS® AC PEAK CYCLING	PEAK POWER SAVERS® DYNAMIC PEAK PRICING PROGRAM	SMART THERMOSTAT PROGRAM
Annual O&M	$2,463,438	$282,261	$12,273,050
Annual Capital Expenditures	$690,148	0	0
Annual Customer Incentive Expenditures	$2,798,518	$1,883,770	$0

For purposes of resource planning, residential DR costs are incorporated into the IRP using *planning-level estimates*. Cost assumptions are calibrated to realized program expenditures where available and projected forward using conservative escalation factors. The Company does not assume incremental capital-intensive expansion of residential DR programs beyond the levels evaluated as achievable and cost-effective.

8.3.3 Demand Reduction Capability

Table 8-4 provides a summary of projected DR capabilities for the planning year. These projections are inputs for IRP scenario development and planning and do not necessarily indicate performance targets or operational guarantees.

Table 8-4: Planning year residential DR reduction capability

PARAMETER	PEAK POWER SAVERS® AC PEAK CYCLING	PEAK POWER SAVERS® DYNAMIC PEAK PRICING PROGRAM	SMART THERMOSTAT PROGRAM
Total demand reduction capability (MW)*	34 MW	22 MW	45 MW
Maximum single-event MW reduction**	48 MW	31 MW	64 MW
Expected interruption duration (per day | per month | per year)	• Season: Summer only, June 1 – August 31 • Days: Weekdays only (no weekends or holidays) • Duration: Up to 4 hours per event • Event Window: 12pm-8pm • Maximum number of events: not specified in the rate book or T&Cs	• Season: Summer only, June 1 – August 31 • Days: weekdays only (no holidays) • Event duration for both programs is up to 4 hours.	• Season: Summer only, June 1 – August 31 • Days: Weekdays only (no weekends or holidays) • Duration: Up to 4 hours per event • Event Window: 12pm-8pm • Maximum number of events: 7
MISO resource registration type	DRR – Type I	Unregistered	DRR – Type I

* For programs that are registered with MISO, the total demand reduction capability is the amount expected to be registered with MISO.
** Projected enrolled MWs for both MISO registered and unregistered programs.

Residential DR programs are available during summer system peak conditions, when residential cooling load contributes most significantly to overall system demand. Demand reduction capability for residential programs varies by program design, enabling technology, and customer participation characteristics.

Planning assumptions for each program reflect differing operational characteristics and are calibrated to historic performance and independent study results.

For IRP modeling purposes, residential DR resources are treated as summer-only capacity contributions and are subject to conservative assumptions regarding availability, event limits, and customer response.

8.3.4 Historic Performance

CE's residential DR programs have demonstrated measurable peak demand reductions during designated events. Historical experience indicates that direct load control programs deliver more consistent per-event reductions, while price-responsive programs exhibit greater variability in customer response.

Historic enrollment trends and event performance results have informed the planning assumptions used in this IRP. Program refinements implemented in recent years have supported more accurate estimation of delivered demand reductions.

The Company uses observed program performance to validate and adjust IRP assumptions rather than to establish forward-looking performance guarantees. As such, historic results are treated as informative inputs to planning rather than binding commitments.

8.3.5 Forecast

Table 8-5 and Figure 8-2 show that residential DR capability is projected to decline gradually over the planning period, from 100 MW in 2026 to 78 MW in 2050, or from 1.23% to 1.04% of baseline summer demand. This decline is driven primarily by the gradual reduction in Device Cycling capability. The program entered maintenance mode in 2025 and is no longer actively expanding participation, resulting in a gradual decline in enrolled capacity over time. Existing participants and periodic move-in/move-out enrollment initiatives help preserve a portion of the program's capability, but overall enrollment is expected to decrease as legacy equipment attrition occurs.

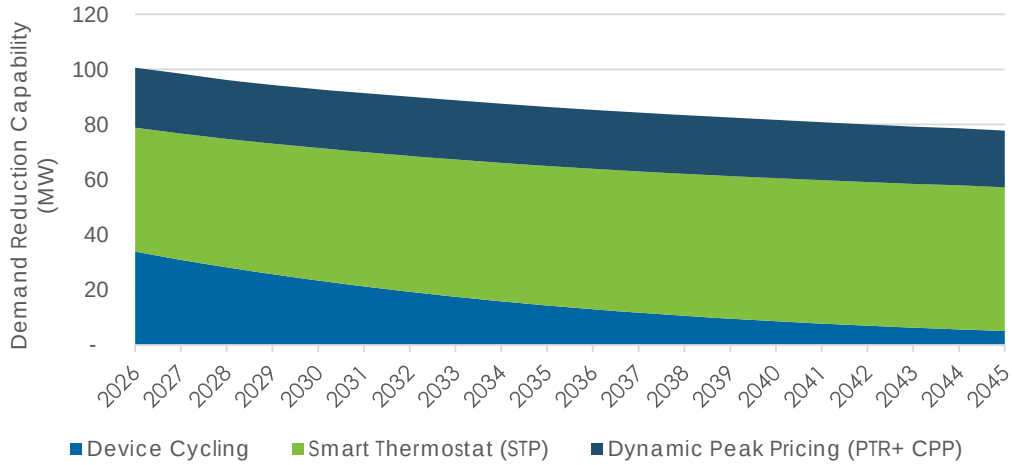
As a result, the composition of the residential DR portfolio shifts toward greater reliance on smart thermostat resources. Overall, residential DR remains a meaningful component of summer peak management, although its relative contribution declines over the forecast horizon.

Table 8-5: Residential demand response capability (MW)

PROGRAM	2026	2027	2030	2035	2045	2050
Baseline Summer Demand (MW)[1]	8,153	8,123	8,118	8,090	7,635	7,465
Device Cycling	33.9	30.9	23.4	14.3	5.1	5.1
Smart Thermostat Program	45.0	45.8	48.1	50.6	52.2	52.2
Dynamic Peak Pricing (PTR+ CPP)	21.8	21.8	21.3	21.4	20.5	20.5
Total DR Potential	100.6	98.4	92.7	86.4	77.8	77.8
Demand Savings (% of Baseline)	1.23%	1.21%	1.14%	1.07%	1.02%	1.04%

1) BAU Coincident Peak Demand before adjustments

Figure 8-2: Forecasted residential demand reduction capability, 2026-2045



Forecasted residential DR costs differ by program and expenditure type. AC Peak Cycling is the only program with capital costs, which decline over time. O&M is the largest cost category for AC Peak Cycling and the Smart Thermostat Program, while DPP has no capital costs and relatively lower O&M costs. Customer incentive costs are material for AC Peak Cycling and DPP, with DPP increasing over the planning period.

Table 8-6: Forecasted residential DR costs

EXPENDITURE TYPE	COST PARAMETERS	PEAK POWER SAVERS® AC PEAK CYCLING	PEAK POWER SAVERS® DYNAMIC PEAK PRICING PROGRAM	SMART THERMOSTAT PROGRAM
Capital	2026 Cost	$690,148	$0	$0
	Expected CAGR through 2045	-8%	N/A	N/A
	2045 Cost	$156,762	$0	$0

EXPENDITURE TYPE	COST PARAMETERS	PEAK POWER SAVERS® AC PEAK CYCLING	PEAK POWER SAVERS® DYNAMIC PEAK PRICING PROGRAM	SMART THERMOSTAT PROGRAM
O&M	2026 Cost	$2,463,438	$282,261	$12,273,050
	Expected CAGR through 2045	-7%	2%	3%
	2045 Cost	$563,225	$405,393	$21,722,540
Customer Incentive	2026 Cost	$2,798,518	$1,883,770	$0
	Expected CAGR through 2045	-7%	2%	N/A
	2045 Cost	$639,836	$2,705,536	$0

8.4 Commercial and Industrial Demand Response Programs

Consumers Energy's C&I DR programs are designed to provide reliable, dispatchable reductions in electricity demand from large C&I customers during periods of system stress. These programs play a significant role in supporting both summer and winter reliability and represent the majority of the Company's DR capability reflected in this IRP.

The primary C&I DR offerings included in this IRP are:

- **Contractual Demand Response Programs**, under which customers commit to provide specified load reductions during events in exchange for performance-based compensation; and
- **Interruptible Service Programs (GI and GI-2)**, which provide customers with a reduced electric rate in exchange for agreeing to curtail load during system emergencies or other defined conditions.

These programs are generally available on a year-round basis, enabling CE to rely on commercial DR resources to support both summer and winter peak conditions, subject to program-specific constraints.

Within the IRP, C&I DR resources are evaluated as dispatch-limited, yet dependable capacity contributors, capable of supporting resource adequacy and reducing reliance on wholesale market purchases during critical conditions. These resources are not assumed to be continuously available and are subject to defined limits on event frequency, duration, and notification requirements, which are reflected in conservative planning assumptions.

Table 8-7 summarizes CE's C&I DR programs included in this IRP and provides a high-level comparison of program design, enrolled capacity, and key planning assumptions used in the Company's resource analysis. The values shown reflect current program characteristics and modeling inputs rather than performance targets or guaranteed outcomes.

Table 8-7: C&I demand response program summary (2026)

	CONTRACTUAL DR PROGRAM	INTERRUPTIBLE RATE (GI PROVISION)
Brief Description	A year-round program for large C&I customers that provides contracted load reductions during peak or emergency conditions in support of system reliability.	A rate-based program for large C&I customers that offers discounted service in exchange for curtailing load during system emergencies.
Incentive	• Summer - $25 per kilowatt nominated • Fall, Winter, Spring - $9 per kilowatt nominated • An additional $0.45 per kilowatt for any extra kilowatt reductions you make on Event Day	Bill savings through a discounted rate / tariff credit.
Current Enrollment (participants)*	1,474	22
Current Enrolled Capacity (Summer MW)*	279.8 MW	209.5 MW
Operating Season	Year-round	Year-round
Historic Performance (contextual)	An event was called on July 15, 2026, in response to an Energy Emergency Alert Level 2 from MISO. Together, Contractual DR and interruptible rates delivered approximately 410 MW of load reduction.	
2045 Projected Enrollment (MW)	276.2 MW	226.1 MW

* End of year, 2025 See Case No. U-20628.

Since its inception in 2017, the company's C&I DR programs have continued to evolve and grow in its ability to contribute to reliable, safe, affordable and sustainable electric offerings.

In recent years, some of the successes include:

- **Exceeded 2025 C&I DR Enrollment Goals** – Achieved 280 MW of enrolled C&I Contractual DR, surpassing 2025 targets and reinforcing portfolio reliability through strong customer engagement and retention.
- **$2.5M Cost Reduction Through Enel X Contract Renegotiation** – Reduced program operating costs by $2.5 million for the vendor that provides the customer enrollment portal and initiating events called by MISO while maintaining service quality and event performance, delivering greater customer value and long-term cost stability.
- **Transition to Year-Round C&I DR Product** – Expanded from a summer-only offering to a year-round resource, improving seasonal flexibility, aligning with MISO requirements, and supporting system reliability across all seasons.
- **Improved Load Relief Accuracy** – Enhanced measurement, baselines, and performance tracking to deliver more accurate load relief results, increasing confidence in event performance and strengthening IRP capacity value.

These successes highlight the progress made in customer outreach and education as well as the learning and implementation of feedback throughout the life of the

program. The Company continues to collect feedback and lessons learned to further refine the programs and ensure the best programs are offered.

8.4.1 Program Descriptions

Contractual Demand Response Program
CE's Contractual DR program is available to large C&I customers capable of reducing electricity consumption during system peak or emergency conditions. Participating customers typically provide curtailable load from operational processes, building systems, or other controllable equipment. No specific utility-installed technology is required, although customers may use internal energy management systems or controls to implement load reductions. Customers enroll through a contractual agreement with the Company that specifies the committed demand reduction and event requirements. The program is marketed through direct outreach to large C&I customers by account representatives and through engagement with customers that have significant peak demand. The program operates year-round to support system reliability during periods of system stress. During DR events, participating customers are required to reduce load to the contracted level within the specified notification period and maintain the reduction for the duration of the event.

Interruptible Rate (GI Provision)
CE's GI and GI-2 interruptible service programs are rate-based DR options available to large C&I customers with substantial and flexible electricity loads. Customers participating in these programs agree to reduce electricity consumption during system emergencies in exchange for a reduced interruptible rate. Load reductions are typically achieved through operational adjustments or the curtailment of energy-intensive processes, and the Company does not require installation of specific enabling technology. Customers enroll by selecting the interruptible service tariff and executing the applicable service agreement with the Company. The programs are marketed through direct engagement with eligible large C&I customers and through the Company's account management team. The programs operate year-round and are designed to provide capacity during emergency conditions. When an interruption event is called, participating customers must curtail load to their committed level within the required response time and maintain the reduction for the duration of the interruption.

8.4.2 Cost and Investment

C&I DR programs involve a combination of customer incentives or rate discounts, program administration costs, and limited capital expenditures associated with program enrollment and management.

Costs reflected in this IRP include incentive payments or bill credits, vendor or aggregator service costs, and internal administrative expenses. Cost assumptions are calibrated to recent program expenditures and Commission-approved program designs.

For planning purposes, C&I DR costs are incorporated into IRP modeling as programmatic expenditures associated with capacity procurement, rather than capital investments with long useful lives.

Table 8-8: 2026 Table 8-8 summarizes planning year expenditures for the company's C&I DR programs, including annual O&M, capital, and customer incentive costs for Contractual DR and the Interruptible Rate program. These forecasts are for modeling input and planning only and do not necessarily indicate performance targets or operational guarantees.

Table 8-8: 2026 C&I DR expenditures

2026 COST PARAMETERS	CONTRACTUAL DR	INTERRUPTIBLE RATE (GI PROVISION)
Annual O&M	$5,979,992	$5,136,471
Annual Capital Expenditures	$103,801	$0
Annual Customer Incentive Expenditures	$4,008,401	$4,560,578

8.4.3 Demand Reduction Capability

Table 8-9 provides a summary of projected DR capabilities for the planning year. These projections are inputs for IRP scenario development and planning and do not necessarily indicate performance targets or operational guarantees.

Table 8-9: Planning year C&I DR reduction capability

PARAMETER	CONTRACTUAL DR	INTERRUPTIBLE RATE (GI PROVISION)
Total demand reduction capability (MW)*	230.5 MW	209MW
Maximum single-event MW reduction**	256.1 MW	220.0 MW
Expected interruption duration (per day | per month | per year)	Maximum of 5 events in Summer and Winter and 3 events in Spring and Fall. Event duration is limited to 4 hours, Monday through Friday, 11 AM to 7 PM.	Maximum event duration of 4 hours. No limit on number of events.
MISO resource type	DR – LMR	DR - LMR

* For programs that are registered with MISO, the total demand reduction capability is the amount expected to be registered with MISO.
** Projected enrolled MWs for both MISO registered and unregistered programs.

Commercial DR programs provide the largest share of DR capability within CE's portfolio. Due to the scale of participating customer loads and the contractual nature of program commitments, commercial programs are capable of delivering substantial and dependable peak demand reductions relative to residential offerings.

Interruptible service programs generally provide the most reliable demand reductions, particularly during winter peak conditions, as they are driven by contractual obligations

and often tied to large process loads. Contractual DR programs provide additional flexibility and contribute materially to both summer and winter capacity needs. In IRP modeling, commercial DR resources are treated as dispatch-limited capacity resources.

8.4.4 Historic Performance

CE's commercial DR programs have demonstrated consistent performance in delivering load reductions during dispatched events. Historic experience indicates high performance from G2, while G1 performed below expectations.

Observed performance has informed the planning assumptions used in this IRP, including estimates of dependable capacity contribution, appropriate derating for non-performance risk, and realistic limits on event frequency. Periodic program refinement and customer engagement efforts have supported continued reliability and participation over time.

The Company uses observed program performance to validate and adjust IRP assumptions rather than to establish forward-looking performance guarantees. As such, historic results are treated as informative inputs to planning rather than binding commitments.

8.4.5 Forecast

Table 8-10 and Figure 8-3 show that C&I DR capability is projected to increase modestly over the planning period, from 439 MW in 2026 to 472 MW in 2045. However, this increase does not outpace demand, so overall program impact is expected to decrease gradually from 2026 to 2035, and then rise slightly again in 2045 to 2026 levels as compared to baseline annual demand. Contractual DR programs show the most consistent growth over time, while interruptible services increase modestly for several years and then slightly decline in later years. Overall, both programs contribute significantly to demand side flexibility and reductions annually, despite not quite keeping pace with expected demand growth.

Table 8-10: C&I DR capability (MW)

PROGRAM	2026	2027	2028	2030	2035	2045
Baseline Demand Projection (MW)	2,901	2,944	2,995	3,040	3,102	3,118
Contractual DR Program	231	233	237	240	246	253
GI/GI2	209	211	214	216	217	219
Total DR Potential	439	444	451	456	463	472
Demand Savings (% of Baseline)	15.15%	15.09%	15.05%	15.00%	14.92%	15.15%

Percentage of baseline calculated using the previous year's baseline electric demand.
Estimates based on BAU

Figure 8-3: Forecasted C&I DR capability, 2026-2045

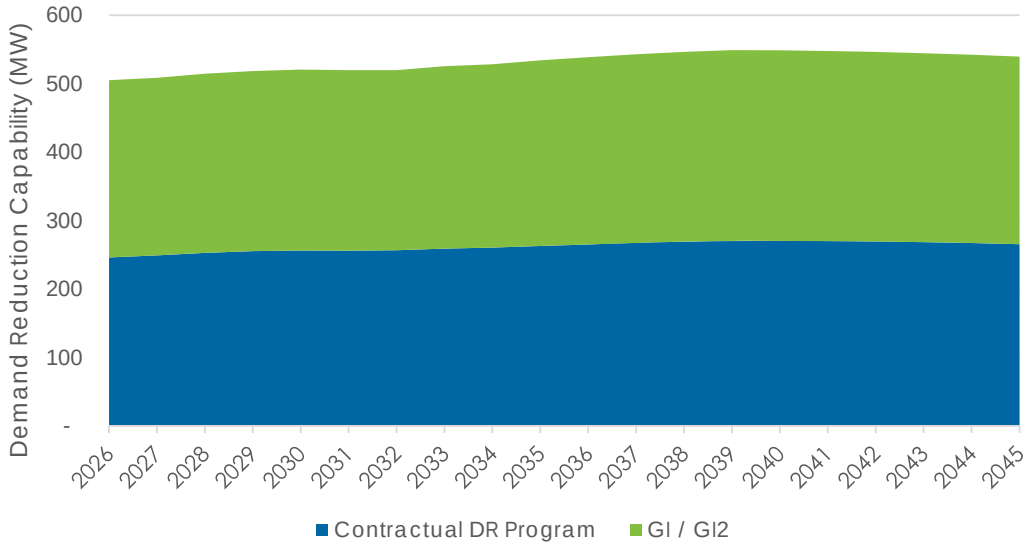


Table 8-11 summarizes forecasted commercial DR program costs by expenditure type for the Company's Contractual DR and Interruptible Rate programs, including capital, O&M, and customer incentive costs in 2026 and 2045, as well as the assumed growth in costs over the planning period.

Table 8-11: Projected C&I DR costs

EXPENDITURE TYPE	COST PARAMETERS	CONTRACTUAL DR	INTERRUPTIBLE RATE (GI PROVISION)
Capital	2026 Cost	$103,801	$0
	Expected CAGR through 2045	2%	N/A
	2045 Cost	$152,083	$0
O&M	2026 Cost	$5,979,992	$5,136,471
	Expected CAGR through 2045	3%	2%
	2045 Cost	$9,860,408	$8,072,092
Customer Incentive	2026 Cost	$4,008,401	$4,560,578
	Expected CAGR through 2045	3%	2%
	2045 Cost	$6,609,453	$7,176,038

8.5 Dispatch Criteria for Demand Response

CE has established operational criteria for initiating residential and commercial DR events to ensure system reliability, efficient peak demand management, and mitigation of exposure to elevated wholesale market prices. Dispatch decisions for DR resources are based on forecasted system conditions, operational constraints, and program-specific parameters.

Residential DR events are typically triggered when at least two of the following criteria are met:

1. MISO load is forecasted to reach 117,500 MW on a given day;
2. CE load is forecasted to reach 27,000 MW for four consecutive hours; and
3. MISO capacity reserve margin is forecasted to fall below 5%. C&I DR events are primarily initiated during system emergency conditions, including events called by MISO, when forecasted system load and reserve margin conditions indicate elevated reliability risk.

DR resources are not continuously available and are subject to defined limits on event frequency, duration, seasonality, and notification requirements. Accordingly, DR is dispatched selectively during periods when system conditions warrant curtailment and when the resource provides the greatest operational and economic value.

8.6 DR Resource Evaluation

CE evaluates their DR programs based on their cost, achievable participation levels, and accredited capacity value. Eligible DR resources are registered with MISO as Load Modifying Resources and are credited with capacity value at a benchmark of approximately 75% of MISO's Cost of New Entry (CONE).

Cost-effectiveness is assessed primarily at the portfolio level, while individual program performance is monitored to ensure continued alignment with planning assumptions. Programs that no longer meet cost-effectiveness thresholds may be scaled back or transitioned to maintenance mode.

In determining whether to pursue incremental DR or rely on alternative resource options, CE compares the cost and value of additional DR against other means of meeting system needs, including market purchases and supply-side resources. DR is selected where it provides a cost-effective means of reducing peak demand and avoiding or deferring capacity needs. However, CE does not pursue DR expansion beyond levels that remain economically justified, recognizing that additional enrollment may require higher-cost program offerings with diminishing returns. As such, the Company's approach is to develop DR up to the level that is both achievable and cost-effective, with remaining resource needs met through a combination of purchased capacity, energy, or other supply-side resources, consistent with least-cost, reliable system planning.

8.7 Supply Side Resources

Consumers Energy consider DR as part of an integrated framework that also includes market purchases and supply-side resources. During the summer of 2020, the Company established load- and price-based triggers to guide the dispatch of DR resources, as described in the "Dispatch for Demand Resources" section above. Because these programs allow for only a limited number of events per season (e.g., 8 events annually for Contractual DR and 10 for A/C cycling and 14 for time-of-use (TOU) pricing), the triggers are designed to identify the highest system load days and most critical conditions. This approach ensures that the limited number of available DR events is deployed when it provides the greatest reliability and economic benefit.

8.8 Energy Waste Reduction

EWR programs are a foundational component of Consumers Energy's demand-side resource strategy and are designed to achieve permanent reductions in customer energy consumption and associated peak demand. EWR programs support residential, commercial, industrial, agricultural, and income-qualified customers through cost-effective efficiency measures that reduce total energy usage, lower customer bills, and mitigate long-term system costs. By reducing electricity consumption on a sustained basis, EWR lessens exposure to wholesale market volatility, defers or avoids investment in new generation and delivery infrastructure, and supports achievement of the Company's reliability, affordability, and clean energy objectives.

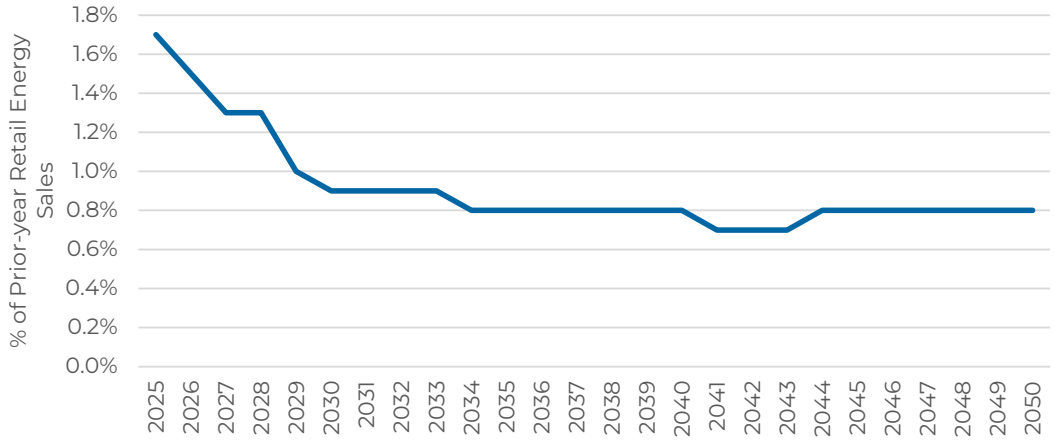
Within this IRP, EWR is treated as a load-reducing planning resource, rather than a dispatchable resource. Energy savings achieved through EWR programs are incorporated directly into the Company's load forecast, reducing both projected annual energy requirements and coincident peak demand. These reductions are reflected in the baseline demand used in IRP modeling and serve to lower future capacity and energy needs that would otherwise be met through supply-side resources or market purchases.

In addition to embedded baseline savings, the IRP evaluates incremental levels of EWR as part of resource optimization, consistent with the use of EWR "blocks" representing higher levels of savings at increasing marginal cost. This approach allows the IRP to assess the cost-effectiveness of additional efficiency relative to alternative resource options under a range of system conditions.

8.8.1 EWR Savings Assumptions

The IRP assumes average annual incremental EWR savings that are achievable and cost-effective over the planning horizon. Annual savings are expressed as a percentage of prior-year retail energy sales and are consistent with achievable potential identified through independent EWR potential studies and historical program performance. While the Company continues to pursue higher savings levels through its biennial EWR plan filings when achievable and cost-effective, the IRP reflects savings levels that are expected to be deliverable on a sustained basis over the long term.

Figure 8-4. Forecasted EWR savings (% of prior-year retail energy sales)



8.8.2 Costs and Investments

For purposes of resource planning, EWR costs are represented at the portfolio level and include annual O&M expenditures, capital investments, and any approved performance incentives or cost-sharing mechanisms. These costs reflect the resources necessary to deliver the energy and peak demand reductions included in the IRP and are consistent with costs provided in EWR plan filings and supporting exhibits. Detailed program-level cost recovery, performance evaluation, and reconciliation are addressed through separate EWR proceedings and are not determined through the IRP.

8.8.3 Contribution to Resource Adequacy

By reducing both annual energy consumption and summer coincident peak demand, EWR contributes materially to system resource adequacy. Peak demand reductions attributable to EWR are embedded in the load forecast used for IRP modeling and reduce the amount of incremental supply-side capacity required to meet reliability targets. These benefits accrue across the planning horizon and complement other demand-side and supply-side resources in the Company's portfolio.

8.9 Conservation Voltage Reduction

CVR is an important component of CE's distribution system optimization strategy and supports the Company's efforts to deliver reliable, affordable, and cleaner energy to customers. Enabled by advanced grid technologies, including AMI, advanced distribution management capabilities, and enhanced voltage monitoring and control systems, CVR reduces energy consumption by optimizing service voltage levels delivered to customers while maintaining compliance with regulatory voltage standards. By operating the system more efficiently, CVR reduces both energy usage and peak demand without requiring active customer participation or BTM investments.

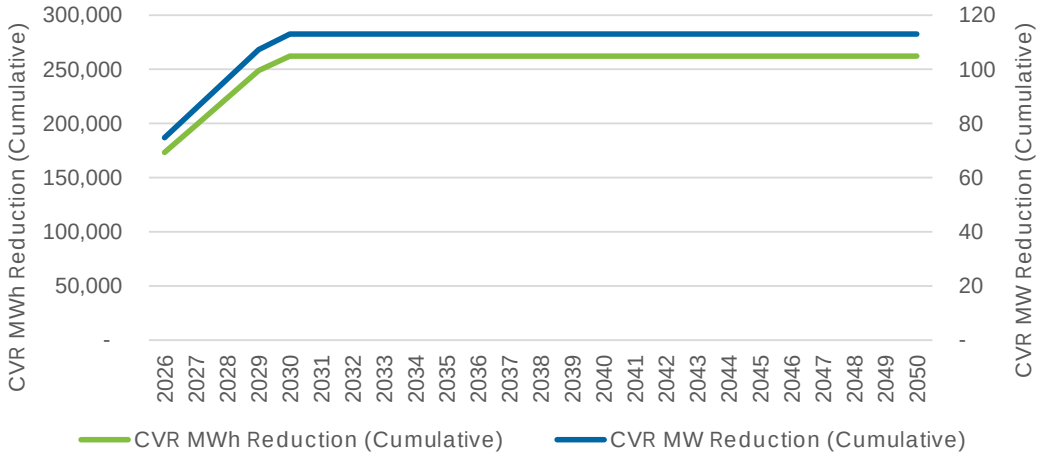
CVR is achieved through coordinated control of substation and feeder voltage regulating equipment, including transformer load tap changers, line regulators, and capacitor banks. These technologies work together to maintain customer voltages near the lower end of the acceptable range, which reduces system load and associated

generation requirements. Continuous monitoring and automated control enable dynamic adjustments in response to changing system conditions, allowing the Company to capture energy savings while maintaining power quality and reliability.

Since initial deployment, CE has expanded CVR capabilities as part of its broader grid modernization efforts. Following early operational testing and validation on select circuits, the Company has integrated CVR into standard distribution operations and continues to deploy the necessary sensing, communications, and control infrastructure across additional feeders where cost-effective. CVR provides systemwide benefits, including reduced peak demand, deferred infrastructure investments, lower operating costs, and reduced emissions.

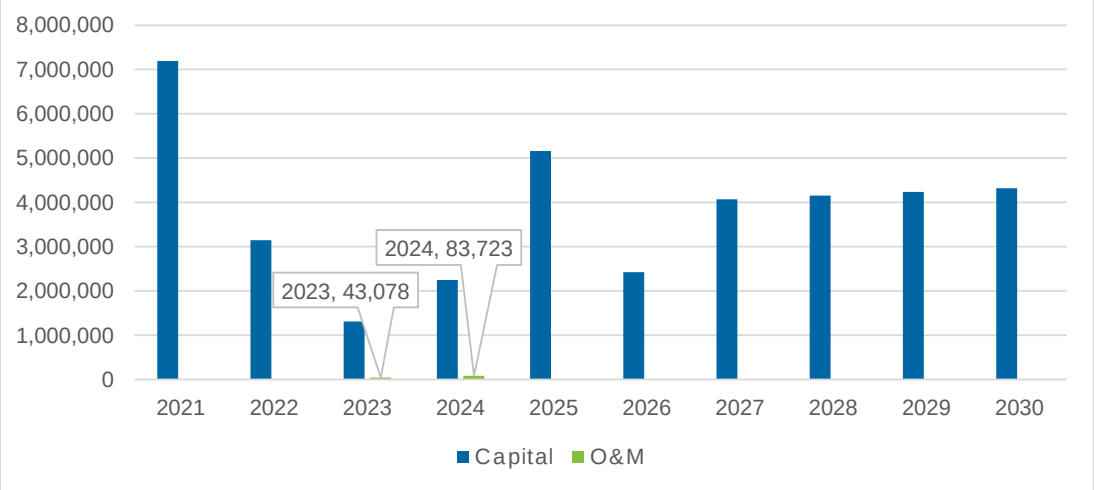
Since its initial deployment in 2018, the CVR program has expanded rapidly, delivering approximately 62 MW of peak demand reduction by 2025 across roughly 500 distribution circuits. As shown in Figure 8-5, the Company projects CVR capability to continue increasing in the near term, reaching 113 MW and 262,255 MWh of cumulative reduction by 2030, after which reductions remain flat through 2050. This forecast indicates that CVR is expected to provide a meaningful and sustained contribution to peak demand reduction over the planning period.

Figure 8-5: CVR peak demand reductions, 2026-2050



As shown in Figure 8-6, Capital expenditures were highest in the initial years of the program to support deployment of Volt/Volt-Ampere Reactive (VAR) Optimization equipment and controls across priority circuits. Capital spending peaked at approximately $4.1 million in 2022, declined to about $3.8 million by 2025, and is expected to continue decreasing through 2030 as the program transitions from large-scale deployment to targeted expansion. In contrast, O&M spending has increased over time as the number of CVR-enabled circuits has grown. Between 2020 and 2025, O&M expenditures increased at an average annual rate of roughly 30%, reflecting the rapid expansion of deployed circuits. Looking ahead, O&M growth is expected to moderate, slowing to an average annual increase of about 9% through 2030 as the program matures.

Figure 8-6: CVR expenditures, 2018-2040



8.10 Electric Vehicle Load Shape Management

In addition to EWR, DR, and CVR, CE manages the system impacts of growing EV adoption through load shape management strategies. Managed EV charging programs influence *when* EVs charge by shifting a substantial portion of charging activity to off-peak hours, thereby mitigating the contribution of EV adoption to system peak demand.

EV load shape impacts are incorporated into the IRP through dedicated EV hourly load profiles applied within the load forecast, rather than being treated as dispatchable demand-side resources. As a result, EV shape shifting reduces peak demand growth associated with electrification while accommodating continued increases in total EV energy consumption. Detailed EV program design and performance are addressed in the Transportation Electrification sections of this filing.

8.11 Proposed Course of Action – Demand-Side Resources

Demand-side resources are a critical component of CE's strategy for meeting customers' energy needs in both the near term and over the planning horizon. These programs provide cost-effective, reliable capacity and energy savings while supporting the Company's clean energy and affordability objectives. The PCA assumes continued expansion and performance of DR and EWR programs, supplemented by CVR initiatives. Together, these DSM resources are projected to provide more than 2,615 ZRCs by 2040. Table 8-12 illustrates the incremental growth of these programs over the planning period.

Projected investment requirements include approximately $396 million in capital expenditures for DR and CVR initiatives and approximately $869 million in associated O&M costs. EWR programs represent an additional projected investment of approximately $4.4 billion over the planning horizon.

Table 8-12. Proposed course of action – demand side resource

DEMAND-SIDE RESOURCE	MW REDUCTIONS			MISO SUMMER ZRC		
Planning Year	2026	2030	2040	2026	2030	2040
AC Cycling	34	23	9	45	30	11
Smart Thermostat Program	45	48	52	59	64	68
Contractual DR	231	240	253	304	316	334
G1/G2	209	216	219	319	326	344
EWR	1,072	1,312	1,031	1,060	1,297	1,019
DPP	22	21	21	29	28	28
Summer Time of Use Rate	96	50	9	95	49	9
CVR	78	124	138	77	123	137
EV Shape Shifting	-	-	673	-	-	665

8.12 Future Integration of Demand-Side Resources and Virtual Power Plants

Throughout this section, the Company has described a range of customer-side resources that reduce energy consumption, lower peak demand, shift customer load, or provide customer-sited energy supply. Collectively, these resources provide many of the foundational capabilities commonly associated with VPPs. DR programs provide dispatchable load reductions during periods of system need, energy efficiency programs reduce baseline energy requirements, time-varying rates and managed EV charging introduce load flexibility, and DG resources contribute customer-sited energy production. Together, these resources demonstrate how customer participation can support system reliability and flexibility.

The Company views these programs as building blocks for increasing VPP capabilities. As customer participation, technology adoption, and coordination capabilities continue to evolve, opportunities may emerge to more closely integrate customer-side resources and realize additional system benefits. Rather than representing a separate resource category, VPPs can be viewed as the increasingly coordinated operation of customer-side resources that are already providing value to the electric system today. The Company will continue to evaluate future opportunities for customer-side resource integration through its resource planning, pilot programs, technology evaluations, and procurement activities.

Renewables and Renewable Portfolio Standards Requirements

Section 9

9 Renewables and Renewable Portfolio Standards Requirements

9.1 Renewable Energy Plan

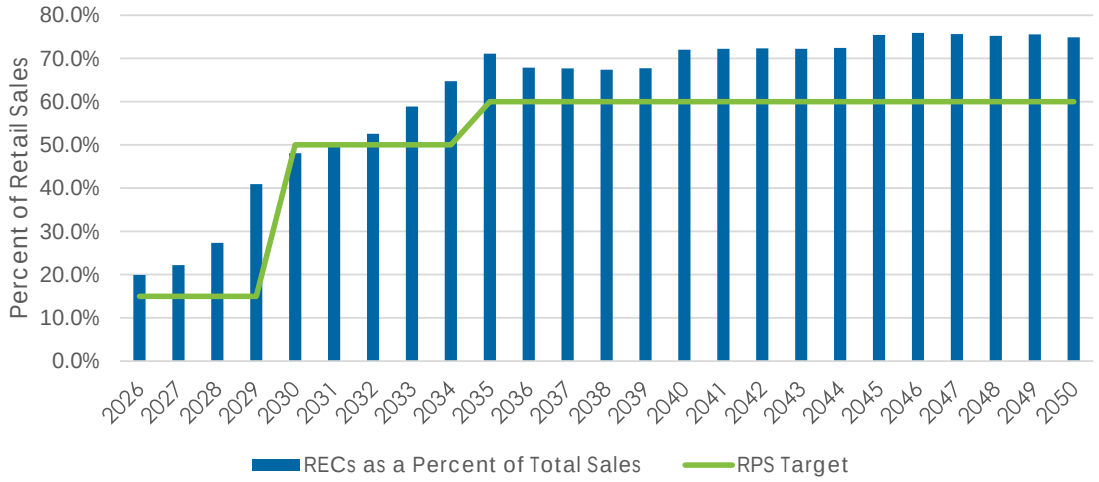
9.1.1 Overview of Renewable Energy Requirements

CE's Renewable Energy Plan (RE Plan) is designed to comply with Michigan's renewable energy statutory framework, which requires electric providers to meet specified renewable energy targets using eligible renewable resources and RECs. Current requirements include achieving at least 50% renewable energy by 2030 and 60% by 2035, measured as a share of retail sales. Compliance may be achieved through Company-owned generation, PPAs, and REC procurement consistent with statutory and Commission guidance. The RE Plan demonstrates how the Company's resource portfolio will meet these obligations while maintaining reliability and cost effectiveness.

The RE Plan is integrated with the Company's IRP and CEP. The IRP identifies a PCA to meet forecasted demand at the lowest reasonable cost while maintaining reliability. Renewable resource additions from the IRP are used to demonstrate compliance in the RE Plan, while the CEP provides the broader strategy for reducing emissions and advancing a cleaner energy portfolio. Together, these plans ensure that renewable deployment supports statutory requirements, system reliability, and customer affordability.

Figure 9-1 illustrates CE's projected renewable energy compliance trajectory over the planning horizon. CE projects compliance with the 15% renewable energy standard through 2029, followed by an increase to the 50% standard beginning in 2030 and the 60% standard beginning in 2035. The Company's compliance strategy relies on existing and planned renewable resources included in the PCA, supplemented by REC purchases and REC banking as necessary to maintain compliance over the planning period. CE forecasts compliance with applicable renewable energy requirements through 2045.

Figure 9-1: Projected REC share relative to RPS requirements, 2026–2050



9.1.2 Renewable Portfolio and Resource Strategy

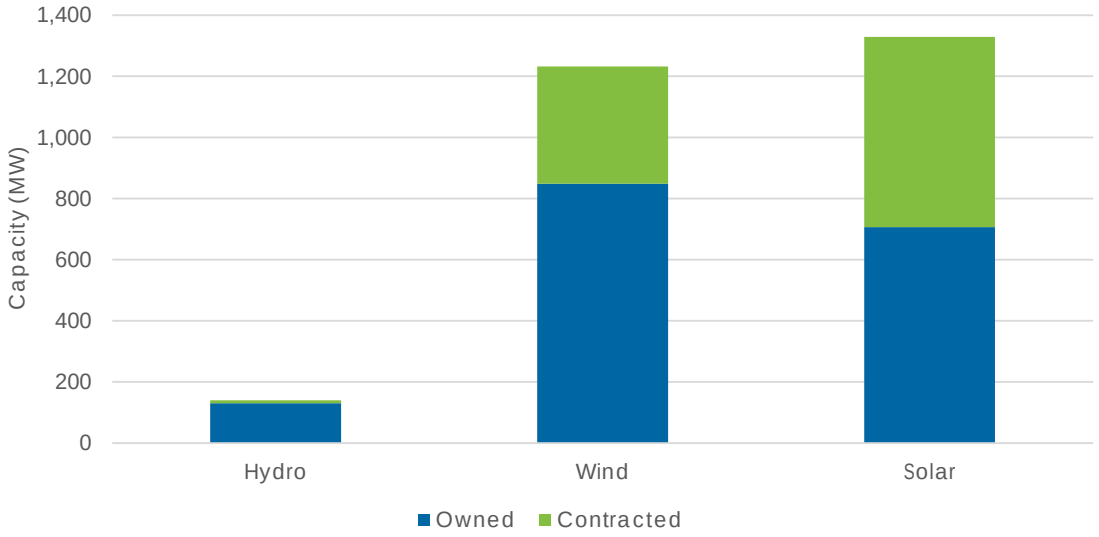
Existing Resources

CE's existing renewable portfolio consists of a combination of Company-owned renewable generating assets and long-term PPAs, as described in Section 7, Existing Supply-Side Resources. Company-owned renewable resources include seven utility-scale wind facilities such as Lake Winds Energy Park, Cross Winds Energy Park Phases I–III, Crescent Wind, and Gratiot Wind Farm, as well as seven operating solar installations and Solar Gardens projects. In addition, the Company operates 13 hydroelectric facilities that contribute renewable energy and capacity to the system. Together, these owned assets provide a baseline level of renewable generation that supports compliance with statutory requirements.

The Company also relies on renewable PPAs to supplement its owned portfolio and maintain compliance flexibility. Active agreements include contracts for wind generation from facilities such as Beebe Renewable Energy, Heritage Garden Wind Farm, Heritage Stoney Corners Wind Farm phases, Michigan Wind 2, and Apple Blossom Wind, as well as solar resources including River Fork Solar and Experimental Advanced Renewable Program (EARP) Solar. The Company also holds smaller hydroelectric PPAs that contribute incremental renewable supply. These contracted resources diversify the renewable portfolio geographically and technologically while reducing development risk and capital requirements.

Total capacity of existing renewable resources is summarized in Figure 9-2.

Figure 9-2: Existing renewable resources



Collectively, existing renewable assets and PPAs provide a substantial portion of the renewable energy used to meet current requirements, while planned additions under the PCA will support compliance with increasing statutory targets over the planning horizon.

Planned Additions

Under the PCA, CE plans to add approximately 6,200 MW of solar capacity and 3,208 MW of wind capacity by 2045. Solar deployment continues to increase beyond this point, reaching 8,826 MW by 2040 and 9,766 MW by 2050, while the wind portfolio remains relatively stable in later years.

9.1.3 REC Portfolio Calculation Methodology

The foundation of the REC obligation is the Company's jurisdictional retail sales. These sales are adjusted to remove customer-driven renewable participation to avoid double counting:

- Retail sales attributable to customers enrolled in voluntary green pricing (VGP) programs under Section 61 are excluded.
- DG outflow from customers participating under Section 173 is also excluded.

The resulting value, retail sales minus VGP sales minus DG outflow, constitutes compliance sales, the statutory basis for calculating required RECs.

CE determines its REC compliance obligation using the average megawatt-hours of electricity sold to retail customers in Michigan over the previous three calendar years, consistent with statutory provisions and Commission guidance. Applying the applicable renewable energy percentage to this three-year average smooths annual variability in sales and provides a stable basis for planning. This approach ensures that short-term fluctuations in load do not create artificial volatility in compliance requirements.

CE satisfies its REC requirement through three channels:

- Purchased RECs, capped at 5% of the requirement through 2035.
- RECs from utility-owned renewable resources included in the IRP build plan.
- RECs from long-term PPAs with renewable energy suppliers.

Michigan allows unused RECs to be banked for future compliance. CE uses banking to manage rising Renewable Portfolio Standard (RPS) requirements, building surplus in years with excess renewable generation and drawing down the bank when annual REC supply falls short of the 50% requirement in 2030 or the 60% requirement beginning in 2035.

9.1.4 Incremental Cost of Compliance

The incremental cost of compliance with existing renewable energy standards for the required compliance period ending December 31, 2045 is ($304) million as established in Case No. U-21816, Exhibit A-4 (MRB-1), line 16.

CE does not anticipate the need for an incremental renewable energy surcharge to maintain compliance with Michigan's renewable energy standard, and expects renewable compliance costs to be managed through existing recovery mechanisms.

9.2 Customer-Initiated Renewable Energy Programs and Demand

9.2.1 Program Portfolio

Consumers Energy offers a portfolio of VGP programs that enable residential, commercial, and industrial customers to support renewable energy generation beyond standard electric service. The Company's VGP offerings include the REP, Green Giving, Solar Gardens, MI Sunrise Solar, and the REC Program, providing customers with options ranging from renewable energy subscriptions and community solar participation to the purchase of RECs. These programs support a range of customer sustainability objectives while allowing CE to align renewable resource development with anticipated customer demand.

Renewable Energy Program and Green Giving

The REP allows customers to match up to 100% of their annual electricity consumption with renewable energy generated from designated CE wind and solar resources. The program serves residential, commercial, and industrial customers and provides participating customers with the environmental attributes associated with their subscribed renewable energy. RECs associated with smaller customer subscriptions are retired on the customer's behalf, while larger C&I participants may elect to receive transferred RECs and International RECs (IRECs), subject to program requirements. Green Giving is a companion offer that allows customers to support renewable energy development through voluntary contributions and subscriptions. CE periodically evaluates participation levels and renewable resource availability to ensure sufficient renewable supply is available to support customer subscriptions.

Solar Gardens and MI Sunrise Solar Pilot

CE's Solar Gardens program is a voluntary community solar offering that allows residential and business customers to subscribe to shared solar facilities in 500-watt blocks through multiple payment options. The pooled Solar Gardens resources are located at Western Michigan University, Grand Valley State University, and Cadillac. Subscribers receive bill credits based on facility generation and associated MISO market revenues, and the corresponding RECs are retired on their behalf. The MI Sunrise Solar pilot expands access to community solar for income-qualified households by allowing nonprofit organizations to subscribe on behalf of eligible customers and allocate bill credits to participating households. CE expects customer participation in community solar programs to continue growing and currently assumes the addition of approximately 3 MW of Solar Gardens capacity beginning in 2030 to support future subscription demand.

Renewable Energy Credit Program

The REC Program is a VGP offering that allows customers to match their electricity use with renewable energy through the purchase of unbundled RECs sourced from Michigan-based or national renewable facilities. Program options include RECs from existing resources as well as from new facilities developed to meet future demand, with certain products requiring longer-term commitments and primarily serving C&I customers. RECs associated with the program are retired on behalf of participating customers, enabling voluntary support for renewable energy beyond statutory requirements. CE will continue to procure REC supply as needed to meet customer participation and maintain program flexibility.

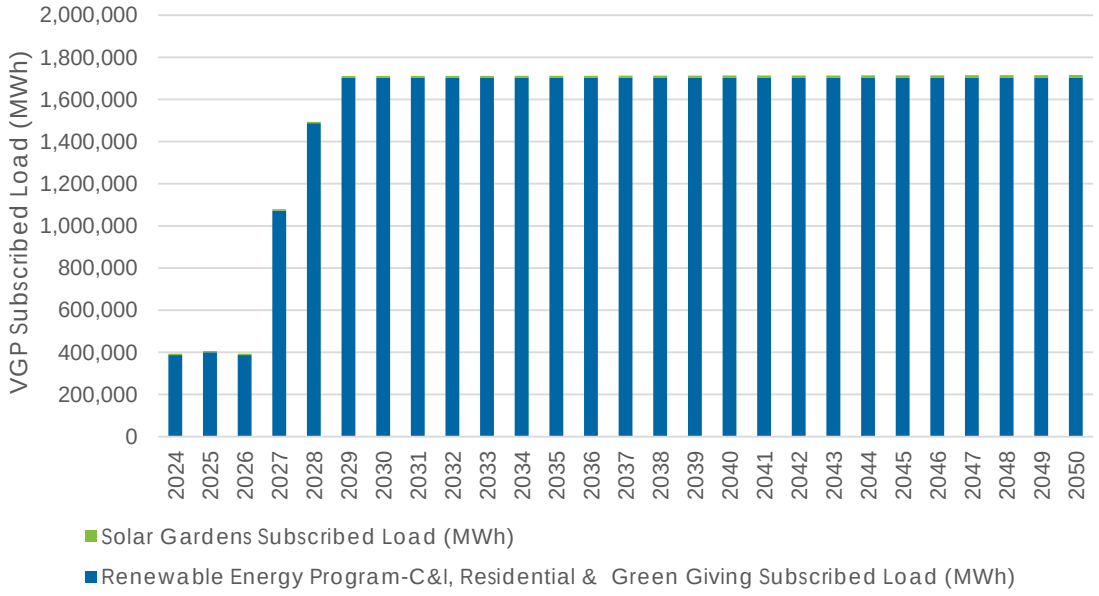
External Power Purchase Agreement Option

CE also offers an External PPA option for qualifying full-service customers with new load additions served at primary voltage. Under this option, customers may contract directly with third-party renewable energy providers for wind or solar generation located within the MISO footprint while continuing to receive retail electric service from CE. The program provides customers with an additional pathway to meet sustainability objectives through dedicated renewable energy procurement while leveraging CE's existing electric delivery infrastructure.

Voluntary Green Pricing Forecast

CE projects VGP subscribed load to increase from approximately 0.4 million MWh in 2024–2026 to more than 1.7 million MWh by 2029, driven primarily by REP participation and associated renewable resource additions. Thereafter, subscribed load remains relatively stable through the end of the planning period, reflecting CE's expectation that existing and planned renewable resources will be sufficient to meet anticipated participation in the REP, Green Giving, and Solar Gardens offerings. While the Company does not currently forecast significant incremental REP growth beyond 2029, CE will continue to monitor customer demand and market conditions and evaluate additional renewable resources as needed. Solar Gardens subscriptions represent a relatively small but growing portion of total VGP demand, with the forecast assuming approximately 3 MW of additional Solar Gardens capacity beginning in 2030.

Figure 9-3: VGP subscription forecast



Large Customer Renewable Energy Pilot Program Tariff

In November 2025, the Commission approved tariff terms governing service to very large electric customers, including data centers, in CE's service territory. The tariff applies to customers with a minimum load of 100 MW (or aggregated load meeting specified thresholds) and includes provisions intended to protect other customers from cross-subsidization and stranded-cost risk, such as a minimum 15-year contract term, minimum billing demand requirements, collateral provisions, and exit fees for early termination.

The Commission also required CE to file customer-specific proceedings for each large-load customer served under the tariff to demonstrate that the costs of serving the load are borne by that customer. This framework supports large customer renewable and clean energy procurement while ensuring that associated system costs and resource needs are addressed through the Company's broader planning processes.

Environmental Advanced Renewable Program

The EARP is a voluntary program that allows customers with DG resources to sell the energy produced by their systems to CE. Eligible technologies include solar photovoltaic systems and anaerobic digesters. Under the program, participating customers enter into contracts to provide the output from their facilities to the distribution system at a fixed rate.

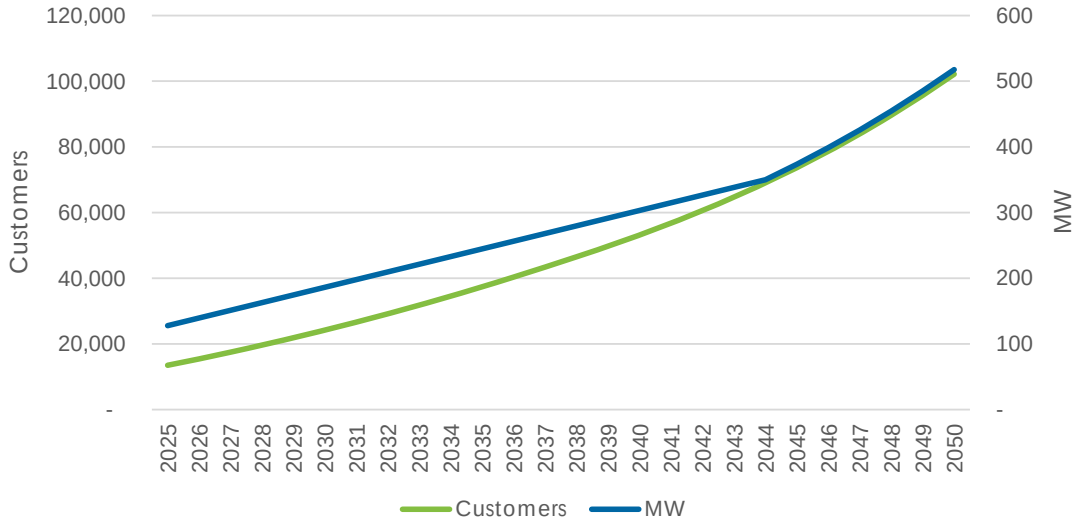
EARP Solar and EARP Anaerobic Digestion include customer contracts representing 6.8 MW of installed solar capacity and 1.8 MW of anaerobic digestion capacity. These distributed resources contribute incremental renewable energy supply while supporting customer participation in renewable generation.

9.3 Distributed Generation, DERs, and Virtual Power Plants in Planning

The DG program allows customers to generate electricity using renewable energy systems up to 150 kW (or up to 550 kW for anaerobic digesters) at their home or place of business and sell excess generation back to the Company for bill credits. The Company files a Distributed Generation Annual Report with the Commission[12] each year to provide updates on the number of participants, installed capacity, and program characteristics.

CE projects continued growth in DG participation throughout the planning period. Installed DG capacity is forecasted to increase from approximately 128 MW in 2025 to 518 MW by 2050, while participating customers are projected to increase from approximately 13,500 to more than 102,000 over the same period. This growth reflects continued customer interest in customer-sited renewable energy technologies and increasing adoption of DERs. As participation grows, CE will continue to incorporate DG forecasts into load forecasting, distribution planning, and resource planning activities. More information on DG programs and forecast are available in Section 8, Demand-Side Resources.

Figure 9-4: Forecasted distributed generation



DG was modeled using two alternative approaches to reflect different cost perspectives. Under the first approach, DG was represented using residential solar and storage cost assumptions from National Renewable Energy Laboratory (NREL) and was

[12] The Company's most recent report was filed in March 2026. Michigan Public Service Commission, (Mar 2026), *Consumers Energy Company's Annual Interconnection and Distributed Generation Report*, filed in Case No. U-20890, accessible at: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00001sDCTeAAO

allowed to compete with other resource options in the capacity expansion model. This approach largely reflects a societal cost perspective, as it captures the customer-side cost of deploying DG resources rather than only the costs borne by the utility. Because residential-scale DG is generally less cost-competitive than utility-scale resources, the model only selects DG in limited circumstances, primarily when other resource build limits are reached. This approach was also used to help evaluate the relative economics of customer-sited DG compared to utility-scale resource additions.

Under the second approach, DG was modeled based on the utility cost of customer outflows to the grid, rather than the full customer installation cost. In this framework, exported generation is assigned an outflow cost, while generation consumed behind the meter is treated as a load reduction. This approach is intended to reflect the utility cost perspective more directly and better align with IRP requirements that the model should include only costs borne by all ratepayers. Because this treatment results in DG appearing as a relatively low-cost resource, DG availability is constrained based on the amount not already reflected in the load forecast and the applicable program cap.

For purposes of the broader DER/VPP assessment, DG solar, DG storage, and DR were modeled as individual selectable resources rather than as a single bundled resource. Collectively, selections of these individual distributed resources were used to represent DER/VPP adoption within the modeling framework.

Energy Storage Target Requirements

Section 10

10 Energy Storage Target Requirements

Under Act 235, electric providers must file plans by December 31, 2029, describing how they will support Michigan's statewide target of deploying 2,500 MW of energy storage. For purposes of meeting this target, only energy storage systems placed in service on or after the Act's effective date (February 27, 2024) count toward the deployment requirement.[13]

The Commission allocates a portion of this statewide requirement to each electric provider using the methodology approved in Case No. U-21751, which is based on each utility's share of in-state retail peak demand. Based on this methodology, CE's proportional share of the statewide storage target is approximately 817 MW.[14]

CE plans to satisfy this requirement through a combination of existing storage resources and new battery storage procurements identified through competitive solicitations and the IRP modeling process.

10.1 Existing Storage Resources

As discussed in Section 7, Existing Supply-Side Resources, the Company's primary existing storage resource is the Ludington Pumped Storage Plant, a pumped hydroelectric storage facility jointly owned by CE and DTE Electric. The Company notes that this capacity does not count toward the 2023 energy law statewide target.

CE owns 51% of the six-unit Ludington pumped storage facility, representing roughly 1,122 MW of capacity. The facility can operate for approximately eight hours at full output, providing significant duration storage capability to the system.

Tibbits, Century Oaks, and Armstrong are the only other utility-scale storage resources operating. Located in Branch County, Tibbits came online in June of 2025 and is a four-hour, 100 MW (400 MWh) storage system. Century Oaks, located in Huron County, was energized in April of 2026 and is a four-hour, 200 MW (800 MWh) storage system. Finally, Amstrong is located in Calhoun County, came online in May 2026, and four-hour, 2.5 MW (10 MWh) storage system.

In addition to the utility-scale units, Consumers Energy operates several pilot and distributed battery storage projects, many of which were developed through the Company's Grid Storage Program to evaluate the operational and reliability benefits of battery storage on the distribution system. Smaller amounts of customer-owned BTM storage are also present through distributed generation and net metering programs.

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[13] Michigan Public Service Commission, (Jan 2025), *Statewide Energy Storage Target*, accessible at: https://www.michigan.gov/mpsc/commission/workgroups/2023-energy-legislation/statewide-energy-storage-target

[14] Michigan Public Service Commission Staff, (Jan 2025), *Statewide Energy Storage Target — Initial Calculation of Individual Electric Provider Allocations*, issued pursuant to the Commission's January 23, 2025 Order in Case No. U-21571, accessible at: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000mSpLqAAK

All existing storage resources are generally capable of providing up to four to eight hours of discharge. The Company currently does not operate longer-duration (10+ hour) or multi-day storage resources.

Table 10-1 summarizes Consumers Energy's existing storage portfolio. The operating portfolio includes 1,491 MW/ 9,243 MWh of storage capacity. By technology type, this includes 1,170 MW/ 8,000 MWh of pump-storage capacity, and 307 MW / 1,222 MWh of lithium-ion storage capacity, and 14 MW / 21 MWh of customer-owned storage capacity.

Of the existing storage resources shown in Table 10-1, only Tibbits, Century Oaks, and Armstrong came online after the Act's effective date and are counted toward the Company's storage compliance target, representing a combined 302.5 MW / 1,210 MWh of qualifying storage capacity.

Table 10-1: Operating energy storage resources

RESOURCE	IN-SERVICE DATE	SIZE (MW)	ENERGY (MWh)	TECHNOLOGY TYPE
Utility-Scale				
Ludington Pumped Storage*	Pre-Act 235	1,170	8,000	Pumped-storage hydropower
Tibbits	2025	100	400	Lithium-ion
Century Oaks	2026	200	800	Lithium-ion
Armstrong	2026	2.5	10	Lithium-ion
Distributed/Pilot				
Airpark	Pre-Act 235	2	8	Lithium-ion
Circuit West	Pre-Act 235	0.5	0.5	Lithium-ion
Parkview	Pre-Act 235	1	1	Lithium-ion
Innovation Center	Pre-Act 235	0.1	0.35	Lithium-ion
The 200 Building (solar + BESS**)	Pre-Act 235	0.25	0.5	Lithium-ion
Star of the West	Pre-Act 235	0.25	0.5	Lithium-ion
Bissell	Pre-Act 235	0.25	0.5	Lithium-ion
Cadillac Solar + BESS	Pre-Act 235	0.5	1	Lithium-ion
Customer-Owned BTM				
Residential Net Metering	N/A	13.8	20.7	N/A
Commercial Net Metering	N/A	0.29	0.44	N/A

*Represents 51% share of the capacity of Ludington.
**Battery Energy Storage System

10.2 Planned Storage Resources

To support system reliability and meet Michigan's energy storage deployment targets, CE conducted competitive battery storage solicitations following the settlement of the Company's 2021 IRP. The solicitations resulted in the selection of several utility-scale battery storage projects expected to enter service between 2026 and 2028.

These projects primarily consist of four-hour lithium-ion battery energy storage systems that provide capacity, energy shifting, and operational flexibility to support reliability

and the integration of renewable resources. The selected projects include both contracted battery storage facilities and utility-developed projects, totaling approximately 628 MW/2,510 MWh of storage capacity. Three of the planned projects expected to be completed in 2028 are now likely to be delayed. The Company plans to substitute additional projects through the competitive solicitation process. All proposed projects are lithium-ion resources. Table 10-2 summarizes CE's planned storage portfolio.

Table 10-2: Planned energy storage resources

RESOURCE	SIZE (MW)	ENERGY (MWh)	EXPECTED COD	TECHNOLOGY TYPE
Owned				
Weadock	45	180	12/31/2026	Lithium-ion
Iosco	30	120	12/31/2026	Lithium-ion
Contracted				
Grand Basin	100	400	5/31/2027	Lithium-ion
Hackett	100	400	5/31/2028	Lithium-ion
Lakeside	100	400	5/31/2028	Lithium-ion
Voyager	100	400	6/1/2027	Lithium-ion
Voyager II	150	600	5/31/2028	Lithium-ion

In addition to the storage projects already under contract, Consumers Energy's independent administrator, Enel X, issued a 2025 All-Source solicitation on June 2, 2025. The solicitation sought up to 1,500 MW of clean generation for the Company's IRP, VGP program, and RE Plan, and included dedicated tranches for energy storage resources. Bids were due on August 28, 2025, and the Company is currently determining the final awards resulting from that solicitation.

Project costs are based on pricing submitted through the Company's competitive storage solicitation. Final costs are subject to contract terms and regulatory approval and are reported in confidential IRP schedules. Energy storage capital and operational cost assumptions are discussed in more detail in Section 16, Resource Screen.

Overall, the Company's planned additions are expected to provide short-duration storage capacity that supports peak demand periods and increasing levels of renewable generation. At present, CE's storage portfolio is expected to consist primarily of short-duration battery storage resources.

10.3 Compliance with Statewide Storage Target

CE's existing and planned energy storage resources exceed the Company's allocated share, 817 MW, of Michigan's statewide 2,500 MW energy storage deployment target. In 2026, the Company's eligible operating storage resources total 219 MW.[15] Planned storage additions, including contracted and Company-owned resources, increase eligible storage capacity to 930 MW by 2029, exceeding the Company's allocated share of the statewide target.

[15] In 2026, only 118 MW of Century Oaks' operating capacity is assumed to be available, with the full 200 MW available beginning in 2027. Similarly, 1 MW of Armstrong is assumed to be in operation in 2026, with the full 3 MW available beginning in 2027.

The Company will continue to monitor energy storage technology developments, system reliability needs, and evolving regulatory requirements in future IRP filings to ensure continued alignment with Michigan's energy storage deployment objectives.

The storage capacity (MW) build plan under the PCA is included in Figure 10-1, and the storage generation capability (MWh) under the PCA is included in Figure 10-2.

Figure 10-1: Annual operating storage capacity (MW)

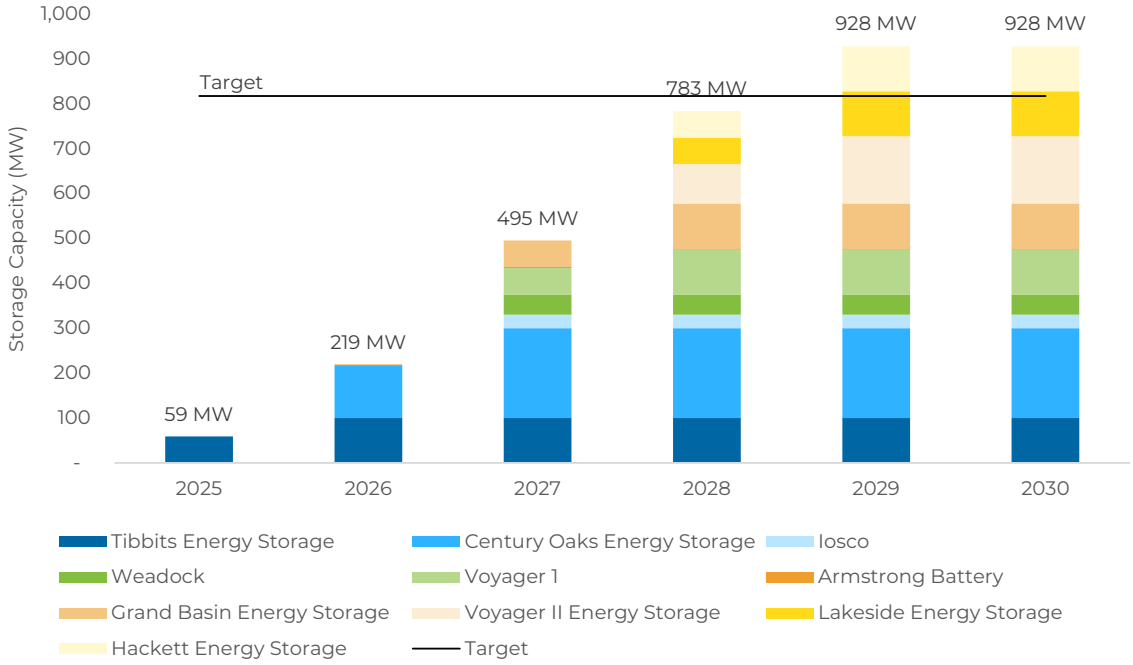
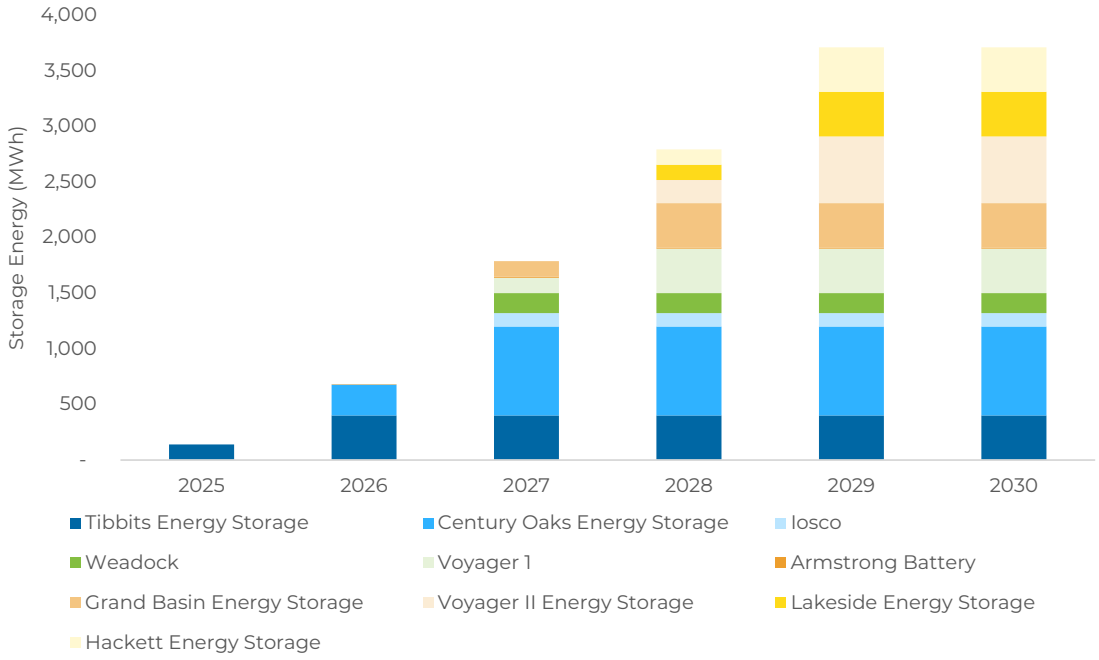


Figure 10-2: Annual storage generation capability (MWh)



Clean and Renewable Energy Standards

Section 11

11 Clean and Renewable Energy Standards

As discussed in Section 9, Renewables and RPS Requirements, Act 235 established a RPS requiring electric providers to achieve renewable energy compliance levels of 15% through 2029, 50% from 2030 through 2034, and 60% beginning in 2035. The same legislation established a Clean Energy Portfolio Standard (CPS) requiring electric providers to achieve 80% clean energy compliance beginning in 2035 and 100% clean energy compliance beginning in 2040. CE's PCA is designed to satisfy both requirements through a portfolio of renewable generation, clean energy resources, RECs, and banked compliance attributes.

The Company's renewable and clean energy compliance strategy is integrated with the resource portfolio selected through the IRP modeling process. Renewable and clean energy resources are evaluated alongside other supply-side and demand-side resources to develop a least-cost portfolio that satisfies reliability, affordability, resource adequacy, and statutory compliance requirements.

11.1 Planned REC Portfolio

CE's compliance strategy relies on a diversified REC portfolio that includes RECs generated by Company-owned renewable resources, RECs generated by contracted renewable resources, Michigan IRECs, and limited purchases of MISO-sourced RECs where authorized. The Company also maintains a bank of surplus RECs that may be used for future compliance within the applicable statutory banking period.

The PCA includes renewable generation from existing and planned wind and solar facilities, together with contracted renewable resources obtained through competitive solicitations. RECs generated by these resources comprise the primary source of compliance attributes used to satisfy both RPS and CPS requirements. The Company also assumes continued use of authorized MISO-based REC purchases through the 2035 compliance year.

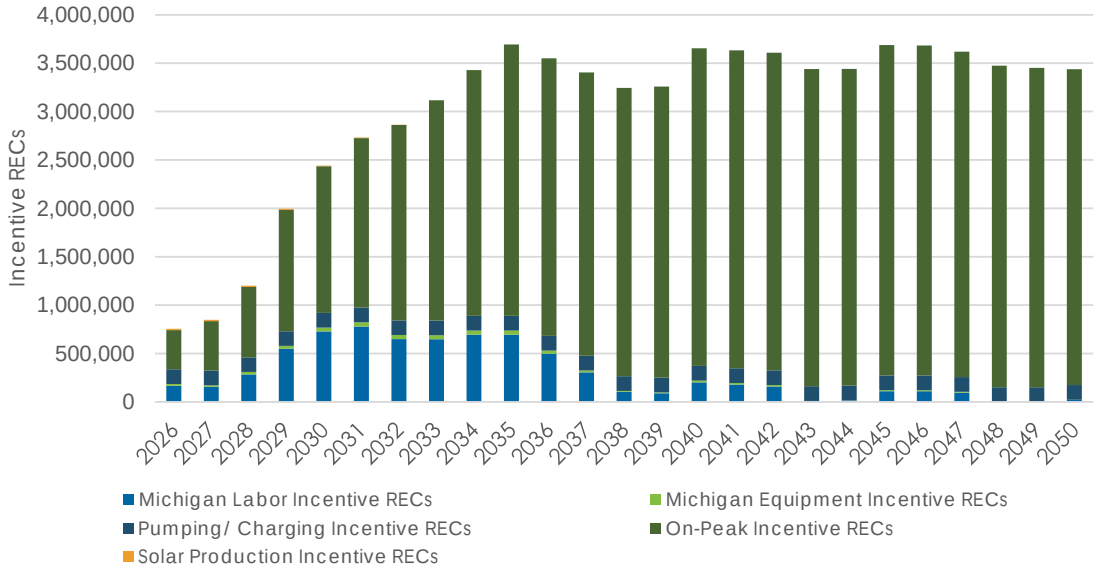
CE's compliance modeling tracks annual REC production, use, and banking balances to ensure compliance obligations can be met throughout the planning horizon while maintaining sufficient flexibility to address future uncertainty. The Company assumes that banked RECs are applied on a first-in, first-out basis consistent with statutory banking limitations.

11.2 Michigan Incentive RECs

The PCA includes forecasted Michigan IRECs associated with eligible renewable energy facilities. Under Michigan law, IRECs may be earned for qualifying solar generation, the use of Michigan-manufactured equipment, Michigan labor, on-peak renewable generation, and renewable energy paired with eligible energy storage systems. The Company's compliance forecast incorporates projected IRECs from both Company-owned and contracted renewable resources that meet applicable statutory requirements. These credits provide additional compliance value and support CE's projected compliance with renewable and clean energy requirements.

Figure 11-1 summarizes forecasted IRECs by incentive category over the planning horizon. On-peak incentive RECs comprise the largest share of projected IRECs, supplemented by Michigan labor, pumping/charging, Michigan equipment, and solar production incentive RECs. Together, these credits provide a meaningful contribution to the Company's compliance portfolio throughout the planning period.

Figure 11-1: Forecast Michigan Incentive RECs by category



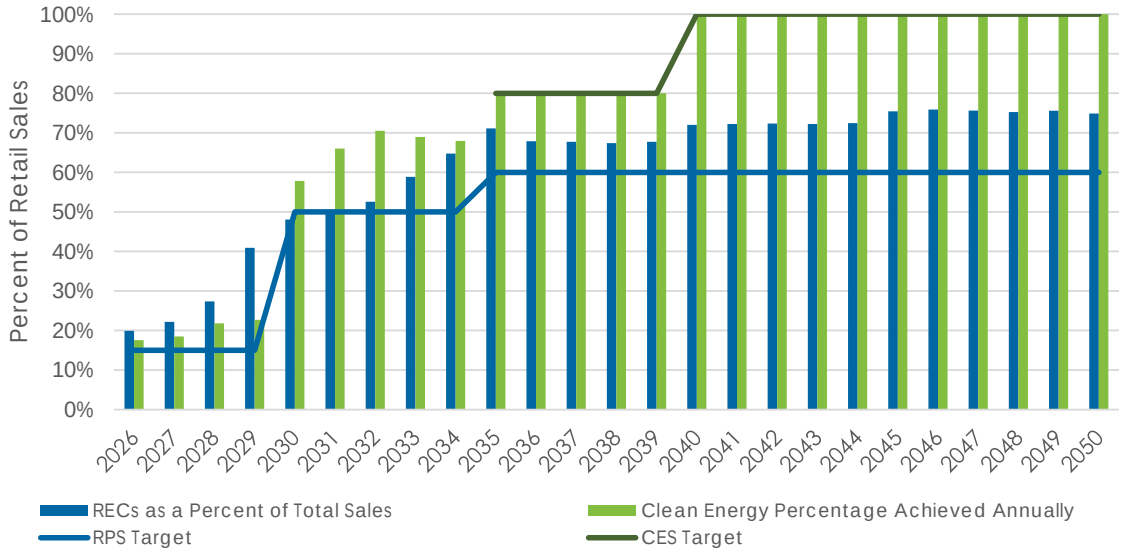
11.3 Forecast Compliance Levels

The PCA is designed to maintain compliance with Michigan's renewable energy and clean energy standards throughout the planning horizon. CE projects compliance with the 15% renewable energy standard through 2029, the 50% standard from 2030 through 2034, and the 60% standard beginning in 2035.

The transition to the 50% RPS requirement in 2030 is supported through a combination of current-year REC production and previously banked RECs accumulated during earlier compliance years. As shown in Figure 11-2, the Company enters 2030 with substantial banked REC balances that support compliance as the statutory requirement increases from 15% to 50%.

For clean energy compliance, the PCA achieves the required 80% CES from 2035 through 2039 and the 100% CES beginning in 2040. Compliance is supported through a combination of renewable generation, banked RECs, [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], clean energy PPAs, PURPA generation that qualifies as clean energy, and a CC gas turbine (CCGT) facility with CCS.

Figure 11-2: Projected REC and CES shares relative to requirements



11.4 Key Planning Assumptions

Several key assumptions underline the Company's renewable and clean energy compliance forecasts.

First, the PCA relies on forecasted retail sales and customer delivery growth assumptions incorporated into the IRP. Higher projected sales increase both renewable and clean energy compliance obligations.

Second, the PCA assumes continued development of renewable generation resources included in the Company's resource portfolio, including planned wind and solar additions and associated REC production. The modeling reflects a combination of Company-owned and contracted renewable resources and assumes approximately a 40% owned and 60% contracted ownership mix for future unnamed solar resources and a fully contracted approach for future unnamed wind resources.

Third, the PCA assumes continued REC banking and the availability of MISO-sourced REC purchases through 2035 consistent with statutory limitations. The analysis also incorporates projected IREC production and assumes that renewable resources included in the portfolio continue to generate compliance attributes throughout their expected operating lives.

Finally, the Company's clean energy compliance forecast assumes [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], future CCGT generation equipped with CCS technology, anticipated PURPA generation, and incremental renewable resource additions necessary to achieve the 80% and 100% CPS.

11.5 Risks and Uncertainties

The Company's compliance strategy is subject to several risks that may affect future performance.

Key risks include project development and commercial operation delays, renewable resource availability, supply-chain constraints, permitting and siting challenges, interconnection delays, curtailment of renewable generation, financing conditions, and changes in federal tax credit availability. Any of these factors could affect the timing or quantity of renewable generation and associated RECs available for compliance.

Additional clean energy compliance risks include the development and performance of CCS technology, the availability of CO_2 transportation and sequestration infrastructure, future treatment of PURPA resources, and changes in statutory or regulatory requirements governing clean energy compliance.

CE plans to manage these risks through ongoing portfolio planning, project monitoring, procurement discipline, regulatory updates, and maintenance of a flexible resource portfolio capable of adapting to changing market conditions and compliance requirements.

Peak Demand and Energy Forecasts

Section 12

12 Peak Demand and Energy Forecasts

An accurate load forecast is the foundation of the IRP analysis. The forecast determines whether existing resources are sufficient to meet customer demand and identifies whether additional resources may be required over the planning horizon.

CE developed electric energy and peak demand forecasts using regression-based econometric models that analyze historical class-level electric usage, customer counts, weather, and economic and demographic variables. These models are supplemented with externally developed forecasts and adjustments for EVs, large customer load, DG, EWR, CVR, DR, and ROA.

The section is organized to first describe how the forecast was developed, then explain the scenarios and key forecast drivers, and finally present the resulting bundled energy and peak demand forecast used for resource planning.

12.1 Forecast Development Metrology

12.1.1 Key variables

The key variables used in developing the base case forecast for each scenario are weather, economy, and demographics.

Table 12-1: Key forecast variables

VARIABLE	ROLE IN FORECAST DEVELOPMENT
Weather	Captures seasonal variation in energy and peak demand using a 15-year average of Heating Degree Days (HDDs) and Cooling Degree Days (CDDs).
Economy	Reflects expected economic activity in the service territory, including employment and industrial production forecasts from S&P Global.
Demographics	Supports long-term customer forecasts using county-level population projections and related customer growth indicators.
Exogenous Adjustments	Reflects forecast components that are developed outside of the regression model, including EVs, large loads, DG, EWR, CVR, DR, and ROA.

12.1.2 Energy Forecasting Methodology

The Company developed its energy forecast using a combination of econometric forecasting techniques and externally developed forecast adjustments. Historical energy sales, customer counts, weather, economic, and demographic data form the foundation of the forecast, while emerging load drivers and load-modifying resources, such as EVs, large customer growth, EWR, DG, and ROA, are incorporated through supplemental forecast adjustments. The overall process used to develop the energy forecast is summarized in Table 12-2.

Table 12-2: Energy forecast generation process

STEP	DESCRIPTION
STEP 1	Gather class-level historical data, including monthly electric energy sales, monthly customer counts, monthly billing days, seasonal indicator variables, and daily temperature observations. Daily temperatures are converted into monthly Heating Degree Days-60 (HDD60) and Cooling Degree Days-60 (CDD60) for use in the econometric models.
STEP 2	Import economic and demographic variables from S&P Global (formerly IHS Markit) into the modeling framework. These variables include historical and projected employment, industrial production, and population data covering the Company's electric service territory.
STEP 3	Incorporate externally developed, exogenous electric use forecasts, including impacts from EWR, CVR, large customer load growth, EVs, DPP programs, the Residential Summer On-Peak (RSP) rate, and ROA. These inputs reflect Commission-adopted assumptions, industry expectations, or end-use analyses and are not estimated within the regression models.
STEP 4	Review all imported observations and inputs to identify data anomalies, outliers, or quality issues prior to running the econometric models. Data errors are corrected or excluded as appropriate to ensure model integrity.
STEP 5	Execute regression models and evaluate their statistical performance using standard metrics, including adjusted R-squared, Mean Absolute Percent Error (MAPE), and coefficient significance tests such as t-statistics and p-values.
STEP 6	Apply the estimated regression models to the forecast period, incorporating projected values of all independent variables, to produce class-level energy forecasts for each month, year, and scenario.

12.1.3 Peak Demand Forecast Methodology

The peak demand forecast builds upon the energy forecast by combining econometric peak demand modeling with adjustments for factors that influence seasonal system peaks. These adjustments include the impacts of EV charging, large customer load growth, EWR, CVR, DR programs, and other forecast components that affect peak demand requirements. The process used to develop the peak demand forecast is summarized in Table 12-3.

Table 12-3: Peak demand forecast process

STEP	DESCRIPTION
STEP 1	Import the Company's monthly system peak demands, corresponding minimum and maximum daily temperature data, forecasted base electric energy consumption, seasonal indicator variables, and customer counts into the peak demand modeling framework. An average of the minimum and maximum temperatures is used to develop the peak HDD and CDD variables prior to model execution.
STEP 2	Review the imported observations to identify data anomalies, outliers, or quality issues before executing the peak demand econometric model.
STEP 3	Regress the observed system peak demands against the seasonal indicator variables, peak degree day variables, and forecasted base electric energy consumption using regression-based econometric techniques.
STEP 4	Combine the results of the econometric peak demand model with the Company's projected peak demand adjustments, including impacts from EWR, CVR, large customer load growth, EVs, DPP programs, the RSP rate, and ROA Program.

12.1.4 Model Validation

The Company evaluates model performance using standard statistical measures, including adjusted R-squared and MAPE. The regression models generally exhibit strong

historical fit, with adjusted R-squared values above 0.90 and MAPE values generally below 3%. These metrics support use of the models for long-term planning, while recognizing that actual conditions may differ from forecasted conditions over the planning horizon.

12.2 Forecast Scenarios and Uncertainty

12.2.1 Load Forecast Scenarios

CE developed its load forecasts to be consistent with the planning scenarios evaluated in Section 6, Scenarios & Sensitivities. The forecast framework begins with the Company's core IRP scenarios, including BAU, later updated to BAU Current, which serves as the Company's utility-specific replacement for MIRPP Scenario 2 and reflects the Company's most probable planning assumptions, and PCC, which is aligned with MSO and reflects a future with higher electrification and decarbonization. In addition, CE evaluated the ALG scenario, which aligns with MISO Future 1a and represents a future with substantially higher economic development load growth.

As the IRP progressed and additional information became available regarding signed and highly probable large-load customers, CE developed forecast refinements to better represent a range of potential demand outcomes. These refinements include the PLG scenario, which retains the underlying BAU assumptions while incorporating approximately 1,500 MW of signed and highly probable large-load additions and represents the Company's most likely load outlook. CE also developed the HLG forecast to evaluate an upper-bound economic development future with substantially greater large-load growth. Together, BAU, PCC, ALG, PLG, and HLG provide a consistent set of load forecasts that reflect both uncertainty in electrification and uncertainty in economic development load growth.

The load scenarios are summarized in Table 12-4.

Table 12-4: Load scenarios

LOAD FORECAST SCENARIO	DESCRIPTION
Business-as-Usual (BAU)	Includes existing, operational, and contracted loads as of mid-2024
BAU Current	Represents BAU load plus an additional manufacturing load (approximately 100 MW) contracted during IRP case development
Probable Load Growth (PLG)	Represents Current load plus 1.5 GW of signed large load commitments and a probability-adjusted view of the broader development pipeline; this is the load forecast included in the Company's PCA
Alternate Plan High Load Growth ("HLG")	Builds upon the PLG forecast, increasing large load growth for a total of 2.2 GW above Current load levels
Aggressive Load Growth (ALG)	Represents a higher bookend of load growth, up to a maximum of 3.5 GW above Current load levels

MIRPP Scenario One (MSO) and Physical Climate Change (PCC)[16]	Corresponds to MIRPP Scenario #1 requirements contemplating increased electrification

Note: PCC and MSO use the same underlying load forecast. The only difference between the scenarios is the treatment of EWR in the IRP modeling, not the forecasted energy or peak demand.

12.2.2 Forecast Uncertainty

Forecasting future energy consumption and peak demand over a 25-year planning horizon inherently involves uncertainty. While the Company's forecast models demonstrate strong historical performance, actual results may differ due to changes in economic conditions, customer behavior, technology adoption, public policy, and other factors that cannot be predicted with certainty. To account for these uncertainties, CE evaluated multiple forecast scenarios reflecting different assumptions regarding load growth, electrification, economic development, and demand-side resource adoption.

Economic and Demographic Uncertainty

Economic activity is one of the primary drivers of electricity consumption and customer growth. The Company's forecasts rely on long-term projections of employment, industrial production, and population within its service territory. Actual economic conditions may differ from current expectations due to changes in regional economic development, industrial activity, business investment, or broader macroeconomic conditions. In particular, future growth associated with large C&I customers, including data centers and advanced manufacturing facilities, could materially influence future energy and peak demand requirements.

Weather and Climate Uncertainty

The forecasts are developed using a 15-year average of HDDs and CDDs to represent normal weather conditions. Actual weather patterns may differ from historical averages, resulting in higher or lower energy consumption and seasonal peak demand. Over longer planning horizons, changes in climate conditions may also affect electricity usage patterns, including increased cooling requirements, changing seasonal peak characteristics, and evolving electrification needs.

Customer Behavior and Technology Adoption

The Company's forecast incorporates assumptions regarding customer adoption of emerging technologies and participation in utility programs, including EVs, DG, EWR programs, DR programs, and ROA participation. The pace of adoption of these technologies and programs may vary from current expectations as technology costs, consumer preferences, market conditions, and program participation evolve over time.

Additional shifts in customer behavior due to electrification driven by aggressive decarbonization are included in the PCC scenario. These additional sources of electrification include electrification of residential and commercial heating and

[16] The PCC load forecast differs from that used in the MSO primarily due to differences in assumed levels of EWR.

electrification of industrial processes. The level of growth is tied to MISO Series 1a – Future 3a.[17]

Electrification and Policy Uncertainty
Future electrification represents one of the most significant sources of long-term uncertainty. The Company evaluated multiple scenarios that reflect differing levels of transportation electrification, residential and commercial heating electrification, industrial process electrification, and broader decarbonization efforts. The PCC and MSO futures evaluate conditions under which electrification and decarbonization progress more rapidly than in the Company's base planning outlook, resulting in higher energy requirements and peak demand growth. By evaluating multiple futures, the IRP assesses the robustness of resource plans under a wide range of potential outcomes.

Managing Forecast Uncertainty
Because no single forecast can fully capture all possible future conditions, the Company developed a range of planning scenarios and sensitivities that reflect differing assumptions regarding economic development, electrification, large customer growth, and demand-side resource deployment. Together, these scenarios provide a structured framework for evaluating resource needs and portfolio performance under a range of plausible future conditions and support the development of a resource strategy that remains flexible and reliable as actual conditions evolve.

12.3 Historical and Base Forecast Trends

12.3.1 Historical Growth

From 2019 to 2025, weather-normalized electric sales remained relatively flat, with a system-level growth rate of approximately 0.02%. Residential, commercial, and industrial energy consumption grew at CAGRs of 0.15%, 0.07%, and 0.39%, respectively. Other sources of sales comprise a small portion of the overall sales, including streetlighting, inter-department sales, and wholesale sales. These classes declined at a CAGR of -20.28%, mainly due to wholesale sales dropping in 2024.

Following 2019, electric energy sales were significantly affected by the COVID-19 pandemic. In 2020, pandemic-related behavioral changes and government restrictions increased remote work and reduced or suspended operations among certain C&I customers, resulting in a temporary increase in residential energy and a decline in C&I energy.

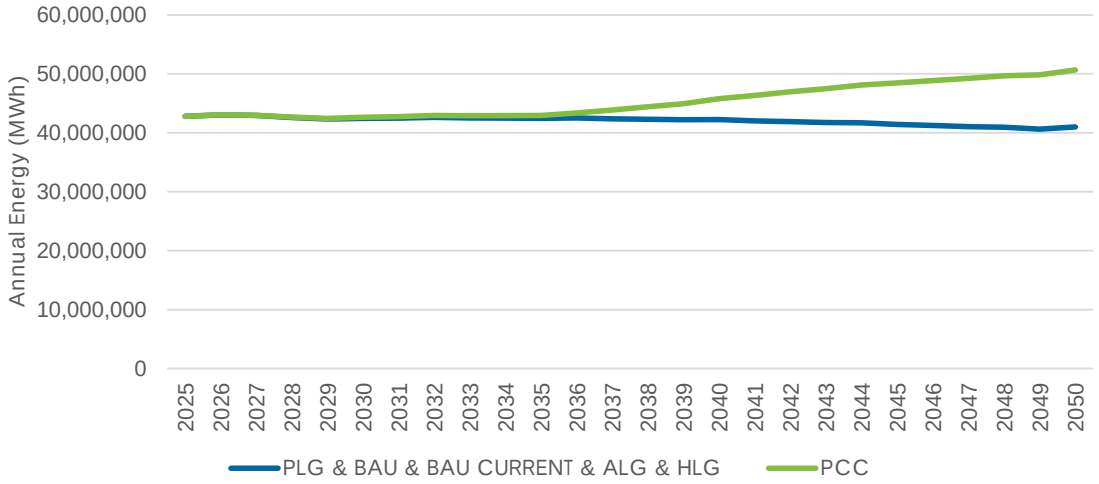
These effects were behavioral in nature and are reflected in the historical data used to develop the forecast models. As economic activity normalized, usage patterns began returning toward longer-term trends, which are captured in the Company's base case forecast.

[17] Midcontinent Independent System Operator, Inc., (Nov 2023), *MISO Futures Report – Series 1A*, accessible at: https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf

12.3.2 Base Forecast

From these regression models, the Company creates its base forecast for energy and peak demand for each month, year, and scenario. As shown in Figure 12-1, the same base forecast underlies the BAU, BAU Current, ALG, PLG, and HLG scenarios, while the PCC scenario is projected to grow over time due to additional electrification driven by more aggressive decarbonization targets. Additionally, the PCC scenario is projected to experience higher load growth in the winter months than the summer months, reflecting the anticipated increase in heating electrification and the effect of warming climate patterns.

Figure 12-1: Base energy forecast



12.4 Future Growth Drivers

Future electric load growth within the Company's electric service territory is being driven by several emerging and expanding end uses, most notably EVs and large load customers such as data centers and advanced manufacturing facilities.

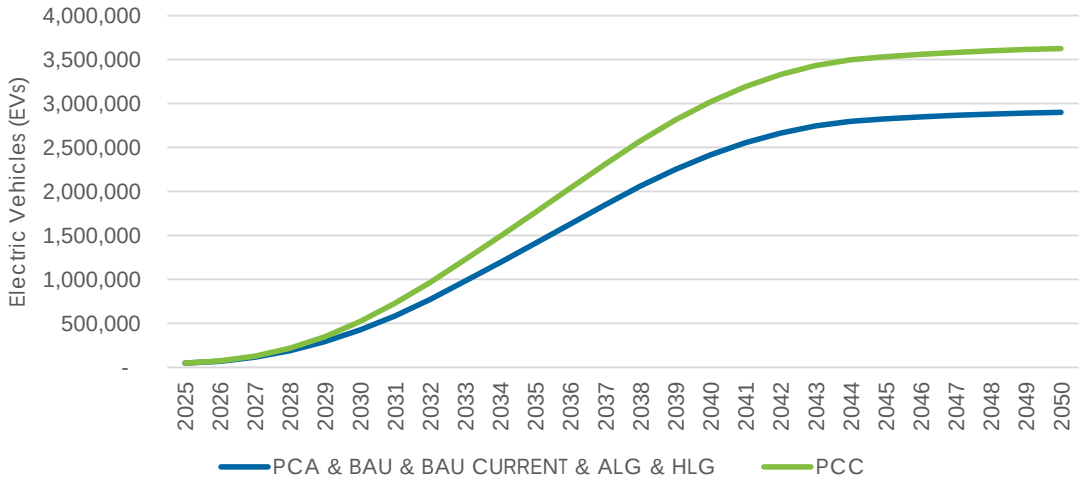
12.4.1 Electric Vehicles

EV adoption within the Company's service territory has increased rapidly in recent years and is expected to continue growing over the planning horizon. Registered EVs increased from 4,714 in 2017 to 50,617 by the end of 2025, representing a CAGR of approximately 35%. As of 2025, EVs located within the Company's service territory accounted for approximately 32% of all registered EVs in the state of Michigan.

The Company develops EV adoption forecasts using historical vehicle registration data within its service territory. The base case forecast is derived from recent adoption trends using a rolling quarterly growth rate calculated from the most recent two years of observed EV registrations. This approach captures current market momentum while providing a consistent foundation for projecting future adoption levels. The resulting forecast exhibits the traditional S-shaped adoption pattern commonly observed for emerging technologies, with rapid growth in the near and medium term followed by gradually slower growth as market penetration increases.

To reflect uncertainty in future EV adoption, the Company develops low and high adoption cases around the base forecast. The base case forecast reflects the Company's central expectation for EV adoption and is used in the BAU, BAU Current, PLG, ALG, and HLG scenarios. The high EV adoptions trajectory reflects accelerated transportation electrification and is used in the PCC scenario. The low EV adoption trajectory is maintained as a forecasting sensitivity to evaluate downside adoption outcomes but is not used as a core IRP planning scenario. Each alternative trajectory is developed by
applying a ±25% adjustment to the annual EV adoption trajectory, phased in gradually between 2026 and 2031. Under the low case, adoption reaches approximately 75% of the base forecast by the end of the ramp period, while the high case reaches approximately 125% of the base forecast. The forecast for registered EVs is shown in Figure 12-2.

Figure 12-2: Forecast for registered EVs in the CE territory



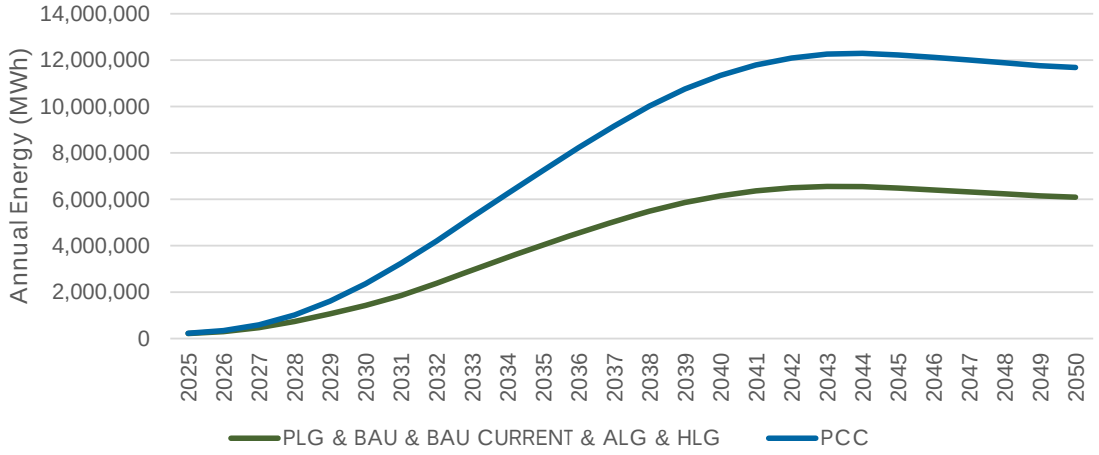
Projected EV registrations are then translated into electric load using assumptions regarding vehicle miles traveled, charging requirements, and average EV efficiency. The resulting EV energy consumption forecast is incorporated as an exogenous input to the Company's econometric energy and peak demand forecasting models. Consistent with the Company's transportation electrification strategy, EV load is modeled using dedicated hourly charging profiles that reflect expected charging behavior and managed charging programs, rather than assuming EV charging follows the system load shape.

In the BAU, BAU Current, PLG, ALG, and HLG outlooks, the base EV adoption trajectory is applied. EV adoption within the service territory is projected to grow at an average annual rate of approximately 17.8% through 2050. This growth translates into incremental electric load growing from approximately 216 GWh in 2025 to approximately 6,023 GWh by 2050, reflecting a CAGR of approximately 14.2%.

In the PCC scenario, the high EV adoption case is applied to reflect accelerated electrification driven by climate policy. Under this outlook, EV adoption within the service territory is projected to grow at an average annual rate of approximately 18.8%

through 2050. This increase translates into incremental electric load growing from approximately 228 GWh in 2025 to approximately 11,623 GWh by 2050, reflecting a CAGR of approximately 17.0%. The resulting forecast for energy consumption is shown in Figure 12-3.

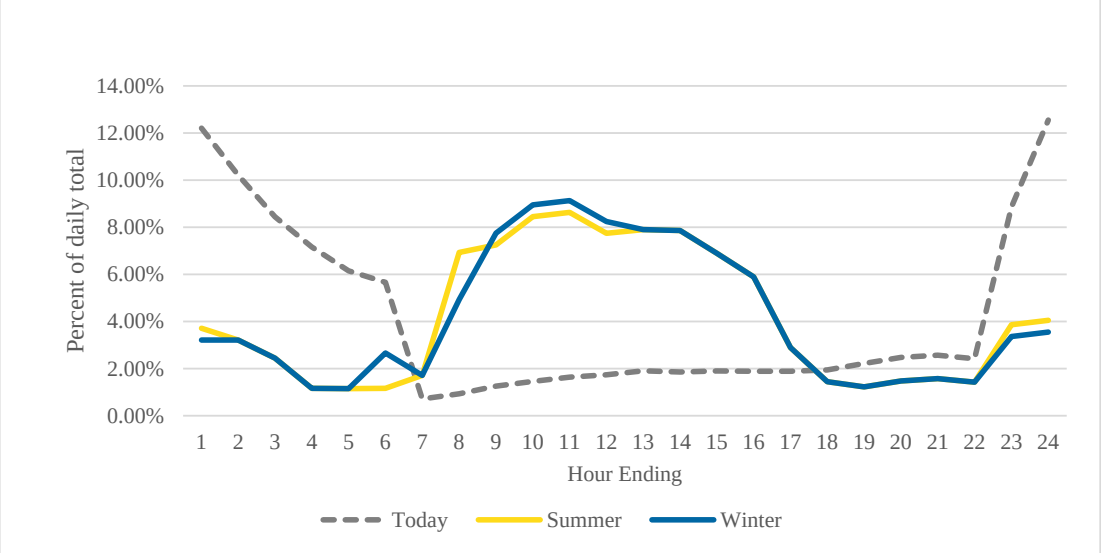
Figure 12-3: Forecast for energy demand by EVs in the CE territory



EV energy forecasts are converted to peak demand contributions using assumptions about charging behavior, which evolves over the planning horizon. Currently, the Company has successfully incentivized customers to perform the vast majority (95%) of EV charging is during the overnight hours, when system risk is lowest. However, as solar and storage penetration increases, daytime risk is expected to decline, shifting the highest-risk periods toward late evening hours after the sun has set and batteries have discharged.[18] As a result, current EV charging strategy could coincide with emerging periods of grid stress. To address these concerns, the Company's forecast assumes a managed transition toward daytime charging over the planning horizon, capitalizing on abundant solar generation and avoiding contribution to emerging overnight risk conditions. The assumed charging profiles for 2035 is shown in Figure 12-4, and is adjusted across the forecasting horizon. This shift in charging behavior is reflected in time-varying charging distribution assumptions applied to the EV energy forecast, which are used to produce an estimated EV contribution to seasonal peak demand in each forecast year.

[18] Midcontinent Independent System Operator, Inc., (Mar 2024), *Resource Accreditation White Paper, Version 2.1*, accessible at: https://cdn.misoenergy.org/Resource%20Accreditation%20White%20Paper%20Version%202.1630728.pdf

Figure 12-4: 2030 EV charging profiles



12.4.2 Additional Electrification

In addition to transportation electrification, the Company's forecast reflects broader electrification trends considered through the PCC/MSO scenario, including increased electric end-use adoption and associated load growth. These scenarios evaluate the impact of higher electrification levels on both energy requirements and peak demand and provide a range of potential future outcomes should electrification accelerate beyond current expectations.

12.4.3 Data Centers and Large Customers

In addition to EV growth, increased demand from data centers and other large manufacturing customers represents a significant source of future load growth within the Company's service territory. These customers operate with a high load factor (modeled at 90%) and are expected to require electricity service at similar levels across all hours.

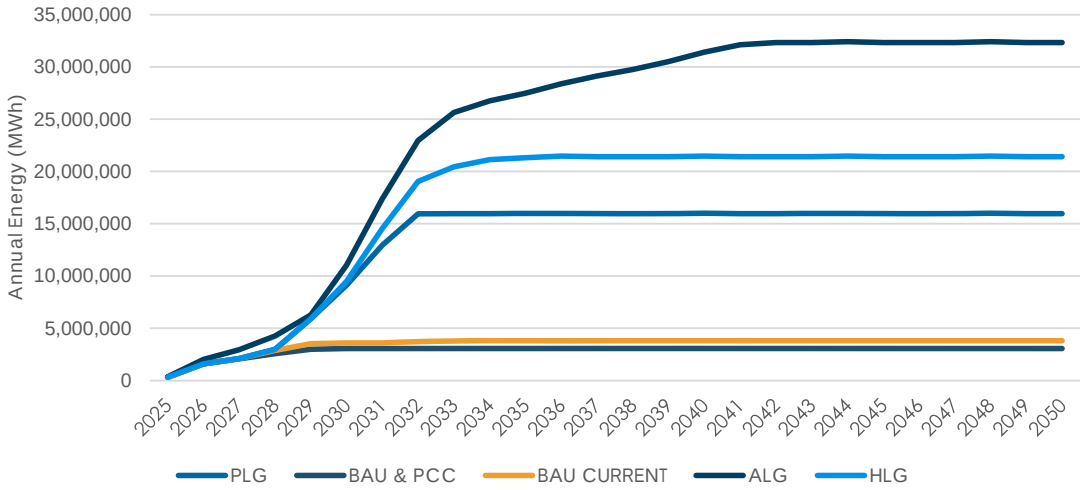
The BAU forecast, which reflects only current existing large load contracts as of the start of the IRP modeling process, includes a limited number of existing large customers over the IRP planning horizon. This was updated based on a recent signing of a large manufacturing customer and is represented in the BAU Current forecast. These customers are expected to contribute approximately 400 MW of new, around-the-clock demand.. From an energy perspective, large customer load is projected to increase from energy needs by over 3,000 GWh by 2050. These loads reflect anticipated developments within the Company's service territory and are explicitly incorporated into the base case forecast.

The PLG load growth level incorporates approximately 1,500 MW of signed and highly probable large-load additions identified as the IRP modeling process progressed. This translates into an additional 6,000 GWh of energy needs by 2030 and nearly 13,000 GWh by 2050.

To evaluate uncertainty around the Company's large-load outlook, CE also developed a HLG forecast. HLG retains all underlying BAU assumptions but incorporates an additional 2,200 MW of prospective large-load growth beyond the BAU forecast. Under the HLG forecast, large customer demand increases to 2,458 MW by 2050, corresponding to approximately 21,411 GWh of annual energy requirements.

The ALG scenario represents a broader high-growth future that extends beyond the Company's large-load forecast assumptions. In addition to substantially higher economic development load growth within CE's service territory, ALG assumes a higher-growth regional environment consistent with MISO Future 1a. Under the ALG scenario, large customer demand increases to 3,948 MW by 2050, corresponding to approximately 32,324 GWh of annual energy requirements. The large-load trajectory in each forecast is shown in Figure 12-5.

Figure 12-5: Large load growth forecast



In addition to the core planning scenarios, the Company evaluated low, medium, and high large load sensitivities to assess uncertainty associated with future economic development load growth. These sensitivities reflect alternative levels of large customer load growth based on a probabilistic assessment of known prospective large-load customers and provide a range of potential outcomes around the Company's forecast assumptions. Additional discussion of the methodology, assumptions, and role of these sensitivities within the IRP analysis is provided in Section 6, Scenarios and Sensitivities.

12.4.4 Legacy Large Loads

While the large load forecasts described above represent potential future growth from new data centers and other large customers, the Company also develops customer-specific forecasts for key existing large customers within its service territory. These legacy large loads are forecasted based on known production plans, contracted demand levels, and operating schedules. Because they represent committed load with a high degree of certainty, their forecasts are held constant across the BAU, BAU Current, PLG,

ALG, and HLG scenarios and are incorporated directly into the bundled generation requirements forecast for each scenario.

12.5 Demand-Side and Load-Modifying Resources

The Company's forecasts incorporate the impact of EWR, CVR, and DR programs. Together, these resources significantly reduce both summer and winter peak demand requirements across all planning scenarios. Peak demand reductions generally increase over time as participation in demand-side programs expands and additional conservation measures are deployed. Across the planning horizon, embedded peak demand reductions average approximately 1,070 MW to 1,477 MW during summer peak periods and 943 MW to 1,186 MW during winter peak periods, as shown in Table 12-5. Relative to gross peak demand, these reductions lower summer peaks by approximately 12% to 15% and winter peaks by approximately 14% to 16%, reducing capacity requirements and deferring the need for additional utility-scale resource investments.

Table 12-5: Average annual embedded peak demand reduction from demand-side resources

SCENARIO	AVG SUMMER REDUCTION (MW)	AVG SUMMER % REDUCTION	AVG WINTER REDUCTION (MW)	AVG WINTER % REDUCTION
BAU	1,070	13%	943	16%
BAU Current	1,070	13%	943	16%
PLG	1,070	12%	945	14%
PCC	1,477	15%	1,186	15%
HLG	1,070	11%	945	13%
ALG	1,211	14%	1,065	14%

12.5.1 Energy Waste Reduction

Since 2009, CE has been implementing a diverse and balanced portfolio of EWR. EWR programs that have achieved significant energy savings for all major sectors and customer classes, including small businesses and low-income customers. EWR programs have delivered meaningful economic, social, and environmental benefits, as shown by over 15 years of program success, and is an integral part of maintaining affordable and reliable energy. As such, CE is strongly committed to helping customers get the most value possible for every kWh of electricity or cubic foot of natural gas through its comprehensive portfolio of EWR programs and opportunities for all customers.

While the incremental savings fluctuate over time, the average annual savings for 2026 through 2040 are 0.8% and are based on an updated 2025 EWR Potential Study conducted by TRC Companies, Inc. This savings level is lower than the potential modeling in the Case No. U-21090 IRP (previously estimated to be 1.1%). This drop in potential savings is due to market saturation of efficient technology (e.g., lighting) and stricter codes and standards (e.g., water heating). The included EWR savings as a percentage is shown in Figure 12-6. The reduction in energy consumption for EWR is shown in Figure 12-7.

Figure 12-6: Projected EWR savings

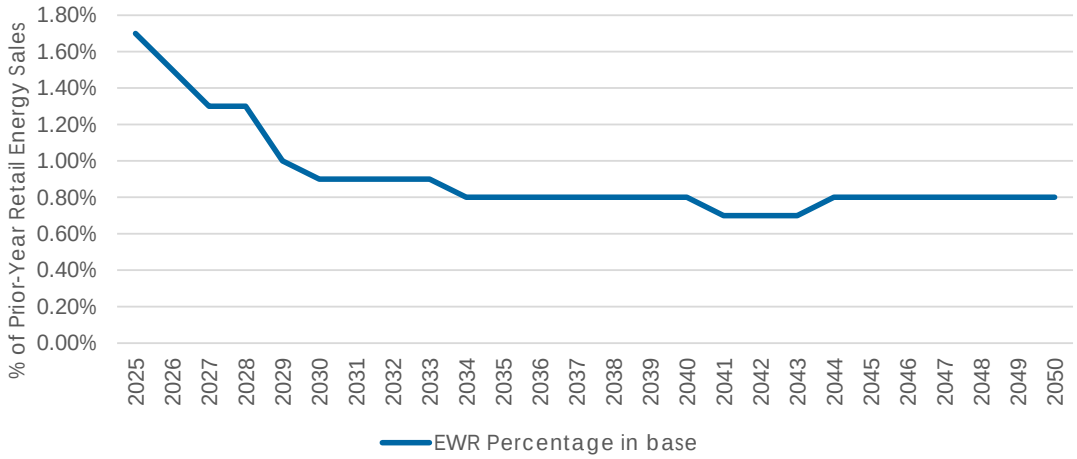
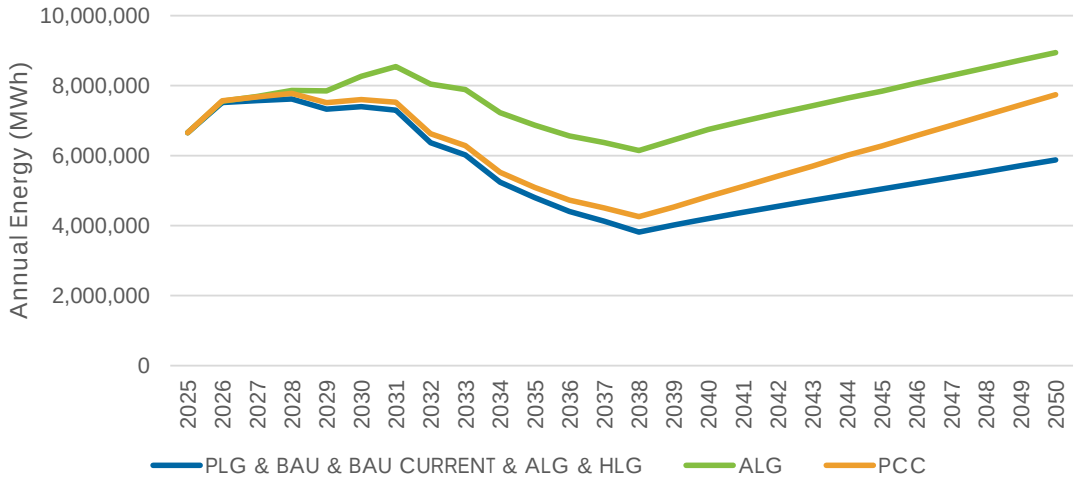


Figure 12-7: Energy Reduction from EWR



12.5.2 Conservation Voltage Reduction

CVR is a DSM technique that reduces energy consumption and peak demand by slightly lowering the voltage delivered to customers within acceptable regulatory limits. Because many electrical devices consume less energy at lower voltages, CVR produces measurable reductions in both energy use and peak demand without affecting customer service quality. The Company incorporates projected CVR impacts as an adjustment to the peak demand forecast, reflecting the expected demand reduction achievable through continued deployment of CVR-capable infrastructure across the service territory.

12.5.3 Demand Response

DR programs help manage system capacity by reducing peak demand, lowering the need for additional generation resources or capacity purchases. These programs provide a flexible and scalable capacity resource that supports reliability while helping reduce overall costs for customers.

CE's DR portfolio has delivered significant benefits, including more than 650 MW of peak demand reduction, nearly 332,000 participating customers, expanded year-round program offerings, and increased customer participation in key programs such as the Smart Thermostat Program.

The DR capacity levels included in the Power Supply Cost Recovery (PSCR) plan are based on historical program performance, assumptions from the Company's prior IRP, and the findings of the 2025 Demand Response Potential Study. Under the current forecast, Consumers Energy plans to maintain the Dispatchable Pricing Program, expand Smart Thermostat and C&I DR offerings, modestly increase participation in the Interruptible Rate program, and continue the expected transition of the legacy A/C Cycling Program.

DR is treated as a capacity-side resource and is incorporated directly into the Company's resource portfolio rather than the load forecast. Additional discussion of the Company's DR programs is provided in Section 8, Demand-Side Resources.

12.5.4 Distributed Energy Resources and Non-Wires Alternatives

The Company evaluated a range of DERs and demand-side alternatives within the IRP process, including EWR, DR, DG solar, and VPP resource options. These resources were incorporated into the resource planning process and evaluated alongside traditional utility-scale generation resources, as discussed in Section 8, Demand-Side Resources. To the extent these resources are developed beyond the levels embedded in the forecast, they can reduce system energy requirements, lower peak demand, and defer or offset future utility-scale resource additions. However, because deployment levels depend on customer adoption, participation rates, program performance, and other factors outside of the Company’s direct control, the Company does not rely exclusively on these resources to satisfy long-term resource adequacy requirements. Instead, these resources are evaluated as part of a balanced portfolio of supply-side and demand-side solutions.

12.6 Retail Open Access

ROA refers to customers that take electric supply from an alternative electric supplier (AES) rather than from the utility. These customers remain physically interconnected to the Company’s system but excluded from the Company’s generation planning obligation. For IRP and load forecasting purposes, energy consumption associated with ROA customers remains part of total system load, but the Company is not obligated to meet the generation needs required to support the energy and peak demand from these customers. To forecast future ROA deliveries, the Company uses the historic growth rate for the total commercial sector and caps the total number of ROA customers at 10% of current load levels.

12.7 Alignment with Distribution Planning Forecasts

The electric deliveries, generation requirement, and peak demand forecasts used in the IRP are developed through the Company's standard forecasting process and serve as a common foundation for both long-term resource planning and distribution planning. Accordingly, the IRP and distribution planning functions rely on consistent

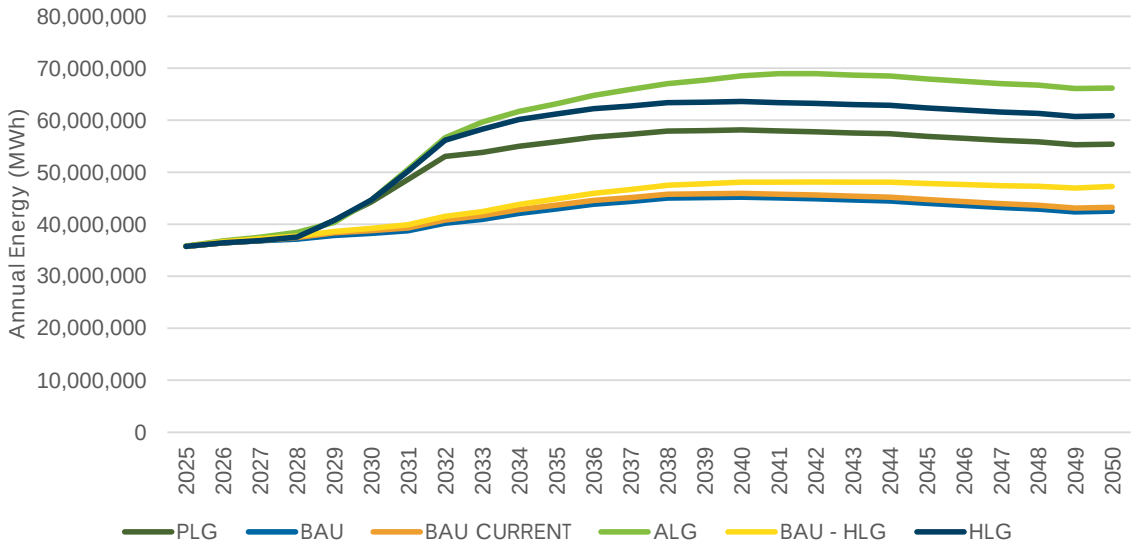
assumptions regarding customer growth, economic development, electrification, DG, EWR, and EV adoption. Where distribution planning studies require more granular locational or circuit-level analysis, additional distribution-specific adjustments may be applied; however, these adjustments do not alter the underlying Company-wide forecast used to evaluate long-term energy and peak demand requirements in the IRP. The Company also coordinates with distribution planners and engineers to ensure that distributed resource assumptions reflected in the IRP appropriately account for interconnection requirements, cost treatment, and system impacts. In addition, the Company's Electric Distribution Infrastructure Investment Plan (EDIIP) is aligned with the IRP and supports the distribution system investments needed to integrate the PCA.

12.8 Bundled Peak and Energy Demand Forecast

The forecast components described throughout this section are combined to develop the Company's bundled energy and peak demand forecasts used for resource planning. New and emerging load sources, including EVs and large customer development, are added to the base forecast, while demand-side resources such as EWR, CVR, and DR reduce forecast energy and peak demand requirements. The resulting net load forecast is adjusted for ROA participation, and a 6.78% system loss factor is applied to convert customer demand into generation requirements. The bundled generation requirements forecast serves as the basis for evaluating future resource needs and developing the Company's long-term resource strategy.

The bundled energy forecast, shown in Figure 12-8, reflects the Company's expected generation requirements after incorporating forecast load growth, electrification impacts, large customer additions, demand-side resource impacts, ROA participation, and system losses. Across all scenarios, energy requirements increase relative to current conditions, with the magnitude of growth driven primarily by assumptions regarding large customer development and electrification. The PLG, ALG, HLG, and PCC scenarios result in materially higher energy requirements than BAU, reflecting alternative views of future load growth and customer adoption trends.

Figure 12-8: Bundled energy forecast



The bundled peak demand forecast, shown for summer in Figure 12-9 and for winter in Figure 12-10, incorporates the same underlying drivers as the energy forecast while also reflecting the timing of load growth, EV charging behavior, and embedded peak demand reductions from demand-side resources. As a result, peak demand does not increase uniformly from year to year. Projected peak demand may rise or fall in individual years as the timing of the system peak shifts across hours, seasons, and weather conditions, and as the contribution of resources such as EV charging, storage, solar generation, and demand-side programs changes over time.

Summer peak demand remains the Company's largest planning requirement across most scenarios, although winter peak demand grows significantly in futures with higher electrification, particularly under PCC. The resulting forecasts illustrate how different assumptions regarding economic development and electrification can influence future capacity needs.

Figure 12-9: Summer peak demand forecast

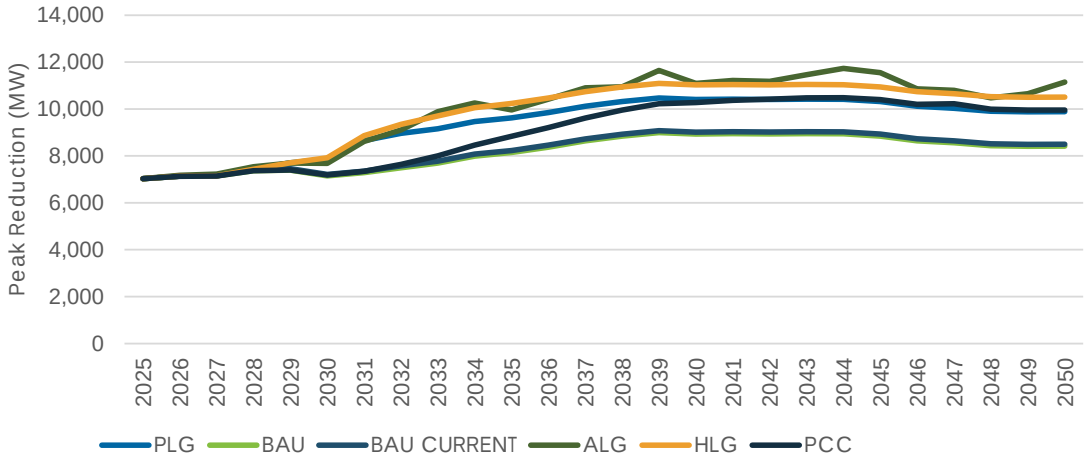
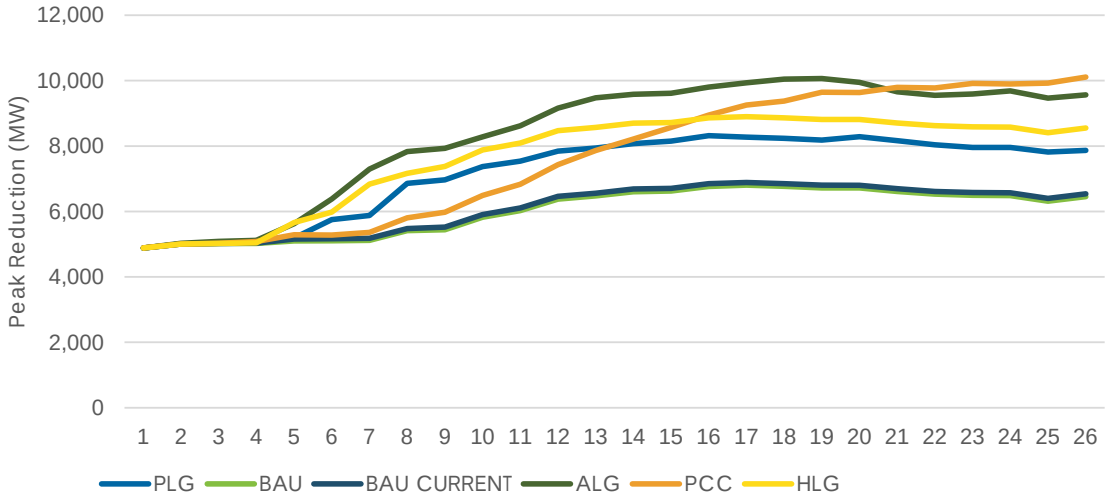


Figure 12-10: Winter peak demand forecast



While annual forecast values provide insight into the magnitude of future load growth, the CAGRs shown in Table 12-6 provide a consistent basis for comparing scenarios. BAU reflects the Company's base planning outlook, while PLG, HLG, and ALG demonstrate the impact of additional economic development and large customer growth. PCC exhibits comparatively strong winter peak growth due to increased electrification of heating and other end uses. Together, these growth rates illustrate the range of potential demand outcomes considered in the IRP.

Table 12-6: Forecasted average annual growth rate by scenario

SCENARIOS	ENERGY	SUMMER PEAK	WINTER PEAK
BAU	0.69%	0.72%	1.12%

SCENARIOS	ENERGY	SUMMER PEAK	WINTER PEAK
BAU Current	0.76%	0.76%	1.17%
PLG	1.77%	1.37%	1.92%
PCC	1.71%	1.40%	2.95%
HLG	2.15%	1.62%	2.26%
ALG	2.49%	1.86%	2.72%

Capacity and Reliability Requirements

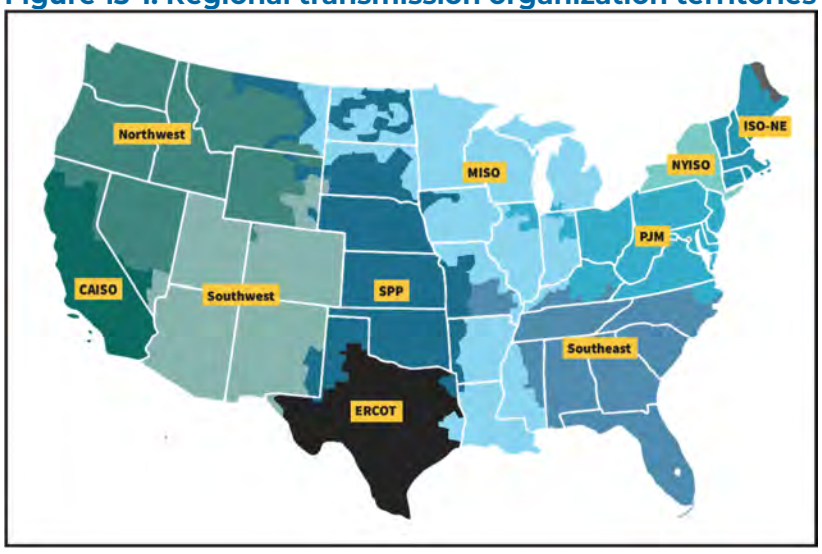
Section 13

13 Capacity and Reliability Requirements

13.1 Midcontinent Independent System Operator, Inc.

The Company operates within the MISO footprint. MISO serves as the regional transmission operator (RTO) for much of the Midwest and Central U.S., including Michigan, and is responsible for operating the regional transmission system and administering wholesale energy, capacity, and ancillary service markets. The Company participates and complies with MISO's centralized resource adequacy construct, which also informs Michigan State laws related to resource adequacy. MISO was established as the nation's first RTO by the Federal Energy Regulatory Commission (FERC) in 2001 and today operates across portions of 15 states and the Canadian province of Manitoba (shown in Figure 13-1).

Figure 13-1: Regional transmission organization territories[19]



As part of this regional framework, the Company participates in MISO's centralized resource adequacy construct, which establishes capacity obligations intended to ensure sufficient resources are available to meet forecasted peak demand plus required reserves. MISO's resource adequacy requirements, including planning reserve margins and LRZ requirements, are an important input to the Company's long-term resource planning, capacity position, and evaluation of future resource needs. MISO's Local Clearing Requirement (LCR) is designed to ensure that each LRZ has access to sufficient local capacity after accounting for local reliability needs, import capability, and export commitments.

13.1.1 MISO's Energy Market

MISO provides all market services for energy, operating reserve, and transmission service in accordance with the terms of the MISO Open Access Transmission, Energy

[19] Federal Energy Regulatory Commission, (N.D.), *RTOs and ISOs*, accessible at: https://www.ferc.gov/power-sales-and-markets/rtos-and-isos

and Operating Reserve Markets Tariff (MISO Tariff). This includes operation and settlement of the Day-Ahead Energy and Operating Reserve Market (DA Energy Market) and the Real-Time Energy and Operating Reserve Market (RT Energy Market), collectively referred to as the MISO Energy Markets. The Company participates in the MISO Energy Markets. The DA Energy Market takes place on the day preceding the actual operating day and is a forward-looking market where energy and operating reserves for the next day are bought and sold. An operating day spans a 24-hour period, beginning and ending at midnight, Eastern Standard Time. The DA Energy Market is a financially binding market that provides for economic and reliable operation of the electric system for the next operating day. The RT Energy Market takes place on the actual operating day and is designed to continuously balance electric supply and demand at the lowest cost while recognizing transmission system conditions. The DA Energy Market and the RT Energy Market are designed to work together to meet electric needs in the MISO footprint each day in the most economical manner.

13.2 MISO's Ancillary Services Market

MISO also operates an Ancillary Services Market (ASM), which is a collection of secondary services offered to ensure the reliability and availability of energy. The ASM provides generation regulation, spinning, supplemental, and other ancillary services, with both a day-ahead and real-time component.

Generation regulation serves to continually balance electrical supply and demand. Spinning reserves and supplemental services provide energy to meet demand on the system in the event of a sudden and unexpected loss of generation or transmission service.

13.3 MISO's Capacity Market

MISO also administers a capacity market, a centralized resource adequacy construct designed to ensure that sufficient generating capacity is available to meet forecasted peak demand plus a planning reserve margin to accommodate generator outages or unexpected outcomes. This construct is implemented through the PRA, which secures capacity for a single forward PY running from June 1 through May 31. Market participants submit offers for qualified capacity resources, including: thermal generation, renewable generation, energy storage, DR, and external resources that meet deliverability requirements.

Alternatively, LSEs may opt out of the resource adequacy construct by developing a Fixed Resource Adequacy Plan (FRAP), which identifies specific resources that will be used to meet their capacity obligation. LSEs that do not demonstrate sufficient capacity through the PRA, bilateral arrangements, or a FRAP may be subject to a capacity deficiency charge.

Michigan's State Reliability Mechanism (SRM) works in coordination with MISO's resource adequacy construct. MISO establishes seasonal capacity obligations, accredits resources, and administers the PRA, while the SRM requires Michigan LSEs to demonstrate to the MPSC that they have secured sufficient owned or contracted

capacity to meet those obligations on a forward basis.[20] In this way, the SRM does not replace MISO's capacity construct, but provides a state-level backstop to ensure that Michigan retail load is not overly reliant on future residual market purchases to satisfy resource adequacy needs.

These regional and state resource adequacy requirements also provide an important foundation for the Company's IRP. Michigan's IRP requirements direct utilities to evaluate resource portfolios capable of serving customers reliably and cost-effectively over the planning horizon. MISO's resource adequacy framework helps translate that reliability objective into specific planning considerations, including accredited capacity, PRMR, locational capacity needs, and deliverability. Accordingly, the Company's IRP evaluates whether existing and planned resources are sufficient to meet customer needs in the context of both MISO's regional reliability framework and Michigan's state-level capacity demonstration requirements.

13.4 Planning Reserve Margin Requirement

MISO's capacity market is grounded in a reliability standard equivalent to a one-day-in-ten-years LOLE. Based on this standard, MISO establishes an annual PRMR for the system. The PRMR reflects the forecasted coincident peak demand plus a reserve margin designed to maintain the target reliability level.

MISO expresses capacity needs on both an installed capacity (ICAP) and unforced capacity (UCAP) basis. ICAP reflects the nameplate or installed capacity of resources, while UCAP reflects the portion of capacity expected to be available after accounting for forced outages and other performance-related adjustments. As a result, UCAP is generally lower than ICAP and provides a more reliability-adjusted measure of the capacity available to meet resource adequacy needs.

For the PY 2025-2026, MISO's systemwide peak load is projected to be 123,576 MW in the summer. The UCAP needed to maintain resource adequacy is 132,389 MW, resulting in a 15.7% PRMR on ICAP basis and 7.9% on a UCAP basis.[21]

These PRMR values are used as the basis for the Company's resource adequacy planning and capacity expansion modeling in this IRP for years before DLOL[22] is implemented.

[20] Michigan Legislature, (accessed Apr. 2026), *Michigan Compiled Laws, Section 460.6w, Resource adequacy tariff that provides for capacity forward auction; option for state to implement prevailing state compensation mechanism for capacity*, accessible at: https://www.legislature.mi.gov/Laws/MCL?objectName=MCL-460-6W

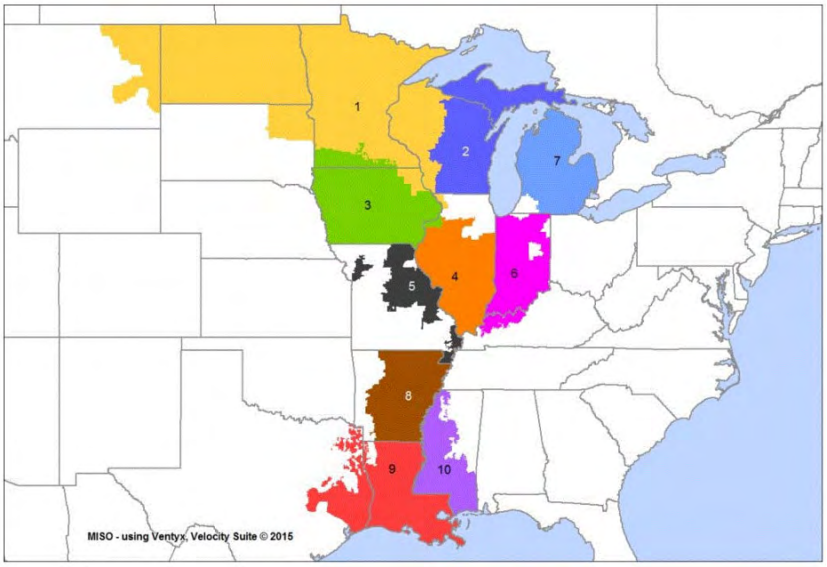
[21] Midcontinent Independent System Operator (MISO), (Mar. 2025), *Planning Year 2025-2026 Loss of Load Expectation (LOLE) Study Report*, accessible at: https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf

[22] DLOL is discussed more in Section 13.9.

13.5 Local Resource Zones

In addition to the overall PRMR target, MISO's footprint, shown in Figure 13-2, is divided into LRZs to account for transmission constraints and deliverability limitations. A map of the LRZs is given in Figure 13-2. Michigan is split into two LRZs: Zone 2 and Zone 7. Michigan's Upper Peninsula is connected with Wisconsin as part of Zone 2. The Lower Peninsula is designated as Zone 7; the exception is a small part of southwest Michigan that is part of the PJM market. The Company's operational footprint is situated in Zone 7. As a subset of LRZ 7, the Company must meet its proportional share of the local reserve margin requirements.

Figure 13-2: MISO Local Resource Zones[23]



13.6 Local Reliability Requirement

Each zone has a Local Reliability Requirement (LRR) to maintain local resource adequacy. The LRR is defined as the amount of UCAP required within a LRZ to meet the 0.1 days/year LOLE standard at the time of that zone's peak load, before accounting for imports or exports.

In the MISO LOLE study for PY 2025-2026, Zone 7 is modeled with a peak summer load of 20,953 MW[24] and an LRR of 23,844 MW on a UCAP basis.[25] This LRR forms the basis for determining the Company's share of local capacity obligations.

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[23] MISO, (Oct 2025), Attachment VV – MAP of Local Resource Zone Boundaries, accessible at: https://docs.misoenergy.org/miso12-legalcontent/Attachment_VV_-_MAP_of_Local_Resource_Zone_Boundaries.pdf

[24] MISO, (Mar. 2025*), Planning Year 2025-2026 Loss of Load Expectation (LOLE) Study Report*, accessible at: https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf

[25] Ibid.

13.7 Capacity Import and Export Limits

The MISO LOLE working group (LOLEWG) determines the CIL and CEL to and from each MISO LRZ. The CIL and CEL are calculated values that represent the transmission system's ability to reliably transport power between zones under specified system conditions. CIL and CEL are updated annually by the LOLEWG to capture changes in these capabilities as a result of modifications to the electric system. The CIL represents the maximum amount of capacity that can be reliably imported into a LRZ under peak conditions while respecting transmission constraints. The Zonal Import Ability (ZIA) is a similar concept to the CIL, but accounts for factors like controllable exports. The CEL represents the maximum amount of capacity that can be exported out of a LRZ under peak conditions without violating transmission limits.

For PY 2025/26, Zone 7 has a summer CIL of 3,579 MW, a summer ZIA of 3,569 MW, and a summer CEL of 5,716 MW.[26]

13.8 Local Clearing Requirement

The LCR is the minimum amount of UCAP that must clear locally in the PRA, after accounting for transmission import capability and exports. The LCR is computed as the LRR less the ability to import (ZIA) and controllable exports (*LCR = LRR − Zonal Import Ability − Controllable Exports*). For PY 2025/26, Zone 7 has a summer LCR of 20,275 MW on a UCAP basis.[27] The final PRA LCR may differ based on updated load forecasts, transfer capability, and export commitments.

The Company's share of the LCR determines the portion of local capacity it must supply within Zone 7.

13.9 MISO's Direct Loss of Load Construct

Since CE's last IRP filing, MISO has revised its capacity accreditation framework. In 2024, MISO received FERC approval to adopt the DLOL methodology for assigning seasonal capacity credit for resources.[28] The DLOL framework is similar to the traditional effective load carrying capability (ELCC) methodology in many ways, but places even more emphasis on a resource's contribution during modeled load shedding events.[29]

The DLOL methodology remains under active refinement by MISO. DLOL is scheduled to go into effect in PY 2028/29.[30] MISO has not yet issued binding DLOL accreditation

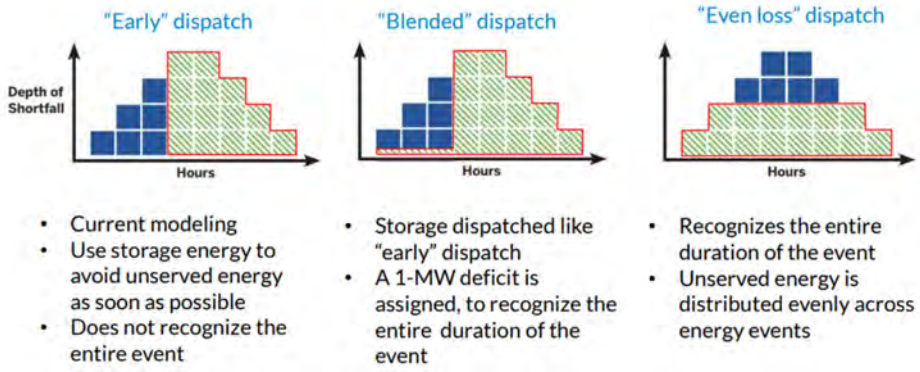
[26] Ibid.
[27] Ibid.
[28] MISO, *Midcontinent Independent System Operator, Inc. submits tariff filing per 18 C.F.R. § 35.13(a)(2)(iii): 2024-03-28 Resource Accreditation Reform to be effective 9/1/2024 under ER24-1638, Filing Type 10, Accession No. 20240328-5329, Federal Energy Regulatory Commission eLibrary (filed March 28, 2024)*, available at: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240328-5329
[29] MISO, *Resource Accreditation White Paper (Version 2),* available at: https://cdn.misoenergy.org/Resource%20Accreditation%20White%20Paper%20Version%202.1630728.pdf
[30] MISO, *Planning Year 2025–2026 Indicative DLOL Results*, available at: https://cdn.misoenergy.org/PY%2025-26%20Indicative%20DLOL%20Results657893.pdf

values; rather, it has provided "indicative results" intended to inform stakeholders and guide early planning. These values represent only a snapshot in time. DLOL is a new accreditation construct, and MISO continues to refine its methodology based on stakeholder feedback and evolving system conditions.

Among all resource types, storage has shown the most significant variability across MISO's indicative DLOL studies. Storage is inherently challenging to model in both DLOL and ELCC frameworks, due to charging and discharging flexibility, state-of-charge limitations, and the duration of the resource. In MISO's initial DLOL analyses, storage received relatively low accreditation values. Under those early assumptions, storage was dispatched to avoid load shedding as soon as reliability stress appeared. This "early" dispatch mitigated early shortage events but sometimes resulted in the storage resources fully depleting stored energy before later load shedding events occurred. Although storage did reduce overall unserved energy, it was not fully recognized for that contribution because DLOL evaluates contribution during the modeled shortfall events themselves, rather than earlier hours where load shedding was entirely prevented. Because storage resources had already discharged before load shedding events, its accredited value was low relative to its contribution.

Following feedback from stakeholders, MISO took steps to modify its approach. MISO changed how modeled storage is being dispatched during shortfall events. MISO explored alternative "blended" and "even loss" dispatch logics (shown in Figure 13-3).[31]

Figure 13-3: Variations in storage dispatch methods during Loss-of-Load Event[32]



Under the updated "even loss" dispatch method, MISO dispatches storage across the peak of the load shedding event, decreasing its overall depth but having no impact on

[31] *MISO, LOLE Modeling Enhancements – Storage Modeling, presentation to the Resource Adequacy Subcommittee (RASC), April 9, 2025,* available at: https://cdn.misoenergy.org/20250409%20RASC%20Item%2008%20LOLE%20Modeling%20Enhancements%20Storage%20Modeling689245.pdf

[32] *MISO, LOLE Modeling Enhancements – Storage Modeling, presentation to the Resource Adequacy Subcommittee (RASC), April 9, 2025,* available at: https://cdn.misoenergy.org/20250409%20RASC%20Item%2008%20LOLE%20Modeling%20Enhancements%20Storage%20Modeling689245.pdf

the duration. By changing the timing of the storage dispatch, the resource is recognized for muting the overall load shedding event and is accredited accordingly. Similarly, a "blended" method captures contributions toward preventing early load shedding events. At the date of writing, MISO has indicated a preference for even loss modeling but not definitively selected a modeling approach.[33]

The adoption of DLOL values will also impact the reserve margin targets set by MISO. By shifting the focus from the single coincident peak to the broader set of hours in which reliability risk actually materializes, adopting the DLOL construct changes the underlying risk profile used to calibrate PRMR and LCR. Because system reliability stress may occur during hours when demand is below the annual peak, the reserve margin needed to satisfy a DLOL-based reliability benchmark will likely differ from current LOLE-calibrated margin and, depending on the distribution of risk across hours, may result in a lower required reserve margin.[34] MISO has also provided indicative results for future reserve margin requirements.[35]

During this IRP effort, the Company reviewed indicative values supported by MISO modeling for DLOL values and future reserve margins. However, MISO has not yet provided a finalized set of DLOL accreditation projections. For purposes of this IRP, the Company assumed that MISO will adopt the even loss approach to modeling storage resources.

13.10 Projected Assumptions Around DLOL and PRMR

For the purposes of this IRP, the Company reviewed relevant indicative values supported by MISO modeling. However, these values represent a snapshot in time and may change in the future for the reasons discussed above.

DLOL values are developed for each of the four seasons. Figure 13-4. presents the season DLOL values assumed for the purposes of this IRP.

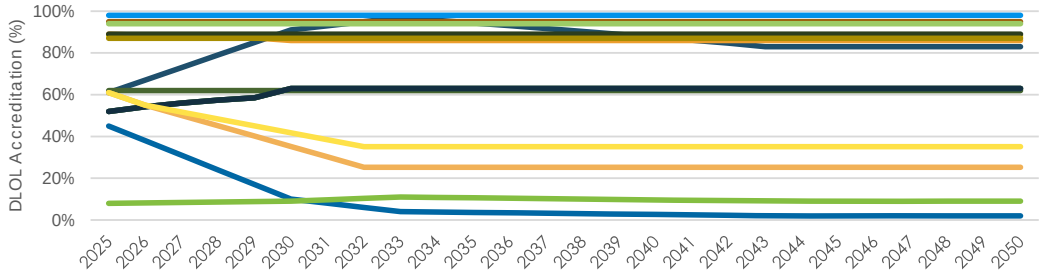
[33] MISO, *Indicative DLOL Results, Planning Year 2025–2026 (Update – April 2025),* Apr 2025, available at: https://cdn.misoenergy.org/PY%2025-26%20Indicative%20DLOL%20Results657893.pdf

[34] MISO, *RAN Reliability Requirements and Sub-annual Construct: Planning Reserve Margin Requirement (PRMR) Allocation (RASC-2020-4 and 2019-2)*, presented to the Resource Adequacy Subcommittee, Jul 2025, https://cdn.misoenergy.org/20250709%20RASC%20Item%2006%20PRMR%20Allocation%20%28RASC-2020-4%20and%202019-2%29705843.pdf

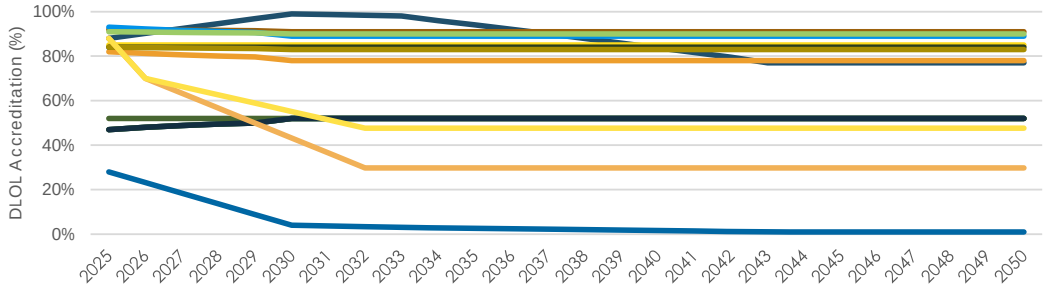
[35] MISO, *Planning Year 2025-2026 Indicative Direct Loss of Load (DLOL) Results*, 2025, https://cdn.misoenergy.org/Indicative%20DLOL%20Results%20PY%202025-2026667100.pdf

Figure 13-4: DLOL values

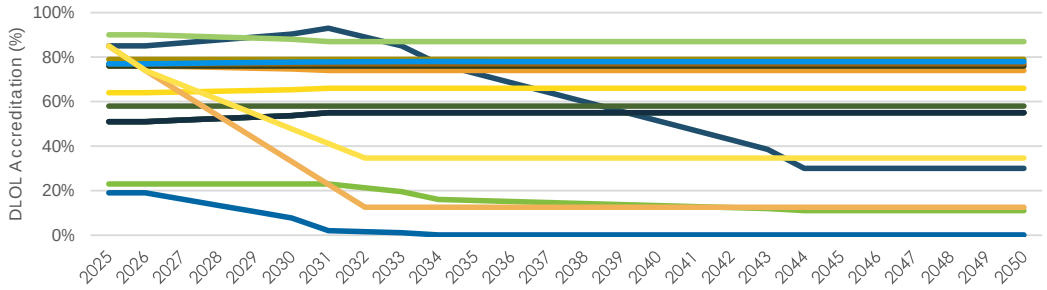
Summer



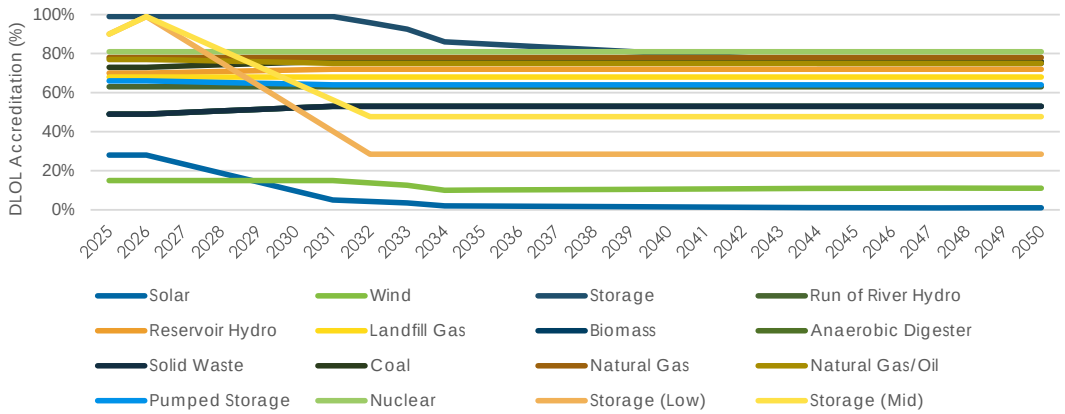
Fall



Winter



Spring



The PRMR values assumed in this IRP after the DLOL is implemented in 2028/2029 are shown in Table 13-1.

Table 13-1: Planning Reserve Margin targets

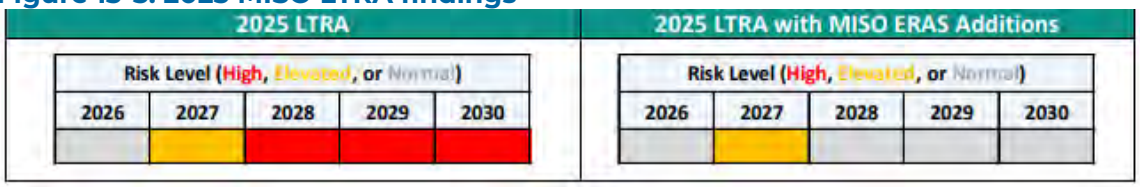
	SPRING	SUMMER	FALL	WINTER
PRM (%)	0.99%	2.22%	5.92%	5.53%

13.11 MISO Resource Adequacy

The capacity outlook across the broader MISO footprint has tightened considerably in recent years, driven by the convergence of accelerating generator retirements and unprecedented load growth. According to the NERC, MISO forecasts its summer peak demand to grow from approximately 127 GW in 2026 to 143.7 GW by 2035, with data centers alone accounting for as much as 18 GW of that growth.[36] However, MISO's approach to forecasting data centers is evolving, creating a material source of planning uncertainty.[37]

At the same time, accredited thermal capacity has decreased by 8.8 GW,[38] driven primarily by reductions in accredited capacity of existing facilities and retirements. These trends have drawn significant attention from reliability authorities. For example, NERC's 2025 Long-Term Reliability Assessment identified MISO as facing heightened resource adequacy risk, with elevated risk beginning in 2027 and high risk beginning in 2028 under base-case assumptions. NERC's subsequent ERAS sensitivity analysis found that timely implementation of expedited resource additions could eliminate projected reserve margin shortfalls and reduce MISO's risk classification to elevated risk in 2027 and normal risk from 2028 through 2030, though this improvement depends on the on-time commercialization of those resources, as shown in Figure 13-5. [39]

Figure 13-5: 2025 MISO LTRA findings



13.12 Zone 7 Resource Adequacy

Looking forward, the capacity outlook for Zone 7 has changed materially since the 2021 IRP, driven by significant shifts in both supply and demand. On the supply side, CE had planned to retire its 1,420-MW J.H. Campbell Generating Station (Campbell) in West

[36] NERC, (Apr. 2026), *2025 LTRA Sensitivity Case: Addition of ERAS Resources in the MISO Assessment Area,* accessible at: https://www.nerc.com/globalassets/our-work/assessments/2025-ltra-sensitivity-miso-eras.pdf
[37] RTO Insider, (Apr. 2026), *MISO Load Forecast: Data Centers Drive 163-GW Peak by 2035*, accessible at: https://www.rtoinsider.com/130187-miso-load-forecast-165gw-peak-2035/
[38] NERC, (Jan. 2026), *2025 Long-Term Reliability Assessment*, accessible at: https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf
[39] Ibid.

Olive, Michigan by May 31, 2025, as part of the Company's commitment to exit coal generation[40] — a plan approved by the Commission.[41] However, the U.S. Department of Energy has issued a series of 90-day emergency orders under Section 202(c) of the Federal Power Act directing CE to keep the plant operational past its planned retirement date, citing elevated reliability risk in MISO's North and Central regions.[42,43,44] As of the date of this filing, the retirement of Campbell remains pending, with the timing subject to ongoing federal orders and active litigation.[45]

Partially offsetting the loss of Campbell's capacity, the Palisades Nuclear Generating Station (Palisades)— retired in May 2022 — is in the process of being restarted by Holtec International, with a return to service targeted for 2026. Once operational, Palisades would restore approximately 800 MW of firm, carbon-free generation to Zone 7, and would represent the first restart of a nuclear facility in U.S. history. Holtec also has longer-term plans to add two advanced small modular reactors at the site, bringing total potential site capacity to approximately 1,400 MW. [46]

Compounding the supply challenge is unprecedented load growth within Zone 7. DTE Electric has received regulatory approval for special contracts to serve power to a 1,383-MW data center in Saline Township, Washtenaw County — representing approximately a 25% increase in DTE's total electric load — and has filed request for approval of a second 1,000-MW data center in Van Buren Township, Wayne County. DTE has disclosed a pipeline of up to 7 GW of additional potential large load.[47] DTE has indicated that it will support its load growth with additional investments in renewable

[40] Consumers Energy, (Jun. 2021), *Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan's Clean Energy Transformation*, accessible at: https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation
[41] Michigan Public Service Commission, (Jun. 2022), *Order Approving Clean Energy Plan Settlement Agreement, Case No. U-21090*, accessible at: https://mi-psc.force.com/sfc/servlet.shepherd/document/download/069t000000DmNGrAAN
[42] U.S. Department of Energy, (May 2025), *Order No. 202-25-3 (Initial Campbell Emergency Order),* accessible at: https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20(MISO)%20202(c)%20Order_1.pdf
[43] U.S. Department of Energy, (Aug. 2025), *Order No. 202-25-7 (Second Extension of Campbell Emergency Order),* accessible at: https://www.energy.gov/sites/default/files/2025-08/MISO%20Order%20No.%20202-25-7.pdf
[44] U.S. Department of Energy, (Nov. 2025), *Order No. 202-25-9 (Third Extension of Campbell Emergency Order),* accessible at: https://www.energy.gov/ceser/2025-doe-202c-orders
[45] Michigan Attorney General Dana Nessel, (Feb. 2026), *AG Nessel to Challenge New DOE Order Forcing Illegal, Costly Operations of J.H. Campbell Plant*, accessible at: https://www.michigan.gov/ag/news/press-releases/2026/02/20/ag-nessel-to-challenge-new-doe-order
[46] Holtec International, (Apr. 2026), *Holtec Palisades*, accessible at: https://holtecinternational.com/products-and-services/holtec-palisades/
[47] Utility Dive, (Oct. 2025), *DTE Inks First Data Center Deal to Grow Electric Load 25%,* accessible at: https://www.utilitydive.com/news/dte-data-center-deal-transformational-growth-earnings/804231/

energy, storage, and DR resources.[48] Additional detail will be provided in DTE's updated IRP filing.

Taken together, these developments represent a fundamentally different planning environment for Zone 7 compared to prior IRP cycles. CE continues to monitor Zone 7 and MISO-wide capacity conditions closely, including PRA outcomes and updated MISO LOLE study results, to assess the cumulative impact on the Zone's ability to meet its LCR and the Company's overall resource adequacy outlook. This is a key theme underpinning the modeling assessments in this IRP.

13.13 Existing Fleet

CE continues to maintain a diverse and flexible resource portfolio, as discussed in Section 7, Existing Supply-Side Resources. The Company's portfolio includes a balanced mix of baseload, intermediate, peaking, intermittent, demand-side, and storage resources that help reduce energy usage and deliver electricity to customers in an affordable, environmentally responsible, and reliable manner. Assumptions related to resource age, capacity factors, licensing, and expected retirements or expiring contractual obligations are also described in Section 7, Existing Supply-Side Resources.

13.14 Projected Cost and Revenues to Comply

The Company is obligated to meet the capacity obligations set in MISO's capacity construct or pay a deficiency charge. It can meet its obligation through the PRA or by developing a FRAP. Based on these requirements, the Company's accredited capacity portfolio meets its proportional share of the Zone 7 LRR and LCR. The Company currently plans to meet its obligation through the PRA. The costs to comply are contemplated through the remainder of this IRP.

13.15 PCA Compliance with Capacity and Reliability Requirements

The Company's PCA was developed through the capacity expansion and production cost modeling process described Section 5, Analytical Approach, and is designed to satisfy applicable MISO and Michigan resource adequacy requirements over the planning horizon. The PCA includes a combination of dispatchable capacity resources, including the MCV PPA, new natural gas-fired CTs, [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], battery storage, wind, and solar resources selected through optimization modeling to meet projected capacity needs, PRMR, renewable and clean energy standards, and reliability objectives. The Company evaluated resource selections using assumptions reflecting MISO's evolving resource adequacy framework, including seasonal accreditation and DLOL requirements, and concluded that the PCA appropriately balances affordability and reliability objectives, while supporting compliance with applicable resource adequacy requirements.

[48] DTE Energy, (Apr. 2026), *Data Centers and Customer Rate Protection*, accessible at: https://www.dteenergy.com/us/en/quicklinks/data-center-facts.html

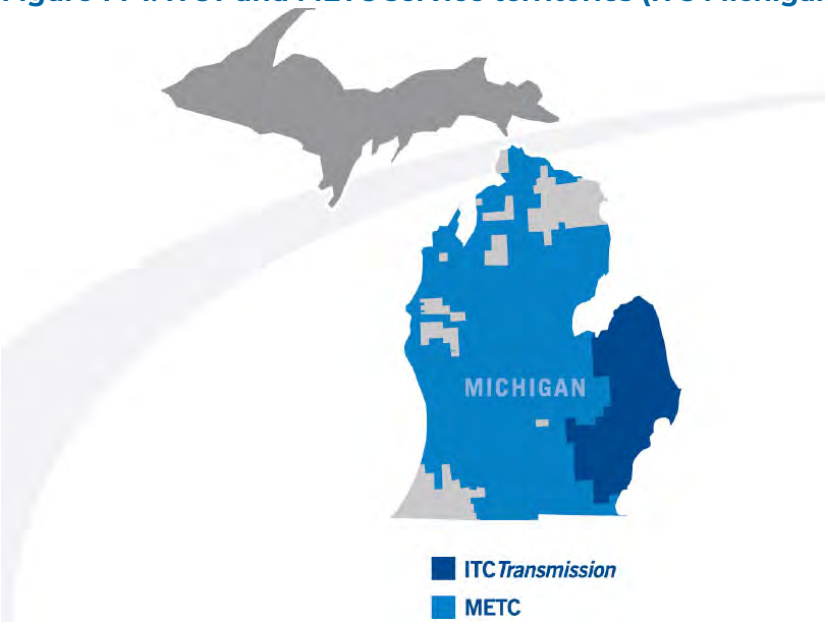
Transmission Analysis

Section 14

14 Transmission Analysis

CE serves load within MISO LRZ 7, which includes most of Michigan's Lower Peninsula. Transmission service within CE's footprint is provided primarily by METC, while ITC serves portions of southeast Michigan. These transmission systems are interconnected with the broader MISO transmission network, enabling Consumers Energy to import and export capacity and energy subject to transmission constraints and MISO reliability requirements.

Figure 14-1. ITCT and METC service territories (ITC Michigan)



As the RTO, MISO administers regional transmission planning and grid operations across its footprint under a FERC-approved tariff. Through its transmission planning processes, MISO works with transmission owners, utilities, and other stakeholders to identify transmission needs and evaluate solutions that support reliability and efficient energy delivery across the region.

Transmission capability between CE, other Michigan utilities, and the broader MISO system is represented in MISO reliability and LOLE studies through CIL and CEL. These limits constrain the amount of capacity that can be reliably transferred between regions during stressed system conditions and prevent overreliance on external generation during reliability events. Accordingly, while the IRP focuses on identifying a prudent supply- and demand-side resource strategy, it must also consider whether those resources can be reliably delivered to customers and what transmission upgrades may be needed to support the Company's preferred plan.

14.1 Transmission Owner Engagement

Beginning in early 2025, CE engaged METC 17 times through a series of structured meetings to define study scope, modeling assumptions, and scenarios for the 2026 IRP transmission analysis.[49]

Topics addressed through this engagement included:

- Load forecast assumptions;
- Resource siting methodologies and use of the MISO Definitive Planning Phase and Replacement queues;[50]
- Alignment of transmission study scenarios with IRP expansion model sensitivities;
- Treatment of storage resources, including charging assumptions and potential transmission interactions;
- Transmission costs and risks associated with accessing out-of-state resources; and
- Evaluation of Michigan's existing CIL and potential increases to that limit.

CE and METC iteratively refined model inputs and scenario assumptions as the IRP simulations evolved, including adjustments to resource quantities and siting as new capacity accreditation information became available.

The Company incorporated METC's feedback and study results into its IRP decision-making, including the development of transmission cost assumptions, evaluation of CIL sensitivities, and consideration of transmission alternatives informing the Company's PCA.

14.2 Transmission Study Scope and Scenarios

14.2.1 Transmission Study Framework

For the 2026 IRP, METC conducted a comprehensive Transmission Impacts Study evaluating the effects of CE's proposed generation additions, retirements, and load assumptions on the METC and ITCT systems. The analysis was based on MISO MTEP25[51] base models, which represent the 10-year planning horizon (2035) and include approved LRTP Tranche 1 and Tranche 2.1 projects.[52] Results were assessed for two study years: 2035 and 2045.

The Transmission Impacts Study included:

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[49] Consumers Energy and METC met on February 11, February 27, March 11, April 8, June 17, June 25, July 22, August 12, September 2, September 30, October 29, November 20, and December 17 of 2025, and January 21, February 11, June 22, and June 29 of 2026. In addition, the parties held an informal coordination meeting on January 15, 2025.

[50] Midcontinent Independent System Operator (MISO), (Jul 2026), *Generator Interconnection Studies and Procedures*, accessible at: https://www.misoenergy.org/planning/resource-utilization/GI_Studies/#t=10&p=0&s=&sd=

[51] MISO, (Dec 2025), *MTEP25 Transmission Portfolio,* accessible at: https://cdn.misoenergy.org/MTEP25%20Report731648.pdf

[52] MISO, (Jul 2026), *Long Range Transmission Planning*, accessible at: https://www.misoenergy.org/planning/long-range-transmission-planning/

- Steady-state thermal analysis;
- Steady-state voltage analysis;
- Dynamic stability analysis; and
- Identification of required transmission upgrades with planning-level cost estimates.

All cost estimates are planning-level estimates and depend on assumed resource locations, operating conditions, and future MISO planning outcomes.

14.2.2 Transmission Study Scenarios

METC evaluated six scenarios developed by CE. Collectively, the scenarios were designed to test transmission system performance across a range of plausible futures, including differing load growth trajectories, resource mixes, siting assumptions, and reliance on external resources.

Scenario 1: 2021 PCA / 2024 RE Plan Reference
Updated representation of the Company's 2021 PCA settlement and 2024 RE Plan.

Scenario 2: Current Load Growth
Portfolio sufficient to meet the Company's current baseline load forecast.

Scenario 3: PLG
Portfolio sufficient to meet the Company's current load forecast plus approximately 1.6 GW of large load growth.

Scenario 4: ALG
Portfolio sufficient to meet the Company's HLG sensitivity, including significantly higher demand associated with accelerated electrification and economic development.

Scenario 5: Out-of-State Leverage
Portfolio sufficient to support the Company's probable load forecast with increased leverage of out-of-state resources. Scenario 5 included three variants designed to evaluate the transmission implications of alternative approaches for meeting load growth with a reduced level of in-state resource development.

Scenarios 5a and 5b examined the effects of different siting assumptions for major in-state generation resources, while Scenario 5c evaluated a resource portfolio similar to Scenario 5a under dispatch assumptions informed by MISO's indicative DLOL accreditation framework.

Scenario 6: PCA
Portfolio representative of the Company's preliminary PCA as of November 2025.

No single METC study scenario exactly replicates the final PCA. Instead, the Company relied on the results of Scenarios 6, 5a, and 5c to evaluate transmission impacts associated with the PCA. Scenario 6 most closely reflects the PCA's in-state resource development strategy, while Scenarios 5a and 5c provide insight into the transmission implications of increased leverage of out-of-state resources. Together, these scenarios

provide a reasonable range of transmission outcomes and demonstrate that the PCA can be supported through planned transmission upgrades and anticipated transmission capability within LRZ 7. The Company elected to use Scenario 6 transmission costs for planning purposes because they represent the most conservative transmission investment estimate among the scenarios considered representative of the PCA.

14.3 Transmission Constraints and Required Network Upgrades

14.3.1 System Constraints

Across all scenarios, METC identified transmission system constraints associated with generator retirements and integration of new resources. These constraints include:

- Thermal overloads on transmission lines and station equipment;
- Voltage limitations caused by retirement of large synchronous generation; and
- Localized stability issues.

Steady-state analysis identified approximately 140 to 190 thermal violations across scenarios. Scenario 5 sensitivities were evaluated to assess the transmission implications of increased reliance on imports and reduced accredited renewable output. Scenario 5a identified 177 thermal corrective action plans (CAPs), while Scenario 5c identified 158 CAPs. METC found that Scenario 5c did not require any unique thermal upgrades beyond those already identified in Scenario 5a, indicating that the reduced renewable accreditation assumptions and associated increase in imports did not introduce new transmission reliability constraints within Michigan.

For Scenario 6, METC identified 168 thermal corrective projects, consisting of approximately 146 line upgrades and 22 substation upgrades. Voltage analysis identified a regional reactive power deficiency in northeast Michigan driven by thermal plant retirements, requiring approximately 150 MVAR of dynamic reactive support. CE's allocated share of this investment is approximately $15 million (in 2025 dollars).

Dynamic stability analysis of the 2045 system identified one localized disturbance that was mitigated through dynamic reactive support; no broader system-wide stability concerns were observed.

In addition to the thermal constraints identified through the transmission evaluation, METC identified several localized transmission reliability concerns associated with changing resource locations and generation retirements. These included a regional reactive power deficiency in northeast Michigan requiring approximately 150 MVAR of dynamic reactive support and a localized stability concern near the Port Calcite area requiring installation of a synchronous condenser. These findings illustrate that transmission needs are not limited to bulk transfer capability and also include localized transmission system requirements necessary to maintain voltage performance and system stability as the generation fleet evolves.

14.3.2 Network Upgrades and Interconnection Costs

For purposes of this IRP, the Company incorporates a generic transmission network upgrade cost assumption of $117.45 per kW of generation capacity for all transmission-connected generation technologies located in Michigan. This assumption is based on a review of executed GIAs and Multiparty Facility Construction Agreements (MPFCAs) associated with interconnections to METC and ITC Transmission systems.

The Company surveyed 68 executed GIAs from MISO definitive planning phase queues between 2017 and 2020, supplemented by 35 additional projects from the MISO DPP-2021 East Phase 2 System Impact Study. Network upgrade costs across these projects varied widely, reflecting differences in generator size, voltage level, location, and system conditions. The weighted average of these historical costs forms the basis of the Company's generic planning-level assumption.

In addition, METC performed a scenario-specific Transmission Evaluation for the six IRP resource build scenarios discussed in Section 14.2.2. METC estimated transmission network upgrade costs allocated to the Company ranging from approximately $96 per kW to $166 per kW, depending on the scenario evaluated. Based on these results, the Company incorporated the transmission network upgrade costs from Scenario 6, approximately $154.8 per kW, into the development and evaluation of the PCA. Because definitive transmission upgrade costs are determined through future MISO interconnection and retirement studies, the Company also evaluated a higher transmission cost sensitivity of $200 per kW, to reflect uncertainty around future transmission investment needs. The $200 per kW sensitivity was established prior to completion of METC's transmission analysis and was informed by MISO DPP-2021 East Phase 2 interconnection study results, which indicated average network upgrade costs of approximately $193 per kW. The value was rounded to $200 per kW to represent a reasonable upper-bound sensitivity for future transmission investment needs.

METC did not identify discrete transmission "no-regrets" interconnection zones[53] that would be applicable across all IRP scenarios. Interconnection cost and transmission upgrade requirements remain highly dependent on individual resource characteristics and siting decisions, which are evaluated through MISO's Definitive Planning Phase and associated system impact studies. Accordingly, transmission impacts are most appropriately represented at a planning level in this IRP, with definitive siting and cost determinations deferred to subsequent MISO processes.

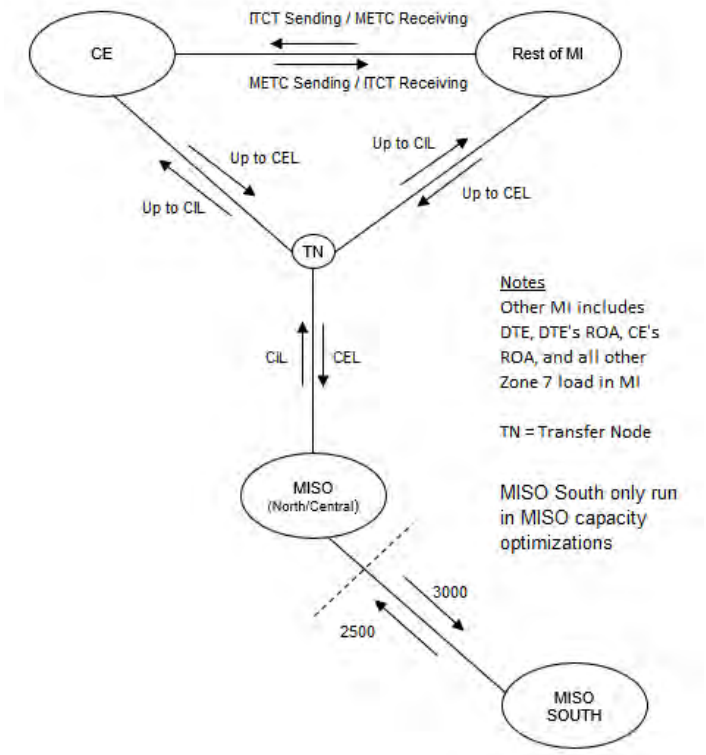
14.4 Capacity Import and Export Limits

In MISO's resource adequacy framework, transmission capability between LRZs is represented through seasonal CILs and CELs. These limits represent the maximum amount of capacity that can be imported into or exported from a zone during reliability events and are intended to reflect transmission constraints that may restrict deliverability under stressed conditions. As a result, the LOLE study does not assume

[53] "No regrets" interconnection zones are areas where transmission investment is expected to support reliable and cost-effective generator interconnection across a range of plausible future resource and load conditions, reducing the risk that upgrades become unnecessary if individual projects or assumptions change.

unlimited access to external capacity but instead reflects the extent to which LSEs may rely on neighboring zones subject to seasonal transmission capability. The Company's representation of MISO's framework, with modifications to represent transmission limitations pertinent to Michigan, is illustrated in Figure 14-2.

Figure 14-2: Transmission limits in MISO LOLE study



The Company based its initial CIL and CEL assumptions on the most recent public MISO reports available at the start of the IRP modeling process, specifically the PY 2025–2026 LOLE Study Report,[54] which provides seasonal CIL and CEL values for LRZ 7. Beginning in PY 2023/2024, MISO adopted a seasonal resource adequacy construct, and the Company reflected seasonal CIL and CEL values consistent with this framework. The CIL and CEL values in the PY 2025-2026 LOLE report are included below.

Table 14-1: Capacity import limit / capacity export limit values

	SUMMER	FALL	WINTER	SPRING
CIL, MW	3,579	5,125	4,762	5,166
CEL, MW	5,716	5,158	5,712	5,499

[54] MISO, (Mar 2025), *Planning Year 2025-2026 Loss of Load Expectation (LOLE) Study Report*, accessible at: https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf

Since the start of the IRP modeling process, MISO has published updated LOLE study results, including PY 2026–2027 values. The Company reviewed these updates and determined that they did not materially alter the conclusions of the IRP analysis. The Company also considered the impact of approved MISO transmission expansion projects, including LRTP Tranche 1 and Tranche 2.1 facilities, which are expected to increase transmission transfer capability into and out of LRZ 7 over time. These approved projects were reflected through adjustments to CIL and CEL assumptions consistent with their anticipated in-service dates.

METC evaluated the potential impacts of the IRP resource build scenarios on CIL and determined that none of the scenarios studied resulted in a significant reduction in LRZ 7 import capability. Any variations observed were modest and within the range typically associated with assumed generation siting and dispatch.

The Company's PCA does not rely on sustained exports in excess of established CEL values, and therefore CEL does not constrain the Company's preferred resource strategy. Based on publicly available MISO data, approved transmission expansion projects, and transmission owner analysis, the Company concludes that existing and anticipated CIL and CEL levels are sufficient to support the PCA, and no additional transmission investment is required solely to increase import or export capability for IRP purposes.

14.5 Storage, GETs, and Transmission Alternatives

CE, in coordination with METC, evaluated Grid Enhancing Technologies (GETs), energy storage transmission co-benefits, and CIL expansion as potential alternatives to conventional transmission upgrades. These alternatives were considered as part of the IRP engagement process.

14.5.1 Grid Enhancing Technologies

METC and the Company discussed GETs, including dynamic line ratings, power flow control devices, advanced conductors, and topology optimization. GETs were evaluated to facilitate, defer, or replace transmission upgrades. METC advised that certain GETs, such as dynamic line ratings, cannot be relied upon as baseline solutions for long-term transmission planning because their performance is highly dependent on real-time conditions, and that other contemplated GETs, such as power flow control devices or advanced conductors, required location-specific engineering and system topology conditions with evaluations being highly dependent on explicit siting of generation resources. As a result, GETs were considered qualitatively but were not assumed to offset or replace the conventional transmission upgrades identified in the METC transmission evaluation for the IRP.

14.5.2 Storage Transmission Co-Benefits

The Company and METC also evaluated whether transmission-connected storage resources could provide measurable transmission system co-benefits. While storage may offer localized congestion relief or voltage support when available and appropriately dispatched, METC concluded such benefits are highly dependent on location, system

conditions, and state of charge, and therefore cannot be reliably quantified or credited at the IRP planning level. Unless explicitly designated as transmission assets, storage resources cannot be solely relied upon to meet transmission planning criteria, and thus storage co-benefits were considered qualitatively and not monetized in the transmission analysis.

14.5.3 Capacity Import Limit Expansion

As an additional alternative, CE requested METC evaluate the feasibility and cost of increasing LRZ 7's CIL by 2,000 MW. METC estimated approximately $305 million of incremental in-state transmission investment would be required, with additional out-of-state constraints likely increasing total costs. Given the limited economic benefit identified in IRP modeling and the ability of the PCA to meet reliability requirements without incremental CIL increases, the Company did not pursue additional CIL expansion beyond expected increases from the approved LRTP projects.

Fuel Supply

Section 15

15 Fuel Supply

This section describes the fuel price forecasts, delivered fuel price development, and natural gas transportation and storage assumptions used in the Company's IRP for owned fossil fuel plants. It includes commodity price forecasts for the BAU reference scenario, as well as alternative scenarios and sensitivities.

The section also summarizes fuel procurement and delivery for the Company's existing and planned fossil-fueled generating facilities, including facility-specific arrangements for gas procurement, transportation, and delivery, and, where applicable, oil storage and inventory practices. The projected annual fuel costs across the PCA and alternative portfolios is discussed in Section 17, Model Results.

Because no coal-fired resources are included in the resource portfolios in this IRP, the Company did not develop or utilize a coal price forecast in its modeling.

15.1 Natural Gas

15.1.1 Forecast Methodology

The reference case natural gas forecast is based on the Henry Hub natural gas price forecast from the EIA's 2025 AEO, published in April 2025, specifically Table 13, "Natural Gas Supply, Disposition, and Prices," consistent with MPSC Case No. U-18418. The high natural gas sensitivity is based on the 2025 AEO's "Low Oil and Gas Supply" case, also published in April 2025. The high natural gas price forecast was evaluated as part of the IRP sensitivity analysis, as discussed in Section 6, Scenarios & Sensitivities.

The 2025 AEO forecast was used because it was the most recently available update at the time the CE team began working on this IRP. Between the AEO 2025 and AEO 2026 forecasts (published April 2026), the average reference case[55] Henry Hub spot price over 2025-2050 changes from $5.5 /MMBtu to $6.3/MMBtu, and from $10.1/MMBtu to $12.9 MMBtu over the same period in the low oil and gas supply case.[56]

To reflect monthly variation in natural gas prices, the Company applied seasonality to the Henry Hub forecast across all sensitivities. This seasonality is based on observed differences between monthly gas prices and the annual average, with separate adjustments for winter, spring/fall, and summer periods.

15.1.2 Delivered Fuel Cost

In the IRP modeling, fuel price forecasts are specified as scenario-level inputs and incorporated into each applicable Aurora optimization for the applicable scenario or sensitivity. Once a natural gas price path is assigned to a scenario or sensitivity, that forecast is applied consistently within that case across the modeled portfolios, including the Aurora-selected optimal plan, the PCA, and any alternative portfolios.

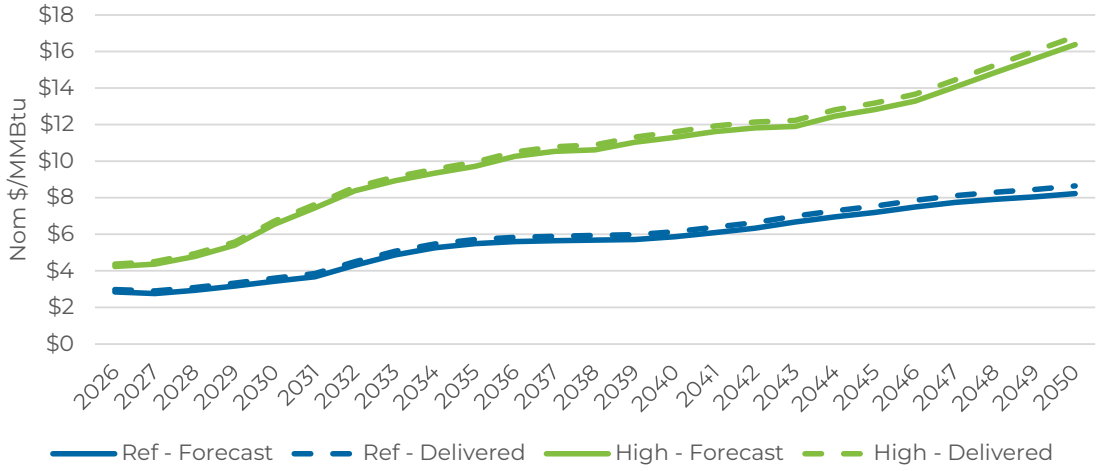
[55] Renamed to the Counterfactual Baseline case in AEO2026
[56] All values are in nominal dollars

Delivered natural gas prices for each generating facility are developed by applying plant-specific transportation, delivery, and gas-management assumptions to the underlying commodity price forecast. These delivered fuel prices are used by Aurora in hourly dispatch and production cost modeling throughout the planning period and reflect the transportation, delivery, and gas-management arrangements applicable to each facility, escalated as needed over the IRP study period.

For new Company-owned natural gas-fired generation, the Company assumed direct interconnection to its gas transmission system with firm transportation service. New CT and CC units were modeled under the existing Consumers Energy Gas Transportation Service Rate XXLT. Gas commodity costs were based on the traded CE Citygate pricing point, with delivered gas prices reflecting CE Citygate pricing plus the applicable XXLT tariff charges.

Figure 15-1 shows the average annual Henry Hub price under the EIA Reference and High natural gas forecasts, along with the corresponding average annual delivered fuel costs for Company natural gas-fired generating facilities.

Figure 15-1: Average annual Henry Hub price



15.2 Oil

15.2.1 Forecast Methodology

The Company develops its oil price forecast using a composite of West Texas Intermediate (WTI) crude oil projections sourced from EIA together with additional third-party forecast providers. This composite crude oil forecast, expressed in nominal dollars per barrel, serves as the basis for the Company's low-sulfur fuel oil price forecast.

To develop the delivered low-sulfur fuel oil price forecast used in the IRP, the Company converts the crude oil forecast to nominal dollars per MMBtu using the historical relationship between crude oil prices and low-sulfur fuel oil prices, together with applicable transportation assumptions. The resulting delivered oil price forecast is used consistently across the base case and all IRP scenarios.

The Company primarily maintains fuel oil capability at applicable generating units for reliability and emergency operating purposes. As a result, fuel oil is expected to represent only a small portion of total fuel expenditures during the planning period relative to natural gas-fueled generation.

15.2.2 Delivered Fuel Cost

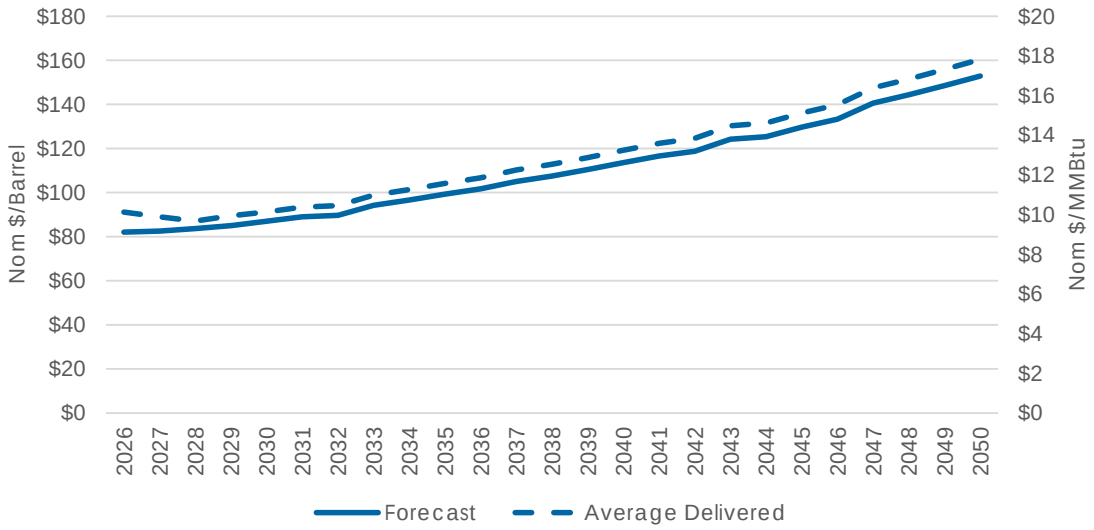
For the applicable generating facilities, the delivered low-sulfur fuel oil forecast reflects plant-specific transportation, delivery, storage, and fuel management assumptions. For the Company's existing generating facilities, transportation costs are embedded in the forecasted delivered oil price. No separate high or low oil price cases are modeled.

For Karn Units 3 and 4, the Company maintains onsite fuel oil storage and manages oil inventory levels based on established targets. This approach supports operational reliability while providing flexibility in fuel procurement.

The Proposed PCA does not include any new utility-owned generating plant requiring a delivered oil price assumption.

Figure 15-2 compares the forecasted composite crude oil price with the corresponding average delivered fuel oil cost over the planning period. As shown, the delivered fuel oil cost generally tracks the underlying oil forecast while reflecting the transportation, delivery, storage, and fuel management assumptions applicable to the Company's generating facilities.

Figure 15-2: Oil price forecast and average delivered fuel oil cost



15.3 Fuel Supply and Infrastructure

15.3.1 Natural Gas Transportation and Storage

For existing resources, fuel procurement practices vary by facility and reflect plant design, fuel capability, and connected pipeline systems.

Karn Units 3 and 4. These units can operate on natural gas, fuel oil, or blends. Natural gas is supplied via two independent sources: the Company's gas distribution system and the DTE Gas northern Michigan gathering system accessed via the Phillips 66 (P66) Bay Area Pipeline. Gas is procured on a spot-market basis for these units.

Zeeland Generating Station. Gas is delivered from the ANR Pipeline system through a lateral owned by SEMCO Energy Gas Company (SEMCO). The Company uses a third-party gas management services agent to procure/deliver gas to the SEMCO interconnection on a firm basis and maintains a firm transportation contract with SEMCO for delivery from ANR to the plant.

Jackson Generating Plant. Gas is supplied from the Vector Pipeline system through a lateral owned by the Company's gas utility, with a third-party gas management services agent procuring gas and managing deliveries.

Covert Generating Facility. Gas supply comes from the ANR Pipeline system, with a third-party gas management services agent procuring and managing deliveries.

For new Company-owned natural gas-fired generation, the IRP assumes direct interconnection to the Company's gas transmission system. The transmission system includes substantial natural gas storage capacity, with a portion of storage provided through the existing XXLT transportation tariff. The Company's transmission network interconnects with multiple major interstate pipelines (including Trunkline, ANR, Great Lakes, Vector, and Panhandle Eastern), providing access to diverse supply regions.

For the CCGT with CCS resource, the Company has not identified a specific project site. As a result, site-specific fuel interconnection, CO_2 transportation, and sequestration costs have not been separately estimated in this IRP and would be developed as part of future project-specific evaluation.

For generation not interconnected to the Company's gas transmission system, the Company evaluates gas supply and transportation needs through its ongoing PSCR processes to ensure appropriate firm transportation and storage arrangements are in place to maintain secure and reliable supply.

Resource Screen & Alternative Analysis

Section 16

16 Resource Screen

The Company meets customer capacity and energy needs through owned resources, PPAs, and short-term market purchases. After portfolio modeling identifies future capacity needs, a resource screen defines the candidate options for capacity expansion, including generic new builds, extensions of existing resources, long-term procurements, and demand-side resources. Each option is either modeled as a selectable candidate, evaluated through a specific portfolio or procurement alternative, or screened out if it is not technically, commercially, or regionally suitable.

A resource screen supports the optimal outcome determined in the modeling process by paring down from the universe of possible resource options to those best suited to meet customer needs from economic, sustainability, and feasibility perspectives. The candidate resource options determined then compete with one another in the capacity expansion process to supply capacity and energy needs in a least-cost combination.

The resource screen follows the following primary steps:

1. **Establish the baseline portfolio.** The Company identifies existing generating resources and previously approved planned resources that are already incorporated into Company planning objectives. These resources will be present in all expansions.
2. **Develop assumptions for new supply- and demand-side resources.** The Company develops cost and operating assumptions for potential new resource options.
3. **Conduct a technical screen.** Potential resources are screened for commercial availability, technology maturity, development feasibility, and siting constraints.
4. **Evaluate resource economics.** Resources that pass the technical screen are evaluated using screening-level economic metrics, including LCOE and LCOA.
5. **Finalize the candidate resource list.** Based on the technical and economic screening results, the Company identifies the resources that will be represented in the capacity expansion model. Depending on the resource type, these resources may be modeled as selectable resource options, embedded planning assumptions, or fixed portfolio elements.

The remainder of this section details the review of existing, planned, and potential resource additions used over the modeling forecast period, as well as a description of the screening process used to determine which resources are included in the capacity expansion model.

16.1 Existing and Approved Resources

16.1.1 Existing Generation

The existing Company-owned generation portfolio includes coal, natural gas, oil, hydroelectric, solar, energy storage, wind, DR, energy efficiency programs, and other renewable and clean resources.
Additionally, CE transacts with the MISO energy market for short-term energy and capacity purchases. A summary of existing generation resources is shown in Table 16-1.

Table 16-1: Existing owned and contracted generation by technology

EXISTING GENERATION RESOURCES (AS OF 2026)	SUMMER GENERATING CAPACITY (MW)	WINTER GENERATING CAPACITY (MW)
Coal	60	60
Gas/Oil Fired	5,031	5,306
Hydroelectric	140	140
Wind	1,232	1,232
Solar	1,696	1,696
Energy Storage (Ludington Pump Storage)	1,170	1,170
Energy Storage (BESS)	321	321
Other Renewables and Clean Resources	187	187
Demand Response (DR)	540	242
Energy Efficiency	887	769

Table 16-2 summarizes the Company's 2026 ZRC accreditation by technology type across the four planning seasons.

Table 16-2: Total ZRC accreditation by technology type (2026)

	SPRING	SUMMER	FALL	WINTER
Coal	44	53	50	46
Natural Gas/Oil	3,434	4,344	4,002	3,849
Hydro	71	73	63	67
Wind	167	91	165	256
Solar	439	649	397	210
Storage	222	394	456	225
Other Renewables	122	134	123	134

16.1.2 Previously Approved Planned Generation

The Company's baseline resource portfolio reflects planned resource additions that were previously approved through prior Commission proceedings, including the Company's 2021 IRP settlement and subsequent procurement approvals. As shown in Table 16-3, these named planned additions include approximately 1,920 MW of solar resources and 828 MW of battery storage resources, with expected commercial operation dates between 2026 and 2028. The planned solar and storage additions include both Company-owned and contracted resources. These resources are treated as committed or planned additions in the starting point for this IRP, and the current IRP evaluates the Company's remaining long-term resource needs after accounting for these additions.

Table 16-3: Planned resource additions

NAME	TECHNOLOGY	EXPECTED COD	CAPACITY (MW)	TYPE
Mustang Mile Solar Project	Solar	12/23/2028	150	Owned
Washtenaw Solar Project	Solar	1/1/2028	150	Owned
Sunfish Solar	Solar	8/31/2026	309	Owned
Logan Solar	Solar	6/1/2028	146	Owned

NAME	TECHNOLOGY	EXPECTED COD	CAPACITY (MW)	TYPE
Springport	Solar	6/1/2028	300	Owned
2030 Solar Garden Expansion	Solar	1/1/2030	3	Owned
Caledonia	Solar	6/1/2028	117	Owned
Karn Solar	Solar	12/31/2026	85	Owned
Liberty	Solar	6/1/2028	220	Owned
Freshwater Solar 1	Solar	6/1/2027	300	Contracted
Armstrong	Storage	5/31/2026	2.5	Owned
Weadock	Storage	12/31/2026	45	Owned
Iosco	Storage	12/31/2026	30	Owned
Voyager II Energy Storage	Storage	5/31/2028	150	Contracted
Lakeside Energy Storage	Storage	5/31/2028	100	Contracted
Hackett Energy Storage	Storage	5/31/2028	100	Contracted
Grand Basin Energy Storage	Storage	5/31/2027	100	Contracted
Voyager Energy Storage	Storage	6/1/2027	100	Contracted

16.2 Potential New Resource Additions

To evaluate alternatives for meeting the identified need, the Company considered a broad range of potential resource additions across multiple categories. The categories considered are included in Table 16-4.

Table 16-4: New resource additions categories considered in the resource screen

CATEGORY	REPRESENTATIVE TECHNOLOGIES CONSIDERED	DESCRIPTION
Dispatchable Firm Generation	CT, CCGT, reciprocating internal combustion engine (RICE), nuclear (large-scale and small modular reactors (SMRs)), NG + CCS, geothermal, combined heat and power (CHP), micro turbines.	Dispatchable resources capable of providing firm capacity, reliability, energy price hedging, and operational flexibility during peak and emergency conditions.
Renewable and Clean Generation	Solar PV, wind, biomass, landfill gas.	Variable energy resources that produce zero-fuel, low-emission electricity subject to weather and seasonal availability.
Energy Storage	4-hr, 8-hr, long-duration storage, thermal storage, compressed air, flywheel, fuel cells, pumped hydro.	Technologies that store energy for later use to provide renewables firming, peak capacity, energy shifting, and system flexibility.
DSM / VPPs	DR, EWR, DERs, Voltage Optimization, BTM customer-owned generation, BTM biogas, EV charging, home generators and battery storage.	Technologies that provide energy on the demand side or offer coordinated curtailable load.

16.3 Technical Screening

To keep model outputs reasonable and efficient, narrowing the scope of candidate resources to those best suited to the Company's service territory is an essential step. Certain technology options were thus screened out due to various considerations including technical feasibility, fuel supply, siting, scalability, and constructability considerations. Internal and external subject matter experts were consulted to provide judgement on whether individual resources, particularly advanced technologies, were suitable for consideration in the capacity expansion process. Of the resources screened out, they were primarily omitted for reasons related to commercial availability, regional climate and geologic conditions, cost, and resource class, among others. Resources which were screened out include:

Thermal Storage

This resource remains more expensive and less commercially viable than alternatives for long-duration energy storage.

Compressed Air

This resource remains more expensive and less commercially viable than alternatives for long-duration energy storage. It also faces suitability and safety concerns.

Flywheel Storage

This resource remains more expensive and less commercially viable than alternatives for long-duration energy storage.

Combined Heat and Power

While the company maintains an existing program with Michigan businesses that may benefit from a CHP resource, these partnerships require a specific counterparty and thus were not modeled as a generic selectable resource in capacity expansion. However, the Company plans to continue to evaluate these opportunities as they arise.

Fuel Cell

Initial technical screening indicated fuel cell technologies remain a higher-cost option relative to other energy storage and dispatchable resource alternative. Additionally, fuel cells have limited demonstrated deployment at utility scale for capacity planning applications.

Hydrogen

This technology is not yet commercially viable at utility scale due to infrastructure requirements and the significant energy needed for hydrogen production. The Company will continue to monitor future developments.

Geothermal

The Company's service territory exhibits an insufficient thermal resource within reasonable drilling depth to support geothermal development.

Biomass

This resource faces limited fuel supply and opportunities for development at scale.

Landfill Gas

This resource faces limited fuel supply and suitable landfill locations within Company service territory.

Pumped Hydro Storage

The Company's service territory contains limited opportunity for additional pumped hydro beyond existing facilities.

Offshore Wind

This resource faces development challenges in the Great Lakes region due to limited wind resource availability.

Small Modular Reactor (SMR) Nuclear

Technology remains commercially nascent, with development timelines extending beyond the relevant planning horizon.

16.4 Resource Characterization Assumptions

New resource cost and performance assumptions were developed using NREL's 2024 Annual Technology Baseline (ATB) unless otherwise stated. The ATB provides technology-specific projections for capital costs, fixed O&M costs, performance characteristics, and long-term cost trajectories, and is commonly used in utility integrated resource planning. The NREL ATB is also recommended within the IRP MIRPP. Consistent with ATB conventions, renewable resource cost inputs are expressed in real 2022 dollars and were escalated as appropriate for use in the Company's modeling framework.

16.4.1 Coordination with Transmission and Distribution Planning

The resource assumptions used in this IRP were developed to reflect coordination across supply, transmission, and distribution planning functions. On the supply side, the resource screen identifies the existing, planned, and potential resource options considered for capacity expansion modeling, including owned resources, PPAs, demand-side resources, and new supply-side additions.

From a transmission planning perspective, transmission capabilities, limitations, and network upgrade costs are reflected in the modeling framework as constraints and cost adders that affect resource viability and deliverability. From a distribution planning perspective, forecasts and assumptions for DG, demand-side resources, and distributed resource options are incorporated into the IRP through load forecast adjustments, demand-side resource modeling, and technology-specific proxy assumptions where applicable.

This approach supports alignment between the forecasts used for IRP modeling and the forecasts used for distribution planning, while recognizing that certain distributed and demand-side resources are evaluated through separate planning processes and then reflected in the IRP modeling assumptions. Together, these inputs allow the IRP to evaluate supply-side resource needs in a manner informed by transmission deliverability, distribution-level considerations, and the Company's broader system planning processes.

16.4.2 Dispatchable Firm Generation

Combined Cycle

CC units consist of one or multiple CTs and a steam turbine which recovers waste heat. Capturing waste heat supports greater efficiency and thus fuel savings. H-class units for natural gas-fueled CC resources were included in portfolio modeling. These units are newer than the F-class units and have greater thermal efficiency. The H-class units were modeled in both 1x1 and 2x1 configurations, which specifies the quantity of CTs and steam turbines used, respectively.

In a CC (1x1) configuration the resource has a nominal output of 649 MW, whereas a CC (2x1) configuration has a nominal output of 1,450 MW. Both have similar capital costs on a $/kW basis, with the 2x1 configuration being marginally less expensive. Both are assumed to be available starting in 2033, based on supply chain and permitting expectations. Additional operational and cost characteristics can be found in Table 16-5.

Table 16-5: Combined cycle resource characteristics

DESCRIPTION	UNITS	2x1 H-CLASS CC	1x1 H-CLASS CC
First Year Available	1/1/20xx	2033	2033
Maximum Capacity	MW	1,450	649
Minimum Capacity	MW	725	325
Operating Life	Yrs	50	50
Fixed O&M	$/kW-yr (2025)	35.75	42.00
FOM Escalation Rate (Nominal)	%	1.58%	1.69%
Variable O&M	$/MWh (2025)	2.28	2.68
VOM Escalation Rate (Nominal)	%	1.79%	1.86%
Transmission Network Upgrade Cost	$/kW (2025)	117.45	117.45
Capital Cost (in First Year Available)	$/kW (2022)	1,531	1,806
Capital Cost Escalation Rate (Nominal)	%	1.74%	1.74%
DLOL Summer (2026 | 2040)	%	95% | 95%	
DLOL Winter (2026 | 2040)	%	77% | 77%	
Annual Forced Outage Rate	%	5%	5%
Annual Maintenance	%	10%	10%
Heat Rate	Btu/kWh	6,196	6,068

Combustion Turbine

CT units can provide fast response to peaking power demand. They have quick ramp rates and greater operational flexibility than CC units. Depending on configuration and

technology type, they generally have higher heat rates than CC units, as latent heat is not recovered in a steam generator.

Two classes of CT were included in portfolio modeling: an F-class CT and a group of five RICE units. The F-Class CT has a nominal output of 233 MW, whereas the RICE units have a nominal output of 85 MW. Tradeoffs exist between these two units as the CT unit is of lower capital cost in $/kW, but the RICE unit exhibits greater operational flexibility and efficiency. Both are assumed to be available in 2031 as the development timeline is accelerated compared to larger CC units. Additional operational and cost characteristics are shown in Table 16-6.

Table 16-6: Combustion turbine resource characteristics

DESCRIPTION	UNITS	F-CLASS CT	RICE
First Year Available	1/1/20xx	2031	2031
Maximum Capacity	MW	233	85
Minimum Capacity	MW	37	12
Operating Life	Yrs	50	30
Fixed O&M	$/kW-yr (2025)	27.68	55.00
FOM Escalation Rate (Nominal)	%	1.86%	1.86%
Variable O&M	$/MWh (2025)	7.47	7.50
VOM Escalation Rate (Nominal)	%	2.50%	2.50%
Transmission Network Upgrade Cost	$/kW (2025)	117.45	117.45
Capital Cost (in First Year Available)	$/kW (2022)	1,460	2,866
Capital Cost Escalation Rate (Nominal)	%	1.58%	1.58%
DLOL Summer (2026 | 2040)	%	95% | 95%	
DLOL Winter (2026 | 2040)	%	77% | 77%	
Annual Forced Outage Rate	%	5%	2%
Annual Maintenance	%	7%	3%
Heat Rate	Btu/kWh	9,717	8,102

Advanced Clean Baseload Technologies

To support evaluation of resources capable of meeting capacity, energy, and clean energy needs, the Company evaluated advanced clean baseload technologies, including natural gas CC with CCS, new large-scale nuclear, and geothermal. These resources are capital intensive but can provide firm, dispatchable capacity and around-the-clock clean energy that complements variable renewable and storage resources.

Geothermal was screened out before cost characterization due to limited regional viability. New large-scale nuclear was retained in the resource screen and characterized using NREL's large nuclear prototype, which represents advanced nuclear light-water and non-light-water technologies. Nuclear was assumed to become available in 2040, reflecting long development and construction lead times and regulatory approval processes.

The CC with CCS is modeled in the same configuration as a conventional 2x1 CC, with an additional parasitic load and heat rate penalty and cost premium required by the CCS process. It is assumed to be available in the same timeframe as a conventional CC unit, although additional permitting for sequestration siting is necessary. Operational and cost characteristics for CC + CCS and Nuclear can be found in Table 16-7.

Table 16-7: Advanced base load resource characteristics

DESCRIPTION	UNITS	2x1 H-CLASS CC + CCS	NUCLEAR
First Year Available	1/1/20xx	2033	2040
Maximum Capacity	MW	1,233	1,000
Minimum Capacity	MW	616	150
Operating Life	Yrs	50	60
Fixed O&M	$/kW-yr (2025)	67.09	219.69
FOM Escalation Rate (Nominal)	%	0.93%	2.50%
Variable O&M	$/MWh (2025)	5.02	3.66
VOM Escalation Rate (Nominal)	%	1.40%	2.50%
Transmission Network Upgrade Cost	$/kW (2025)	117.45	117.45
Capital Cost (in First Year Available)	$/kW (2022)	2,817	14,295
Capital Cost Escalation Rate (Nominal)	%	1.34%	1.47%
DLOL Summer (2026 | 2040)	%	95% | 95%	94% | 94%
DLOL Winter (2026 | 2040)	%	92% | 91%	90% | 87%
Annual Forced Outage Rate	%	5%	3%
Annual Maintenance	%	10%	6%
Heat Rate	Btu/kWh	7,220	10,497

16.4.3 Renewable Generation

The Company evaluated wind and solar PV resources as potential renewable additions. Wind resources include representative in-state land-based wind and offshore wind options, while solar PV is represented as a generic utility-scale resource as well as distributed solar PV. Resource availability assumptions reflect commercially achievable development timelines, with new renewable resources first available beginning in 2029 to account for site acquisition, permitting, interconnection studies, and construction.

Although wind and solar resources have low operating costs and no direct fuel expense, renewable development remains subject to several uncertainties. These include permitting and siting constraints, interconnection queue delays, network upgrade requirements, supply chain variability, and limits on achievable project scale at specific sites. In addition, wind and solar output varies with weather, time of day, and season, which affects capacity accreditation and contribution to reliability during peak system periods. These considerations were reflected through build constraints, hourly production curves, and capacity accreditation assumptions and evaluated further in the capacity expansion modeling.

Table 16-8 and Table 16-9 summarize the cost, performance, and availability assumptions used to represent wind and solar resources in the Company's portfolio modeling.

Table 16-8: Wind resource characteristics

DESCRIPTION	UNITS	IN-STATE	OFFSHORE
First Year Available	1/1/20xx	2029	2029
Maximum Annual Capacity Additions	MW/yr	300	300
Minimum Project Size	MW	100	100
Operating Life	Yrs	30	30
Fixed O&M	$/kW-yr (2022)	40.25	89.24
FOM Escalation Rate (Real)	%	-0.45%	-0.39%
Transmission Network Upgrade Cost	$/kW (2022)	117.45	117.45
Capital Cost (in First Year Available)	$/kW (2022)	1,486	5,698
Capital Cost Escalation Rate (Real)	%	-0.77%	-2.84%
Capacity Factor	%	30%	35%
DLOL Summer (2026 | 2040)	%	15% | 11%	15% | 11%
DLOL Winter (2026 | 2040)	%	23%| 13%	23%| 13%

Table 16-9: Solar PV resource characteristics

DESCRIPTION	UNITS	UTILITY-SCALE SOLAR PV	DISTRIBUTED SOLAR PV
First Year Available	1/1/20xx	2029	2029
Maximum Annual Capacity Additions	MW/yr	1,000	25
Minimum Project Size	MW	50	0.15
Operating Life	Yrs	35	35
Fixed O&M	$/kW-yr (2022)	21.15	N/A
FOM Escalation Rate (Real)	%	-1.41%	N/A
Transmission Network Upgrade Cost	$/kW (2022)	117.45	N/A
Capital Cost (in First Year Available)	$/kW (2022)	1,216	N/A
Capital Cost Escalation Rate (Real)	%	-2.54%	N/A
Capacity Factor	%	22%	22%
DLOL Summer (2026 | 2040)	%	38% | 2.64%	38% | 2.64%
DLOL Winter (2026 | 2040)	%	19% | 0.1%	19% | 0.1%

16.4.4 New Storage Technologies

Energy storage cost and performance assumptions were developed using NREL's 2024 ATB Medium Technology Cost Scenario, supplemented by technology-specific assumptions and Company modeling inputs. The Company evaluated 4-hour, 10-hour, and 100-hour storage resources to capture a range of potential portfolio roles, including short-duration capacity, energy shifting, and longer-duration reliability support. The 4-hour and 10-hour resources are represented as lithium-ion battery storage with an assumed 20-year operating life and 85% round-trip efficiency, while the 100-hour resource reflects a longer-duration storage technology with a 30-year operating life and lower round-trip efficiency.

All storage resources are assumed to be first available beginning in 2029, reflecting expected timelines for siting, permitting, interconnection studies, procurement, and construction. Resource size limits were included to reflect commercially achievable project scales and practical development constraints.

Table 16-10 summarizes the cost, performance, degradation, and availability assumptions used to represent storage resources in the Company's portfolio modeling.

Table 16-10: Storage resource characteristics

DESCRIPTION	UNITS	4-HOUR	10-HOUR	[CONFIDENTIAL] [redacted]
First Year Available	1/1/20xx	2029	2029	[redacted]
Maximum Annual Capacity Additions	MW/yr	1,000	1,000	[redacted]
Minimum Capacity	MW	50	50	[redacted]
Round-Trip Efficiency	%	85%	85%	[redacted]
Duration	Hrs	4	10	[redacted]
Operating Life	Yrs	20	20	[redacted]
Fixed O&M	$/kW-yr (2022)	47.74	47.74	[redacted]
FOM Escalation Rate (Real)	%	-1.3%	-1.3%	[redacted]
Transmission Network Upgrade Cost	$/kW (2022)	117.45	117.45	[redacted]
Capital Cost (in First Year Available)	$/kW (2022)	1,687	3,698	[redacted]
Capital Cost Escalation Rate (Real)	%	-1%	-1%	[redacted]
DLOL Summer (2026 | 2040)	%	67% | 87%	67% | 87%	[redacted]
DLOL Winter (2026 | 2040)	%	85% | 51%	85% | 51%	[redacted] [END CONFIDENTIAL]

16.5 Levelized Cost of Energy Screening

As part of the resource screening process, the Company conducted a preliminary economic comparison of viable supply-side resource technologies using LCOE and LCOA. This analysis was performed after initial technical screening and prior to portfolio optimization to inform which technologies were reasonable candidates to be offered into the Aurora capacity expansion model and to aid in interpreting model results.

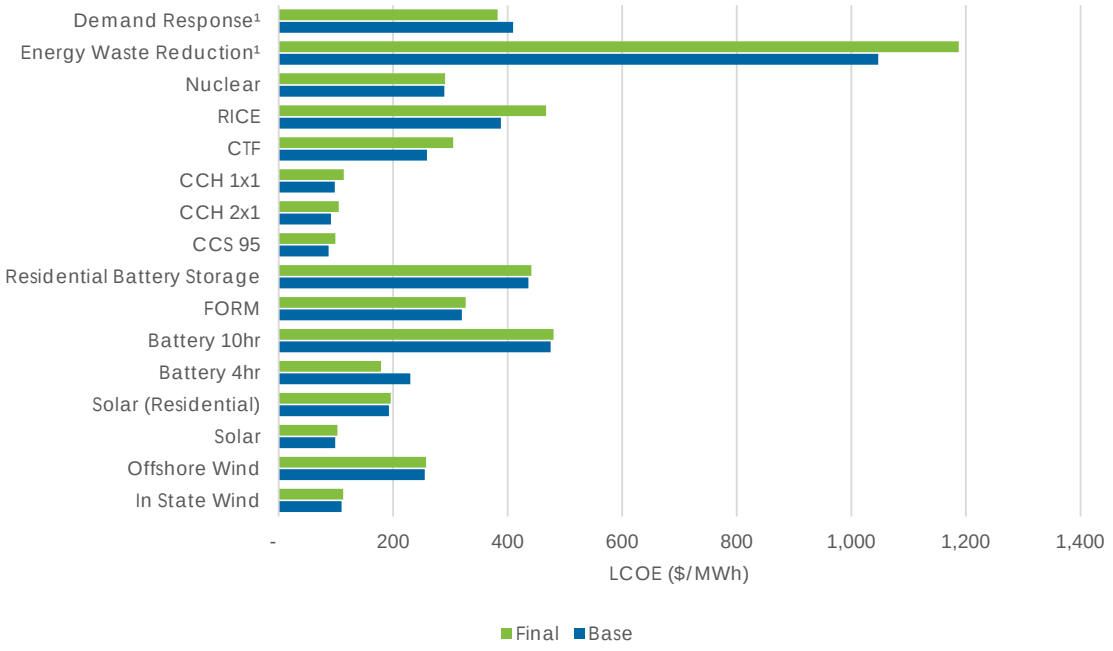
LCOE measures the levelized cost per megawatt-hour of electricity produced over a resource's life, incorporating capital costs, fixed and variable O&M costs, fuel, applicable network upgrade costs, and offsetting revenues such as federal tax credits. Costs are discounted and levelized into a single representative value and compared against expected lifetime energy production. LCOE provides a consistent basis for comparing energy-producing resources but can overstate the apparent cost of capacity-oriented technologies that are designed to operate infrequently. In addition, LCOE does not reflect the timing of energy delivery, correlated performance during peak or high-risk system conditions, or interactions with other resources in a portfolio, which are critical considerations for system reliability and are evaluated through capacity expansion modeling rather than screening metrics.
To address this limitation, the Company also evaluated resources using LCOA. LCOA uses the same levelized cost numerator as LCOE but divides by energy availability rather than actual energy production, recognizing the value of resources that may not frequently dispatch but are available to support reliability during critical hours.

The Company initially developed screening metrics using the best available assumptions at the outset of the IRP process and subsequently refined those assumptions as additional information became available. Key updates included

incorporating Fall 2025 Request for Proposal (RFP) pricing for four-hour battery storage resources, updated turbine pricing information for generic natural gas technologies, revisions to EWR assumptions reflecting updated embedded savings and incremental resource potential, and updates to DR assumptions related to line loss treatment. The final screening results therefore reflect assumptions that are consistent with those used in the subsequent portfolio modeling and evaluation process.

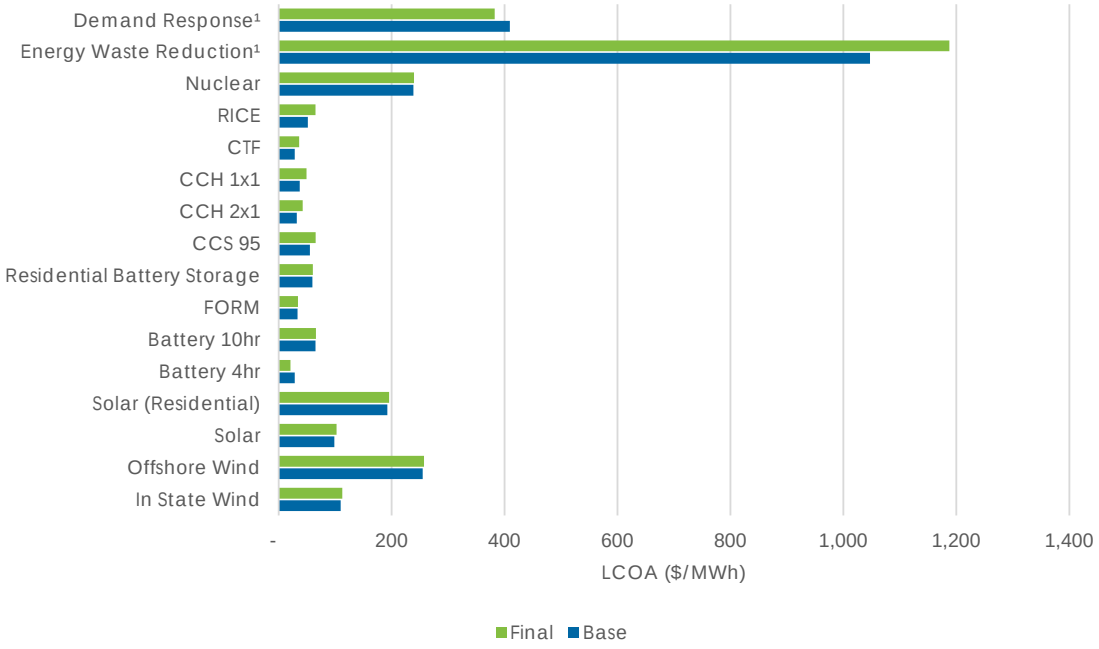
Figure 16-1 and Figure 16-2 compare the initial and final LCOE and LCOA screening results for 2031, illustrating the relative economics of the technologies considered in the screening analysis. Consistent with expectations, energy efficiency, renewable resources, and battery storage generally exhibit among the lowest LCOE values, while dispatchable thermal resources exhibit higher LCOE values due to their lower expected utilization and greater reliance on capacity value. When evaluated on an LCOA basis, the relative position of several dispatchable technologies improves, reflecting their ability to provide dependable capacity and support system reliability. Taken together, the results demonstrate the importance of evaluating both energy and capacity value when screening resource alternatives and support the continued consideration of a diverse set of technologies in the portfolio modeling process.

Figure 16-1: LOCE values by technology



1) These resources show their annual cost and not the levelized cost for a specific build year.

Figure 16-2: LCOA values by technology



1) These resources show their annual cost and not the levelized cost for a specific build year.

LCOE and LCOA were used solely as screening and interpretive tools. Neither metric was used as an input to the Aurora optimization, and neither influenced portfolio selection directly. Final resource selections were determined entirely through least-cost system optimization subject to reliability, policy, and operational constraints.

Based on the combined technical review and LCOE/LCOA screening, the Company focused its modeling on natural gas CTs, natural gas CC units with and without carbon capture, RICE units, nuclear resources, wind, solar, and battery storage. New coal resources and other technologies were not advanced due to unfavorable economics, limited commercial readiness, or inconsistency with Michigan's clean energy requirements.

16.6 Evaluation of Specific Resources

The resource screening process evaluated a broad range of supply-side resource options capable of providing energy, capacity, renewable energy, and clean energy attributes. As the planning process progressed, the Company identified several executable resource opportunities that aligned with the needs identified through the IRP, including the proposed Karn and Thetford CT projects, a new PPA with MCV, and [CONFIDENTIAL] [redacted] [END CONFIDENTIAL].

These resources were selected for further evaluation because they provide distinct combinations of accredited capacity, dispatchable energy, reliability benefits, and clean energy attributes. The Karn and Thetford projects provide dispatchable capacity

and operational flexibility needed to support reliability as existing resources retire and customer demand grows. MCV preserves dispatchable energy and capacity from an existing CC facility, while [CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

To support comparison among these executable resource options, the Company developed project-specific LCOE and LCOA estimates, which are presented below.

Table 16-11: LCOE and LCOA values for specific resources [CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

The project-specific results illustrate the differing roles of the executable resource options. The Karn and Thetford projects are primarily capacity-oriented resources that provide dispatchable capacity and operational flexibility to support reliability and resource adequacy needs. In contrast, MCV and [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] provide substantial annual energy production in addition to accredited capacity. As a result, the relative performance of these resources differs across the LCOE and LCOA metrics, highlighting the importance of evaluating both energy and capacity value when comparing resource alternatives.

16.7 Additional Resources

In addition to the supply-side resources advanced through the technical and economic screening process, the Company also considered a set of additional resource categories that play important roles in long-term planning but were not modeled as selectable new-build options in the capacity expansion analysis. These resources are discussed at a high level in this section, with detailed treatment provided in the relevant IRP sections.

16.7.1 Distributed Generation

DG resources were not included as selectable options within the Aurora capacity expansion model. DG adoption is accounted for directly in the Company's load forecast and net energy requirements rather than treated as a controllable supply-side alternative. This approach reflects both the customer-driven nature of DG deployment and the Company's limited ability to rely on DG to meet firm capacity needs.

16.7.2 Demand-Side Resources

Demand-side resources, including EWR and DR programs, are not screened alongside supply-side generation options using economic metrics such as LCOE or LCOA. Instead, these resources are developed, modeled, and evaluated separately, consistent with Commission guidance and prior IRP practice. Demand-side resource availability, costs, and performance assumptions are described in Section 8, Demand-Side Resources, and these resources are incorporated directly into the capacity expansion modeling as selectable options where applicable.

16.7.3 Market-Based Supply Options

The Company did not include long-term reliance on capacity market purchases as a resource option to address the identified capacity need. Following the enactment of the 2016 Energy Law, capacity market purchases are intended to address short-term or transitional reliability needs and are not a dependable solution for sustained, multi-year capacity shortfalls. Continued reliance on unspecified market capacity would be inconsistent with the Company's obligation to demonstrate a concrete and executable strategy for meeting the SRM requirements established under Act 341. Market purchases therefore were not advanced as a long-term planning alternative in this IRP.

16.7.4 Long-Term Power Purchase Agreements

Existing long-term PPAs are treated as part of the Company's existing resource portfolio and were included in the resource baseline used for capacity expansion modeling. The IRP assumes that existing PPAs are renewed at their current levels and terms unless otherwise specified. The treatment of existing PPAs, including expiration dates and renewal assumptions, is described in detail in Section 7, Existing Supply-Side Resources.

16.7.5 Transmission Resources

Transmission remains an important component of the Company's overall reliability strategy but is not screened as a generation alternative using LCOE or LCOA metrics. Instead, transmission capabilities, limitations, and network upgrade costs are incorporated into the modeling framework as constraints and cost adders affecting resource viability and deliverability. A detailed discussion of transmission assumptions, including import and export capability and anticipated network upgrade impacts, is provided in Section 14, Transmission Analysis.

16.8 Summary of Alternatives Advanced to Portfolio Modeling

Table 16-12 presents the final candidate resource selection resulting from the resource screening process. The table summarizes the technologies evaluated, the determination for each resource, and the primary rationale for inclusion or exclusion. Resources selected for inclusion were carried forward as candidate options in the

Company's portfolio modeling, while excluded resources were not modeled further due to cost, maturity, siting, or regional feasibility considerations.

Table 16-12: Final resource screening determination

CATEGORY	TECHNOLOGIES CONSIDERED	DETERMINATION	REASONING
Dispatchable Firm Generation	2x1 H-Class CC	Include	Moderate cost, high accreditation resource
	1x1 H-Class CC	Include	Moderate cost, high accreditation resource
	1x0 F-class CT	Include	Low cost, high accreditation, flexible resource
	5x0 Reciprocating Engine	Include	Moderate cost, high accreditation, flexible resource
	2x1 H-Class CC + CCS	Include	High cost, high accreditation, clean baseload resource
	New Large-scale Nuclear	Include	Firm, carbon-free capacity with high accreditation, offset by high costs, long lead times, and execution risk.
	SMR Nuclear	Exclude	Limited commercial maturity and long development timeline
	Micro Turbine	Exclude	Limited scalability and unfavorable economics relative to alternatives
	Home Generators	Exclude	High cost, lack of coordinated dispatch
Renewable Generation	In-State Wind	Include	Moderate cost, energy rich resource, with good regional suitability
	Offshore Wind	Exclude	High cost resource with limited regional suitability in the Great Lakes
	Solar PV	Include	Low cost, energy rich resource with moderate regional suitability
	Biomass	Exclude	Limited fuel supply and scalability
	Behind the Meter Biogas	Exclude	Limited methane availability and scalability
	Landfill Gas	Exclude	Limited methane capture availability and scalability
	CHP	Exclude	Requirement for site-specific opportunities, cannot be modeled generically
	Geothermal	Exclude	Limited regional viability, lack of commercially proven advanced geothermal options
Energy Storage	4-Hour	Include	Low cost, capacity rich resource, enables better round-the-clock renewable target compliance
	10-Hour	Include	Moderate cost, capacity rich resource, enables better round-the-clock renewable target compliance
	100-Hour	Include	Moderate cost, capacity rich resource, enables better round-the-clock renewable target compliance
	Compressed Air	Exclude	Low commercial maturity
	Flywheel	Exclude	Low commercial maturity
	Thermal	Exclude	Low commercial maturity
	Fuel Cell	Exclude	Uncertain fuel availability, limited scalability
	Pumped Hydro	Exclude	Limited siting available for generic expansion
Existing Resource /	MCV PPA 2030-2040	Include	Existing operational resource providing capacity and energy benefits without new-build development risk

CATEGORY	TECHNOLOGIES CONSIDERED	DETERMINATION	REASONING
Procurement Options			
Demand-Side Resources & VPPs	EWR	Include (modeled separately)	Evaluated through demand-side potential studies and incorporated directly into modeling assumptions
	DR	Include (modeled separately)	Provides capacity value and load flexibility; evaluated separately from supply-side resources
	CVR	Include (modeled separately)	Reduces system demand through voltage optimization
	DG	Include (load forecast adjustment)	Reflected in load forecast rather than modeled as a selectable supply-side resource
	EV Charging / Managed Charging	Include (modeled separately)	Evaluated through demand-side modeling assumptions
	BTM Batteries / VPPs	Include (modeled separately)	Evaluated separately as distributed demand-side resources
Identified Specific Resources	Karn CT	Include	High accreditation, dispatchable capacity resource identified to address reliability and resource adequacy needs
	Thetford CT	Include	
	MCV PPA 2030-2040	Include	Existing operational resource providing dispatchable energy and capacity without new-build development risk
	[CONFIDENTIAL] [redacted]	[redacted]	[redacted] [END CONFIDENTIAL]

Modeling Results

Section 17

17 Modeling Results

17.1 Portfolio Design Strategy

The Company's portfolio design strategy was developed to identify a resource plan that provides the best overall balance of reliability, affordability, clean energy progress, diversity, and implementation feasibility over the planning horizon. Portfolio development incorporated the Company's planning objectives, load forecasts, resource assumptions, and applicable regulatory requirements, including Michigan's clean energy, renewable energy, EWR, and energy storage requirements.

The Company's modeling framework evaluated a broad range of supply-side and demand-side resources, including existing resources, renewable generation, battery storage, demand-side resources, VPPs, nuclear resources, natural gas resources, and emerging technologies. Portfolios were evaluated across scenarios and sensitivities reflecting uncertainty in load growth, fuel prices, technology costs, transmission capability, resource availability, electrification, and regulatory requirements

While economic optimization was a key component of the analysis, portfolio selection was not based solely on minimizing modeled costs. The Company also considered reliability and resource adequacy, affordability and customer cost impacts, regulatory compliance, portfolio diversity and resilience, technology maturity and execution risk, and flexibility to respond to changing market conditions and customer demand.

The Company used optimization modeling to identify resource portfolios capable of meeting PRMR and hourly energy needs at least cost. These portfolios were then evaluated through scenario, sensitivity, and risk analyses to assess their performance across a range of potential future conditions rather than under a single forecast.

The portfolio designs presented in this section were developed using the assumptions, resource options, forecasts, and constraints described elsewhere in this IRP. Additional detail on the modeling framework is provided in Section 5, Analytical Approach, with supporting assumptions discussed in the relevant sections of the filing. This section focuses on portfolio evaluation results and the relative performance of the portfolios across the scenarios and sensitivities considered.

17.2 Phase 1: Optimized Portfolio Designs

The Company developed and evaluated a series of portfolio designs to assess alternative resource strategies, load growth outcomes, and implementation pathways. These portfolio designs were developed using the BAU planning assumptions and differ primarily with respect to resource availability, required resource additions, and incremental economic development load assumptions. Following development, applicable portfolios were evaluated under additional scenarios and sensitivities to assess performance under a broad range of future conditions.

The portfolio designs were developed in two phases. First, the Company developed a set of optimized portfolios to identify economically attractive resource additions and assess the value of specific resource options. These *optimization* portfolios were used to

understand how resource selections change under different assumptions regarding resource availability. Second, insights from the optimization modeling were used to develop a series of *executable* portfolios, including plans at the current (BAU), probable (PLG), and high (HLG) levels. These planning portfolios were designed to evaluate specific resource strategies and load growth assumptions identified as most relevant to the Company's long-term planning objectives.

17.2.1 Phase 1: Optimization Phase Portfolio Designs

The optimization portfolios were designed to answer a series of focused planning questions regarding resource selection and portfolio economics. While not all portfolio designs considered during the optimization phase are presented in this report, the summarized portfolios allow the company to draw insights based on what the Aurora model selected as resource additions subject to the assumptions associated with each design.

Portfolio design 1 (PD1) serves as the baseline optimization. Under this design, Aurora is allowed to select from the full set of eligible supply-side and demand-side resources needed to satisfy PRMR, clean energy requirements, renewable energy requirements, and forecasted customer demand. The resulting portfolio provides a benchmark against which other portfolio designs can be compared.

Portfolio design 3 (PD3) evaluates the economic value of the proposed MCV contract by requiring its inclusion within the optimized portfolio. Comparing the results of PD3 against PD1 allows the Company to evaluate the costs, benefits, and resource planning implications associated with the MCV agreement.

Portfolio design 4 (PD4) expands the set of resources available to Aurora by introducing additional special prototype offerings, including enhanced VPP resources, DG resources, offshore wind, and alternative thermal technologies. This portfolio was developed to evaluate whether broadening the set of available resource options meaningfully changes the optimal resource plan.

17.2.2 Portfolio Design Summary

The portfolio designs varied specific resource assumptions to assess the value of key resource decisions and identify recurring patterns in resource additions, technology selections, and portfolio performance across a range of future conditions. As shown in Table 17-1, the primary variables evaluated during this phase included the potential value of the MCV agreement and the impact of expanding the set of candidate resources available to the model.

Table 17-1: Optimized portfolio design summary

DESIGN	PORTFOLIO TYPE	INCREMENTAL LOAD (MW)[57]	MCV	KARN / THETFORD	[CONFIDENTIAL] [redacted] [END CONFIDENTIAL]	CCS	PURPOSE
1	Optimization	n/a	●	●	●	●	Baseline least-cost optimization
3	Optimization	n/a	✓	●	●	●	Evaluate MCV
4*	Optimization	n/a	●	●	●	●	Evaluate prototype resources

*Portfolio 4 includes additional prototype resources, including enhanced VPP resources, DG resources, offshore wind, and alternative thermal technologies.
✓ **Required**: Resource is a fixed component of the portfolio design and is included before optimization. Aurora optimizes the remainder of the portfolio around the resource.
● **Available**: Resource is available for Aurora to select but is not required. Inclusion depends on optimization results.

17.2.3 Phase 1 Scenario and Sensitivity Analysis

For the first phase of modeling, the planning-information phase, most scenarios and sensitivities were evaluated across PDs 1, 3, and 4. These model runs were constructed and considered to assess the relative economics and risk of different new resource addition combinations, timing, and amounts.

The Phase 1 analysis evaluated PDs 1, 3, and 4 across the BAU, ALG, PCC, and MSO scenarios, including sensitivities related to load growth, renewable availability, DG, natural gas prices, transmission capability, transmission network upgrade costs, and other key planning uncertainties. The BAU, ALG, and PCC scenarios also included sensitivities evaluating accelerated retirement or conversion pathways for Zeeland and Covert, as well as variations in generation technology costs. Because the purpose of each modeling phase differed, not every portfolio was evaluated in every scenario or sensitivity, and not every sensitivity was applicable to every portfolio.

The following tables show the NPV of the phase 1 PDs 1, 3, and 4 under the four scenarios, BAU, ALG, PCC, and MSO. Resource-specific performance assumptions used in the risk assessment, including technology operating characteristics, capacity factors, availability assumptions, and load factors, are described in Section 15, Resource Screen.

[57] PDs 1, 3, and 4 do not include approximately 91 MW of load associated with a subsequently identified large customer. This load is incorporated into portfolio designs 95 through 99, with portfolio designs 96 and 99 including additional incremental large-load growth beyond the 91 MW adjustment. As a result, the approximately 1,600 MW of incremental load reflected in the PCA and the approximately 2,300 MW reflected in Alternate Plan 1 are not directly comparable to incremental load values presented elsewhere in this IRP because they are based on different starting assumptions.

Table 17-2: Net Present Value (NPV) of Business-as-Usual (BAU) sensitivities

BAU NPV RESULTS ($MILLION)			
SENSITIVITY DESCRIPTION	BASE	MIDLAND COGENERATION VENTURE NEW CONTRACT	SPECIAL PROTOTYPE OFFERINGS
"Current" Load Forecast from June 2025	47,452.73	46,766.97	47,441.64
"Current" Load Forecast from June 2025 + 500 MW ED	50,497.69	49,735.13	50,479.14
"Current" Load Forecast from June 2025 + 1000 MW ED	53,642.80	52,892.08	53,634.89
"Current" Load Forecast from June 2025 + 1500 MW ED	56,738.19	55,915.39	56,836.89
"Current" Load Forecast from June 2025 + 2000 MW ED	60,115.36	59,397.11	60,242.12
"Current" Load Forecast from June 2025 + 2500 MW ED	63,700.13	63,032.58	63,809.99
"Current" Load Forecast from June 2025 + 3000 MW ED	67,314.98	66,779.71	67,432.01
"Current" Load Forecast from June 2025 + 3500 MW ED	76,083.42	75,588.17	75,461.70
Capacity Import Limit/Capacity Export Limit "Low" Sensitivity	47,482.77	46,792.75	47,470.77
Capacity Import Limit/Capacity Export Limit "High" Sensitivity	47,407.75	46,667.61	47,400.50
Transmission Network Upgrade Costs Increase	48,797.18	47,984.92	48,785.67
Zeeland Plant Early (2040) Retirement	47,908.44	47,204.86	47,901.72
Covert Plant Early (2040) Retirement	47,993.06	47,256.45	48,037.12
Zeeland Plant + CCS Retrofit	49,044.31	48,263.00	49,032.95
Renewable, Storage and Natural Gas Resource Cost Increase	54,599.55	52,843.92	54,586.97
Natural Gas Resource Cost Increase	48,908.92	48,128.40	48,881.95
DG Solar Outflow Cost			47,395.61
CIL High Sensitivity with METC update	47,429.96	46,676.49	47,416.03
High Gas Price	54,643.00		
2% EWR	90,244.25		
2.5% EWR	114,223.48		
Atypical Weather	51,194.81		
HLG	50,266.49		
Low EV Load	47,193.02		

Table 17-3: NPV of Aggressive Load Growth (ALG) sensitivities

ALG NPV RESULTS ($MILLION)			
SENSITIVITY DESCRIPTION	BASE	MIDLAND COGENERATION VENTURE NEW CONTRACT	SPECIAL PROTOTYPE OFFERINGS
Aggressive Load	69,382.26	68,975.17	69,502.95
"Current" Load Forecast from June 2025 + 500 MW ED	50,353.61	49,563.60	50,345.96

ALG NPV RESULTS ($MILLION)			
SENSITIVITY DESCRIPTION	BASE	MIDLAND COGENERATION VENTURE NEW CONTRACT	SPECIAL PROTOTYPE OFFERINGS
"Current" Load Forecast from June 2025 + 1000 MW ED	53,294.91	52,491.40	53,284.08
"Current" Load Forecast from June 2025 + 1500 MW ED	56,347.00	55,543.91	56,438.51
"Current" Load Forecast from June 2025 + 2000 MW ED	59,642.93	58,876.17	59,768.66
"Current" Load Forecast from June 2025 + 2500 MW ED	63,113.22	62,374.60	63,216.01
"Current" Load Forecast from June 2025 + 3000 MW ED	66,374.31	65,733.94	66,478.87
"Current" Load Forecast from June 2025	47,437.34	46,596.91	47,427.52
CIL/CEL "Low" Sensitivity	69,445.75	69,020.99	69,565.73
CIL/CEL "High" Sensitivity	69,365.25	68,957.36	69,484.97
Transmission Network Upgrade Costs Increase	71,916.64	71,341.30	72,018.01
Zeeland Plant Early (2040) Retirement	69,923.42	69,502.87	70,046.48
Covert Plant Early (2040) Retirement	70,011.49	69,592.93	70,126.28
Zeeland Plant + CCS Retrofit	70,105.43	69,702.03	70,217.60
Renewable, Storage and Natural Gas Resource Cost Increase	82,129.45	81,310.49	82,217.80
Natural Gas Resource Cost Increase	72,097.80	71,412.58	72,203.06
DG Solar Outflow Cost			69,436.81
CIL High Sensitivity with METC update	69,368.60	68,960.36	69,489.63

Table 17-4: NPV of Physical Climate Change (PCC) sensitivities

PCC NPV RESULTS ($MILLION)			
SENSITIVITY DESCRIPTION	BASE	MIDLAND COGENERATION VENTURE NEW CONTRACT	SPECIAL PROTOTYPE OFFERINGS
"Current" Load Forecast from June 2025 + Electrification	66,749.18	66,500.47	64,626.70
"Current" Load Forecast from June 2025+Electrification+500 MW ED	70,703.92	70,698.59	68,668.92
"Current" Load Forecast from June 2025 + Electrification+1000 MW ED	77,598.21	77,331.67	72,631.04
"Current" Load Forecast from June 2025+Electrification+1500 MW ED	82,260.30	81,442.35	77,125.59
"Current" Load Forecast from June 2025+Electrification+2000 MW ED	96,191.01	85,211.77	84,222.03
"Current" Load Forecast from June 2025+Electrification+2500 MW ED	112,736.04	92,488.78	88,505.48
"Current" Load Forecast from June 2025 + Electrification+3000 MW ED	118,934.01	97,065.20	96,973.98
"Current" Load Forecast from June 2025 + Electrification+3500 MW ED	126,031.81	102,942.76	110,635.49
CIL/CEL "Low" Sensitivity	66,778.63	66,526.36	64,636.46
CIL/CEL "High" Sensitivity	66,720.57	66,481.92	64,625.51

PCC NPV RESULTS ($MILLION)			
SENSITIVITY DESCRIPTION	BASE	MIDLAND COGENERATION VENTURE NEW CONTRACT	SPECIAL PROTOTYPE OFFERINGS
Transmission Network Upgrade Costs Increase	68,719.01	68,448.21	66,481.92
Zeeland Plant Early (2040) Retirement	68,885.88	68,830.07	66,299.04
Covert Plant Early (2040) Retirement	69,854.42	69,789.64	66,953.98
Zeeland Plant + CCS Retrofit	67,289.23	66,829.95	65,567.38
Renewable, Storage and Natural Gas Resource Cost Increase	80,196.50	78,985.61	76,000.13
Natural Gas Resource Cost Increase	67,597.75	67,414.76	66,318.36
DG Solar Outflow Cost			64,615.05
CIL High Sensitivity with METC update	66,716.67	66,461.45	64,627.02

Table 17-5: NPV of MIRPP S1 (MSO) sensitivities

MSO NPV RESULTS ($MILLION) [58]		
SENSITIVITY DESCRIPTION	BASE	SPECIAL PROTOTYPE OFFERINGS
"Current" Load Forecast from June 2025 + Electrification	58,637.84	57,582.68
"Current" Load Forecast from June 2025+Electrification+500 MW ED	62,575.30	
"Current" Load Forecast from June 2025+Electrification+2000 MW ED	77,716.82	
"Current" Load Forecast from June 2025 + Electrification+3500 MW ED	92,921.46	
High Gas Price	61,052.01	
20% Renewable Reduction	61,046.22	
2.5% EWR	120,685.08	
Land-Based Renewable Cap	58,943.70	
DG 10%		57,881.52
DG 15%		58,106.98
DG 20%		58,361.40
Atypical Weather	61,843.08	

The Phase 1 scenario and sensitivity analysis was designed to evaluate portfolio performance across a broad range of future conditions and identify resource strategies that remained effective under uncertainty. One of the most consistent findings across the scenarios and sensitivities evaluated was the economic value of the MCV agreement. PD3, which includes the MCV agreement beginning in 2030, consistently produced lower NPVs than the comparable PD1 and PD4 cases, indicating that the agreement provides economic value across a wide range of future conditions. The analysis also provided insights regarding the effects of load growth, demand-side

[58] Only sensitivities required by the MPSC are reported for the MSO scenario.

resources, renewable development, transmission availability, and other key planning uncertainties. Additional discussion of these sensitivities is provided below.

Load Growth and Customer Demand

The load growth and customer demand sensitivities evaluated alternative large-load outcomes, economic development trajectories, and customer demand forecasts. Higher demand generally increased portfolio costs and accelerated the need for additional resources, while lower demand reduced or deferred certain additions. However, changes in demand did not result in a one-for-one change in portfolio capacity. Renewable energy, clean energy, and resource adequacy requirements remained important drivers across all load-growth outcomes, resulting in continued additions of renewable resources, storage, and dispatchable capacity. Changes in demand instead affected how and when those requirements were met, including the amount of renewable and storage capacity selected, the timing of larger dispatchable resources, and the relative reliance on CT, CC, and CCS resources. Overall, the sensitivities show that customer demand affects both the magnitude and sequencing of future resource needs, while reinforcing the value of a diverse portfolio capable of meeting energy, capacity, renewable, and clean energy requirements.

Energy Efficiency and DERs

The demand-side resource sensitivities evaluated higher levels of EWR and DG adoption. Distributed resources reduced system needs and lowered portfolio costs in certain cases, although those benefits generally diminished at higher penetration levels. The analysis also showed that achieving EWR levels above the base assumptions required increasingly costly program investments. As a result, while demand-side resources provide value and reduce future resource needs, they did not fully replace the need for supply-side resources in the optimized portfolios.

Renewable, Transmission, and Cost Uncertainty

The Company evaluated sensitivities related to renewable resource availability, transmission capability, transmission network upgrade costs, fuel prices, and future resource costs. Reduced renewable availability, higher transmission costs, and increased resource costs generally increased portfolio costs and reduced planning flexibility. However, these sensitivities did not fundamentally alter the resource strategy identified by the modeling. Renewable resources, storage, and dispatchable capacity continued to play important roles across the sensitivities evaluated, demonstrating the value of maintaining a diverse portfolio and continued access to renewable development opportunities and transmission infrastructure.

Existing Resource Value

The analysis also highlighted the value of existing resources and contractual arrangements. Earlier retirement of Zeeland and Covert generally increased portfolio costs by accelerating replacement resource needs. Similarly, PD3, which includes the MCV agreement beginning in 2030, consistently produced lower NPVs than the comparable PD1 and PD4 cases across the scenarios and

sensitivities evaluated. These results indicate that the MCV agreement provides economic value across a broad range of future conditions while supporting long-term reliability objectives.

Phase 1 demonstrated the value of the MCV agreement, highlighted the importance of firm accredited capacity, and showed that economic development load growth was a major driver of future resource needs. These findings, together with updated information regarding load growth, [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], CT development costs, and commercial resource opportunities, formed the basis for the executable portfolios evaluated in Phase 2.

17.3 Phase 2: Executable Portfolio Designs

Phase 1 identified resource strategies that performed well across a range of future conditions. Building on those findings, the Company developed a smaller set of executable portfolios reflecting updated load forecasts, project-specific resource information, and other planning assumptions available later in the IRP process. The resulting portfolios were evaluated using updated economic, reliability, market dependency, and risk analyses.

The executable portfolios differ primarily in their assumptions regarding economic development load growth and the inclusion of key resource decisions, including the MCV PPA, [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], Karn and Thetford CTs, and CCS resources. The portfolios align with the BAU, PLG, and HLG forecast outlooks described in Section 12.

To avoid implying a preferred outcome before completion of the evaluation process, the executable portfolios are described using neutral portfolio design labels throughout the Phase 2 analysis. The final designations of Support Plan, Alternate Plan, and PCA are assigned only after the portfolios have been evaluated across economic, reliability, market dependency, and risk criteria. Table 17-6 summarizes the executable portfolio designs evaluated in Phase 2.

Load Growth Plan (PD96) represents the Company's HLG outlook and evaluates the resource implications of substantially higher economic development load growth. This portfolio provides insight into how resource requirements change if additional large-load opportunities materialize beyond the Company's most likely forecast.

2021 IRP Plan (PD97) represents an updated version of the 2021 IRP PCA fully optimized portfolio under current conditions. This portfolio is evaluated using the Company's BAU load outlook and allows Aurora to select resources based solely on optimization results, providing a benchmark against which the other executable portfolios can be compared.

Current Load Plan (PD98) represents the Company's BAU load outlook and evaluates the same core resource strategy ultimately reflected in the probable load plan under lower economic development load growth assumptions. This portfolio isolates the effect of incremental large-load growth on future resource needs.

Probable Load Plan (PD99) represents the Company's PLG outlook and incorporates approximately 1,500 MW of signed and highly probable large-load additions together with the MCV PPA, [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], and Karn and Thetford CTs. Aurora optimizes the remaining resource additions over the planning horizon around these resource commitments.

Table 17-6: Executable portfolio design summary

DESIGN	PORTFOLIO TYPE	INCREMENTAL LOAD (MW)[59]	MCV	KARN / THETFORD	[CONFIDENTIAL] [redacted] [END CONFIDENTIAL]	CCS	PURPOSE
96	High Load Plan	~2,200	✓	✓	✓	◇	Higher load future
97	2021 IRP	~91	◇	◇	◇	◇	2021 IRP PCA optimized for current conditions
98	Current Load Plan	~91	✓	✓	✓	◇	BAU load future
99	Probable Load Plan	~1,500	✓	✓	✓	◇	Probable load future

✓ **Required**: Resource is a fixed component of the portfolio design and is included before optimization. Aurora optimizes the remainder of the portfolio around the resource.
◇ **Optimization Result**: Resource is available for selection in Aurora optimization modeling.

17.3.1 Executable Portfolio Build Plans

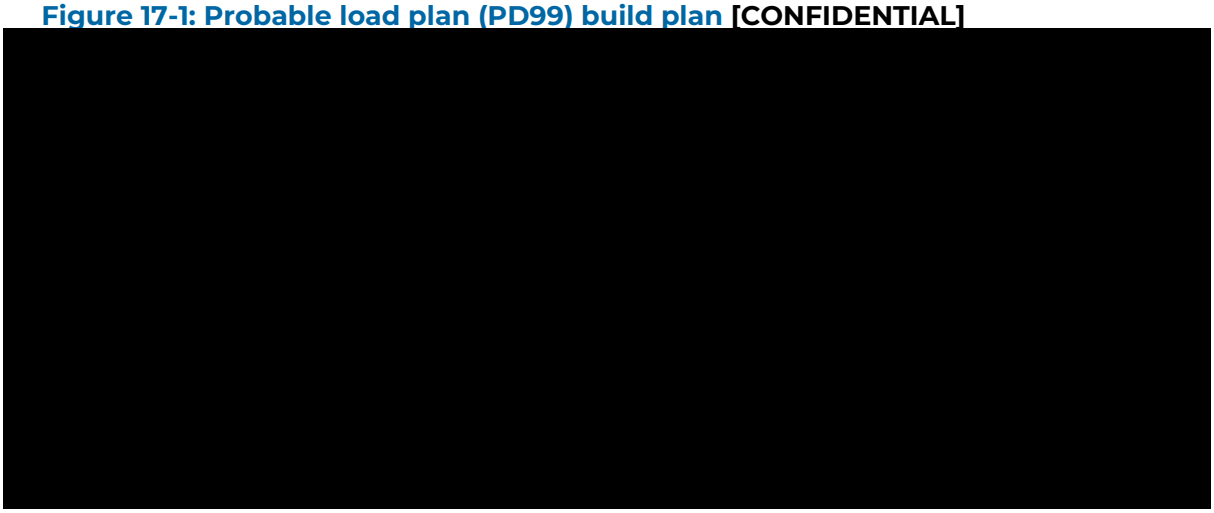
The figures below illustrate the resource build plans associated with the four executable portfolios. The build plans presented below summarize the timing of major resource additions and retirements for each executable portfolio. More detailed resource cost, performance, capacity factor, and operating assumption information for the modeled resources is provided in Section 15, Resource Screen.

Figure 17-1 shows the development pathway for the PD99 at the PLG load level, including approximately 1,500 MW of incremental economic development load. The portfolio includes the MCV agreement, [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], and new CTs at the Karn and Thetford sites, while allowing Aurora to optimize the remaining resource additions. The resulting build plan incorporates significant renewable and storage development to satisfy renewable energy, clean energy, and resource adequacy requirements while supporting the Company's anticipated customer growth. By 2050, the portfolio includes approximately 9,800 MW of new solar capacity, 2,700 MW of new wind capacity, and more than 3,200 MW of battery storage, supplemented by new thermal resources, including CT additions and a

[59] PDs 1, 3, and 4 do not include approximately 91 MW of load associated with a subsequently identified large customer. This load is incorporated into portfolio designs 95 through 99, with portfolio designs 96 and 99 including additional incremental large-load growth beyond the 91 MW adjustment. As a result, the approximately 1,500 MW of incremental load reflected in the PCA and the approximately 2,200 MW reflected in Alternate Plan 1 are not directly comparable to incremental load values presented elsewhere in this IRP because they are based on different starting assumptions.

CCS unit in 2040. Together, these resources provide a diverse portfolio that balances reliability, affordability, and compliance with evolving policy requirements.

Figure 17-1: Probable load plan (PD99) build plan [CONFIDENTIAL]



[END CONFIDENTIAL]

Figure 17-2 presents the build plan associated with high load plan (PD96), which assumes approximately 2,200 MW of incremental economic development load. Relative to PD99, this portfolio reflects a future in which customer growth exceeds the Company's expected load outlook, resulting in additional renewable, storage, and capacity resources over the planning horizon. By 2050, PD96 portfolio includes approximately 272 MW more total capacity than the PCA, driven primarily by the addition of a second CCS unit of roughly 1,200 MW in 2035 and approximately 860 MW of incremental battery storage capacity. The figure demonstrates how resource requirements generally scale with increasing demand while maintaining compliance with renewable energy, clean energy, and reliability requirements.

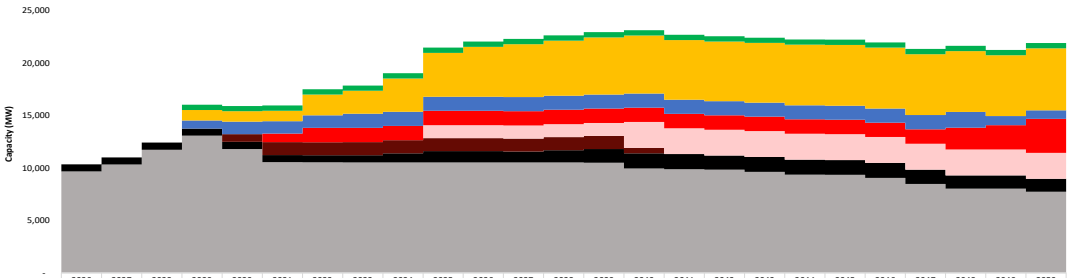
Figure 17-2: High load plan (PD96) build plan [CONFIDENTIAL]



[END CONFIDENTIAL]

Figure 17-3 presents the build plan for the 2021 IRP plan (PD97). This portfolio serves as a reference case that reflects how the Company's resource plan would evolve under current planning assumptions if it were developed without the specific resource decisions incorporated into the PD96, PD98, and PD99. PD97 assumes current load levels and allows Aurora to optimize resource additions using updated assumptions regarding resource costs, accreditation, transmission capability, renewable and clean energy requirements, and reliability standards. It is intended to demonstrate what the Company's resource plan would look like if the 2021 IRP strategy were re-optimized using today's assumptions, policies, costs, load forecasts, reliability standards, and resource opportunities. Relative to PD99, PD97 includes approximately 6,560 MW less renewable capacity and 788 MW less battery storage capacity by 2050. In addition, the portfolio adds CCS resources in both 2035 and 2040, compared to a single CCS addition in 2040 in the PCA. [CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Figure 17-3: 2021 IRP (PD97) build plan



	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
New Wind	-	-	-	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
New Solar	-	-	-	1,000	1,000	1,000	1,988	2,182	3,182	4,182	4,760	5,048	5,252	5,441	5,534	5,689	5,689	5,689	5,771	5,802	5,802	5,802	5,802	5,802	5,912
New Battery Storage	-	-	-	769	1,186	1,186	1,186	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,363	1,499	868	814
New CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New CT	-	-	-	-	-	806	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	2,074	2,307	3,239
New NGCC+CCS	-	-	-	-	-	-	-	-	-	1,233	1,233	1,233	1,233	1,233	2,466	2,466	2,466	2,466	2,466	2,466	2,466	2,466	2,466	2,466	2,466
New Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MCV New Contract	-	-	-	-	727	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240	515	-	-	-	-	-	-	-	-	-	-
VPP (New Demand Response)	675	676	679	682	682	679	679	684	867	1,068	1,073	1,038	1,170	1,312	1,448	1,442	1,347	1,413	1,429	1,400	1,433	1,359	1,274	1,274	1,232
Existing Portfolio	9,673	10,332	11,735	13,077	11,810	10,550	10,535	10,531	10,531	10,531	10,531	10,531	10,530	10,501	9,949	9,881	9,835	9,635	9,371	9,352	9,052	8,477	8,028	8,027	7,737
Total Capacity	10,348	11,008	12,414	16,028	15,904	15,961	17,502	17,850	19,033	21,466	22,050	22,302	22,638	22,939	23,125	22,689	22,549	22,415	22,249	22,233	21,966	21,343	21,643	21,245	21,900

Figure 17-4 presents the resource build plan for current load plan (PD98), which reflects substantially lower economic development load growth than assumed in the PD99. This portfolio was developed to isolate the impact of forecasted customer growth on resource planning decisions by evaluating a resource strategy similar to PD99 under current load assumptions. Relative to PD99, the portfolio requires approximately 4,450 MW less renewable capacity and 788 MW less battery storage capacity by 2050. The portfolio also eliminates the new CC unit built in 2050 in PD99, while incorporating approximately 930 MW more CT capacity. These differences illustrate how lower load growth reduces the need for incremental energy and capacity resources while altering the least-cost mix of technologies used to satisfy reliability and policy requirements. The resulting portfolio provides a useful benchmark for understanding the influence of large-load growth on future resource needs.

Figure 17-4: Current load plan (PD98) build plan [CONFIDENTIAL]



[END CONFIDENTIAL]

Following development of the executable portfolios, the Company applied the updated planning assumptions consistently across the Support Plan, Alternate Plan, and Probable Load Plan portfolio evaluations. For the Probable Load Plan, which was ultimately selected as the PCA, the Company also incorporated updated load assumptions associated with the final planning outlook. These updates ensured that the economic, reliability, market dependency, and risk analyses reflected the most current information available during the IRP process.

17.3.2 Phase 2 Scenario and Sensitivity Analysis

The Company then evaluated the executable portfolios using only the scenarios and load forecasts relevant to each portfolio design. The 2021 IRP portfolio (PD97) was only evaluated on BAU current load sensitivities. The executable PD96 and PD98 plans, which represent the high load plan and current load plans, respectively, were only evaluated in the BAU and MSO scenarios at the corresponding load levels. Finally, the probable load plan, PD99, was similarly evaluated only in the BAU and MSO scenarios at the PLG load levels. As a result, the portfolios shown in Table 17-7 were developed to serve different levels of customer demand and are not directly comparable on a standalone cost basis. The most meaningful cost comparison is therefore among portfolios that share a common load forecast, including current load and the 2021 IRP portfolios.

To further evaluate the economic implications of the proposed Karn and Thetford CTs, the Company developed three versions of PD97, which is a re-optimized version of the Company's 2021 IRP strategy using current planning assumptions. During development of the executable portfolios, the Company obtained updated project-specific cost estimates for the Karn and Thetford CT facilities that were not available during the initial optimization phase. To understand the impact of this updated information, 2021 IRP(a) was evaluated using the lower end of the CT cost range, 2021 IRP(b) was evaluated using the upper end of the CT cost range, and 2021 IRP(c) was evaluated using the upper-end CT cost assumption while requiring inclusion of the Karn and Thetford CT facilities.

Additional information supporting the portfolio evaluation is provided elsewhere in this IRP. Detailed resource cost and performance assumptions, including resource capacity factors, accreditation assumptions, operating characteristics, and technology-specific load factors, are provided in Section 15, Resource Screen. Forecasts of energy, capacity, and fuel prices used in the modeling are described in Sections 11 and 14. Annual revenue requirement and customer rate impact analyses associated with the proposed resource plan are provided in Section 20, Rate Impact, Financial Information, and Affordability. Resource additions, retirements, and portfolio development pathways are presented through the portfolio build plans and supporting figures in this section.

Table 17-7 presents portfolio NPV results used for comparative evaluation. Additional annual revenue requirement, present value revenue requirement, and customer affordability metrics for the selected portfolio are provided in Section 20, Rate Impact, Financial Information, and Affordability.

Table 17-7: NPV results by portfolio

NPV RESULTS ($MILLION)						
PORTFOLIO NAME	PROBABLE LOAD PLAN (PD99)	HIGH LOAD PLAN (PD96)	CURRENT LOAD PLAN (PD98)	2021 IRP(a) (PD97)	2021 IRP(b) (PD97)	2021 IRP(c) (PD97)
BAU	64,466.75	69,751.46	51,531.08	50,587.69	50,931.65	50,816.60
MSO	65,414.51	70,854.82	52,300.36			

While the executable portfolios incorporate several resource decisions that were informed by factors beyond pure cost optimization, including reliability, clean energy compliance, implementation feasibility, and resource diversity, the modeling results provide economic support for these resources.

Comparison of 2021 IRP plans (a), (b), and (c) demonstrates the economic value of the proposed Karn and Thetford CT facilities. 2021 IRP(a) and (b) are open optimizations in which Aurora determines the economically preferred resource mix under alternative CT cost assumptions. 2021 IRP(c) uses the same upper-end CT cost assumption as 2021 IRP(b) while requiring inclusion of the Karn and Thetford CT facilities. Comparing 2021 IRP(b) and (c) therefore isolates the incremental economic effect of including the CT projects under the more conservative cost assumption. As shown in Table 17-7, 2021 IRP(c) produces a lower NPV than 2021 IRP(b) when surplus capacity value is recognized, providing economic support for inclusion of the Karn and Thetford CT facilities in the executable portfolio.

17.3.3 Projected Annual Fuel Costs Forecasts

Fuel costs were evaluated across the executable portfolio build plans as well as the optimized portfolios developed under the MSO, PCC, and ALG scenarios.

Differences in projected fuel costs reflect variations in load growth, resource mix, dispatch patterns, and reliance on fossil-fueled generation over the planning horizon. Figure 17-5 and Table 17-8 summarize annual fuel costs across each portfolio.

The executable portfolios generally exhibit lower fuel costs on average than the portfolios optimized under each scenario because the executable portfolios incorporate [CONFIDENTIAL] [END CONFIDENTIAL].

Fuel costs in the probable load plan and current load plan are nearly identical despite differing load levels. Both portfolios contain a similar fleet of dispatchable resources, and incremental load in the high load plan is met primarily through additional renewable generation, storage, and demand-side resources rather than increased fossil generation. The current load plan produces the lowest average fuel costs of the executable portfolios. Although the probable load plan serves higher load than the 2021 IRP load plan, the portfolio's combination of [CONFIDENTIAL] [END CONFIDENTIAL], renewable generation, storage resources, and demand-side programs limits dependence on fuel-consuming resources across much of the planning horizon.

The optimized ALG, PCC, and MSO portfolios all exhibit higher average fuel costs than the executable portfolios because they do not include [CONFIDENTIAL] [END CONFIDENTIAL].

Figure 17-5: Total fuel cost for existing owned resources, by portfolio

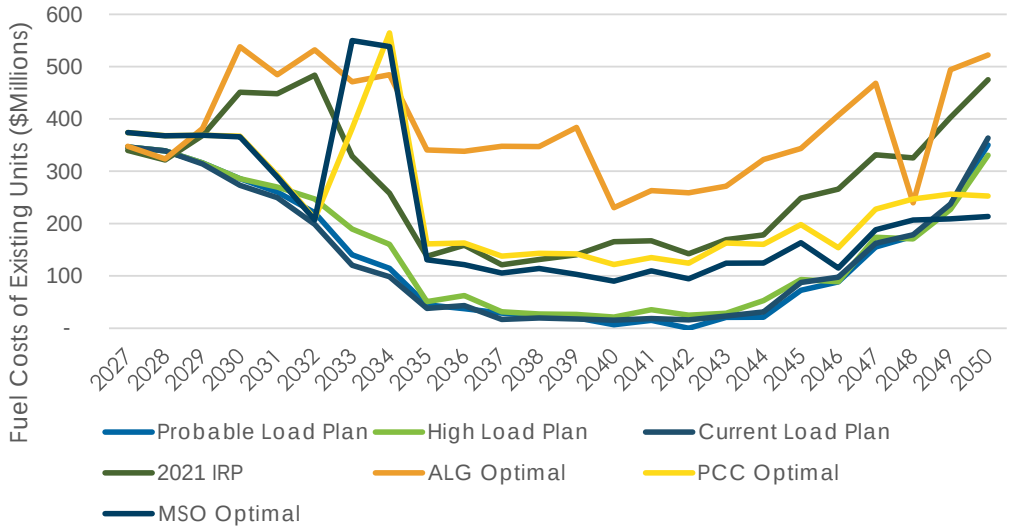


Table 17-8: Projected annual fuel costs for existing owned units by portfolio, $ millions

PORTFOLIO	2027	2030	2035	2040	2045	2050	2026-2050 AVG
Probable Load Plan	$346.31	$285.71	$44.52	$6.44	$72.35	$350.38	$138.16
High Load Plan	$346.28	$285.72	$50.73	$21.22	$92.90	$330.41	$149.80
Current Load Plan	$346.28	$272.94	$37.79	$15.49	$87.39	$363.46	$137.66
2021 IRP	$339.83	$450.90	$137.30	$165.28	$248.68	$474.85	$273.24
ALG Optimal	$347.78	$538.20	$340.75	$230.37	$343.57	$522.17	$380.87
PCC Optimal	$373.85	$366.99	$161.01	$121.86	$197.77	$252.57	$237.89
MSO Optimal	$373.74	$365.62	$130.57	$90.00	$163.39	$213.39	$219.63

17.4 Electric Reliability Analysis

As discussed in Section 5, Analytical Approach, the reliability analysis methodology in this IRP included a combination of risk metrics from stochastic analysis, market exposure assessment and a reliability assessment for an identified sample year, 2032. The year 2032 was selected because it represents a period in which load growth, planned resource retirements, and near-term resource decisions converge.

These three analytical lenses are applied to a common set of portfolios, though not every analysis evaluates the same portfolio group. The reliability and market dependency assessments evaluate three planning portfolios and two additional sensitivity portfolios: battery support (a) and (b), 2021 IRP (PD97), and current load plan (PD98) are all evaluated using the current-load forecast, while the probable load plan (PD99) is evaluated using their respective higher economic development load assumptions.

Battery support plans (a) and (b) were developed as controlled comparison portfolios to evaluate whether battery storage could serve as an alternative to the Karn and Thetford CTs. In these portfolios, the CTs are replaced with 3,000 MW and 4,000 MW of incremental battery storage, respectively, with the 4,000 MW case representing the maximum quantity of storage the Company believes could reasonably be developed and placed in service by 2032. Together, these portfolios allow the Company to evaluate the reliability and market dependency implications of substituting increasing amounts of storage for firm thermal capacity. The risk assessment evaluates a different portfolio set, as it also includes the optimal portfolios produced for each modeled scenario, which are not included in the reliability and market dependency analyses.

A detailed description of the objectives, methodologies, assumptions, and performance metrics associated with each assessment is provided in Section 5, Analytical Approach, while this section focuses on the key findings and planning implications of those analyses.

Taken together, the analyses provide a consistent picture of portfolio performance. Within the common load forecast evaluated in the reliability and market dependency analyses, the portfolios that include the Karn and Thetford CTs, 2021 IRP plan (PD97) and current load plan (PD98), exhibit stronger reliability performance and substantially lower dependence on external market purchases than the storage-based alternatives. These are not isolated findings. Rather, two separate analyses evaluating different aspects of system performance point to the same conclusion: portfolios with greater firm, dispatchable capability within the CE zone are associated with improved reliability outcomes and reduced market dependence.

The reliability, market dependency and risk analyses each evaluates a different aspect of portfolio performance. The reliability assessment measures the frequency, duration, and magnitude of potential resource shortfalls; the market dependency assessment measures the extent to which a portfolio relies on energy from outside the CE zone; and the risk assessment evaluates the sensitivity of portfolio costs to changes in key planning assumptions. The significance of the results is therefore not that one analysis proves another, but that independent assessments of reliability, market dependence, and cost risk identify similar benefits associated with portfolios that contain greater amounts of firm, dispatchable capability.

17.4.1 Reliability Assessment

The reliability assessment evaluates portfolio performance under uncertainty using a stochastic simulation framework that jointly considers variability in electric demand, renewable generation output, thermal generator availability, and MISO market availability. Each portfolio was evaluated across 600 simulation samples representing alternative weather conditions and outage patterns that are representative of the wide range of credible operating conditions that can face the grid. This approach provides a probabilistic assessment of portfolio reliability and allows the Company to compare the resilience of alternative resource strategies under a broad range of future operating conditions. Additional details regarding the methodology are provided in Section 5.

Reliability risk was evaluated using three complementary metrics in 2032:

- LOLE, measured in event days per year, which quantifies how frequently resource shortfalls occur;
- LOLH, measured in hours per year, which quantifies the duration of resource shortfall events; and
- nEUE, measured in parts per million, which quantifies the magnitude of unserved energy relative to total customer demand.

Table 17-9: Reliability assessment results

PORTFOLIO TYPE	LOLE (EVENT-DAYS/YR)	LOLH (HOURS/YR)	nEUE (PPM)	PURPOSE
MISO Standard	**0.1**	**2.4**	**20**	**Benchmark**
2021 IRP (PD97)	0.18	0.6	5.8	Current conditions benchmark
Current Load Plan (PD98)	0.02	0.1	0.4	BAU load future
Probable Load Plan (PD99)	0.19	0.7	4.4	Probable load future

PORTFOLIO TYPE	LOLE (EVENT-DAYS/YR)	LOLH (HOURS/YR)	nEUE (PPM)	PURPOSE
Battery Support Plan (a)	0.59	3.9	51.3	3GW minimum of storage to replace gas
Battery Support Plan (b)	0.23	1.1	12.4	4GW minimum of storage to replace ga

Table 17-9 presents CE zone reliability results for the portfolios evaluated, drawn from 600 samples per portfolio. The portfolios are grouped by load forecast, because reliability metrics are only comparable between portfolios evaluated against the same demand. Results are CE zone only. Each figure is the mean of 600 samples, comprising 120 weather draws and five independent forced-outage draws. Portfolios under different load forecasts are not directly comparable.

Among the executable portfolios, the current load plan (PD98) produces the strongest reliability results, as shown in Table 17-9. The probable load plan (PD99), however, satisfies both energy-based reliability metrics (LOLH and nEUE) with substantial margin while serving approximately 30% more load than the Current load forecast portfolios.

The controlled comparison between the 2021 IRP plan (PD97), and the two battery support plans provides additional insight into portfolio design tradeoffs. Replacing firm thermal capacity with increasing amounts of battery storage improves reliability relative to a simple capacity expansion outcome but does not fully replicate the reliability performance achieved by portfolios that retain dispatchable thermal resources. These results suggest that firm, dispatchable capacity continues to provide reliability benefits that are not entirely replaced by additional storage under the conditions evaluated.

17.4.2 Market Dependency

The market dependency assessment evaluates the frequency, duration, timing, and magnitude of reliance on external market purchases under representative operating conditions. Additional detail regarding the methodology and metrics is provided in Section 5, and results are shown in Table 17-10.

Table 17-10: Market dependency assessment results

PORTFOLIO TYPE	DEPENDENCY DAYS[1]	DEPENDENT HOURS	PERCENT OF YEAR	LONGEST RUN[2]	MAX DEPTH (MW)	MEAN DEPTH (MW)	OVERNIGHT SHARE[3]
2021 IRP (PD97)	15	31	0.35%	6	-1,218	-460	6.5%
Current Load Plan (PD98)	4	9	0.10%	4	-585	-273	0.0%
Probable Load Plan (PD99)	63	142	1.62%	8	-1,867	-449	19.7%
Battery Support Plan (a)	127	342	3.89%	15	-2,433	-535	24.0%
Battery Support Plan (b)	127	340	3.87%	11	-2,433	-521	23.5%

1) Dependency days matches the event-day convention used for LOLE.
2) Longest run duration is in continuous runs, which are not broken at midnight.
3) Overnight share is the fraction of dependent hours falling in hours 1 through 6.

The market dependency analysis highlights an important distinction between portfolios that rely on firm, dispatchable capacity and those that rely more heavily on battery storage. Under a common load forecast, battery support (a) exhibits substantially

greater dependence on external market purchases than the 2021 IRP plan (PD97), including more than ten times as many dependency hours (342 hours versus 31 hours), more than eight times as many dependency days (127 days versus 15 days), and continuous dependency events more than twice as long (15 hours versus 6 hours).

The differences are not limited to the magnitude of market dependence, but also its persistence. The 2021 IRP plan (PD97) experiences market dependence only intermittently and records no dependency hours in seven months of the year. By contrast, battery support plans (a) and (b) exhibit dependency in every month of the year, with approximately one-quarter of dependency hours occurring overnight. Increasing storage from 3,000 MW to 4,000 MW improves reliability performance but does not materially change the most severe market dependency events. In fact, both portfolios experience essentially the same maximum dependency level, indicating that additional storage does not fully address extended periods when stored energy has been depleted.

These results suggest that storage and dispatchable resources provide different system benefits. Storage is effective at addressing many short-duration reliability needs, while firm dispatchable resources provide additional resilience during prolonged periods of system stress. As a result, portfolios containing greater amounts of firm, dispatchable capability generally exhibit both lower market dependence and stronger reliability performance.

Among the portfolios evaluated, the current load plan (PD98) demonstrates the lowest level of market dependence, with only nine dependency hours occurring across four days during the modeled year. The probable load plan (PD99) also performs favorably relative to the storage-focused alternatives, reinforcing the conclusion that portfolios containing firm, dispatchable resources are better able to serve customer demand using resources located within the CE zone.

17.4.3 Risk Assessment

The cost risk assessment evaluates the sensitivity of portfolio costs to changes in key planning assumptions, including load growth, fuel prices, capital costs, and resource performance. Additional detail regarding the assessment methodology is provided in Section 5, while results are discussed below.

The risk assessment evaluated seven portfolios. Two of these portfolios, the probable load plan (PD99) and current load plan (PD98), were also included in the reliability and market dependency analyses, allowing the results to be compared across all two assessment frameworks. The remaining four portfolios are the optimized build plans developed for the BAU, ALG, PCC, and MSO scenarios. The 2021 IRP plan (PD97) and the battery support portfolios were not included in the risk assessment because the objective of the analysis was to evaluate the uncertainty associated with the primary planning portfolios and scenario-based optimized portfolios. In addition, each risk variable is evaluated across every portfolio, resulting in a substantial increase in model runs as additional portfolios are added.

As shown in Figure 17-6, PD99's NPV risk is driven primarily by capital cost and load uncertainty. Renewable capital costs produce the largest modeled NPV delta, followed by load, thermal capital costs, storage capital costs, and fuel prices. This ranking indicates that the probable load plan is more exposed to uncertainty in the cost and scale of future resource additions than to fuel price or renewable generation variability. The results are consistent with the resource strategy reflected in the probable load plan, which includes substantial renewable and storage additions over the planning horizon while also relying on dispatchable capacity to support reliability and reduce market dependence.

Figure 17-6: Probable load plan (PD99) risk assessment NPV ranges



1 shows that the ranking of cost risk drivers is broadly consistent across all the portfolios. For each portfolio, renewable capital cost is the largest source of NPV variation, followed by load and thermal capital cost. This indicates that portfolio cost risk is driven primarily by uncertainty in the cost and scale of future resource additions.

The main difference across the portfolios is the relative importance of storage capital cost. Storage capital cost is the fourth-largest risk driver for the probable load plan (PD99) but the smallest risk driver for current load plan (PD98). This difference reflects the amount of storage included in each portfolio. Portfolios with greater storage additions have greater exposure to storage capital cost uncertainty, while portfolios that rely less on storage carry less storage-related cost risk.

Table 17-11: Risk assessment NPV delta

RANK	VARIABLE	PROBABLE LOAD PLAN (PD99)	VARIABLE	CURRENT LOAD PLAN (PD98)
1	Capital cost, renewables	4.84	Capital cost, renewables	2.79
2	Load	2.18	Load	1.81
3	Capital cost, thermal	1.59	Capital cost, thermal	1.

RANK	VARIABLE	PROBABLE LOAD PLAN (PD99)	VARIABLE	CURRENT LOAD PLAN (PD98)
4	Capital cost, storage	1.41	Fuel price	0.70
5	Fuel price	0.46	Capital cost, storage	0.46
6	Renewable generation	0.15	Renewable generation	0.06

Collectively, the risk assessment indicates that portfolio cost uncertainty is driven primarily by uncertainty in renewable capital costs and future load growth, regardless of portfolio design. While the magnitude of individual risk drivers varies across portfolios, the rankings remain broadly consistent. These results suggest that differences in portfolio risk are driven more by the amount and type of future resource additions than by fuel price exposure, reinforcing the importance of maintaining a diversified portfolio capable of adapting to future changes in technology costs and customer demand.

17.5 Conclusion and Finalized Portfolios

The Phase 1 optimization analysis identified several resource strategies and planning decisions that consistently influenced portfolio performance across a range of future conditions. In particular, the analysis highlighted the importance of economic development load growth assumptions, firm accredited capacity resources, the MCV PPA, [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] in meeting stated planning targets.

Based on these findings and updated planning information developed during the IRP process, the Company selected a focused set of executable portfolios for detailed evaluation. These portfolios were designed to test the effects of alternative load growth outcomes and key resource decisions while remaining feasible to implement.
The resulting executable portfolios included, alternate plan current (PD 98) and probable load plan (PD99). Detailed economic, reliability, market dependency, and risk assessments demonstrated that probable load plan provided the strongest overall balance of reliability, affordability, clean energy compliance, resource diversity, and implementation feasibility while serving the Company's most likely load outlook.

Following completion of the Phase 2 evaluations, the Company assigned final portfolio designations based on portfolio performance across the evaluation criteria. Probable Load Plan (PD99) was selected as the Company's PCA. Current Load Plan (PD98) was designated Alternate Plan Current, High Load Plan (PD96) was designated Alternate Plan Growth, and 2021 IRP Plan (PD97) was designated Support Plan 1. Throughout the remainder of this IRP, these final portfolio designations are used.

Proposed Resource Plan

Section 18

18 Proposed Resource Plan

The PCA was developed through Consumers Energy's integrated resource planning process to identify a preferred portfolio that can reliably and affordably serve customers while meeting Michigan's clean energy requirements and other applicable planning obligations. The Company evaluated resource portfolios using its Aurora capacity expansion and production cost modeling framework, with updated assumptions for load growth, fuel prices, technology costs, resource performance, reliability needs, and clean energy compliance. The evaluation considered whether each portfolio could maintain reliability, support reasonable customer costs, meet environmental and clean energy requirements, promote equitable outcomes, and preserve resource diversity and flexibility over the planning horizon.

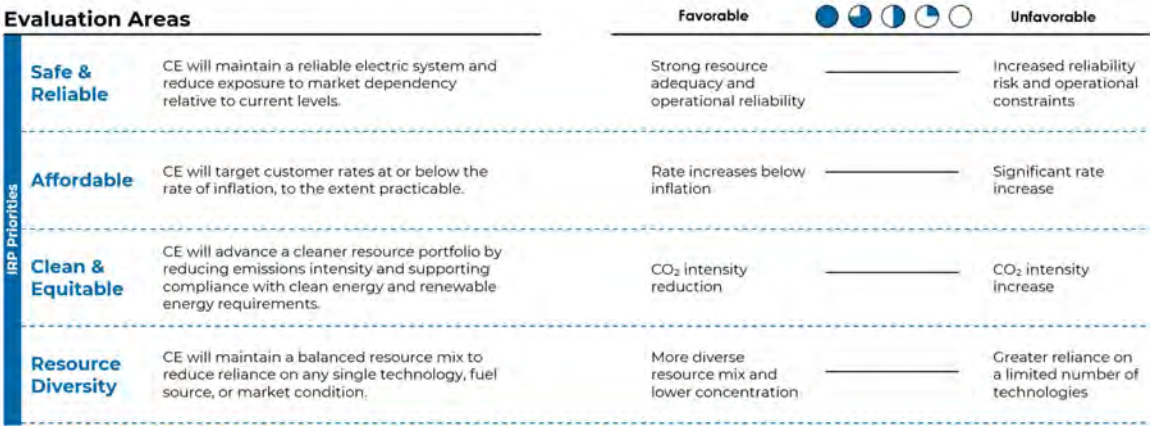
Based on this evaluation, the PCA includes the demand-side and supply-side resources that best balance reliability, affordability, clean energy compliance, risk mitigation, resource diversity, and implementation feasibility. The portfolio continues significant renewable energy additions consistent with Company objectives and Michigan's 2023 energy law, while also adding firm, dispatchable natural gas resources and DSM where needed to support reliability as renewable and energy-limited resources increase. Together, these resources create a complementary portfolio in which renewable generation and storage provide low-cost clean energy, while dispatchable resources provide dependable capacity and energy during periods of low renewable output, extended system stress, or when storage resources become energy constrained. The plan also includes a PPA that [CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. The PCA is designed to meet projected capacity and energy needs, maintain compliance with local, state, and federal requirements, and provide flexibility as load growth, technology costs, and market conditions evolve.

18.1 Portfolio Evaluation

The process used to develop and evaluate the PCA is described in Section 5, Analytical Approach, with portfolio-specific results presented in Section 17, Modeling Results. Through that process, the Company evaluated a range of alternative resource portfolios to identify a plan capable of meeting future energy and capacity needs while balancing reliability, affordability, clean energy progress, equity, and resource diversity objectives. The evaluation considered resource adequacy, market dependence, customer cost impacts, emissions performance, implementation feasibility, and portfolio resiliency under a range of future conditions.

CE evaluates potential IRP portfolios using four core criteria: Safe & Reliable, Affordable, Clean & Equitable, and Resource Diversity. As shown in Figure 18-1, these criteria provide a consistent framework for assessing portfolio performance from the customer perspective and evaluating the tradeoffs associated with different resource strategies. Rather than optimizing a single objective, the Company sought a portfolio that delivers balanced performance across all criteria and can continue to perform under a range of future load, market, technology, and policy conditions.

Figure 18-1: Consumers Energy IRP priorities



18.1.1 How the Plan Satisfies the Principles and Objectives

The PCA was selected because it provides the most balanced performance across the Company's planning objectives while remaining executable under a wide range of future conditions. While certain alternative portfolios performed well against individual evaluation criteria, no alternative portfolio demonstrated the same balance of reliability, affordability, clean energy progress, and implementation feasibility achieved by the PCA.

Figure 18-2 compares the PCA against alternative portfolios, though it should be noted that the load level is not consistent across portfolios. Therefore, the portfolios are compared against metrics that are normalized for load differences. The results demonstrate that the PCA consistently performs well across multiple planning objectives rather than optimizing a single metric at the expense of others. This balanced performance is particularly important given uncertainty surrounding load growth, technology development, market conditions, and future policy requirements.

Figure 18-2: PCA and alternative portfolio scorecard performance



Reliability as of 2032, all other metrics as of 2035.
*Effective Resource Diversity is calculated as 10,000 divided by the HHI Index, a measure of portfolio concentration based on the squared shares of each resource category. The resulting value represents the equivalent number of equally sized resource categories that would produce the same level of concentration. Higher values indicate greater resource diversity.

Reliable

The PCA demonstrates strong reliability performance across all evaluated metrics, achieving a LOLE of 0.19, only modestly above the MISO footprint target of 0.1 events-per-year target,[60] a LOLH of 0.7 hours per year, well below the MISO target of 2.4 hours per year, a nEUE of 4.4 ppm, well below the MISO 20 ppm target, and market dependence of 1.62% of the year, well below CE's historical benchmark of 2.7%. While the Alt Plan Current portfolio achieved lower values for each individual reliability metric, that portfolio was developed to serve a lower level of customer demand than the PCA. The PCA reflects the Company's probable load growth outlook, including a signed contract and highly likely new large-load customers, and therefore was designed to meet a substantially greater level of future customer demand.

Importantly, the Company's reliability assessment found that the PCA continues to provide strong reliability outcomes despite the higher load growth assumption. Although the LOLE result is slightly above the performance of the Alt Plan Current Portfolio and the MISO-wide target, the portfolio performs exceptionally well on the energy metrics (LOLH and nEUE), indicating that expected reliability events are infrequent and limited in magnitude. In addition, the PCA maintains relatively low market dependence compared to other portfolios and historical benchmarks.

[60] It is important to note that the MISO-wide footprint target of 0.1 is not directly applicable to CE on a stand-alone basis, given the additional access to the market that is available for all utility service territories that operate within a wider balancing authority like MISO.

Together, these results indicate that the PCA provides a reasonable and balanced reliability outcome while supporting a significantly larger customer load obligation.

The Company's analysis also demonstrated the value of firm capacity resources in supporting both resource adequacy and reducing market exposure. Portfolios incorporating CTs performed more favorably across reliability and market dependency metrics than storage-heavy alternatives. These resources provide firm capacity and energy that reduce reliance on market purchases during periods of system stress and enhance the portfolio's ability to maintain reliable service under higher load growth conditions. Accordingly, while the PCA was not the top-performing portfolio on every individual reliability metric, it achieved a stronger balance of reliability, market exposure, and long-term load-serving capability than the alternative portfolios evaluated. In addition to providing accredited capacity, these resources enable the Company to maintain reliability as renewable generation and battery storage become a larger share of the portfolio. During periods of low renewable output, prolonged weather events, or when battery storage has depleted its stored energy, dispatchable resources provide continued energy and operating flexibility that complements the portfolio's renewable and storage resources.

Affordable

The PCA has lower costs per kWh than both the Alt Plan Current and Alt Plan Growth portfolios. Relative to the Alt Plan Current portfolio, the PCA's lower costs are driven in large part by higher load growth, which allows for fixed costs of existing and new resources to be spread over more MWh. Meanwhile, the PCA has comparable overall costs relative to the Alt Plan Growth portfolio, with annual cost differences dependent on the timing of load growth and new resource additions.

For income brackets subject to the highest energy burdens, the PCA supports affordability by relying on a combination of customer programs—especially EWR, DR, EV load management, and DG—rather than only supply-side resources, and targeted support for high-burden customers is discussed further in Section 19.

Clean & Equitable

The PCA advances the Company's clean energy objectives through a combination of renewable energy resources and firm capacity needed to maintain reliable service. In evaluating renewable generation, energy storage, demand-side resources, and conventional generation, the Company considered reasonably foreseeable environmental impacts alongside reliability, affordability, resource adequacy, and clean energy compliance requirements. The PCA reflects a balanced approach to these objectives rather than optimizing any single factor in isolation.

The PCA supports compliance with Michigan's clean energy requirements, including achieving an 80% clean energy portfolio by 2035 and 100% clean energy by 2040, while supporting the interim renewable energy requirements established under Public Act 235. The PCA also continues the Company's transition away from coal-fired generation and toward cleaner energy resources. As a result, Company projections indicate carbon emissions will decline by approximately 99% by 2040 relative to 2005 levels.

To evaluate environmental and environmental justice ("EJ") impacts, the Company utilized Michigan's MiEJScreen tool, facility-level emissions analyses, PM and NO_x variability evaluations, COBRA health-impact modeling, and a qualitative review of water quality, waste disposal, land use, and siting considerations. The screening identified EJ communities and potentially vulnerable areas within a three-mile radius of Company facilities, while emissions analyses evaluated generating units located within six miles of identified EJ communities.

The Company's analysis demonstrated that the primary environmental differences among the evaluated portfolios result from projected emissions and the associated public health impacts. Portfolio-level emissions comparisons showed substantial reductions in sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions under the PCA relative to the previously approved portfolio. The Company also utilized EPA's COBRA model to evaluate public health impacts associated with projected fleetwide emissions reductions. The statewide analysis estimated annual avoided health-effect costs of approximately $120 million to $200 million, while county-level analyses likewise indicated positive health outcomes associated with reduced emissions.

Facility-specific evaluations further demonstrated that the proposed D.E. Karn combustion turbine ("DEK CT") is expected to operate with PM and NO_x emissions well below the historic emissions associated with the site. For the proposed Thetford combustion turbine ("THET CT"), projected emissions analyses identified only minimal increases in local NO_x emissions, while the Company's COBRA assessment demonstrated an overall public health benefit for Genesee County associated with fleetwide emissions reductions under the PCA. In addition, air dispersion modeling conducted as part of the THET CT permitting process identified no exceedances of applicable health-based air quality standards. Neither DEK CT nor THET CT is located within a nonattainment area.

The Company also qualitatively reviewed water quality, waste disposal, land use, and siting considerations associated with the evaluated portfolios. This review did not identify any material qualitative differences that distinguished the PCA from the alternative portfolios. The proposed DEK CT and THET CT facilities are located on existing Company-owned generating sites, do not generate coal combustion residuals, and are designed for limited water use without cooling water intake structures. Further, the Company's transition away from coal-fired generation is expected to reduce generation-related water use by approximately 99% compared to historical fleet operations, representing a significant environmental benefit.

Taken together, the Environmental Justice screening results, emissions comparisons, COBRA health-impact assessments, PM and NO_x variability evaluations, and qualitative environmental review indicate that the PCA provides an appropriate balance of environmental performance, public health benefits, reliability, affordability, resource adequacy, and clean energy in compliance with PA 235. While no single portfolio produced the lowest projected emissions for every pollutant, the PCA achieves substantial decarbonization and environmental benefits while supporting the broader objectives of the Integrated Resource Plan.

Resource Diverse

The Company evaluated resource diversity using the HHI, which measures portfolio concentration based on the squared share of each resource category. The analysis was calculated using UCAP rather than ICAP so that resource shares reflect their accredited contribution to reliability, rather than nameplate capacity. The HHI was then converted to an effective resource diversity metric, where higher values indicate a more diversified portfolio.

Greater resource diversity can reduce reliance on any single technology, fuel source, or market condition, helping limit exposure to resource-specific cost, availability, and performance risks. The PCA performs well on this metric, with an effective resource diversity score of 5.7. Alt Plan Growth is the most diversified portfolio at 6.4. The Alt Plan Current portfolio is somewhat more concentrated, with a score of 5.3. Overall, the PCA maintains a balanced mix of accredited resources and performs favorably relative to the other portfolios.

In addition to capacity mix diversity, the PCA also delivers a portfolio that is diverse with regard to geography, development status (new construction vs. existing or repurposed sites), and ownership (owned vs. PPA) attributes. This helps mitigate risk exposure that may be associated with local energy or capacity basis risk; supply chain, permitting, and other development risk; and customer cost exposure over time.

Overall, the Company selected the PCA because it provides the best overall balance of reliability, affordability, clean energy progress, equity, resource diversity, and implementation feasibility. The PCA avoids overreliance on a single resource strategy and instead combines supply-side resources, demand-side resources, contractual resources, and customer-participation programs into a diversified resource plan capable of meeting long-term customer needs. The Company therefore concludes that the PCA represents the most reasonable and prudent resource strategy to serve customers over the planning horizon.

18.2 Technology Resource Mix and Plan to Meet Future Capacity Requirements

The PCA makes use of existing generation interconnections at sites of retired units including Thetford and Karn. Additionally, the PCA employs PPAs from MCV and [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] as it prepares the Company to support anticipated economic development load and contains the following incremental resource options to meet forecast capacity needs:

Table 18-1: Incremental generation capacity by technology

GENERATION TECHNOLOGY	INSTALLED CAPACITY (MW)	SUMMER ZRC CAPACITY (MW)	AVERAGE ANNUAL FUEL($ MILLION)
Solar	9,628	193	0
Wind	3,208	289	0
Demand Response	1,400	1,629	0
Energy Storage (BESS)	3,269	1,149	0

GENERATION TECHNOLOGY	INSTALLED CAPACITY (MW)	SUMMER ZRC CAPACITY (MW)	AVERAGE ANNUAL FUEL($ MILLION)
[CONFIDENTIAL] [redacted]	[redacted]	[redacted]	[redacted] [END CONFIDENTIAL]
Natural Gas CC + CCS	1,233	1,171	458
Natural Gas CT	2,074	1,970	31

The above resource options are developed beginning in 2029 through 2045. The development timeline is informed by the Company's capacity expansion modeling as well as historical performance of existing assets. In the development of supply side resources, the Company will continue to work with communities and interested parties in Michigan to comply with local, state, and federal regulations. Figure 18-3 shows the development schedule of above resources.

Figure 18-3: New build schedule in the PCA [CONFIDENTIAL]



[END CONFIDENTIAL]

18.2.1 Fuel Cost Projections and Commodity Risk

The PCA incorporates fuel cost assumptions developed using the methodologies described in Section 15, Fuel Supply. Fuel price assumptions for natural gas, coal, and oil were incorporated into both the capacity expansion and production cost modeling processes. The Company also evaluated a range of fuel price sensitivities, including higher natural gas price outlooks, to assess the robustness of portfolio performance under alternative commodity market conditions.

The PCA balances the need for firm, dispatchable resources with continued expansion of renewable generation, storage resources, and demand-side resources. This portfolio design helps reduce customer exposure to fuel price volatility while maintaining sufficient dispatchable capacity to satisfy reliability obligations. Renewable resources, storage resources, demand-side resources, and the [CONFIDENTIAL] [redacted]

[redacted] [END CONFIDENTIAL]. Fuel cost projections associated with existing and proposed resources are incorporated throughout the portfolio evaluation and economic analyses supporting selection of the PCA.

18.2.2 Plan for Meeting Future Capacity Requirements

The PCA satisfies projected capacity needs through a diversified combination of existing generation resources, contracted resources, new generation resources, energy storage, and demand-side resources. The Company's load forecasts indicate increasing capacity requirements resulting from customer growth, electrification, and economic development load additions. To satisfy these requirements, the PCA includes replacement of retiring generation with new dispatchable generation resources, continued reliance on existing and expanded contractual capacity arrangements, significant renewable generation additions, expanded storage deployment, and continued growth in demand-side resources.

Near-term resource adequacy is supported through the development of new CT resources at Karn and Thetford, continuation of the MCV resource, and commencement of the [CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. Longer-term resource needs are met through additional renewable resources, storage resources, demand-side resources, and deployment of a CCS resource beginning in 2040. These resources not only satisfy resource adequacy requirements but also provide the operational flexibility needed to integrate increasing levels of renewable generation and energy storage, ensuring the portfolio can reliably serve customers through extended periods of low renewable production and other stressed system conditions.

The Company evaluated these resource additions against projected seasonal planning reserve requirements, clean energy requirements, and reliability criteria. The resulting portfolio maintains compliance with resource adequacy requirements throughout the planning horizon while supporting anticipated customer growth and reducing dependence on market purchases.

18.2.3 Major Investments and Transmission Considerations

Implementation of the PCA requires a combination of Company-owned generation investments, contractual resource procurements, renewable resource development, storage deployment, and supporting transmission infrastructure investments.

Major resource investments include:

- Development of CT resources at the Karn and Thetford sites;
- Long-term PPAs associated with MCV and the [CONFIDENTIAL] [redacted] [END CONFIDENTIAL];
- Continued development of utility-owned and contracted renewable resources;
- Significant deployment of battery energy storage resources; and
- Expanded investment in demand-side and VPP resources.

The Company also evaluated transmission system impacts associated with implementation of the PCA. Transmission capability, import capability, transfer limits, and network upgrade costs were incorporated into the planning analysis. These transmission evaluations confirm that the PCA can be implemented while maintaining reliability within MISO and LRZ 7.

18.2.4 Natural Gas Fuel Supply and Transportation

The Company evaluated the fuel supply requirements associated with the natural gas-fired generating resources included in the PCA and determined that adequate fuel transportation, storage, and delivery arrangements can be established to support reliable operation of the planned facilities. The new natural gas generation resources included in the PCA are expected to utilize existing natural gas infrastructure and transportation arrangements, supplemented by targeted upgrades where necessary. At Karn, existing fuel delivery infrastructure currently serving the Karn Generating Complex is expected to support future operations following retirement of Karn Units 3 and 4. At Thetford, the planned generating facilities are expected to interconnect directly with the Company's natural gas transmission system and utilize existing transmission infrastructure in the area.

The Company's natural gas transmission system includes storage capability and interconnections with multiple interstate pipeline systems, providing access to diverse natural gas supply sources and supporting reliable fuel delivery. The Company will continue to evaluate and secure transportation, balancing, and storage arrangements necessary to maintain adequate fuel supply for generation resources included in the PCA.

18.3 Compliance with State and Federal Planning Requirements

18.3.1 Alignment with Clean Energy Policies and Laws

IRP and Clean Energy Plan Alignment with Renewable Energy Plan

As discussed in Sections 9 and 11, the Company's IRP and CEP are generally aligned with its most recently approved RE Plan. The 2024 RE Plan added up to 2,800 MW of wind and 8,000 MW of solar resources, consistent with the 2021 IRP settlement in Case No. U-21090. The Commission approved the 2024 RE Plan on September 11, 2025, including approximately 1,465 MW of new solar generation to serve projected customer demand under the RE Plan and VGP programs.

The PCA includes additional renewable resources beyond the 2024 RE Plan, resulting in approximately 3,208 MW of wind and 9,628 MW of solar over the planning period. This increase is needed because projected customer deliveries rise after 2032; as load increases, the RPS target also increases. The additional renewable additions support compliance with Michigan's RPS, the CES under Act 235 beginning in 2035, and updated VGP demand.

Future RE Plan filings will reflect actual renewable procurements and compliance activities implemented pursuant to the PCA. To the extent future load growth, VGP participation, or changes in regulatory requirements necessitate additional renewable resources beyond those contemplated in the current RE Plan, the Company will address those additions through future RE Plan proceedings.

18.3.2 IRP Alignment with Statewide Storage Target

As discussed in Section 10, existing and planned energy storage resources in the PCA exceed the Company's allocated share, 817 MW, of Michigan's statewide 2,500 MW energy storage deployment target. Planned storage additions, including contracted and Company-owned resources, increase eligible storage capacity to 928 MW by 2029, exceeding the Company's allocated share of the statewide target.

18.3.3 Demand-Side Resource Strategy and EWR Compliance

The PCA remains aligned with the Company's EWR strategy and incorporates EWR as a foundational component of the resource portfolio. Consistent with Public Act 295 of 2008, as amended, EWR programs reduce customer energy consumption, lower system demand, and defer the need for additional supply-side resources, supporting affordability, reliability, and clean energy objectives.

The PCA also expands the role of customer-side resources beyond traditional EWR programs. DR, CVR, managed EV charging, DERs, and other VPP capabilities are incorporated into the Company's long-term planning framework as dispatchable and flexible resources that contribute to reliability and resource adequacy. These resources provide capacity value, reduce peak demand requirements, and improve utilization of renewable energy resources.

As load growth accelerates and renewable generation becomes a larger portion of the portfolio, VPP resources become increasingly valuable. Managed EV charging programs, in particular, provide the opportunity to shape load growth to better align customer demand with periods of renewable generation production. This flexibility helps reduce market dependence, lower customer costs, and support system reliability.

The PCA therefore treats EWR, DR, CVR, managed EV charging, and other VPP resources not solely as compliance mechanisms, but as integral portfolio resources that complement supply-side investments. Together, these customer-side resources support compliance with EWR requirements while providing meaningful capacity, operational flexibility, and affordability benefits throughout the planning horizon.

18.4 Implementation Plan

The Company intends to implement the PCA through phased procurement, development, construction, and contracting activities. Implementation activities will be coordinated with regulatory approvals, procurement schedules, transmission planning activities, stakeholder outreach, and evolving customer demand forecasts. The Company will continue to monitor key planning assumptions and may adjust implementation timing as necessary to address changes in load growth, technology availability, regulatory requirements, market conditions, and reliability needs.

18.4.1 Short Term Action Plan (2027-2031)

The five-year plan addresses the Company's most immediate reliability, resource adequacy, market reliance, and compliance needs. It serves as the near-term bridge from the Company's current portfolio to the broader long-term transition by replacing retiring local capacity, retaining dependable existing capacity, adding firm clean energy, beginning major renewable and storage additions, and continuing to expand demand-side and VPP-related resources.

The principal objective of the five-year plan is to ensure that the Company can continue to serve customers reliably as Karn Units 3 and 4 retire, the existing MCV arrangement expires, large-load growth begins to materialize, and changes in MISO resource adequacy rules take effect. The five-year plan therefore emphasizes executable near-term resources that provide dependable capacity and energy while beginning the next phase of clean resource additions.

During this period, the Company will advance development, permitting, procurement, engineering, and construction activities associated with planned renewable generation, energy storage resources, firm dispatchable generation, PPAs, and demand-side resources. The Company will also continue implementation of EWR, DR, managed EV charging, and other distributed resource programs that contribute to resource adequacy and customer affordability objectives.

Table 18-2: Short-term action plan

TIMEFRAME	MAJOR ACTIVITY
2026-2027	Advance permitting, engineering, procurement, and development activities for planned generation, storage, and demand-side resources.
2026-2028	Continue renewable generation and energy storage development needed to support reliability and clean energy compliance objectives.
2026-2031	Expand EWR, DR, managed EV charging, VPP, and other customer-focused resource programs.
2027-2028	Complete major equipment procurement and construction readiness activities for planned firm generation resources.
2028-2030	Construct, test, and commission planned supply-side resources and supporting infrastructure.
2031	Place new firm generation resources into service and complete the transition associated with retirement of Karn Units 3 and 4 and expiration of the existing MCV arrangement. [CONFIDENTIAL] [redacted] [END CONFIDENTIAL].

18.4.2 Long-Term Implementation Roadmap (2032-2050)

The PCA will be implemented through a combination of generation development, renewable resource expansion, energy storage deployment, demand-side resource implementation, PPAs, fuel supply planning, transmission coordination, and ongoing portfolio optimization activities. Resource implementation schedules have been developed to maintain reliability while supporting affordability objectives, compliance obligations, and anticipated customer load growth. The Company will continue to

monitor changing system conditions and refine implementation priorities as necessary while maintaining the overall objectives of the PCA.

The implementation plan includes continued investment in renewable generation resources, BESS, demand-side resources, and firm dispatchable resources necessary to support resource adequacy requirements. The PCA also contemplates continued coordination with regional transmission planning processes, power purchase counterparties, fuel suppliers, and regulatory stakeholders to ensure timely implementation of the portfolio.

The Company expects implementation of the PCA to support economic activity throughout Michigan through development, construction, operation, and maintenance activities associated with the planned resource portfolio. Consistent with Company practices, implementation activities will consider opportunities to utilize Michigan labor resources, Michigan suppliers, and Michigan-based materials and services where practical and commercially reasonable. The Company will also continue to comply with applicable labor standards, regulatory requirements, permitting obligations, and procurement requirements throughout implementation of the PCA.

The Company will monitor progress toward implementation objectives and make adjustments as necessary to respond to changes in customer demand, market conditions, technology developments, regulatory requirements, resource availability, and reliability needs. Such adjustments are expected to preserve the overall objectives of the PCA while maintaining flexibility to respond to future uncertainties.

Rate Impact, Financial Information, & Affordability

Section 19

CMS ENERGY

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19 Rate Impact, Financial Information, and Affordability

19.1 Overview

Affordability is a primary objective for CE, and the Company evaluated the projected customer rate cost impacts associated with the PCA by estimating the change in power supply revenue requirement and translating those changes into average rates for each major customer class. This analysis is designed to assess how implementation of the PCA affects customers relative to current power supply rates and cost allocation assumptions.

19.1.1 Methodology

The rate impact analysis was performed in the following steps:

1. The Company established a baseline revenue requirement for power supply using its most recently approved rates.
2. Future revenue requirement projections were developed for the PCA and alternative portfolios by evaluating:
    - Existing resource cost trajectories.
    - Costs associated with new resource investments.
    - Operating costs associated with fuel, O&M, PPAs, and net market purchases.
3. Incremental costs were allocated to customer classes using production cost allocators from the most recent rate case.
4. Class-level revenues were divided by forecast sales to derive:
    - Average rates ($/kWh); and,
    - Percentage change relative to current rates.
5. The projected power supply rates on a per kWh basis were compared for the PCA relative to the alternatives and today's starting point grown at a range of inflation rates.

19.2 Average Rate Impacts

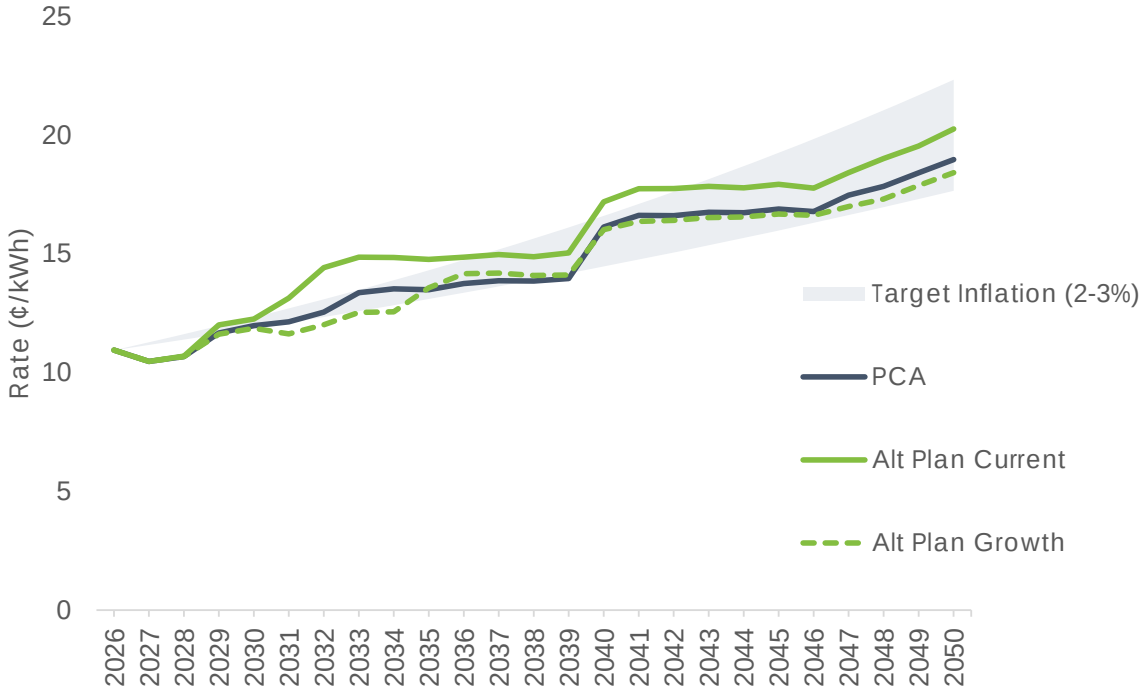
The total annual revenue requirement includes costs associated with existing generation assets, existing renewable assets, Power Plant Securitization, Karn 1 and 2 Securitization, regulatory assets attributable to power supply, PSCR, new generation assets and PPAs, the Financial Compensation Mechanism (FCM), EWR, and DR. The revenue requirement also incorporates amounts transferred to PSCR for RE Plan resources and includes an estimated annual RE Plan surcharge collection beginning in 2029 to recover renewable energy costs not transferred to PSCR. Four allocation factors are used to allocate annual revenue requirements by customer class: capacity, energy, transmission, and EWR. The appropriate allocator is then applied to each line item of the revenue requirement to determine the revenue requirement by customer class for each year, which is then subsequently used to calculate the average rate for each portfolio.

19.2.1 Comparison of the PCA to Alternative Resource Plans

Overall, the IRP analysis concluded that the PCA is the lowest cost plan that meets reliability requirements and renewable and clean energy standards. Specifically, the Company compared affordability outcomes under the PCA to the alternative resource

plans evaluated in the summary scorecard (Alt Plan Current and Alt Plan Growth). Figure 19-1 illustrates that the PCA maintains a rate trajectory that stays within the expected rate of inflation. The PCA also results in lower costs per kWh relative to the Alt Plan Current portfolio due in large part to higher underlying load growth, which allows for fixed costs to be spread over more MWh. The Alt Plan Growth portfolio has a comparable overall cost profile when compared with the PCA, with potential for slightly lower mid-term costs as a result of incremental load growth.

Figure 19-1: PCA and alternative plan rate impacts relative to target inflation

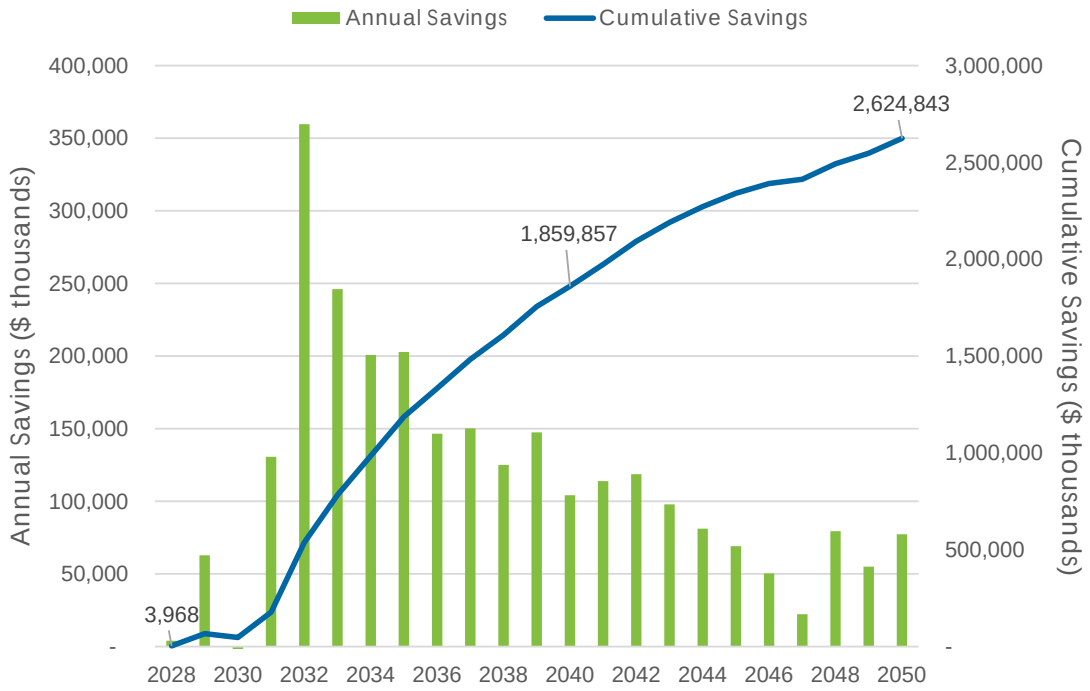


19.3 Total Customer Cost Impacts

Lower projected power supply rates can drive significant savings for CE's existing customers, beginning in 2028 when new large load growth is expected to drive lower costs per kWh for the system. CE estimated the magnitude of this cost reduction by applying the projected decline in power supply costs to the projected kWh of energy sales for CE's existing customers under the Alt Plan Current portfolio. Cumulative nominal cost savings amounted to over $1.85 billion through 2040 and $2.62 billion through 2040. This is illustrated in Figure 19-2.[61]

[61] Note that the annual savings are slightly negative in 2030, although cumulative savings are positive throughout the time horizon. The figure shows only positive values for display purposes.

Figure 19-2: Annual and Cumulative Savings in Power Supply Costs for Existing Customers under the PCA Relative to the Alt Plan Current Portfolio



19.4 Affordability Impact of the PCA

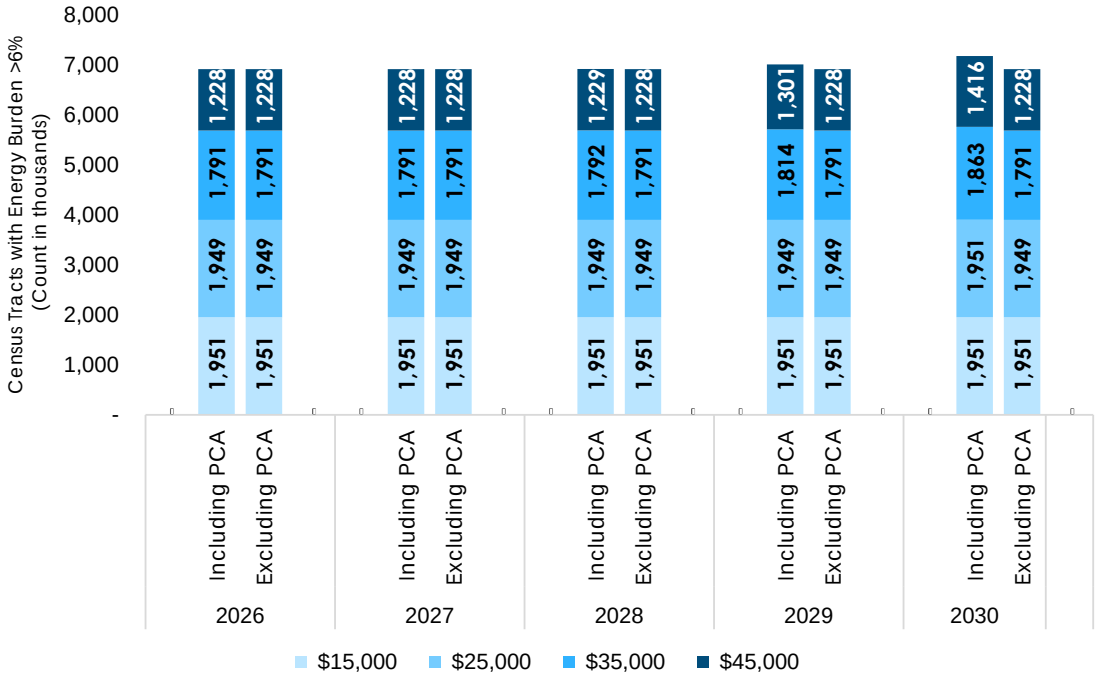
The Company also evaluated the affordability impacts of the PCA by assessing changes in customer energy burden, defined as electricity costs as a percentage of household income.

This analysis compares the PCA to the previously approved resource plan and is based on publicly available data and income segmentation methodologies, consistent with Commission guidance.

The affordability analysis (summarized in Figure 19-3) follows the general framework outlined in Appendix 2 of the filing requirements:

1. Estimate annual residential bills under the PCA;
2. Combine with baseline household energy costs;
3. Develop income distribution using publicly available census data;
4. Calculate total energy costs by income segment; and
5. Compute energy burden (% of income) for each income group.

Figure 19-3: Customer Energy Burden Impact



The PCA's affordability impact is assessed by estimating energy burden for four low-to-moderate income brackets across all census tracts in CE's service territory from 2026–2030. The analysis shows where energy burden may rise to or above the 6% threshold in the PCA compared to the previously approved plan. For these income brackets, the PCA supports affordability by relying on customer programs — especially EWR, DR, EV load management, and DG — rather than only supply-side resources, and targeted support for high-burden customers. Several affordability initiatives are identified for customers with high burdens:

- Dedicating 25% of the electric EWR portfolio and 35% of gas EWR budgets to income-qualified programs for customers at or below 250% of the federal poverty level.
- Continuing geotargeted assistance in Kalamazoo and Flint through 2029, including health and safety funding to enable weatherization.
- Expanding energy assistance access and reducing bill volatility through a dedicated Energy Assistance Team.
- Using the Single Enrollment Flow portal to guide customers to EWR programs, assistance, and payment arrangements based on indicators like payment status, payment history, income, and household size.

Environmental Considerations & Emissions Analysis

Section 20

20 Environmental Considerations and Emissions Analysis

The Company is committed to building a cleaner, more sustainable energy future for Michigan. Our commitment goes beyond meeting state and federal environmental requirements — we have established voluntary goals to reduce air emissions, water use, and landfill waste, and to safeguard our land. Central to these efforts is our commitment to achieve net-zero methane emissions from our natural gas delivery system by 2030, and achieving 100% clean energy by 2040 consistent with the 2023 Clean Energy Law in Michigan. In pursuing these goals, we evaluate all environmental risks and impacts as part of our overall strategy and business planning.

Alongside our voluntary initiatives, we maintain a strong focus on complying with all applicable environmental regulations. For our existing generation assets, the relevant regulations fall into three primary categories:



The Company's existing generation fleet and PCA are subject to a variety of federal and state environmental regulations governing air emissions, water withdrawals and discharges, waste management, and clean energy compliance. These regulations influence resource planning by affecting operating requirements, environmental compliance costs, permitting requirements, and the long-term viability of generating resources. CE evaluated applicable environmental regulations as part of the development of the PCA and alternative resource portfolios to ensure compliance with current requirements and to position the portfolio for anticipated future regulatory obligations.

The following tables identify the principal environmental regulations applicable to the Company's existing generating resources and proposed resources included in the PCA.

20.1 List of Applicable Regulations and Descriptions

Table 20-1: Air quality regulations

REGULATION	ACRONYM	CONTROLLED POLLUTANT	APPLICABLE RESOURCE(S)	COMPLIANCE DATE
Cross-State Air Pollution Rule/ Good Neighbor Plan	CSAPR	NO_x, SO_2	Coal, Gas	Phase I: 2015 Phase II: 2017
Mercury and Air Toxics Standards	MATS	Hg, PM, acid gases, metals	Coal, Oil	2016
Michigan Mercury Rule	MMR	Hg	Coal	2016

REGULATION	ACRONYM	CONTROLLED POLLUTANT	APPLICABLE RESOURCE(S)	COMPLIANCE DATE
NSPS a New, Reconstructed, Modified Combustion Turbines	NSPS	GHG, criteria pollutants	New/modified fossil units	2024
CAA §111(b)/(d) GHG Standards	CAA §111(b)/(d)	GHGs / CO_2	Fossil generation	Varies by unit
PM2.5 National Ambient Air Quality Standards	PM2.5 NAAQS	Fine particulate matter (PM2.5)	Combustion sources	2026
Public Act 235 Clean Energy Standard	Act 235	CO2	Coal, Gas	2035, 2040
Ozone National Ambient Air Quality Standards	Ozone NAAQS	Ozone precursors, primarily NOx and VOCs	Combustion sources	2015

Table 20-2: Water quality regulations

REGULATION	ACRONYM	CONTROLLED POLLUTANT	APPLICABLE RESOURCE(S)	COMPLIANCE DATE
Clean Water Act §316(b)	316(b)	Cooling water intake (fish protection)	Coal, Gas	Rule effective 2014
Steam Electric Effluent Limitation Guidelines	ELG	Wastewater discharges	Coal	2024

Table 20-3: Coal combustion residuals (waste) regulations

REGULATION	ACRONYM	CONTROLLED POLLUTANT	APPLICABLE RESOURCE(S)	COMPLIANCE DATE
Resource Conservation and Recovery Act (CCR Rule)	RCRA / CCR	Coal ash	Coal	2019

20.2 Description of Applicable Environmental Regulations

Cross-State Air Pollution Rule

The Cross-State Air Pollution Rule (CSAPR) is a federal cap-and-trade program that limits SO_2 and NO_x emissions from fossil-fueled electric generating units (EGUs) to address interstate transport of air pollution that contributes to downwind ozone and fine particulate matter nonattainment. Compliance is achieved through emissions budgets and allowance trading programs, with constraints designed to limit reliance on interstate trading and ensure state-level emissions reductions.

CSAPR was implemented in phases, with Phase I effective January 1, 2015, and Phase II effective January 1, 2017. In response to federal court decisions addressing remaining ozone-season NO_x transport obligations, the EPA finalized additional updates beginning with the 2021 ozone season and subsequently strengthened the program through the

CSAPR Update and the Good Neighbor Plan, which further reduced ozone-season NO_x emission budgets for covered states.

The Good Neighbor Plan, finalized in 2023, was stayed by the U.S. Supreme Court in 2024 and has subsequently been administratively stayed by the EPA while the agency reconsiders the rule. Earlier CSAPR requirements remain in effect. Based on current requirements, CSAPR is not expected to materially affect CE's operational structure or costs.

Mercury Air Toxics Standards
The Mercury and Air Toxics Standards (MATS) is a federal Clean Air Act rule finalized by the EPA in 2011 that establishes unit-specific emission limits or work practice standards for coal- and oil-fired EGUs. MATS regulates emissions of mercury, acid gases, non-mercury metals, and organic hazardous air pollutants, and requires compliance through the installation and operation of appropriate control technologies rather than allowance trading or fleet-wide averaging.

Affected units were required to comply by April 16, 2015, with the option for a one-year administrative compliance extension. CE received an extension from the Michigan Department of Environmental Quality, resulting in a compliance date of April 16, 2016.

The underlying MATS requirements remain in effect, although the EPA repealed the more stringent 2024 amendments in 2026, reverting to the prior standards. CE's remaining applicable coal- and oil-fired generating units are subject to MATS requirements.

Michigan Mercury Rule
The Michigan Mercury Rule (MMR) regulates mercury emissions from coal-fired EGUs in Michigan and was adopted prior to the federal MATS. The rule required existing coal units to meet mercury emission limits through specified compliance options, while new units were required to install Best Available Control Technology (BACT). Initial compliance was aligned with federal MATS requirements, with full compliance achieved by April 2016. The rule continues to apply to any remaining applicable sources, although its practical impact has declined as coal units have retired and federal hazardous air pollutant standards now govern most requirements.

CAA §111(b)/(d) GHG Standards
Section 111 of the Clean Air Act regulates greenhouse gas emissions from fossil fuel-fired power plants. The EPA finalized new standards in 2024 for existing coal units and new natural gas-fired units, although the EPA has since proposed repealing portions of those requirements. Given CE's planned coal retirements, impacts to the existing fleet are expected to be limited, but the standards could affect future natural gas generation.

PM2.5 NAAQS
The PM2.5 NAAQS establishes federal limits for fine particulate matter. The EPA strengthened the annual standard in 2024 from 12.0 to 9.0 micrograms per cubic meter. New or modified combustion resources in areas designated nonattainment may face more stringent permitting, control, and emissions offset requirements.

Ozone NAAQS
The 2015 ozone NAAQS establishes an 8-hour standard of 70 parts per billion. Several areas of Michigan remain designated nonattainment, which can trigger additional permitting, emissions control, and offset requirements for new or modified combustion sources. These requirements could affect the siting and permitting of future generation.

Clean Water Act §316B
Section 316(b) of the Clean Water Act regulates cooling water intake structures at power plants and industrial facilities to minimize harm to aquatic organisms from impingement and entrainment. The EPA's rule applies to existing facilities withdrawing more than two million gallons per day from waters of the United States for cooling purposes. Affected facilities must implement measures to reduce impacts on fish and other aquatic life, subject to case-by-case determinations by state permitting authorities. Facilities with very large withdrawals must also conduct entrainment studies as part of their National Pollutant Discharge Elimination System (NPDES) permit applications. The Company's Campbell site is applicable under these definitions and requires entrainment studies submitted to the Michigan Department of Environment, Great Lake, and Energy (EGLE).

Steam Electric Effluent Guidelines
The Steam Electric Effluent Limitations Guidelines (ELGs) regulate wastewater discharges from steam electric power plants under the Clean Water Act. The EPA revised the rule in 2020 and subsequently adopted additional requirements for wastewater streams such as bottom ash transport water, combustion residual leachate, and legacy wastewater. The requirements are implemented through NPDES permits issued by state agencies, with compliance timing determined by EGLE, CE's permitting authority. CE does not have any FGD wastewater streams.

Resource Conservation Recovery Act
Coal combustion residuals (CCR), including coal ash, are regulated under Subtitle D of the Resource Conservation and Recovery Act. EPA rules finalized in 2015 and subsequently strengthened require utilities to manage CCR disposal units to protect human health and the environment, including groundwater monitoring, structural integrity requirements, closure of unlined impoundments, and corrective actions for contamination. Although the federal rule is self-implementing, states may operate approved permitting programs; Michigan received EPA approval for its CCR permitting program in 2022. Facilities must comply with both federal standards and state permit requirements, and enforcement may occur through state action, EPA oversight, or citizen suits. The EPA further expanded the CCR requirements in 2024 to address certain legacy surface impoundments and previously unregulated CCR management units, although portions of those requirements are currently being reconsidered.

20.3 Regulatory Impact on the Proposed Resource Plan

The Company's Proposed Resource Plan continues to be shaped by an evolving regulatory landscape at the federal, state, and regional levels. The plan is designed to maintain compliance with all current air, water, and waste regulations, while reducing exposure to future regulatory costs through accelerated adoption of clean energy resources.

Despite changing regulatory expectations on traditional generation methods, the Proposed Resource Plan continues to align with Michigan's state climate goals (carbon neutral by 2050), while maintaining reliability, affordability, and safety. While there is some uncertainty around the retirement date of the Campbell plant, the current modeling and Proposed Plan assume that this asset will be retired in the coming years. The shift in generation type and asset retirements provides resilience to the Proposed Resource Plan, as most requirements and impacts apply to the assets being retired.

20.4 Capital Costs to Comply at Existing Generating Sites

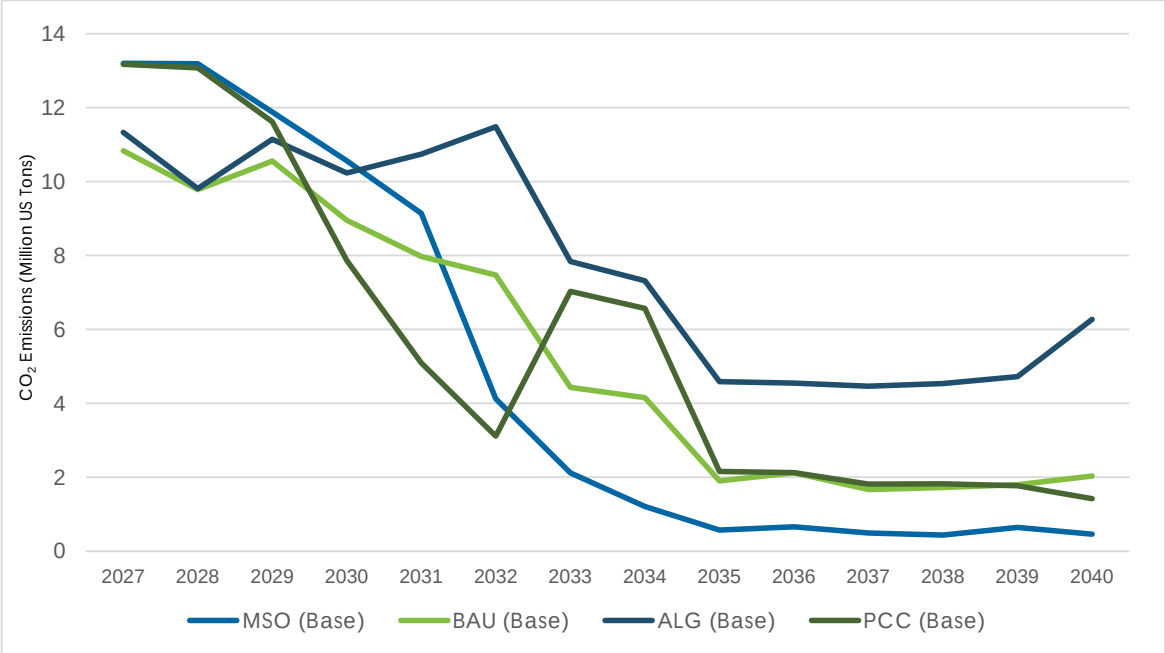
Based on the IRP's environmental compliance analysis, capital investments historically required at existing generating sites have largely been driven by air emission controls, solid waste management, and water regulations. Current environmental costs related to generating sites are very low and are not expected to have a long-term impact in the IRP.

20.5 Emissions Projections

Consistent with the MIRPP, the Company analyzed scenarios including a Business as Usual ("BAU"), MIRPP Scenario One ("MSO"), Aggressive Load Growth ("ALG"), and Physical Climate Change ("PCC"). The analysis demonstrates that projected emissions are highly dependent on future load growth, generation resource additions, retirement schedules, fuel prices, renewable resource availability, and other planning assumptions. Across all scenarios, the Company's resource planning process considered emissions performance alongside reliability, affordability, and clean energy objectives to identify portfolios capable of meeting customer needs under a range of possible future conditions.

The Company evaluated projected carbon dioxide ("CO_2") emissions across all modeled scenarios to assess the relative environmental performance of each resource plan. As shown in Figure 20-1, projected CO_2 emissions generally decline over the planning horizon as coal-fired generation is retired and replaced with lower-emitting and carbon-free resources. The timing and magnitude of emissions reductions vary among scenarios due to differing assumptions regarding future electric demand, resource additions, and system conditions.

Figure 20-1: Projected carbon emissions by scenario (CE Owned Gen. + PPA)



The cumulative emissions reductions projected under each scenario are summarized in Table 20-4.

Table** 20-4**: Total Projected emissions (CE-Owned Gen. + PPA) reduction by scenario

	2027 EMISSIONS (US Tons)	***2040 EMISSIONS (US Tons)***	***TOTAL EMISSION REDUCTIONS (US Tons)***
BAU (Base)	10,832,049	2,031,468	8,800,582
MSO (Base)	13,198,799	460,244	12,738,555
ALG (Base)	11,331,148	6,270,791	5,060,357
PCC (Base)	13,172,190	1,421,801	11,750,389

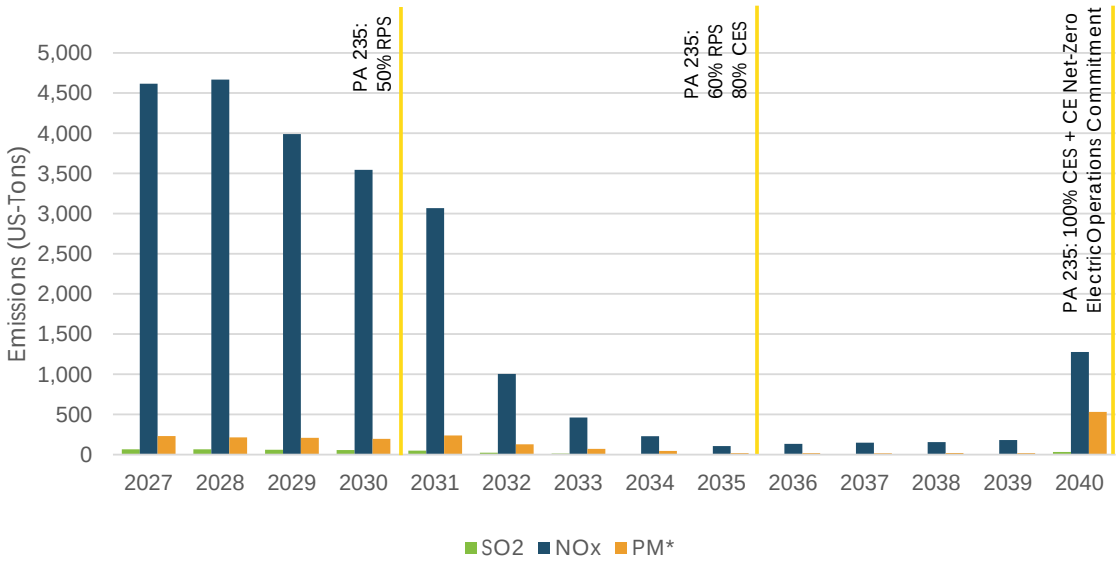
Preferred Course of Action Emissions Performance

The PCA includes the addition of new natural gas-fired generating facilities at the D.E. Karn and Thetford sites to provide dispatchable capacity needed to maintain system reliability and support compliance with Michigan's Clean Energy Law. These facilities are evaluated as part of the Company's overall resource portfolio, and projected statewide emissions continue to decline over the planning horizon as the generation mix becomes increasingly reliant on clean energy resources.

In addition to CO_2 emissions, the Company evaluated projected emissions of sulfur dioxide ("SO_2"), nitrogen oxides ("NOx"), particulate matter ("PM"), and other criteria air pollutants, hazardous air pollutants, and various pollutant precursors. These pollutants are generally projected to decline under the PCA as coal-fired generation is replaced by renewable and natural gas-fired resources.

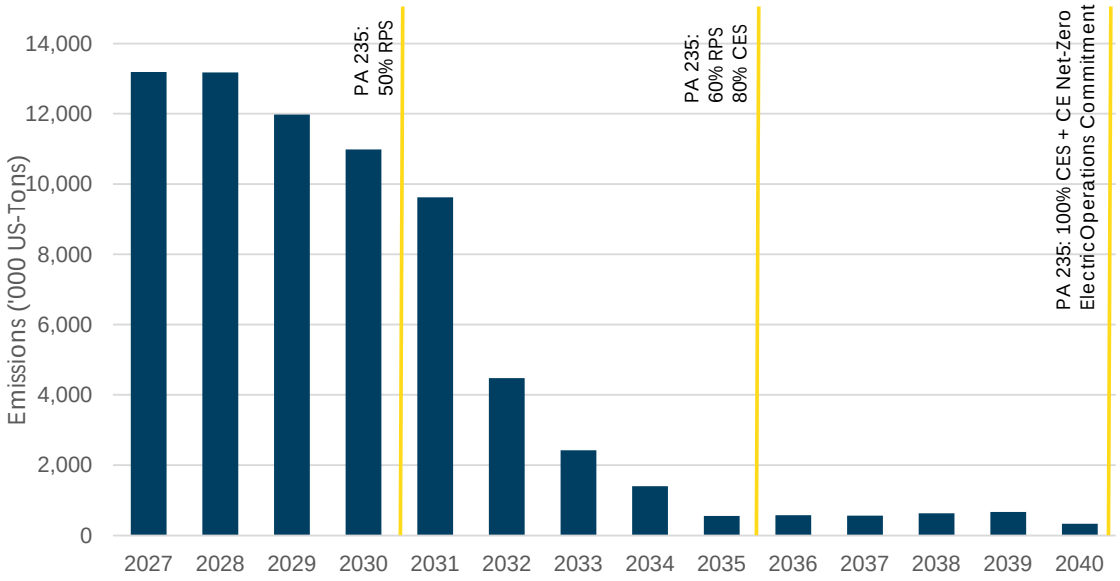
A summary of projected SO_2, NOx, and PM emissions under the PCA is provided in Figure 20-2. Projected CO_2 emissions under the PCA are shown in Figure 20-3.

Figure 20-2: MSO PCA (CE-Owned Gen. + PPA) SO_2, NOx, and PM emissions summary



*CE-Owned Generation only. PM emission rates are not available for PPAs.

Figure 20-3: MSO PCA (CE-Owned Gen. + PPA) CO_2 emissions summary



Portfolio Comparison

The Company compared emissions performance across Portfolio #1, the previously approved portfolio; Portfolio #2, the PCA; and Portfolio #5, the reasonable alternative. The analysis considered how emissions vary under differing load growth, resource addition, retirement, fuel price, renewable development, and other planning assumptions.

While the timing and magnitude of emissions reductions vary among portfolios, each portfolio demonstrates substantial long-term emissions reductions relative to current operations. Portfolio-specific annual emissions projections for all modeled cases and sensitivities are provided in Exhibit A-50 (HAB-2).

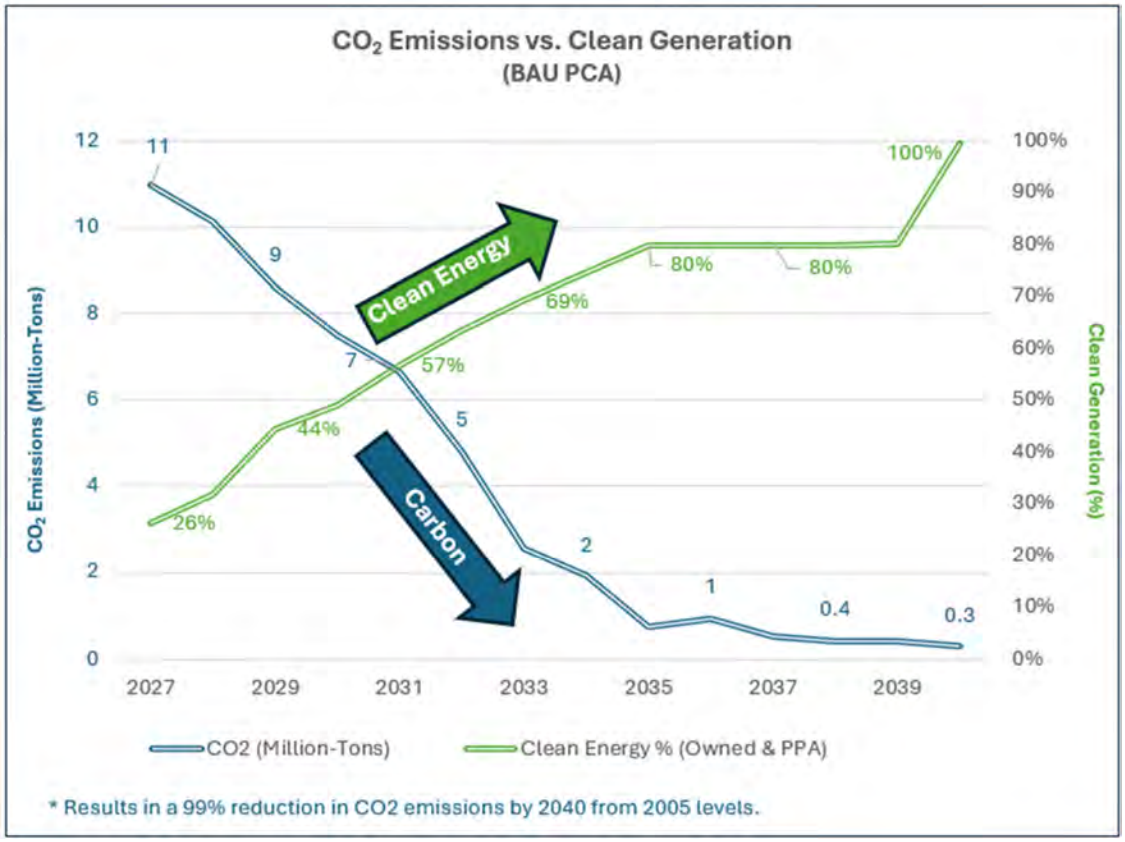
Progress Toward Clean Energy Goals

Historically, the Company's planning efforts were informed by its aspirational goal of achieving net-zero carbon emissions by 2040. To evaluate progress toward that goal, the Company utilized the Electric Power Research Institute ("EPRI") Specified Portfolio methodology, which incorporated emissions from both the Company's generating fleet, PPAs, and MISO market transactions.

Following enactment of Michigan's Clean Energy Law, the Company's planning focus transitioned from an aspirational net-zero objective to compliance with the State's statutory clean energy requirements. Consistent with the Clean Energy Law, the carbon accounting methodology utilized in this IRP is based on the mass emissions associated with the Company's generating fleet and PPAs, but excludes MISO market transactions. Accordingly, while the Company continues to compare projected CO_2 emissions across portfolios and sensitivities to assess relative environmental performance, the emissions presented in this IRP reflect the methodology used for Clean Energy Law compliance.

The PCA is designed to support compliance with Michigan's clean energy requirements, including achieving 80% clean energy compliance by 2035 and 100% clean energy compliance by 2040. In addition, the PCA is projected to reduce fleetwide carbon emissions by approximately 99% from 2005 levels by 2040.

Figure 20-4: CO_2 emissions and clean generation projections



EGLE Advisory Opinion & Environmental Justice Analysis

Section 21

21 EGLE Advisory Opinion and Environmental Justice Analysis

Consistent with the EGLE Advisory Opinion and the Michigan IRP Filing Requirements, the Company conducted a comprehensive Environmental Justice (EJ) and public health analysis of the resource portfolios evaluated in the IRP. The analysis began with an EJ screening using the Michigan Environmental Justice Screening Tool (MiEJScreen) to identify impacted communities and potentially affected areas located near existing and proposed generating facilities. The Company then evaluated projected emissions from facilities located near those communities and compared emissions across the required portfolios, including the previously approved portfolio, the PCA, and the reasonable alternative portfolios.

The Company also performed public health impact modeling using EPA's Co-Benefits Risk Assessment (COBRA) model to evaluate the health impacts associated with projected changes in air emissions. The analysis included both statewide fleet-level assessments and county-level evaluations for counties containing Company generating facilities. In addition, the Company compared the relative health benefits associated with Portfolios #1, #2, and #5 as required by the filing requirements.

To evaluate potential localized air quality impacts, the Company assessed PM and NO_x emissions variability for applicable generating units located within six miles of communities identified through the EJ analysis. The review evaluated whether projected future emissions exceeded historic operating variability and assessed potential impacts on nearby communities where appropriate.

The Company also completed a qualitative review of water quality, waste disposal, land use, and siting considerations associated with the evaluated portfolios. The review considered proposed resource additions and retirements, facility operating characteristics, siting evaluations, and environmental permitting requirements. The analysis concluded that these qualitative factors were not primary differentiators among the evaluated portfolios. However, the Company's transition away from coal-fired generation was projected to reduce generation-related water use and water intensity by approximately 99% compared to historical operations, even with the addition of the proposed Karn and Thetford CT projects.

Overall, the analysis demonstrated that all evaluated portfolios provide meaningful environmental and public health benefits relative to current conditions, although the magnitude of those benefits varies by portfolio and pollutant. The Company concluded that the primary environmental differences among the portfolios are associated with projected emissions and resulting public health impacts. The EJ screening results, emissions analyses, health impact assessments, PM and NO_x evaluations, and qualitative environmental review were considered together with reliability, affordability, resource adequacy, clean energy compliance requirements, and other planning objectives in selecting the Company's PCA.
The applicable portfolios are:

- Portfolio 1: the previously approved portfolio
- Portfolio 2: the PCA
- Portfolio 5: the reasonable alternative

21.1 Purpose and Context

CE is committed to delivering world class performance and hometown service, guided by a triple bottom line – People, the Planet, and Michigan's Prosperity. This commitment shapes our decisions as we work toward an equitable clean energy future.

CE engages directly with communities to understand local needs and create meaningful opportunities for collaboration. Responsibility for EJ is led by the Diversity, Equity, and Inclusion (DE&I) Department in partnership with the Environmental Quality and Sustainability Department.

21.2 Environmental Justice Community Identification

Michigan's EJ screening tool (MiEJScreen), developed and operated by the EGLE, is used to identify communities that may face disproportionate environmental burdens and socioeconomic vulnerabilities. The tool combines environmental indicators, such as pollution exposure and proximity to industrial sources, with demographic factors including income, race, health, and age to generate composite scores for geographic areas across the state. These factors are combined to calculate a MiEJScreen Score, as shown in Figure 21-1.

MiEJScreen was used to identify the highest impacted areas within the Company's service territory. Regions with a composite score of 75 or higher are classified as EJ communities. In addition, an EJ analysis is required for communities that have a score of 75 or higher for the Black, Indigenous, People or Color (BIPOC) and Low-Income Population sublayers. The tool serves as a screening resource to inform planning, outreach, and decision making, rather than standalone regulatory determinations.

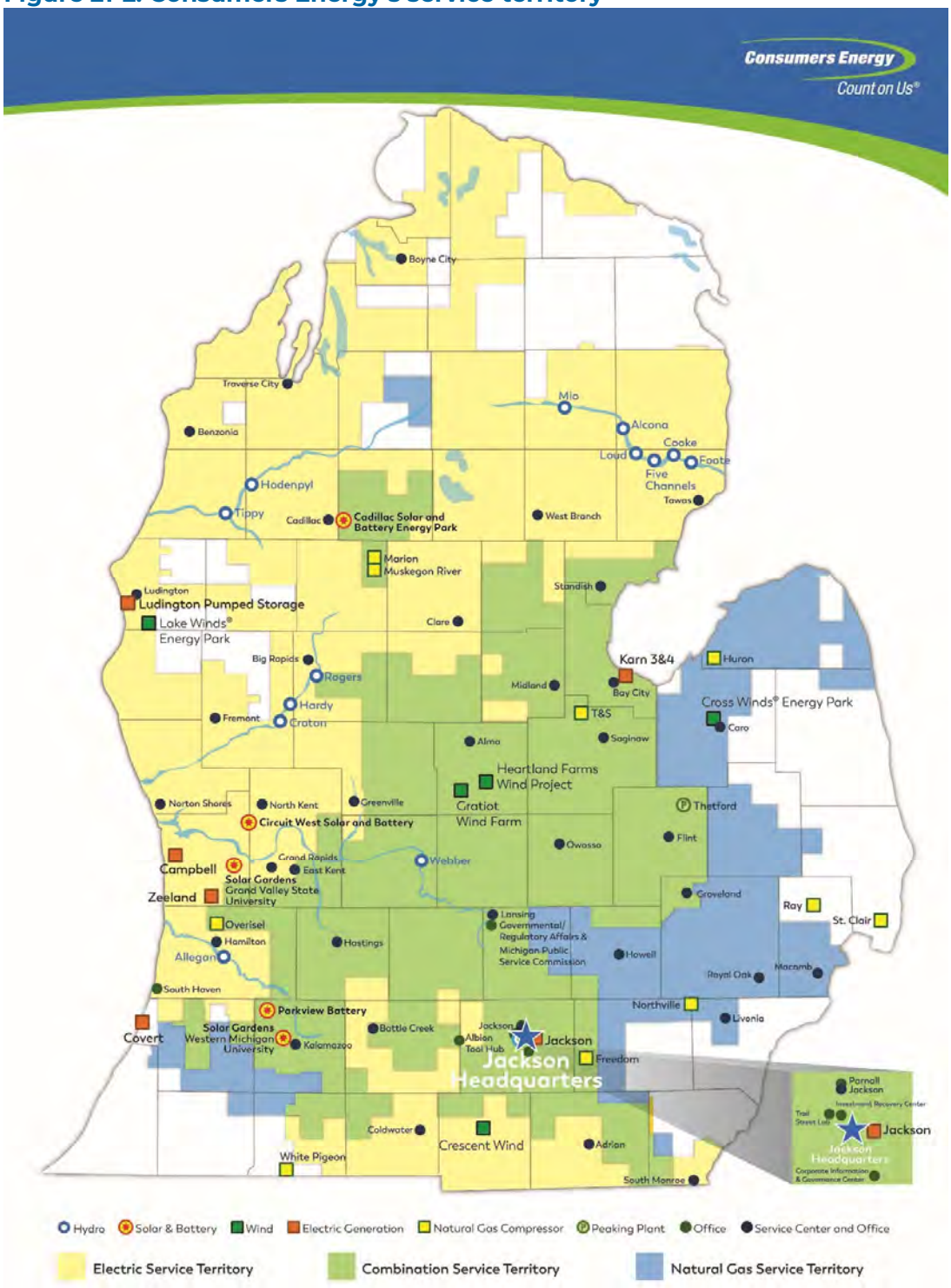
Figure 21-1: MiEJScreen scoring criteria[62]

Categories	Environmental Exposure	Environmental Effects	Sensitive Populations	Socioeconomic Factors
Indicators	NATA Air Toxics Cancer Risk NATA Respiratory Hazard Index NATA Diesel Particulate Matter Particulate Matter ($PM_{2.5}$) Ozone Traffic Density	Proximity to Cleanup Sites Proximity to Hazardous Waste Facilities Impaired Water Bodies Proximity to Solid waste Sites and Facilities Lead Paint Indicator Proximity to RMP Sites Wastewater Discharge Indicator	Asthma Cardiovascular Disease Low Birth Weight Infants Blood Lead Level Life Expectancy	Low Income Population Black, Indigenous, People of Color Population Educational Attainment Linguistic Isolation Population Under Age 5 Population Over Age 64 Unemployment Housing Burden
Sub Scores	**Environmental Conditions** (Average percentile of Environmental Exposure indicators + 0.5 x average percentile of Environmental Effects indicators) / 1.5		**Population Characteristics** (Average percentile of Sensitive Population indicators + average percentile of Socioeconomic Factor indicators) / 2	
Score	**Final Composite Score = Environmental Conditions score x Population Characteristics score** **MiEJScreen Score**			

Modeled geographies include all of CE's service territory, plus surrounding areas that may be affected by future projects. This includes Michigan's Lower Peninsula (excluding DTE's service territory in the Southeast), as shown in Figure 21-2.

[62] DGLE, *MiEJScreen: Environmental Justice Screening Tool (Version 1.0),* accessible at: https://www.michigan.gov/egle/maps-data/miejscreen

Figure 21-2: Consumers Energy's service territory



21.3 Facility-level emissions

Facility-level emissions data was developed using a combination of measured, project-specific, and representative emissions sources to ensure complete coverage of the modeled generating portfolio. For the existing generating fleet, emissions rates were derived from Continuous Emissions Monitoring System (CEMS) data, providing unit-specific measurements of key pollutants, including NO_x, SO_2, CO_2, mercury (Hg), and particulate matter (PM). Emissions values for the Karn and Thetford CT projects were sourced from data developed by the New Generation team and documented in Exhibit A-12 (TPC-7), which provides project-specific emissions characteristics for those resources. For generic gas-fired generating facilities included in the analysis, representative emissions factors were applied where unit-specific operational data were not available. Together, these sources provide a consistent and comprehensive emissions dataset that reflects actual operating performance where available while supplementing future or generic resources with standardized emissions assumptions.

Table 21-1: Facility-level emissions

UNIT	NOx (lb/mmBtu)	SO2 (lb/mmBtu)	CO2 (lb/mmBtu)	Hg (lb/TBtu)	PM (lb/mmBtu)
Zeeland 1	0.032	0.0006	118.858	-----	4.062E-03
Zeeland 2	0.032	0.0006	118.857	-----	2.298E-03
Zeeland CC	0.011	0.0006	118.857	-----	4.091E-03
DE Karn 3	0.121	0.051	121.134	-----	5.790E-06
DE Karn 4	0.121	0.051	121.134	-----	5.790E-06
Jackson	0.063	0.0006	118.857	-----	3.851E-03
Covert 1	0.007	0.0006	118.857	-----	1.839E-03
Covert 2	0.007	0.0006	118.857	-----	2.366E-03
Covert 3	0.007	0.0006	118.857	-----	3.299E-03

21.4 Proximity Analysis

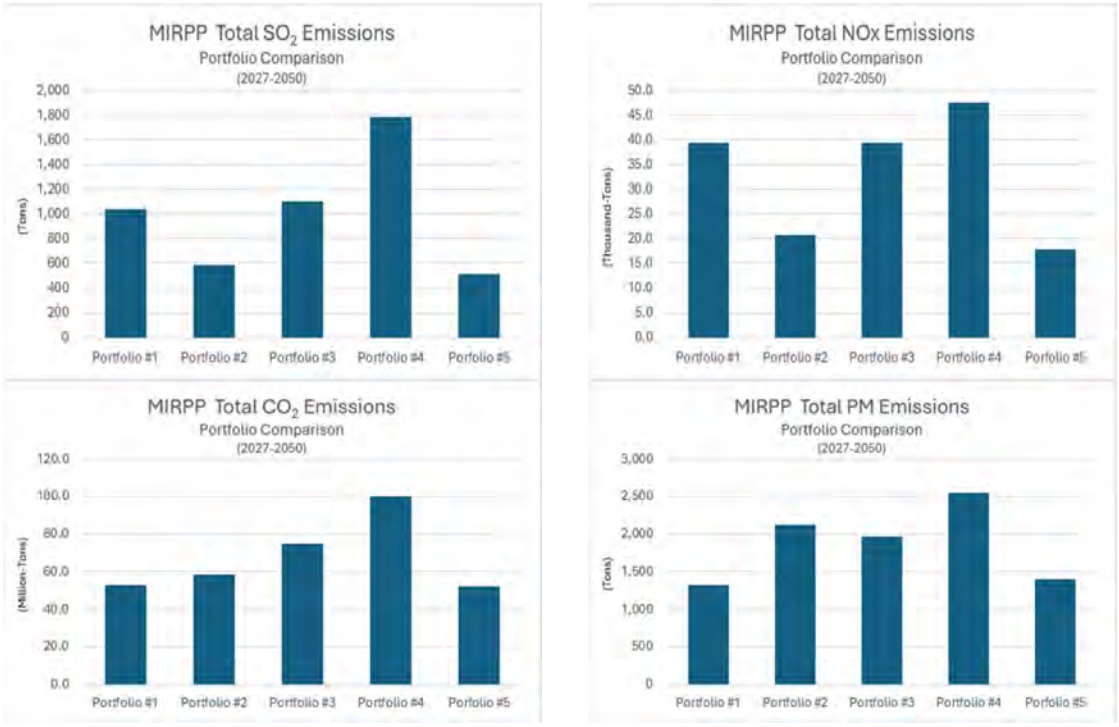
Table 21-2: MiEJScreen summary (evaluated at a 3-mile radius)

RESOURCE	OWNED/ POTENTIAL	ADDRESS	MiEJ SCORE*	POVERTY SCORE*	MINORITY SCORE*
DE Karn Generating Facility	Owned	2742 Weadock Hwy, Essexville, MI 48732	71	**90**	65
Zeeland Generating Facility	Owned	425 North Fairview Road, Zeeland, MI 49464	60	51	**78**
Jackson Generating Facility	Owned	2219 Chapin Street, Jackson, MI 49203	**83**	**99**	**87**
Covert Generating Facility	Owned	26000 77th Street, Covert, Michigan 49043	63	**84**	**81**
Thetford Site	Owned / Potential site	10205 N Genesee Rd, Mt Morris, MI 48458	73	**88**	**46**

*Scores represent maximum of all census tracts.

21.5 Quantitative Emissions Impact Assessment

Figure 21-3: MIRPP Emissions Comparison by Portfolio and Emission Type



The PCA was compared against the previously approved portfolio (Portfolio #1) and other modeled resource alternatives to evaluate the cumulative emissions impacts associated with different resource strategies over the planning horizon. The analysis assessed total SO_2, NO_x, CO_2, and PM emissions from the total Company portfolio. Consistent with the broader EJ and environmental review, the objective was not to identify the portfolio with the lowest emissions for a single pollutant, but rather to understand the environmental tradeoffs associated with each portfolio and evaluate those results alongside reliability, affordability, resource adequacy, and compliance with Michigan's Clean Energy Law.

As shown in the above charts, no single portfolio produced the lowest emissions across all pollutants evaluated. The PCA produced substantially lower SO_2 and NO_x emissions than the previously approved Portfolio #1, reflecting the environmental benefits associated with fleet evolution and planned resource additions. At the same time, the PCA resulted in somewhat higher cumulative CO_2 and PM emissions than certain alternative portfolios. These results demonstrate that each portfolio presents a different combination of environmental outcomes and that selection of a preferred plan cannot be based solely on any individual emissions metric.

The PCA was selected because it provides a balanced pathway that continues significant long-term emissions reductions while maintaining reliable service and supporting compliance with Michigan's statutory clean energy requirements. While

certain alternative portfolios achieved lower emissions for specific pollutants or under certain assumptions, those outcomes were often associated with more aggressive resource development requirements, higher costs, or other tradeoffs. The Company's evaluation therefore considered not only emissions, but also public health outcomes, EJ considerations, and overall system needs. Based on this comprehensive assessment, the Company concluded that the PCA represents the most prudent balance of environmental performance and broader planning objectives, while still achieving approximately a 99% reduction in carbon emissions by 2040 relative to 2005 levels.

21.6 Health Impact Analysis

COBRA is an EPA screening-level model designed to quickly estimate the health and economic benefits of reducing air pollutant emissions. It includes built-in simplified air quality relationships that translate emissions changes directly into PM2.5 concentration changes at the state or county level, allowing users to assess impacts without running complex atmospheric models. It produces estimates of avoided mortality, illnesses, and associated monetary benefits, making it useful for preliminary policy analysis, EJ screening, and early-stage planning.

The COBRA analysis indicates that the PCA produces substantial overall health benefits through reductions in air pollutant emissions. The state level, fleetwide analysis estimates annual avoided health-effect costs in the range of approximately $120 million to $200 million. County level analyses for Bay County, Genesee County, Jackson County, Ottawa County and VanBuren County also indicate positive health outcomes associated with reduced emissions. Accordingly, the COBRA analysis demonstrates that the PCA will lead to public health benefits while supporting the Company's reliability and clean energy objectives. The results of these analyses are provided in Exhibit A-53 (HAB-5).

Table 21-3: COBRA Health Impact Results Summary - BAU PCA comparison: 2023 actual emissions versus 2040 projected emissions

REQUIREMENT / GEOGRAPHY	FACILITY / FLEET	COUNTY	PM HEALTH EFFECTS	OZONE HEALTH EFFECTS	TOTAL HEALTH EFFECTS	DIRECTION	FILING USE
State-level fleetwide	Fleet	Statewide	$73,000,000 to $160,000,000	$47,000,000	$120,000,000 to $200,000,000	Benefits / costs avoided	Fleetwide health-impact comparison
	Fleet	Bay County	$1,100,000 to $2,200,000	$1,500,000	$2,600,000 to $3,700,000	Benefits / costs avoided	Fleetwide emissions - county level health impact
	Fleet	Genesee County	$3,500,000 to $7,800,000	$2,400,000	$6,000,000 to $10,000,000	Benefits / costs avoided	Fleetwide emissions - county level health impact
	Fleet	Jackson County	$1,200,000 to $2,400,000	$740,000	$1,900,000 to $3,200,000	Benefits / costs avoided	Fleetwide emissions - county level health impact
	Fleet	Van Buren County	$330,000 to $690,000	$190,000	$530,000 to $890,000	Benefits / costs avoided	Fleetwide emissions - county level health impact

	Fleet	Ottawa County	$1,400,000 to $2,800,000	$970,000	$2,400,000 to $3,800,000	Benefits / costs avoided	Fleetwide emissions - county level health impact

Table 21-4: COBRA health impact results summary - MSO portfolio comparison: 2023 actual emissions versus 2040 projected emissions

REQUIREMENT / GEOGRAPHY	FACILITY / FLEET	COUNTY	PM HEALTH EFFECTS	OZONE HEALTH EFFECTS	TOTAL HEALTH EFFECTS	DIRECTION				FILING USE
State-level fleetwide	Portfolio #1 (Fleet)	Statewide				$280,000,000 to $600,000,000	$150,000,000	$430,000,000 to $750,000,000	Benefits / costs avoided	Fleetwide health-impact comparison
County-level	Portfolio #2 (Fleet)	Statewide				$260,000,000 to $550,000,000	$81,000,000	$340,000,000 to $630,000,000	Benefits / costs avoided	Fleetwide health-impact comparison
County-level	Portfolio #5 (Fleet)	Statewide				$290,000,000 to $610,000,000	$160,000,000	$440,000,000 to $770,000,000	Benefits / costs avoided	Fleetwide health-impact comparison

Notes:

1. Positive values indicate annual reductions in health effects and associated costs avoided. Negative values indicate annual increases in health effects and associated costs accrued.
2. Values are presented as reported in the COBRA output and rounded to the displayed precision.

21.7 Qualitative Environmental Assessment

The Company assessed the potential effects of the PCA on water resources, waste management, land use, and local environmental conditions. This assessment considered both the environmental characteristics of the proposed resources and the extent to which the PCA reduces exposure to environmental obligations commonly associated with coal-fired generation.

Water Quality Implications. The Company's assessment found that the proposed Karn and Thetford CTs have limited water-related impacts relative to traditional steam-electric generation. Neither facility utilizes cooling water intake structures subject to Section 316(b) requirements, nor do they generate wastewater streams subject to the Steam Electric Effluent Guidelines that apply to coal-fired facilities. Water use is primarily limited to evaporative cooling and routine plant operations, and any hazardous wastewater would be collected and managed off-site in accordance with applicable requirements. The Company does not anticipate future expenditures associated with compliance with water regulations at its gas-fired facilities.

Waste Management and Disposal Considerations. The PCA reduces several waste streams associated with coal-fired generation. The proposed CT facilities do not

generate coal combustion residuals, such as coal ash, and do not produce wastewater streams associated with coal-fired operations. As a result, the portfolio reduces the need for long-term waste handling, disposal, and environmental compliance activities associated with legacy coal generation.

Land Use and Siting Considerations. Proposed CT facilities would be developed on existing Company-owned generating sites, allowing the Company to utilize existing industrial locations and supporting infrastructure. Environmental permitting processes will continue to evaluate site-specific considerations such as wetlands, floodplains, protected species, and other environmentally sensitive resources.

Implications for Nonattainment Areas. The Company evaluated whether the PCA would introduce generation resources into areas that do not meet federal air quality standards. The review found that neither existing Company generating facilities nor the proposed Karn and Thetford facilities are located within designated nonattainment areas.

Overall, the PCA reduces reliance on environmental compliance programs associated with coal-fired generation while limiting water impacts, reducing waste management obligations, utilizing existing generation sites, and avoiding development within nonattainment areas. These considerations support the Company's conclusion that the PCA is consistent with its environmental compliance strategy and broader environmental objectives.

21.8 Environmental Justice Outcomes and Comparisons

The Company considered the EJ screening results, portfolio emissions comparisons, COBRA health impact assessments, PM and NO_x variability evaluations, and qualitative reviews of water quality, waste disposal, land use, and siting considerations when evaluating the portfolios. These analyses demonstrated that all evaluated portfolios provide environmental and public health benefits relative to current conditions, although the magnitude of those benefits varies by pollutant and portfolio. The qualitative review did not identify water quality, waste disposal, land use, or siting considerations that materially differentiated the portfolios.

The PCA also includes the addition of the Karn and Thetford CT projects, which will result in localized environmental burdens associated with construction, operation, and air emissions. However, these facilities are expected to operate infrequently, provide critical reliability and resource adequacy benefits, and support the Company's transition away from coal-fired generation. When evaluated on a system-wide basis, the emissions and environmental impacts associated with these facilities are substantially outweighed by the reductions in emissions, water use, ash generation, and related environmental impacts achieved through the retirement of coal-fired generation and continued deployment of renewable energy resources.

The quantitative analyses showed that the primary environmental differences among the portfolios were associated with projected emissions and the resulting public health impacts. After considering these results together with reliability, affordability, resource

adequacy, clean energy compliance, and other planning objectives, the Company concluded that the PCA provides an appropriate overall balance of environmental performance and the broader objectives of the IRP.

An economic study was conducted to understand the impacts of the proposed Karn and Thetford CT projects. The studies found that both facilities are expected to provide significant economic benefits through construction activity, long-term employment opportunities, labor income, and increased tax revenues for local communities and Michigan state. These benefits were considered alongside environmental, public health, environmental justice, reliability, affordability, and resource adequacy objectives. The analysis concluded that the projects would provide meaningful economic value while supporting the Company's ability to maintain reliable electric service and comply with Michigan's clean energy requirements, and that these benefits outweigh the localized and temporary impacts associated with construction and operation.

Key Tradeoffs Identified

Maintaining reliable service and supporting future load growth may require the addition of new dispatchable generation resources. While the proposed CTs introduce new emissions sources, those impacts were evaluated in the context of existing site conditions, historical emissions profiles, and potential public health effects. As noted above, the proposed facilities offer operational and reliability benefits while producing substantially lower emissions and fewer environmental impacts than historical coal-fired generation at comparable locations. Additionally, the proposed facilities avoid CCR, cooling water intake requirements, and wastewater streams associated with steam-electric coal generation.

21.9 Integration Into Resource Planning Decisions

EJ considerations informed the IRP planning process through both quantitative analyses and an extensive stakeholder engagement program designed to gather input from customers, environmental justice communities, Tribal Nations, technical stakeholders, and other interested parties. Consistent with the Company's commitment to an equitable energy transition, CE conducted targeted outreach in EJ communities across several areas, supplemented by virtual outreach opportunities, technical workshops, customer surveys, and ongoing engagement with Tribal Nations. These efforts were intended to ensure that community perspectives regarding affordability, reliability, environmental performance, access to programs, and energy equity were incorporated into the IRP development process.

Feedback from EJ communities emphasized the importance of maintaining affordable electric service, improving program accessibility, reducing barriers to participation, and ensuring that the benefits of the clean energy transition are shared broadly across communities. While community and stakeholder feedback did not independently determine resource selection outcomes, it provided important context regarding customer priorities, community concerns, and EJ considerations that were evaluated alongside planning requirements, environmental performance, system reliability, resource adequacy, and affordability objectives. As a result, EJ considerations were

integrated directly into the evaluation of resource alternatives and the selection of the PCA.

The Company ultimately selected the PCA after balancing stakeholder priorities with statutory requirements, reliability obligations, affordability considerations, environmental objectives, and the results of its quantitative planning analyses. EJ outreach and community feedback helped inform the Company's understanding of how resource decisions may affect customers and communities, while other analyses provided the analytical basis for comparing alternatives. Together, these inputs supported selection of a portfolio designed to maintain reliable and affordable service, comply with Michigan's clean energy requirements, advance environmental objectives, and reflect the priorities raised through the Company's comprehensive stakeholder engagement process.

News Release

Consumers Energy Count on Us

Consumers Energy Plan Will Power Michigan's Next Generation with Reliable and Affordable Energy

Plan Includes All-Of-The-Above Mix of Solar, Wind, Natural Gas and Storage

JACKSON, MI, Sept. 3, 2026 – Consumers Energy today is unveiling its Energy Supply Plan, a 20-year blueprint to deliver reliable and affordable energy for Michigan through an all-of-the-above mix of natural gas, solar, wind, pumped and battery storage. This long-term strategy reinforces our commitment to transparency as we meet Michigan's energy needs and support the state's growth.

Consumers Energy is committed to putting forward the most affordable energy plan that both delivers reliable service and meets Michigan's clean energy law targets. This all-of-the-above plan keeps costs rising less than the rate of inflation of 3% while investing in the new resources Michigan needs.

"Michiganders count on us to power their lives 24/7/365. This plan takes an all-of-the-above approach that serves our state and customers today and ensures we have the energy supply for our state over the next two decades," said Chris Fultz, Consumers Energy's senior vice president of electric supply. "Our plan will help lower customers' bills while powering Michigan with affordable energy."

The Energy Supply Plan includes expanded renewable energy resources and two fast-starting natural gas plants to supply reliable power to our customers. In addition, we are announcing two contracts to purchase power from third-party sources – a clean resource contract to meet Michigan's clean energy standards and a new agreement to purchase power from a natural gas plant in Midland to support our customers' reliability needs.

Michigan customers will benefit from other aspects of the IRP:

- **New Power Sources:** The addition of over 19 gigawatts (GW) of solar, wind and battery storage resources by 2040 will meet customers' energy needs and targets in Michigan's 2023 energy law. Those will be supported by two new fast-starting natural gas plants, generating 1.4 GW, in Bay and Genesee counties that can serve Michigan at times of high energy demand.
- **Reliable, Efficient Generation:** The plan repurposes existing industrial sites at the Karn Energy Center and in Thetford Township, minimizing land impacts and replacing two retiring plants, delivering fast-starting power when customers need it. The plants will offer a solid reliability foundation that allows us to continue adding renewable energy. The Energy Supply Plan also includes a new long-term power purchase agreement with the Midland Cogeneration Venture to reliably power Michigan customers.

- **Community Investments:** This plan will strengthen the state's workforce by adding thousands of construction jobs and creating hundreds of permanent positions through our investments in natural gas, wind, solar and battery storage. In addition to the expanded workforce, the plan's investments in these local communities will enhance the tax base by billions of dollars.
- **Clean Energy and Customer Resources**: Our plan shows the company's continued commitment to clean energy options, such as solar, wind and battery storage to achieve targets set in the 2023 energy law. Consumers Energy also will continue to expand customer programs that have lowered customers' bills by $8.5 billion since 2009 and are projected to save $18 billion by 2050.

"It's important to see Consumers Energy make this commitment to skilled labor jobs here in Michigan," said Craig Wright, president of the Michigan State Utility Workers Council. "The company's plan to invest in our state will create good-paying, meaningful opportunities for people in our workforce who are ready to do the job and meet Michigan's energy needs now and for years to come."

The full Energy Supply Plan and supporting documents are being filed with the Michigan Public Service Commission today and are subject to approval in the next year.

Consumers Energy is Michigan's largest energy provider, providing natural gas and/or electricity to 6.8 million of the state's 10 million residents in all 68 Lower Peninsula counties. We are committed to delivering reliable and affordable energy to our customers 24/7.

Learn more at ConsumersEnergy.com/EnergySupplyPlan.

Media Contacts: Brian Wheeler, 517-740-1545, or Katie Carey, 517-740-1739



2026 Energy Supply Plan

Consumers Energy
Count on Us®



EXECUTIVE SUMMARY

Powering the Next Generation in Michigan

Affordable, all-of-the-above approach will meet Michigan's energy needs today and for years to come.

Consumers Energy is filing its Energy Supply Plan with the Michigan Public Service Commission. This is our 20-year blueprint to deliver affordable and reliable energy for Michigan through a balanced mix of energy sources.

The plan gives customers, communities and all stakeholders clear visibility into our long-term strategy as Michigan's energy needs grow. It reflects an all-of-the-above approach: expanding clean and renewable resources, adding flexible on-demand generation, strengthening nationally recognized customer programs and supporting Michigan communities through local investment and job creation.

- **New power sources:** Over 19 gigawatts of expanded renewable and clean energy resources, including solar, wind and battery storage.
- **Reliable, on-demand capacity:** Two new natural gas plants at existing industrial sites in Bay and Genesee counties, totaling 1.4 gigawatts and proposed to be in service in 2031.
- **Customer savings:** Consumers Energy is committed to putting forward the most affordable energy plan we can — the lowest-cost plan that both delivers reliable service and meets Michigan's clean energy law targets. This all-of-the-above plan keeps costs rising less than the rate of inflation of 3% while investing in the new resources Michigan needs.
- **Purchasing power:** Two contracts to purchase power from third-party sources – a clean resource contract to meet Michigan's clean energy standards and a new agreement to purchase power from a natural gas plant in Midland to support our customers' reliability needs.
- **Community investment:** Thousands of construction jobs, hundreds of permanent positions and growing Michigan's tax base from energy projects.

Our Energy Supply At A Glance

Our Energy Supply Plan combines dependable, fast-start resources with a major expansion of renewable and clean energy options. This balance increases system flexibility and protects reliability, while also complying with Michigan's 2023 Energy Law.

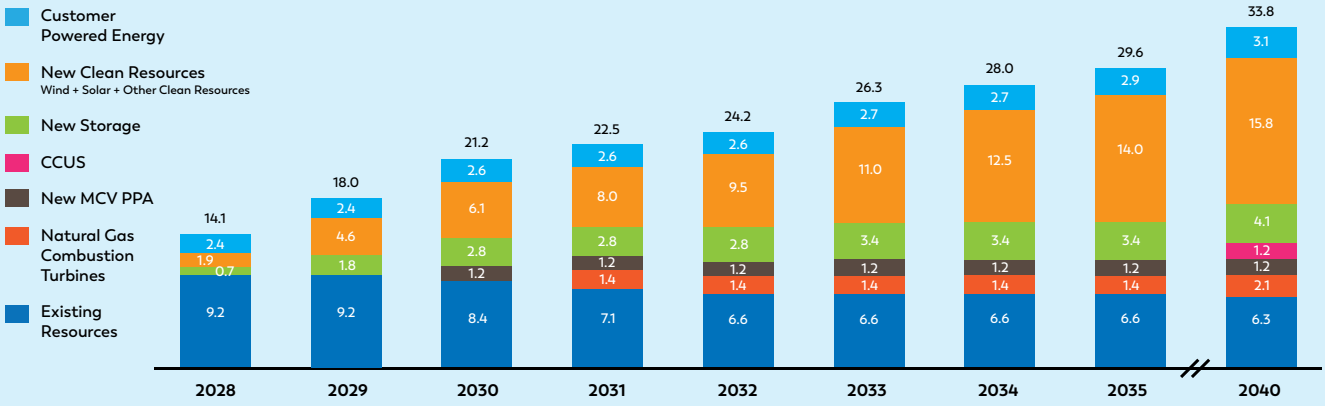
Resource	Role	Detail
Solar, wind and battery storage	Expand clean and capacity	Over 19 GW of new renewable and clean resources
Natural gas at Karn and Thetford	Provide fast, reliable power when needed	456 MW at Karn and 919 MW at Thetford, using existing industrial sites and grid infrastructure
Power Purchase Agreements	Add reliable capacity and emissions-free long term energy	Agreements to support Michigan customers
Pumped storage and hydro resources	Store and dispatch energy	Long-term arrangements include a 30-year agreement to buy power from dams
Energy waste reduction and demand response	Help customers control monthly bills and support the grid	Customers have saved $8.5 billion since 2009 and are projected to save $18 billion by 2050



Plan Highlights

Total Portfolio, Existing & Incremental Resources

Nameplate Capacity (GW)



The Energy Supply Plan provides a practical path to serve customers in every hour and every season while continuing the transition to cleaner resources.

New Michigan power sources

More than 19 GW of expanded renewable and clean energy resources, supported by 1.4 GW of new natural gas generation.

Affordability and reliability

Prioritize the lowest-cost source available at any time while maintaining reliable service.

Existing sites for new generation

Repurpose existing industrial sites at Karn and Thetford to reduce land impacts and leverage existing grid infrastructure.

Continued clean energy progress

Achieve targets set in Michigan's 2023 Energy Law through renewable resources, battery storage, and a clean resource contract.

Customer-centered programs

Strengthen Energy Waste Reduction, Demand Response and other programs that help customers save money and improve reliability.

Community investment

Support communities through taxes, construction jobs, permanent positions and new energy infrastructure.

Growth planning

Prepare for customer growth, electric vehicles, economic development, distributed generation and more.

Transparent process

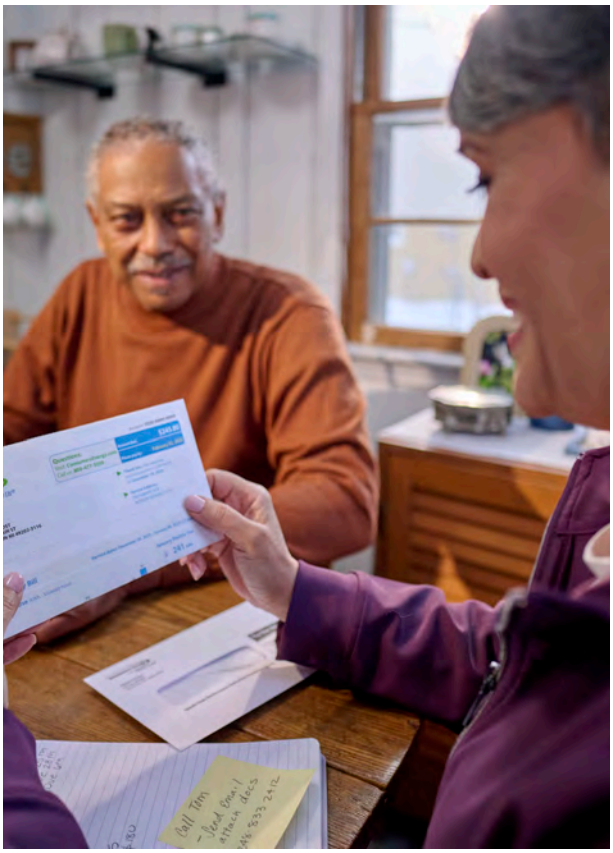
Continue stakeholder engagement through outreach events, giving opportunities for our customers to weigh in.

Reliability: Energy When Michigan Needs It



Our plan takes a balanced and diversified approach to ensure dependable service in all conditions. Efficient, fast-start natural gas generation will help meet customers' needs when demand for energy is high.

- Karn: Over 450 MW proposed at an existing industrial site near Bay City.
- Thetford: Over 900 MW proposed at an existing industrial site in Genesee County.
- Both facilities are proposed to be in service in 2031.
- These units are designed to operate when the system needs support, providing a reliability foundation as Consumers Energy continues adding renewable resources.
- The natural gas plants will repurpose existing industrial sites at Karn and Thetford. This approach minimizes land impacts, leverages existing grid infrastructure and creates Michigan jobs while providing dependable power when customers need it most.



Affordability: Stable Bills And Lower-Cost Energy

We're committed to putting forward the most affordable energy plan possible: the lowest-cost path that delivers reliable service while meeting Michigan's clean energy requirements. Our all-of-the-above approach combines flexible natural gas generation, low-operating-cost renewable resources, and customer programs that reduce demand.

This all-of-the-above plan keeps costs rising less than the rate of inflation of 3% while investing in the new resources Michigan needs.

Expanding Clean Energy

Consumers Energy's plan continues expanding clean energy options such as solar, wind and battery storage.

The plan will achieve the targets set within Michigan's 2023 energy law by pairing renewable resources with clean energy, storage, and customer-powered sources.







Customers As Partners

Customers are central to our plan's success. Energy Waste Reduction and Demand Response programs give customers incentives and tools to use less energy and lower bills.

- **Energy Waste Reduction:** Incentives and solutions that help customers save directly on their bills. Since 2009, customer programs have saved customers $8.5 billion and are projected to save $18 billion by 2050.

- **Demand Response:** Programs that help shift or reduce energy use during periods of peak demand.

- **Customer-Powered Energy:** Customer-powered energy is an important part of our energy strategy and reflected in our Energy Supply Plan through programs that help reduce customer demand during peak periods to promote flexibility in a cost-effective way. In fact, these programs can reduce peak demand by up to 3,100 MW. However, while these programs provide valuable flexibility and peak reduction, they cannot fully replace firm generation resources that are needed to reliably serve customers during extended periods of high demand or when demand response resources are unavailable. The most reliable and affordable path forward is a balanced approach.







Supporting Michigan's Success

The Energy Supply Plan prepares for growth from new families, expanding businesses, relocating industries, electric vehicle adoption, distributed generation and more.

The plan supports Michigan-made energy by strengthening generation in the state and investing in communities where new infrastructure will be built. Those investments are expected to support thousands of construction jobs, hundreds of permanent roles and an enhanced tax base from energy projects, including the natural gas plants and projects in the Renewable Energy Plan approved in 2025.



Support for the Energy Supply Plan



"We applaud Michigan businesses that grow by investing in our state and putting people to work in our community. Consumers Energy is developing a responsible plan to serve Michigan that will create jobs, build our tax base and strengthen the Bay area's economy. We're excited to see their expanded commitment to our community provide benefits now and for decades to come."

- Magen Samyn, President and CEO, Bay Area Chamber of Commerce

"We value Consumers Energy's investment in our community and appreciate the partnership and support behind this effort. While this project will certainly strengthen our local economy, its impact reaches far beyond Hampton Township and Bay County. By taking advantage of existing infrastructure, this project shows Consumers Energy's long-term commitment to provide reliable, affordable energy that will benefit families and businesses across Michigan.

- Hampton Township





"The planned investments by Consumers Energy will create meaningful opportunities for skilled workers across Michigan. These projects will support good-paying jobs and strengthen the skilled trades pipeline for the men and women who build and maintain our state's vital infrastructure."

- Michigan Building Trades Council

The Process

We are listening to the people of Michigan. Our Energy Supply Plan reflects our commitment to providing reliable, affordable, safe and clean energy to nearly 2 million homes and businesses we serve. It's critical for our plan to reflect the ideas and input of stakeholders around the state.

In 2025, we gathered community input as we developed our Energy Supply Plan through a series of engagement efforts, including five public outreach events, three technical workshops and a customer survey. We maintain a dedicated website at **ConsumersEnergy.com/EnergySupplyPlan** where community members can submit questions and comments at any time.

We used community input to help shape several parts of the Energy Supply Plan. Feedback helped us refine our energy mix by balancing renewables with fast-start natural gas to ensure reliable power in all conditions. Community members also asked for more clarity around affordability, which led us to highlight how system flexibility and reduced market purchases help keep bills stable.

We also added clearer explanations of both near-term actions and long-term plans based on requests for more transparency. Finally, we're improving communication by proactively expanding outreach through communicating our plans across various channels and organizing reoccurring events with stakeholders and communities.

The next steps from here will continue to put people first. The Michigan Public Service Commission will review the Energy Supply Plan over the next 12 months, a process that's open to the public and will feature more opportunities for people to contribute their thoughts. We at Consumers Energy are committed to providing more information to the people we serve, ensuring we continue to develop a plan that's best for Michigan.



To learn more about our plan, visit:
ConsumersEnergy.com/EnergySupplyPlan

Consumers Energy Count on Us®

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan and Certificates of Necessity under MCL 460.6s and 460.6t, certain accounting approvals, and for other relief.	)))))))	Case No. U-22127

REDACTED

DIRECT TESTIMONY

OF

KEITH G. TROYER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2026

Q. Please state your name and business address.

A. My name is Keith G. Troyer, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. In what capacity are you employed?

A. I am the Director of Origination and Contracts in the Electric Supply Department.

QUALIFICATIONS

Q. Please describe your educational background and work experience.

A. I received the degree of Bachelor of Science in Engineering with a specialty in Civil Engineering from Michigan State University in 2008. In 2015, I became a Registered Professional Engineer in the state of Michigan. In 2018, I received a Master of Business Administration ("MBA") through Michigan State University's Executive MBA Program.

In July 2009, I joined Consumers Energy as an Electric System Owner. In January 2011, I accepted a position as an Engineer in the Transactions and Resource Planning Section of the Energy Supply Department. In that role, I was responsible for administration and coordination of the Company's Experimental Advanced Renewable Program ("EARP") – Solar, part of the Company's Renewable Energy ("RE") Plan ("RE Plan"). I was involved in the development and implementation of the EARP-Solar expansion in 2011. In June 2013, I began taking on additional responsibilities associated with the RE Plan, including the calculation of the Transfer Price associated with renewable energy and capacity and the tracking of Renewable Energy Credits ("RECs"). In 2014, I was also responsible for supervision of the implementation of the EARP-Anaerobic Digestion pilot.

In December 2016, I transitioned to a new role where my supervisory and direct responsibilities included administering Power Purchase Agreements ("PPAs"), issuing solicitations for energy and capacity, and managing the Company's capacity position with Midcontinent Independent System Operator, Inc. ("MISO"). In September 2019, I became the Director of Contracts and Settlements, where my responsibilities included oversight of the Company's distribution agreements and programs, PPAs, solicitations for energy and capacity, renewable energy compliance, and electric wholesale settlement activities. In March 2025, I became the Director of Origination and Contracts.

Q. What are your responsibilities as Director of Origination and Contracts?

A. My responsibilities include oversight of the Company's solicitations for wholesale electric supply resources, procurement of new resources through bilateral negotiations, and negotiation of new PPAs and PPA amendments.

Q. Have you previously provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I provided testimony in:

- Case No. U-17095-R (direct), the Company's 2013 Power Supply Cost Recovery ("PSCR") Reconciliation Case, regarding 2013 RE Plan expenses recovered through PSCR;
- Case No. U-17631 (direct), the Company's 2013 RE Reconciliation Case, regarding 2013 RE Plan expenses recovered through PSCR, RE compliance, and new renewable capacity compliance;
- Case No. U-17317-R (direct), the Company's 2014 PSCR Reconciliation Case, regarding 2014 RE Plan expenses recovered through PSCR;

- Case No. U-17792 (direct and rebuttal), the 2015 biennial review of the Company's RE Plan, regarding RE Plan expenses recovered through the PSCR, RE compliance, new renewable capacity compliance, and RE programs;

- Case No. U-17803 (direct), the Company's 2014 RE Cost Reconciliation Case, regarding 2014 RE Plan expenses recovered through PSCR, RE compliance, and new renewable capacity compliance;

- Case No. U-17678-R (direct), the Company's 2015 PSCR Reconciliation Case, regarding 2015 RE Plan expenses recovered through PSCR;

- Case No. U-17918 (rebuttal), the Company's 2016 PSCR Plan and five-year forecast, regarding the impacts of net electric metering on energy supply;

- Case No. U-18081 (direct and revised), the Company's 2015 RE Reconciliation case, regarding 2015 RE Plan expenses recovered through PSCR, RE compliance, and new renewable capacity compliance;

- Case No. U-18090 (direct, rebuttal, reopened rebuttal, and second reopened rebuttal, and affidavit), the Company's 2016 Public Utility Regulatory Policies Act of 1978 ("PURPA") case to establish a method and calculation for avoided costs;

- Case No. U-17918-R (direct), the Company's 2016 PSCR Reconciliation Case, regarding 2016 RE Plan expenses recovered through PSCR;

- Case No. U-18241 (direct), the Company's 2016 RE Cost Reconciliation Case, regarding 2016 RE Plan expenses recovered through PSCR;

- Case No. U-18402 (direct and rebuttal), the Company's 2018 PSCR Plan and five-year forecast, regarding long-term PPAs and capacity forecast;

- Case No. U-18231 (direct and rebuttal), the 2017 biennial review of the Company's RE Plan, regarding the Company's Request for Proposal ("RFP") process for new resources, the cost of new renewable resources included in the RE Plan, and the risks that may drive performance to vary, associated with these topics;

- Case No. U-18351 (rebuttal), the Company's 2017 Application to comply with Section 61 of 2016 PA 342, regarding customer credits in voluntary RE programs and competitive solicitations;

- Case No. U-20165 (direct, rebuttal, and second rebuttal), the Company's 2018 Integrated Resource Plan ("IRP"), regarding long-term PPAs, proposed changes to the Company's PURPA avoided cost implementation, the Company's proposal to utilize competitive solicitations and the implementation of the Financial Compensation Mechanism ("FCM");

- Case No. U-20219 (direct and rebuttal), the Company's 2019 PSCR Plan and five-year forecast, regarding long term PPAs and MISO revenue and expenses;

- Case No. U-20202 (direct), the Company's 2018 PSCR Reconciliation Case, regarding purchased power supply costs and the allocation of costs to the renewable resource fund;

- Case No. U-20469 (affidavit), the Company's Application requesting an Order Rescinding Avoided Cost Rates, regarding the Company's avoided costs, obligations to enter new PPAs, and establishment of new avoided costs in the Company's IRP;

- Case No. U-20496 (direct), the Company's Application for approval of Amendments to the PPA with Viking Energy of Lincoln, LLC, Viking Energy of McBain, LLC, and Hillman Power Company;

- Case No. U-20604 (direct), the Company's Application for approval of PPAs;

- Case No. U-15805-S (affidavit), the Company's Application for approval of a renewable energy purchase agreement with River Fork Solar, LLC.

- Case No. U-20525 (direct and rebuttal), the Company's 2020 PSCR Plan and five-year forecast, regarding long-term PPAs and the treatment of MISO revenue and expenses;

- Case No. U-20697 (direct and rebuttal), the Company's 2020 electric rate case, regarding PSCR expenses, transmission cost analysis, state reliability mechanism methodology, and IRP supply implementation activities;

- Case No. U-20220 (direct), the Company's 2019 PSCR Reconciliation Case, regarding purchased power supply costs and the allocation of costs to the renewable resource fund;

- Case No. U-15805-T (affidavit), the Company's Application for approval of amended renewable energy and PPAs with North American - Central LLC;

- Case No. U-20833 (direct), the Company's Application for approval of PPAs with STS Hydropower LLC;

- Case No. U-20838 (direct), the Company's Application for approval of new PPAs with members of the Independent Power Producers Coalition of Michigan;

- Case No. U-20734 (direct), the Company's Application for approval of an amendment to the PPA with Entergy Nuclear Power Marketing, LLC;

- Case No. U-20896 (direct), the Company's Application for approval of an amendment to the PPA with Midland Cogeneration Venture Limited Partnership ("MCV");

- Case No. U-21090 (direct and rebuttal), the Company's Application for approval of an IRP under MCL 460.6t, regarding long-term PPAs, proposed changes to the Company's PURPA avoided cost implementation, proposed changes to the FCM, certain accounting approvals, and for other relief;

- Case No. U-21407 (direct), the Company's Application requesting approval of Amendment No. 3 to the PPA with T.E.S. Filer City Station Limited Partnership;

- Case No. U-21459 (direct), the Company's Application for approval of PPA amendments;

- Case No. U-21507 (direct), the Company's Application for approval of Amendment No. 3 to the PPA with Michigan Power Limited Partnership; and

- Case No. U-21946 (rebuttal), the Company's Application for approval of Amendment No. 4 to the PPA with T.E.S. Filer City Station.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to:

1. Provide an overview and request approval of the Company's PPA with MCV to support this IRP and related Certificate of Need ("CON") filing requirements, and

2. [CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-3 (KGT-1)	The Power Purchase Agreement Between Consumers Energy Company and Midland Cogeneration Venture, Limited Partnership, dated September 17, 2025 and Amendment No. 1 to the Power Purchase Agreement Between Consumers Energy Company and Midland Cogeneration Venture, Limited Partnership dated June 25, 2026;

Confidential Exhibit A-4 (KGT-2)	The Power Purchase Agreement Between Consumers Energy Company [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] dated June 11, 2026; and
Exhibit A-5 (KGT-3)	CON Application Reference Table for New PPAs.

Q. Were these exhibits prepared by you or under your supervision?

A. Exhibit A-3 (KGT-1) and Confidential Exhibit A-4 (KGT-2) were extracted from the Company's records kept in the ordinary course of business and are an accurate copy of those records. Exhibit A-5 (KGT-3) was created under my supervision.

Q. Please provide an overview of the proposed PPAs for which the Company is requesting CONs.

A. The Company is requesting CONs for two new PPAs for a natural gas-fueled combined-cycle generation and a clean resource to support the Company's PCA and the resource need identified in the Company's IRP modeling.

Q. Which Company witnesses provide testimony in support of the Company's request for CONs for the Proposed Karn and Thetford Projects?

A. Several Company witnesses provide testimony in support of the Company's request for CONs for the Proposed Karn and Thetford Projects, with testimony of Company witness Thomas P. Clark speaking directly to the details of the Proposed Projects.

My testimony provides the overall PPA projects and contract overview, and summarizes the roles of the witnesses supporting the Company's request. I also sponsor Exhibit A-5 (KGT-3) that identifies the applicable CON filing requirements for each PPA and the Company witness testimony that addresses each requirement.

- **Steven Q. McLean** addresses the overall IRP and statutory framework supporting the CON requests. His testimony explains the Company's request

under MCL 460.6s, including the requested findings that the power to be supplied by the PPAs are needed, reasonable, and prudent. Company witness McLean also supports inclusion of the IRP as an exhibit to the CON applications.

- **Adam J. Moritz** supports the modeling and economic analysis underlying the CON requests. Company witness Moritz addresses the alternatives analysis that was conducted as part of the Company's broader IRP including alternatives, the no-build option, and comparative costs of supply alternatives. His testimony also explains how the Proposed Projects were evaluated within the Company's IRP modeling and executable portfolio analysis.

- **Angela K. Rissman** forecasts the fuel cost for the natural gas PPA used by Company witness Mortiz to project a portion of the PPA cost.

- **Heather A. Breining** forecasts the emissions for the natural gas PPA. Her testimony addresses expected facility emissions over the term of the PPA.

Section I: New MCV PPA – CON

Background

Q. Please provide background information for the New MCV PPA.

A. On September 17, 2025, the Company entered into a new PPA with MCV for 1240 MW of energy and capacity with deliveries beginning June 1, 2030, and continuing until May 31, 2040 ("New MCV PPA"). This New MCV PPA will begin deliveries on the day following the final day of the existing PPA between Consumers Energy and MCV, ensuring continued deliveries from a reliable, proven supply resource. The New MCV PPA and Amendment No. 1 to the New MCV PPA are provided as Exhibit A-3 (KGT-1).

Q. Why was the New MCV PPA amended?

A. The New MCV PPA required the Company to seek MPSC approval and provided that if approval was not obtained within 12 months, the PPA would be void ab initio. The PPA was amended to grant additional time for the Company to file for and obtain MPSC approval. Amendment No. 1, dated June 25, 2026, extends the MPSC filing deadline to September 30, 2026 and the MPSC approval deadline to 14 months from the date of this

filing. Amendment No. 1, dated June 25, 2026, is provided along with the New MCV PPA in Exhibit A-3 (KGT-1).

Q. How was the New MCV PPA procured?

A. The Company entered into discussions with MCV regarding deliveries beyond May 31, 2030, when the existing PPA expires, to determine whether MCV could provide thermal, dispatchable energy and capacity to support the Company's transition to the clean energy standard while maintaining system reliability. During these discussions, the opportunity for the New MCV PPA was presented by MCV to Consumers Energy.

Q. Was the New MCV PPA acquired through a competitive solicitation process?

A. No. The New MCV PPA is a bilateral transaction and was not acquired through the Company's competitive solicitation process. However, the Company relies on the results of its independently administered RFP procurements to establish market benchmarks for evaluating resource options available to meet its supply needs. These RFPs provide price and non-price information across multiple resource types and commercial operation date ("COD") tranches, which inform the Company's assessment of bilateral opportunities such as the New MCV PPA. As explained in Section XIII of the testimony of Company witness Moritz, and supported with his Confidential Exhibit A-33 (AJM-19), the New MCV PPA was evaluated against the alternatives identified through the Company's modeling efforts for supply alternatives over the study period and was determined to provide customer savings relative to those alternatives.

Q. How does the cost of the New MCV PPA compare to results in the Company's recent solicitations?

A. In the 2025 All Source RFP results discussed by Company witness Beth A. Skowronski as detailed in her Confidential Exhibit A-110 (BAS-2), the Company received proposals for a natural gas fueled combined cycle with and without carbon capture and sequestration ("CCS") as well as biomass and landfill gas thermal generation. The combined cycle proposal's Levelized Cost of Energy ("LCOE") ranged from [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] for traditional generation and [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] with the CCS option. The biomass thermal generation proposal's LCOEs ranged from [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] and the landfill gas proposal's LCOEs ranged from [CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. These resources, like the New MCV PPA, would provide thermal generation to support reliability for customers. These resources could either be dispatchable or baseload depending on the proposal. As shown on Exhibit A-18 (AJM-4) sponsored by Company witness Moritz, the New MCV PPA forecast LCOE including FCM is $86/MWh.

Q. Did the New MCV PPA provide opportunities that would not otherwise have been available or commercially practical through a competitive bid process?

A. Yes. Although it is not a prerequisite for CON approval, the New MCV PPA did present opportunities that the Company likely would have missed if it had not acted to negotiate the PPA when it did. If the Company had not agreed to negotiate in good faith with MCV when it approached the Company to begin negotiations (and instead asked MCV to

participate in the Company's next all-source solicitation or otherwise rejected or delayed negotiations), MCV may have approached other prospective buyers and the Company would have missed a valuable opportunity to secure reliable and dispatchable capacity and energy.

As discussed in the direct testimony of Company witness McLean, the electric utility industry is experiencing significant growth and demand for existing and new generation resources. The availability of significant existing thermal generation that is not under contract is extremely limited, and the ability of new combined-cycle thermal generation of this size that can achieve a 2030 start date is very low due to this shortening of supply compared to growing demand. In these situations, it is important for the Company to move as quickly as possible to secure the transaction for our customers' benefit.

Overview

Q. Please provide an overview of the resource and the PPA?

A. The Midland Cogeneration Facility ("MC Facility") is a natural-gas-fired cogeneration plant located at 100 Progress Place in the City of Midland in Midland County, Michigan. The facility began operation in 1990 and has a nameplate capacity of approximately 1,633 MW. The Company currently purchases 1,240 MW of output under the existing MCV PPA.

Q. What generation technology is the MC Facility?

A. The facility is comprised of 12 natural gas fueled turbine generators, six heat recovery steam generators, and multiple steam turbine generators to produce combined-cycle heat and power to generate electricity and steam, some of which is sold to nearby industrial customers. The MC Facility uses a combination of steam injection systems, dry low-

nitrogen oxides ("NOx") burners, low-NOx burners and flue gas recirculation to control NOx emissions in accordance with its Renewable Operating Permit ("ROP").

Q. What are the expected deliveries from the New MCV PPA?

A. The New MCV PPA is for 1,240 MW of energy and capacity. The Company expects the New MCV PPA to deliver at 99.8% availability for the 1,240 MW portion allocated to the Company with a heat rate of 8.3 MMBtu/MWh. The actual output is dependent on market prices due to the dispatchable nature of the resource and PPA. Company witness Moritz details the annual production expected from the New MCV PPA on page 5 of Confidential Exhibit A-28 (AJM-14) to meet the Company's supply needs.

The MC Facility is expected to operate for the duration of the New MCV PPA as a result of routine maintenance and overhauls of the existing generation facilities. The New MCV PPA includes a provision that allows the Company to monitor the health of the MC Facility through Inspection Reports, in accordance with Section 12 of the PPA.

Q. What benefits can the Company's customers realize from adding this natural gas-fueled combined-cycle PPA to Consumers Energy's supply portfolio?

A. As discussed in the direct testimony of Company witness McLean, the New MCV PPA adds a reliable, proven natural gas fueled, dispatchable supply resource to the Company's supply as the Company transitions to a clean supply portfolio in 2040. By contracting with an existing facility, the Company avoids the development and construction risks associated with a new resource while benefiting from the proven performance of the MC Facility. Developmental and construction risk can be significant to the viability of new generation and predictability of reaching COD. These risks for new generation are discussed in more detail in Part II of the testimony of Company witness Clark. An existing resource provides

significant value in both providing greater certainty that the project can reach COD and demonstrating its historical operational reliability and efficiency. As discussed in the direct testimony of Company witness Moritz, the addition of the New MCV PPA is economically beneficial in modeling scenarios and sensitivities and was economically selected by Aurora relative to other resources, resulting in it being a preferred alternative to economically serve our customers while meeting our energy and seasonal capacity supply needs.

Q. Are there any major state, federal, or local permits required to continue operation of the MC Facility?

A. The current ROP was extended to March 10, 2025 on March 10, 2020[1] (State Registration Number B6527). On August 27, 2024, MCV submitted its application to renew the ROP prior to the September 10, 2024 deadline. Based on publicly available data,[2] the application is still in process.

Q. Are there any expected modifications necessary to natural gas infrastructure to facilitate delivery of power over the PPA term?

A. No, there are no expected modifications necessary to facilitate delivery of power over the PPA term.

Q. Are there any expected modifications necessary to existing road, rail, or waterway transportation facilities to facilitate delivery of power over the PPA term?

A. No, there are no expected modifications to facilitate delivery of power over the PPA term.

[1] https://www.egle.state.mi.us/aps/downloads/ROP/pub_ntce/B6527/B6527%20Final%203-10-20.pdf
[2] https://mienviro.michigan.gov/nsite/DEFAULT/map/results/detail/2461728331767382022/Environmental%20Interests

Q. Are there any expected water or sewer infrastructure modifications to facilitate delivery of power over the PPA term?

A. No, there are no expected additional investments in water or sewer infrastructure. The PPA is for energy from an existing, operating generating facility. The Company does not anticipate any additional water withdrawals, wastewater infrastructure, or sewer investments associated with delivery of power under the PPA.

Q. Could the proposed New MCV PPA result in significant waste impacts?

A. No. The Company is purchasing electricity from an existing facility and is not constructing, owning, or operating the generating units. Waste management associated with facility operations remains the responsibility of the facility owner and operator and is subject to applicable environmental regulations. The PPA itself does not create new waste management obligations for the Company.

Q. How were water and waste considerations evaluated in the Company's assessment of the PPA?

A. The Company considered that MCV is an existing operating facility with established environmental compliance, water management, and waste handling programs. As a result, the PPA provides reliable energy and capacity without requiring new generating infrastructure or associated water and waste facilities.

Q. Are there any expected development and construction activities necessary for delivery of power prior to the PPA start date?

A. No, there are no additional development and construction activities needed prior to the PPA start date.

Q. Does the Company expect that any construction workforce will include residents of Michigan?

A. While no construction workforce is necessary for infrastructure investments prior to the PPA start date, MCV regularly refurbishes its generation equipment, and those refurbishment activities may provide employment opportunities for Michigan residents.

Q. Did the Company consider alternatives to the New MCV PPA as part of the PCA?

A. Yes, as discussed in the direct testimony of Company witness Moritz, alternative supply resources were considered. The addition of MCV to the Company's supply portfolio improved the net present value of the Company's supply plan and it was economically selected by Aurora compared to alternative resources.

Q. What impact does the New MCV PPA have on wholesale markets?

A. MCV is an existing facility that the Company assumes would continue operation if the New MCV PPA was not executed. Therefore, there is no expected impact to wholesale markets.

New MCV PPA Summary

Q. Please provide a summary of the New MCV PPA.

A. The New MCV PPA provides for the purchase of 1,240 MW of Commercial Energy over a 10-year term beginning June 1, 2030, and ending May 31, 2040.

Q. Are there any significant contract provisions that could result in early termination of the contract?

A. Yes, several provisions could result in early termination of the New MCV PPA. First, in Section 2(a) of the New MCV PPA, the agreement became effective upon execution but is contingent on MPSC approval within 14 months of the Company's filing in this docket; if

not approved on the requested basis within that timeframe, the agreement is void ab initio. Second, in Section 2(b) of the New MCV PPA, after the commencement of the term, termination is possible by mutual agreement of the parties. Third, in Section 6(c) and (d) of the New MCV PPA, if Seller fails to provide adequate continuing assurances of secure fuel supplies, Consumers Energy may terminate the New MCV PPA. Fourth, in Section 11 of the New MCV PPA, if Seller provides less than a 0.10 capacity factor for two consecutive years, Consumers Energy may terminate the New MCV PPA. Fifth, in Section 11 and 14(b) of the New MCV PPA, if capacity factor impacts associated with Section 11 exist following Force Majeure, Consumers Energy may terminate the New MCV PPA.

Q. What are the payment terms and conditions in the New MCV PPA?

A. The New MCV PPA payment includes the following payment terms for deliveries beginning in 2030:

1. Fixed Capacity Price: A fixed rate of $5.00/MWh for available Commercial Energy;

2. Fixed Energy Payment: A formulaic rate[3] inclusive of Fixed Firm Gas Transportation Rates plus a fixed rate of $13.51/MWh for available Commercial Energy; and

3. Variable Energy Price: A formulaic rate[4] representative of the MC Facility's variable expense as determined by Gas Price, Heat Rate, and Adders on a $/MWh basis for Commercial Energy delivered to the Company via MISO Financial Schedules.

For the purposes of calculating the Fixed Energy Price under the Agreement, the Fixed Firm Gas Transportation Rate is determined in accordance with the Company's Gas

[3] The formula is detailed on Exhibit A-3 (KGT-1), PPA Exhibit C "Fixed Energy Price Determination."
[4] The formula is detailed on Exhibit A-3 (KGT-1), PPA Exhibit B "Cost of Production Determination."

Rate Book. This Fixed Firm Gas Transportation Rate is added to the $13.51/MWh and then multiplied by a factor to determine on- and off-peak pricing.

For the purposes of calculating the Variable Energy Price under the Agreement, the Gas Price is based on the Platts Gas Daily Consumers Energy city-gate index, together with applicable variable firm gas transportation charges in accordance with the Company's Gas Rate Book. The Heat Rate is initially established at 8.045 MMBtu/MWh and is adjusted annually based on turbine start activity, subject to the parameters specified in Exhibit B. The Adders component includes recovery of demineralized water costs, maintenance costs, NOx compliance costs, and other variable generation costs that may arise as a result of future statutory or regulatory requirements.

The Company's forecast of the Variable Energy Price (a/k/a "Cost Of Production" or "COP" for the purposes of this PPA), Capacity Price, Fixed Energy Price, and Fixed Firm Gas Transportation Rate are shown on page 2 in Confidential Exhibit A-28 (AJM-14).

Q. Are there risks associated with the prices paid under the New MCV PPA? If so, how are they being mitigated and/or contained?

A. Yes, as explained above, the Fixed Energy Price and Variable Energy Price are formulaic and inherently have risks built in that could result in either increases or reductions in cost. From the Company's perspective, the two most significant cost escalation risks associated with the New MCV PPA are (i) variable fuel and variable firm gas transportation cost risk, and (ii) fixed gas transportation cost risk. Both categories of costs are largely pass-through in nature, and therefore affect the ultimate rate paid by the Company to MCV provided under the New MCV PPA.

With respect to variable fuel cost risk, the fuel component is market-based and uncapped. As a result, actual energy costs may exceed current forward market expectations, including the natural gas price forecast as discussed in direct testimony by Company witness Rissman and shown in Exhibit A-85 (AKR-8). The New MCV PPA therefore carries risk to the Company and its customers for higher future natural gas prices. However, this risk is substantially mitigated by the dispatchable operational characteristics of the MC Facility and the structure of MISO's energy market. Because the facility is fully dispatchable, generation will generally be committed only when it is economic to do so. When the cost of producing energy at the MC Facility exceeds prevailing market prices, the Company can satisfy energy needs through market purchases. Conversely, when the facility's production costs are lower than market prices, MISO's economic dispatch signals will tend to increase facility output. Accordingly, the Agreement provides customers with a natural physical hedge against fuel price volatility by allowing generation from the New MCV PPA to compete directly against market alternatives.

With respect to the Firm Gas Transportation Rate risk, variable and/or fixed firm transportation charges are incorporated directly into the Variable Energy Price and Fixed Energy Price and may increase over time due to changes in transportation tariffs, pipeline infrastructure investments, or other regulatory actions affecting gas transportation service. However, this risk is moderated by the fact that such transportation rates are subject to the MPSC's regulatory oversight and approval of the Company's Gas Rate Book through established regulatory processes.

Finally, the Agreement expressly recognizes the potential for future regulatory and environmental compliance costs. Exhibit B and Exhibit C provide that, if future statutes

or regulations impose additional generation-related costs, such costs may be incorporated into the applicable payment calculations through agreement of the Parties or, absent agreement, pursuant to MPSC determination. Accordingly, future environmental compliance requirements may increase the COP and the overall cost of energy supplied under the Agreement over time. While the Agreement transfers a significant portion of fuel, transportation, and environmental compliance cost risk to the Company, those risks are partially mitigated by the dispatchable nature of the MC Facility, the ability of MISO economic dispatch to optimize generation decisions relative to market prices, the Company's diversified supply portfolio strategy as discussed by Company witness McLean, and MPSC regulatory oversight of the Company's transportation rate adjustments. As a result, the Company expects the New MCV PPA to provide customers with reliable, dispatchable generation while preserving operational flexibility in changing market conditions.

Q. Why is it reasonable for the Company and its customers to carry such risk in the New MCV PPA?

A. When costs for utility services are unknown, independent power producers tend to both estimate them conservatively and add a risk premium to ensure that inaccuracies in their forecast of ongoing costs are not detrimental to the economics of the deal. The Company could have required MCV to take on these costs in exchange for embedding them in a higher PPA price that would include such a risk premium. However, the Company anticipates that the overall customer cost will be less over the term of the PPA by having the Company pay for the actual firm gas transportation costs through the PPA that vary

from year to year. In summary, the firm gas transportation costs are integral for delivery under the New MCV PPA and paid for through the New MCV PPA.

As the Company has continued to add PPAs to support its supply portfolio, it has become obvious that risk sharing has a significant impact on the PPA price and ultimately cost to customers. In previous decades, the Company's general strategy for PPA-associated risks was to put the risk on the supplier(s). However, when negotiating more recent PPAs with suppliers, the Company and its supplier(s) generally place the risk on the party that can most adequately manage it. Conceptually, this should result in the lowest cost PPAs and added value to both parties in the negotiation. In this situation, for example, the Company through its significant and diversified portfolio can physically manage fuel cost risk; whereas MCV would require a higher rate plus a risk premium for uncertainty if it were bearing the fuel cost risk. Therefore, it is reasonable for the Company to carry reasonable risk on its PPAs if the expected outcome is lower cost to its customers.

Q. What provisions mitigate risk and promote reliability?

A. The PPA requires continuing assurances of secure fuel supply and delivery, including the ability to escrow a portion of capacity payments if assurances are not maintained, and provides the Company with a right to terminate after prolonged non-compliance. The Seller will maintain firm gas transportation (currently 248,000 MMBtu/day) for supply to serve the New MCV PPA. The agreement provides for MISO-aligned outage coordination and performance verification of Available Capacity, defines treatment of Emergencies, and includes an administrative-disallowance clause that protects customers. Additionally, the New MCV PPA, like most of the Company's PPAs, includes a provision for change in law and/or regulation. This provision obligates the parties to attempt to mitigate significant

harm that arises over the term of the PPA due to economic or operational impacts from governmental authorities and regulatory bodies.

Q. Is the Company requesting an FCM under the New MCV PPA?

A. Yes. The Company is seeking an FCM in accordance with MCL 460.6s(6) which states:

> (6) In a certificate of necessity under this section, the commission shall specify the costs approved for the construction of or significant investment in the electric generation facility, the price approved for the purchase of the existing electric generation facility, or the price approved for the purchase of power pursuant to the terms of the power purchase agreement. For power purchase agreements that an electric utility enters into with an entity that is not affiliated with that electric utility after the effective date of the amendatory act that added section 6t, the commission shall consider and may authorize a financial incentive for that utility that does not exceed the electric utility's weighted average cost of capital.

The Company is permitted to request an FCM under the New MCV PPA because the Agreement satisfies the statutory requirements applicable to long-term PPAs approved by the Commission. The New MCV PPA provides the Company with a long-term source of capacity and energy that supports reliability and resource adequacy obligations while avoiding the need for the Company to construct, own, and operate a comparable generating resource. As recognized under Michigan law, the FCM is intended to provide utilities an opportunity to receive financial compensation when they enter into approved PPAs in lieu of utility-owned generation investments. Had the Company elected to meet these capacity needs through utility ownership, customers would have borne the costs associated with developing, constructing, financing, and operating a new generating facility. The New MCV PPA avoids those significant upfront capital expenditures while providing access to an existing dispatchable generating resource. Consequently, the FCM helps align the Company's financial incentives with the procurement of third-party resources that are

determined to be in customers' best interests. The Company notes that the MCV facility is an existing thermal generating resource and therefore does not qualify as a clean energy resource under MCL 460.6t(15). As a result, the applicable FCM is lower than the incentive available for qualifying clean energy PPAs under that statute. Nevertheless, the New MCV PPA remains eligible for FCM treatment and satisfies the statutory framework for approved purchased-power resources. In addition, the MCV facility is owned and operated by MCV, an entity that is not affiliated with the Company. Accordingly, the New MCV PPA is the product of a transaction between independent parties and does not involve an affiliate-owned resource. For these reasons, the Company respectfully submits that it seeks approval of the full FCM established at its weighted average cost of capital.

Q. Has the Company provided a copy of the New MCV PPA?

A. Yes, Exhibit A-3 (KGT-1) is a copy of the New MCV PPA.

Q. What benefits can be realized with the New MCV PPA?

A. The New MCV PPA will provide the following benefits to the Company, the Company's customers, and the surrounding communities:

1. The PPA supports additional capacity and energy needed to meet the Company's mid- and long-term resource requirements identified in this application.

2. The PPA was benchmarked against recent competitive solicitations and Electric Supply Strategy modeling, confirming that its pricing is competitive and economic.

3. The PPA provides predictable, formula-based energy and fixed capacity pricing for the term of the agreement.

4. The PPA enhances system reliability through strong performance, fuel security, and operational provisions.

5. The PPA was economically selected by Aurora and reduces the Company's forecasted supply expenses compared to alternatives that do not include this transaction.

Q. Please summarize the Company's request with respect to the New MCV PPA?

A. As discussed above, the New MCV PPA was reasonably and prudently negotiated as a new bilateral agreement and will provide 1,240 MW of dispatchable natural gas-fired capacity to support the Company's energy and capacity needs during Planning Years 2030 through 2040.

The PPA supports the Company's IRP, provides customer value by offering competitively benchmarked and transparent pricing, enhances reliability through strong performance and fuel-security provisions, and offers access to existing generation resources without significant new capital investment.

Accordingly, the Company requests that the Commission: approve the New MCV PPA, find all payments and obligations under the agreement to be reasonable and prudent and eligible for recovery, and authorize the associated FCM in accordance with MCL 460.6s.

Q. What approvals does the Company request from the Commission regarding your direct testimony about the New MCV PPA?

A. The Company requests the following in accordance with MCL 460.6s(3):

1. A certificate of necessity that the power to be supplied as a result of the proposed purchase under the New MCV PPA is needed;

2. A certificate of necessity that the size, fuel type, and terms of the New MCV PPA represent the most reasonable and prudent means of meeting a portion of the Company's power needs; and

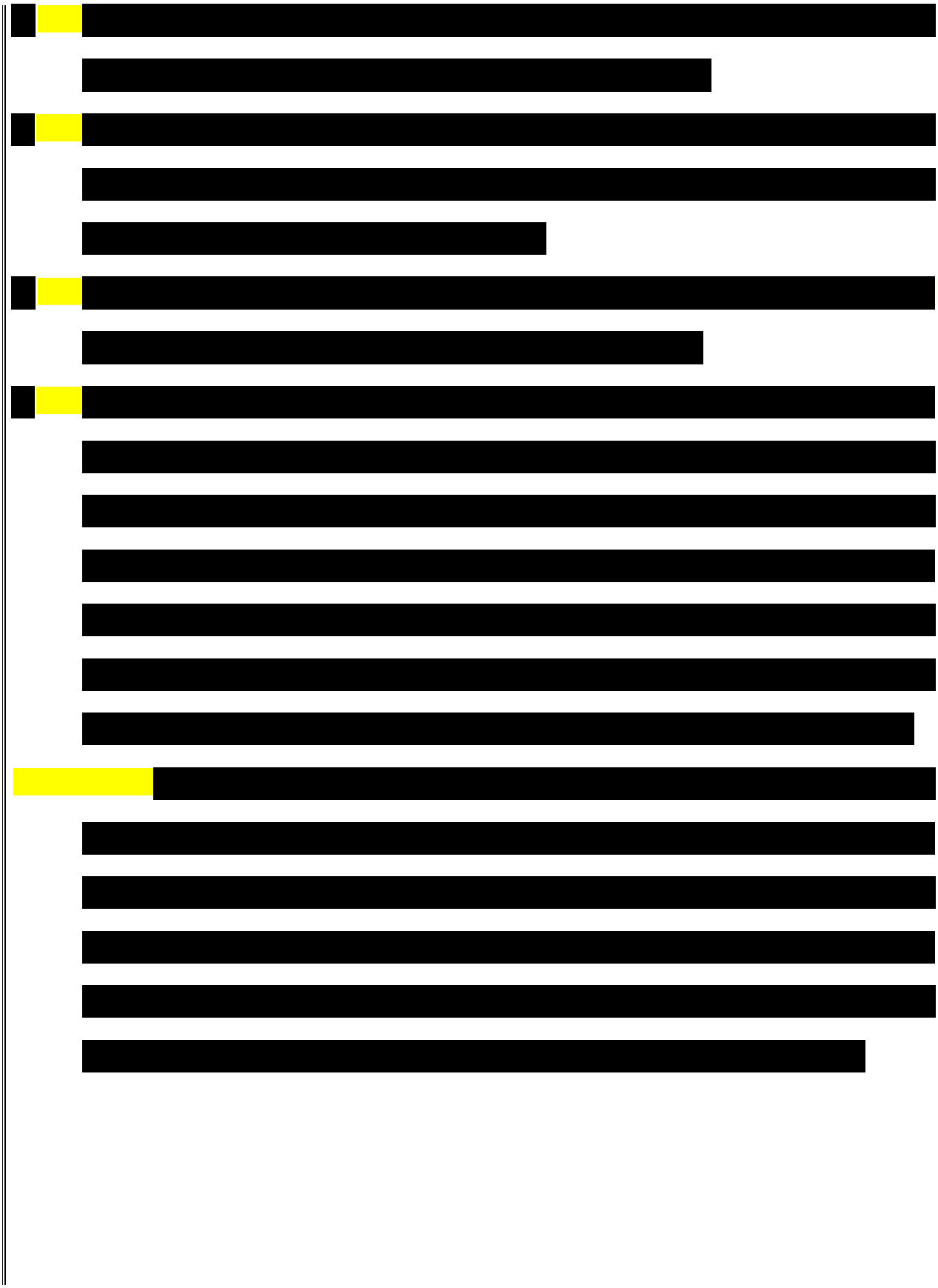
3. A certificate of necessity that the price specified in the New MCV PPA will be recovered in rates from the electric utility's customers.

Additionally, the Company requests approval of the New MCV PPA and any mechanisms necessary to implement these requests.

Section II: [CONFIDENTIAL] [redacted]

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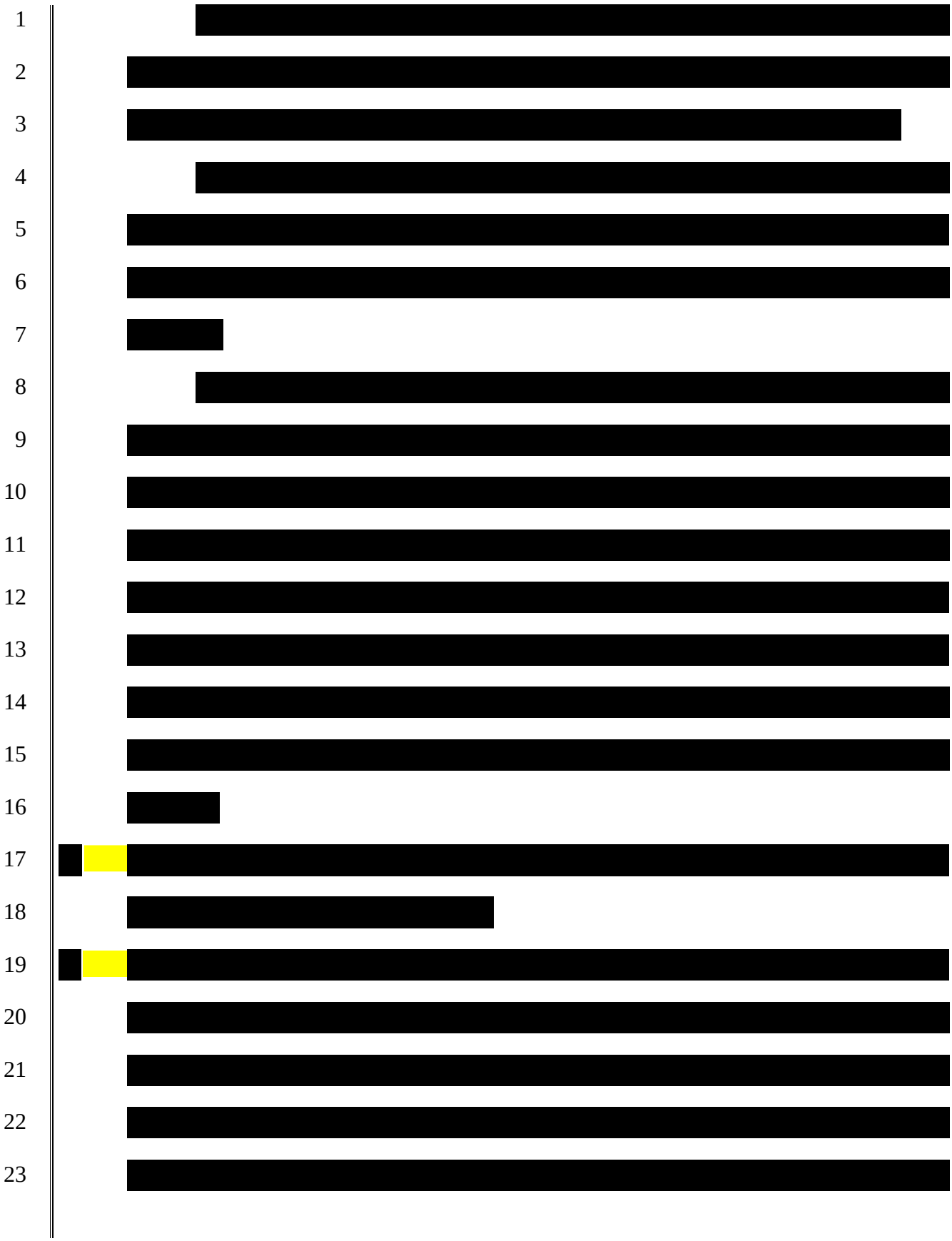
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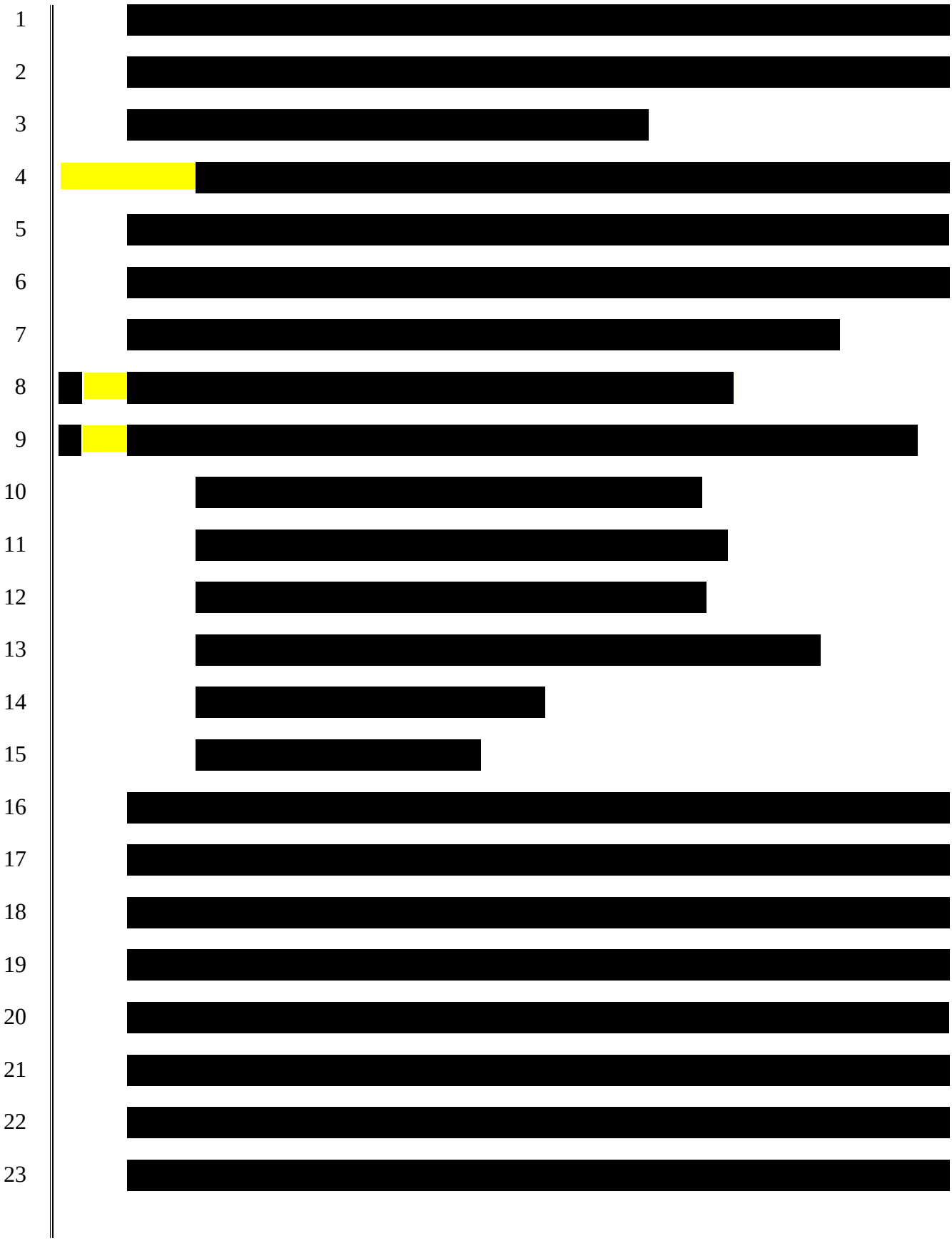


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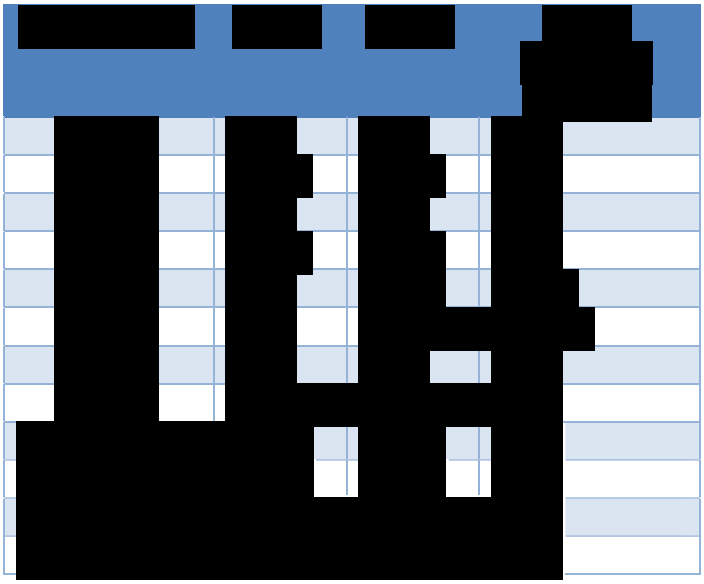






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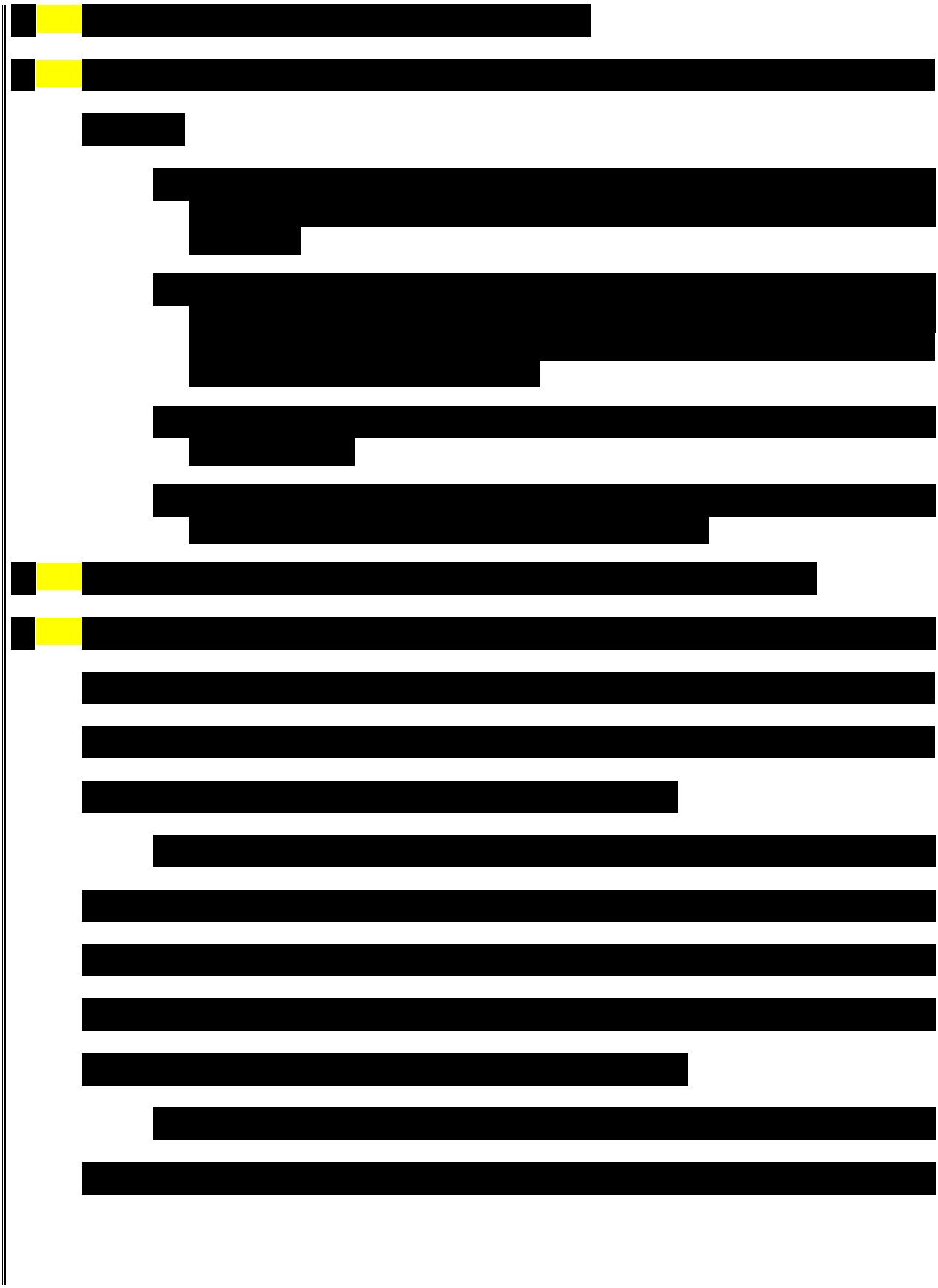
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[END CONFIDENTIAL]

Q. Does this complete your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan and Certificates of Necessity under MCL 460.6s and 460.6t, certain accounting approvals, and for other relief.	)))))))	Case No. U-22127

REDACTED

EXHIBITS

OF

KEITH G. TROYER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2026

Docusign Envelope ID: 8E18DC22-7304-4BD9-BA32-30CC028FFC94

POWER PURCHASE AGREEMENT

BETWEEN

CONSUMERS ENERGY COMPANY

AND

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

Docusign Envelope ID: 8E18DC22-7304-4BD9-BA32-30CC028FFC94

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POWER PURCHASE AGREEMENT
BETWEEN CONSUMERS ENERGY COMPANY AND
MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

POWER PURCHASE AGREEMENT, herein termed "Agreement," effective as of the date provided in paragraph 2(b) ("Effective Date"), between CONSUMERS ENERGY COMPANY, a Michigan corporation, One Energy Plaza, Jackson, Michigan, 49201 herein termed "Consumers," and, Midland Cogeneration Venture Limited Partnership, herein termed "Seller." Consumers and Seller are herein sometimes referred to individually as "Party" and collectively as "Parties," where appropriate.

W I T N E S S E T H:

WHEREAS, Consumers owns electric facilities and is engaged in the generation, purchase, distribution and sale of electric energy in the State of Michigan, and

WHEREAS, Seller operates a gas fired cogeneration plant, known as the MC- Facility, with generator design capacity nameplate ratings of approximately 1633 MW, which also supplies steam and electric energy to The Dow Chemical Company and Corteva Agriscience (herein termed "DOW"), and

WHEREAS, Seller desires to deliver and sell and Consumers desires to receive and purchase hereunder Commercial Energy from the MC-Facility, and

WHEREAS, Consumers desires to schedule its purchases of Commercial Energy from the MC-Facility, and

WHEREAS, Seller will file to obtain certification by the Federal Energy Regulatory Commission ("FERC") for an Exempt Wholesale Generator, and

WHEREAS, Seller has on file with the FERC a Market-Based Rate Tariff filed March 15, 2006, which commenced April 5, 2006 in Docket Number ER06-733-000 ("Tariff') and this Agreement is entered into pursuant to such Tariff and represents negotiated, and

WHEREAS, subject to the terms and conditions herein the Parties desire to enter this Power Purchase Agreement.

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein set forth, the Parties hereto agree as follows:

1. Definitions

Terms used in this Agreement shall have the following meanings:

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1(a) "AES" - means a Michigan licensed Alternative Energy Supplier as defined under MCL 460.10g(1)(a)

1(b) "Available Capacity" - That total electric generating capacity that the MC-Facility is capable of providing after deducting that electric generating capacity (a) required for the supply of electric energy (i) for the operation and maintenance of the MC-Facility, (ii) to DOW and (iii) to Permissible Purchasers, if any, and (b) associated with scheduled outages, scheduled unforeseen outages, forced outages and derates of equipment. In accordance with practices and procedures to be agreed upon by the Parties, such total electric generating capacity shall include the electric generating capacity of equipment (a) which is connected to the Transmission Owner's system and capable of being loaded by Seller and (b) which is not connected to the Transmission Owner's system but is capable of being started, connected and loaded by Seller.

1(c) "Boilers" - Six boilers Seller has installed to generate steam and electric energy, each having a capability of producing 250,000 pounds of steam per hour, as such boilers may be modified or replaced from time to time.

1(d) "Commercial Energy" -The maximum amount of electric energy determined hourly which could be generated by the lower of Contract Capacity and Available Capacity, whether delivered or not.

1(e) "Commercial Operation Date" - The date upon which at least four Boilers are commercially operable to generate steam and electric energy.

1(f) "Commercial Pricing Node" - Has the meaning ascribed to such term by MISO.

1(g) "Consulting Engineer" - The consulting engineering firm retained by Seller pursuant to Section 12.

1(h) "Contract Capacity" - 1240 megawatts of electric capacity.

1(i) "Contract Capacity Factor" - The Contract Capacity Factor shall be calculated by dividing the total megawatt hours of Commercial Energy for which Consumers has paid capacity payments in any calendar year, by (a) the product of the Contract Capacity and the number of hours in such calendar year minus (b) the total megawatt hours of Commercial Energy available to be scheduled during the cumulative duration, exceeding 24 hours, of all Emergencies in such calendar year. For purposes of this definition, only Emergencies which exceed one minute and prevent Consumers from receiving Commercial Energy shall be considered.

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1(j) "Cost of Production" or "COP" - Has the meaning specified in Exhibit B, which is attached hereto and made a part hereof.

1(k) "Designated Network Resource" - Has the meaning ascribed to such term by MISO.

1(l) "DOW Site" - The site of the DOW complex located in Midland County, Bay County and Saginaw County, Michigan.

1(m) "Emergency or Emergencies" - A condition or conditions on the Transmission Owner's system which in the Transmission Owner's or Transmission Provider's reasonable judgment either has or is likely to result in significant imminent disruption of service to customers, or imminent endangerment of life or property.

1(n) "Fuel Supply Capacity" - The Fuel Supply Capacity is the amount of firm fuel delivery and/or fuel storage service required to be obtained by Seller for the months of June, July and August of each year to deliver Contract Capacity pursuant to Section 6.

1(o) "Fuel Supply Energy" - The Fuel Supply Energy shall equal eighty percent (80%) of the average annual megawatt hours of Commercial Energy delivered during the two (2) previous calendar years.

1(p) "Legal Holidays" - New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

1(q) "Locational Marginal Price" or "LMP" - Has the meaning ascribed to such term by MISO.

1(r) "MC-Facility" - The Midland Cogeneration Facility located in Midland County, Michigan. The MC-Facility is deemed to consist of existing equipment, including, but not limited to: generating equipment, including auxiliary and back-up, capable of producing Nameplate Capacity and an annual average of 629,000 lbs/hour of 188 psig process steam; transformers; electric and steam delivery facilities; pipelines and fuel handling equipment; administrative structures; the Boilers; and such other necessary or related facilities, equipment and structures associated with the generation of electricity and steam.

1(s) "MISO" - The Midcontinent Independent System Operator, Inc., including any successor thereto and subdivisions thereof.

1(t) "MISO Rules" means the Open Access Transmission, Energy and Operating Reserve Markets Tariff, including all schedules or attachments thereto, of MISO, as amended

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from time to time, including any successor tariff or rate schedule approved by the FERC, together with any applicable MISO Business Practice Manual as amended from time to time.

1(u) "Nameplate Capacity" – 1633 MW.

1(v) "Off-Peak Hours" - All hours other than On-Peak Hours.

1(w) "On-Peak Hours" - All hours between 7:00 AM and 11:00 PM eastern standard time, Monday through Friday except Legal Holidays.

1(x) "Original Power Purchase Agreement" means Amended and Restated Power Purchase Agreement dated June 9, 2008, as amended by Amendment No. 1, dated as of March 1, 2010, and Amendment No. 2, dated as of October 7, 2020.

1(y) "Permissible Purchasers" - Other entities, including an AES, to which Seller may sell electric energy; provided that, any entity receiving electric energy directly from Seller, or from an AES, that is not a partner in the Midland Cogeneration Venture Limited Partnership or an owner of the MC-Facility shall have its facilities requiring such electric energy on the DOW Site or on a site contiguous to the DOW Site or the site of the MC-Facility.

1(z) "Planning Period" - Means the applicable resource planning period utilized by MISO for capacity resource planning and/or assignment of resource adequacy capacity by MISO to Seller's Plant."

1(aa) "Point of Delivery" - The billing meters used for financial settlement with MISO. The Point of Delivery for purposes of the FBT shall be the CONS.MCV.MCV Commercial Pricing Node or the successor thereof as defined by MISO.

1(bb) "Transmission Owner" - The entity or entities that owns the electricity transmission facilities used to transmit electric energy to Consumers at and from the Point of Delivery.

1(cc) "Transmission Provider" - The entity or entities transmitting or transporting the electric energy to be purchased by Consumers hereunder on behalf of Consumers at and from the Point of Delivery.

2. Effective Date and Term

2(a) This Agreement shall be effective as of the Effective Date upon execution by both Parties; provided, however that the Parties' rights and obligations under this Agreement shall be contingent upon the approval of this Agreement by the MPSC. This Agreement shall be submitted by Consumers to the MPSC for approval under all applicable law no later than June 30, 2026. The foregoing submission shall specifically request MPSC approval of: (i) cost recovery of all

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payments set forth in this Agreement, and (ii) financial recovery available to Consumers under MCL 460.6s or MCL 460.6t.

In the event the MPSC does not issue an order, deemed satisfactory to Consumers, in Consumers' sole discretion, in the commercially reasonable discretion of each Party, regarding Consumers' request to approve this Agreement or any portion of the recovery requested in the application for approval of this Agreement, or the MPSC otherwise does not approve this Agreement as described herein within twelve (12) months of Consumers' request for approval, this Agreement shall be void ab initio and neither party shall have any further liability hereunder.

2(b) Unless terminated as provided in this Agreement, this Agreement shall start on June 1, 2030 and continue in effect through May 31, 2040. Thereafter, and subject to Section 19, this Agreement shall continue in effect unless and until terminated by mutual agreement or on May 31, 2040, or at the end of any Planning Period thereafter.

3. Capacity and Energy Sold by Seller to Consumers

Subject to the terms and conditions hereof, Seller shall sell to Consumers, and Consumers shall purchase from Seller, Commercial Energy. The supply of electric energy by Seller to the MC-Facility, DOW and to Permissible Purchasers, if any, shall have priority over the supply of Commercial Energy to Consumers and the supply of Commercial Energy to Consumers shall have priority over the supply of all other electric energy sales by Seller to third parties, however in no event shall the aggregate supply of electric energy from Seller to the MC-Facility, DOW, and Permissible Purchasers exceed 393 MW as may be increased on a MW for MW basis for any additional capacity installed at the MC-Facility beyond the Nameplate Capacity. Compensation for such Commercial Energy is to be in accordance with Section 9. This Agreement does not obligate Seller to sell, or Consumers to purchase, any capacity or energy other than Commercial Energy, and Seller shall have the right, other than with respect to Commercial Energy, to sell any and all capacity and energy that might be available from the MC-Facility to any third party or into any market.

In the event that Consumers' performance with respect to meeting electric capacity reserve requirements ("Reserve Requirements") is evaluated using Generating Availability Data System ("GADS") (or any successor) data, Seller shall submit the required data to the entity (or entities) that establishes Consumers' Reserve Requirements so that that portion of Consumers' Reserve Requirements that is based on the electric capacity sold by Seller hereunder to Consumers is based on the GADS data associated with the MC-Facility.

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4. Character of Energy

All electric energy, which Seller shall sell and deliver to Consumers hereunder shall be alternating current, three phase and 60 Hertz.

5. [THIS SECTION NOT USED]

6. Fuel Security

6(a) Purpose and Interpretation

The Parties recognize the need for secure fuel supplies for the MC-Facility if it is to fulfill its crucial role as a source of a substantial block of long-term capacity and energy for Consumers and its customers over the term of this Agreement. To that end the Parties have conceived the concept of continuing assurances of sufficient, secure fuel supplies which are set forth in this Section 6. It is further the Parties' intent that satisfaction by the Seller of the terms of this Section 6 be judged on the basis of substantial compliance or functionally equivalent compliance with the elements set forth in Subsection 6(b) as such elements have been interpreted and applied by the Parties during the term of the Original Power Purchase Agreement. These elements are set forth with specificity to provide Seller a "safe harbor" if it can substantially comply with those specified elements.

Prior to Seller executing any fuel supply agreement, Seller may submit such agreement to Consumers for Consumers' evaluation as to whether such agreement satisfies this Section 6. Consumers shall indicate within 30 days of receipt of such agreement whether or not the agreement is so satisfactory.

6(b) Seller's Assurance of Secure Fuel Supplies

Seller shall be deemed to have provided adequate assurance when it substantially complies with the following elements:

(i) For portions of the Fuel Supply Capacity and Fuel Supply Energy that are owned by Seller, Seller shall supply evidence to Consumers that it has sufficient proven and potential reserves, including rights or options to extract such reserves, and the technical capability to produce such fuel;

(ii) For portions of the Fuel Supply Capacity and Fuel Supply Energy that are contracted from suppliers, Seller shall supply evidence to Consumers that it has an agreement with one or more suppliers and that such supplier or suppliers have sufficient dedicated reserves, or the agreement contains

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adequate covenants of the supplier concerning deliverability or limiting future sales of pooled reserves available for sale under the contract, or otherwise dedicating or giving Seller access to the supplier's future reserve additions; and

(iii) Seller shall supply evidence to Consumers that it has an agreement or agreements which provide for firm delivery, or if not firm delivery, sufficient storage service under contracts which warrant delivery, of the expected fuel needs of the MC-Facility, including firm delivery and/or storage service sufficient to demonstrate Fuel Supply Capacity.

Seller may also provide adequate assurance by providing functional equivalents to any of the above elements, which shall be evaluated according to the same standards that applied during the term of the Original Power Purchase Agreement. For purposes of demonstrating adequate assurance, Seller may satisfy this Section 6 by demonstrating firm gas supply purchases for firm delivery to Seller's interconnection with Great Lakes Gas Transmission Limited Partnership's pipeline.

6(c) Seller's Continuing Assurances of Secure Fuel Supplies

Once a year during any calendar year after 2030, Consumers may make a written request to Seller to provide, within 90 days, adequate continuing assurances to Consumers that Seller will be able to meet, as a minimum, the expected fuel needs of the MC-Facility to supply the Fuel Supply Capacity and Fuel Supply Energy for the then current calendar year plus the next calendar year, but not beyond the term of this Agreement. Seller shall be deemed to have provided such adequate continuing assurances when it has established the elements set forth in Subsection 6(b). Consumers' evaluation of agreements which were previously deemed satisfactory in connection with the provision of adequate continuing assurances (including agreements so deemed satisfactory under the Original Power Purchase Agreement) shall be limited to a review of whether then-existing circumstances support a determination that performance under such agreement will continue to be satisfactory. In addition, the Parties agree that Consumers' evaluations of Seller's continuing assurances of secure fuel supplies pursuant to this Subsection 6(c) shall be consistent with the course of performance and standards of interpretation that were used in applying the elements in Subsection 6(b) during the term of the Original Power Purchase Agreement.

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If Seller has failed to supply any evidence of assurance by the required date or if, in Consumers' reasonable opinion, such continuing assurances as have been provided by Seller are inadequate, Consumers shall provide, within 20 days after the required date or the date of submission, whichever is applicable, written notice to Seller. Such notice shall specify in detail the basis for Consumers' determination that adequate continuing assurances have not been provided and shall indicate the percentage of the expected fuel delivery/storage needs and/or fuel supply needs to supply the Fuel Supply Capacity and/or Fuel Supply Energy for which Consumers deems Seller has not provided adequate continuing assurances. Within 180 days of such written notice by Consumers, Seller must provide plans and initiate activities, including commitments and expenditures, to provide such adequate continuing assurances. Such plans and activities shall include any feasible means of providing such assurances and must include, if necessary: (i) construction and operation of facilities for the use of alternate fuels and (ii) execution of contracts for delivery, storage or supplies of alternate fuels so as to establish the same elements set forth in Subsection 6(b).

6(d) Escrow of Capacity Payments

If Seller is unable to provide Consumers with adequate continuing assurances for some percentage of the expected fuel delivery/storage needs and/or fuel supply needs to supply the Fuel Supply Capacity and/or Fuel Supply Energy as required in Subsection 6(c), then, beginning with the first calendar month which commences at least 190 days after Consumers' written notice, required by Subsection 6(c), and continuing each month thereafter until Seller provides such adequate continuing assurances, Consumers shall withhold, in an interest-bearing escrow account with an independent escrow agent, a portion of the capacity payments which it would otherwise pay each month to Seller. Such portion shall be equal to the product of the percentage of the expected fuel delivery/storage needs and/or fuel supply needs to supply the Fuel Supply Capacity and/or Fuel Supply Energy for which Consumers deems Seller has not provided adequate continuing assurance and a factor based upon the number of consecutive months that capacity payments have been withheld pursuant to the following table:

Consecutive Months That Capacity Payments Are Withheld	Factors
1 -12	.05
13-24	.15

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25-36	.40
37 and thereafter	.70

Further, at any time following the 48th consecutive month for which capacity payments have been withheld, Consumers shall have the right, effective upon written notice to Seller, to terminate this Agreement. In the event of such termination, Seller shall pay to Consumers an amount determined in accordance with Exhibit A, which is attached hereto and made a part hereof. Funds in the escrow account at the time of termination shall first be used toward satisfying such amount.

6(e) Restoration and Refund of Capacity Payments

The percentage of the expected fuel delivery/storage needs and/or fuel supply needs to supply the Fuel Supply Capacity and/or Fuel Supply Energy for which Consumers deemed Seller had not provided adequate continuing assurances which is used in the computation of escrow payments set forth in Subsection 6(d) shall be decreased whenever Seller provides Consumers with adequate continuing assurances justifying such a decrease. Such decrease shall be effective commencing with the calendar month during which such assurances are provided. The corresponding capacity payments withheld by Consumers pursuant to Subsection 6(d) shall be refunded to Seller within ten days of provision of such assurances. All interest earned in the escrow account shall be divided equally between Consumers and Seller and paid at the time of such refund."

7. Operation of MC-Facility

7(a) [THIS SECTION NOT USED]

7(b) Seller's Right to Schedule

Seller shall have the right to schedule deliveries of electric energy (except that the Parties shall continue to cooperate to maintain Designated Network Resource status of the MC-Facility for Consumers) and Seller shall be responsible for the charges assessed and payments made by MISO with respect to the asset owner of the Commercial Pricing Node associated with electric energy deliveries under this Agreement.

7(c) Communications

The Parties shall provide for the installation of a communications link between Seller and Consumers, which shall be used by Seller and Consumers to exchange any necessary operating

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information with respect to the MC-Facility and to implement the scheduling of Seller's deliveries of electric energy to Consumers.

7(d) Outages of Generating Equipment

The Parties recognize that information regarding outages of generating capacity is required by Consumers in order to properly operate its electric system. Seller shall provide to Consumers all information relating to outages of generating capacity at the MC-Facility, which would affect Seller's ability to deliver Commercial Energy.

7(d)(i) Scheduled Outages

Seller shall plan and implement scheduled outages and/or planned outages of generating Capacity in accordance with the requirements of the most recent MISO Rules and the Interconnection Agreement. Seller shall confirm with Consumers in writing its schedule of generating Capacity outages planned by Seller for a Calendar Year by August 1st (as such date may be amended by the written mutual agreement of the Parties from time to time) of the prior Calendar Year. Notwithstanding the foregoing, to maximize Resource Adequacy Capacity, Seller should provide planned outage schedules as soon as practical, to provide the best opportunity for an exemption status when commercially practical and reasonable. At least three (3) weeks prior to any scheduled outage and/or planned outage, Seller shall confirm with Consumers the expected start date of such outage and the expected completion date of such outage. Seller shall notify Consumers of any subsequent changes to the outage. As soon as practicable, any oral notifications shall be confirmed in writing. If a modification is made that does not allow MC-Facility to maintain current exemption status per MISO's most recent Business Practice Manual, Seller shall work with Consumers to find an alternative schedule that is able to maintain the same exemption status that was previously in place before modification.

7(d)(ii) Scheduled Unforeseen Outages

A scheduled unforeseen outage of generating capacity is an outage that is neither a scheduled outage pursuant to Subsection 7(d)(i) nor a forced outage pursuant to Subsection 7(d)(iii), but which is generally planned several days to several months in advance of the expected occurrence to perform unforeseen maintenance or to mitigate an operating problem or capacity deficiency at the MC-Facility. Seller shall use its best efforts to plan such outages of generating capacity to accommodate the requirements or obligations of Consumers. Schedules of such outages shall be submitted to Consumers in writing if time permits, or otherwise orally. Consumers shall promptly respond to such submitted schedules and may request modifications in such

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schedules. Seller shall use its best efforts to attempt to comply with such requested modifications. Prior to any scheduled unforeseen outage of generating capacity previously available to Consumers at the MC-Facility, Seller shall orally notify Consumers of the expected start date of such outage, the amount of unavailable generating capacity and the expected completion date of such outage. Such notice shall be given at the time the need for such scheduled unforeseen outage is determined by Seller. Seller shall orally notify Consumers of any subsequent changes in such generating capacity not available to Consumers or any subsequent changes in such outage completion date. As soon as practicable, all such oral notifications shall be confirmed in writing.

7(d)(iii) Forced Outages

Forced outages are uncontrolled losses of generating capacity previously available for production of electric energy for Consumers at the MC-Facility. Seller shall promptly provide to Consumers an oral report of any forced outage occurrence, the amount of generating capacity unavailable and the expected return date of such generating capacity. Seller shall orally notify Consumers as soon as practicable of any subsequent changes in such generating capacity not available and any subsequent changes in the forced outage return date. As soon as practicable, all such oral notifications shall be confirmed in writing.

7(e) Emergency Operation

Consumers shall not be obligated to pay capacity payments or energy payments pursuant to Section 9 for Commercial Energy which the Seller may have available at the MC-Facility during an Emergency occurring on the Transmission Owner's and/or Transmission Provider's system which prevents Consumers from receiving such Commercial Energy, except that Consumers shall pay capacity payments pursuant to Subsection 9(a) and energy payments associated with fixed expense pursuant to Subsection 9(b) for Commercial Energy during an Emergency once the cumulative duration of such Emergencies in a calendar year exceeds 144 hours.

7(f) [THIS SECTION NOT USED]

7(g) Available Capacity

Consumers' knowledge of the Available Capacity is imperative to the economic and reliable operation of its electric system. Seller agrees to declare the Available Capacity of the MC-Facility in accordance with practices and procedures to be established by the Parties. Evaluations of Seller's performance in achieving the declared Available Capacity shall be made at Consumers' option. All performance evaluations shall be conducted in accordance with the following criteria:

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(i) No more than 12 test periods in a calendar year will be selected by Consumers. No tests will be conducted or continued which, in the opinion of Seller, could result in significant degradation of the MC-Facility.

(ii) A test period shall consist of four consecutive hours during which Consumers requests the declared Available Capacity to generate electric energy for delivery to the Transmission Owner's system. Energy generated and delivered during such performance evaluations is Commercial Energy. Once a test period has been initiated it must last four hours unless Consumers and the MC-Facility general manager mutually agree to a shorter duration.

(iii) An hourly deficiency is that amount by which the actual hourly electric energy delivered to the Transmission Owner's system is less than that electric energy which should have been delivered from the declared Available Capacity.

(iv) All hourly deficiencies recorded during each such test period will be added together and the resulting sum divided by the total number of hours in such test period to determine an average hourly capacity deficiency.

(v) A performance factor will be calculated by subtracting the average hourly capacity deficiency from the declared Available

(vi) Capacity in effect at the time and dividing such result by the declared Available Capacity and rounding the resulting factor to the nearest one-thousandth (.001).

(vii) During any such calendar month in which the performance evaluation occurs and an average hourly capacity deficiency occurs which exceeds 1% of the declared Available Capacity, the Capacity Price defined in Subsection 9(a) shall be redetermined by multiplying such rate by the performance factor and rounding the result to the nearest one-tenth of a dollar ($0.1). Such adjusted rate shall be effective only during such month. No adjustment shall be made to Available Capacity as a result of an average hourly capacity deficiency.

As an alternative to performance evaluations by testing, at Consumers' option, no more than once per month Seller shall permit full access by Consumers during regular business hours

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to all pertinent operating records and equipment for the purposes of verifying the declared Available Capacity and applying the provisions of subparagraphs (iii) through (vi) above. The verification of declared Available Capacity pursuant to this paragraph shall be performed in accordance with Operating Practice 5. (The Parties reserve the right to agree to mutually acceptable modifications of Operating Practices.

7(h) [THIS SECTION NOT USED]

7(i) Records

Each Party shall keep and maintain all records as may be necessary or useful in carrying out the provisions of this Agreement or which are required to permit an audit by the other Party. All such records created shall be retained for at least three calendar years following the calendar year in which such records were created. Subject to the need to maintain compliance with all applicable law or codes of conduct, each Party shall make such records available to the other Party for inspections and copying, at the copying Party's expense, upon reasonable notice during regular business hours. Each Party shall have the right, upon 30-days written notice prior to the end of an applicable three-calendar-year period to request copies of such records. The non-requesting Party shall provide such copies, at the requesting Party's expense, within 30 days of receipt of such notice.

8. [THIS SECTION NOT USED]

9. Compensation for Commercial Energy

9(a) Capacity Payment

As the monthly capacity payment for capacity associated with Commercial Energy, Consumers shall pay Seller the sum of the hourly products of $5.00 per megawatt hour (the "Capacity Price") and Commercial Energy.

If for any calendar year the Contract Capacity Factor is less than 0.6, then the Capacity Price stated in the first paragraph of this Subsection 9(a) shall be adjusted for the next calendar year. A Capacity Price adjustment factor shall be determined by dividing such Contract Capacity Factor by 0.75. The Capacity Price for the following calendar year shall then be determined by multiplying the Capacity Price in the first paragraph of this Subsection 9(a) by such Capacity Price adjustment factor and rounding the result to the nearest one-tenth of a dollar ($0.1).

9(b) Energy Payment

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As the monthly energy payment for energy associated with Commercial Energy, Consumers shall pay Seller as follows:

For the energy payment associated with fixed expense, Consumers shall pay Seller the sum of the hourly products of Commercial Energy and the Fixed Energy Price determined in accordance with Exhibit C, which is attached hereto and made a part hereof.

For the energy payment associated with variable expenses, Consumers shall pay Seller the sum of the hourly products of the Commercial Energy quantity contained in the FBT Schedules and the Cost of Production determined in accordance with Exhibit B.

Notwithstanding the immediately preceding paragraph, in the event that the Boilers fail to operate, and Seller's obligation to DOW requires a turbine start-up, and Seller's deliveries are in excess of the scheduled amount of energy, then during such period of turbine operation Consumers shall pay Seller the sum of the hourly products of the excess Commercial Energy generated and delivered and the lower of (a) the Cost of Production divided by two and (b) the real-time Locational Marginal Price at the Commercial Pricing Node for Consumers' load.

9(c) Administrative Disallowances by the Michigan Public Service Commission

If the Michigan Public Service Commission disallows, or states an intention to disallow in the future, recovery of any jurisdictional costs incurred by Consumers as a result of the administration of this Agreement based upon a finding by the Commission that some provision of this Agreement was, or is being, improperly administered in a manner that did or will result in jurisdictional costs incurred by Consumers that should not be recovered from Consumers' customers, such administrative disallowance shall be the responsibility of Seller. To the extent such an administrative disallowance relates to a payment previously made by Consumers to Seller, Seller shall refund such amount to Consumers within 60 days of the date of the Commission order imposing such administrative disallowance. To the extent such an administrative disallowance relates to payments to be made in the future, Consumers shall have the right to adjust its future payments to Seller to an amount consistent with the administrative disallowance finding of the Commission. By way of example and not limitation, an instance of an administrative disallowance would be a circumstance where Seller and Consumers determine that Available Capacity for a specified period is 98%, but the Commission makes a finding that Available Capacity is 97% and disallows cost recovery for the amount of the difference.

The provisions of Subsection 9(c) shall govern over any conflicting provisions of this Agreement.

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9(d) Obligation to Support and Defend

Consumers and Seller shall support and defend the MPSC's order approving the Agreement and in any forum in which they may be challenged.

9(e) [THIS SECTION NOT USED]

10. [THIS SECTION NOT USED]

11. Early Termination

If for each of any two consecutive calendar years the Contract Capacity Factor is less than 0.10, Consumers shall have the right to terminate this Agreement. Such right shall be exercised by giving at least 90 days' written notice to Seller, which notice shall be given within 90 days of the end of the second calendar year. Within 20 days after such notice is given, Seller shall pay to Consumers an amount determined in accordance with Exhibit A. The provisions of this Section 11 regarding payments shall survive any termination of this Agreement by Consumers pursuant to this Section 11.

12. Annual Inspection

A Consulting Engineer shall be retained by Seller. Prior to retaining the Consulting Engineer, Seller shall provide Consumers with a list of potential consulting engineering firms. Seller shall be entitled to select any of the consulting firms named on such list to which Consumers does not object within ten days of receipt of such list.

Seller shall cause the Consulting Engineer to inspect the MC-Facility at least once every three (3) years of the Contract Term. This inspection shall include, at a minimum, all equipment, structures, operating procedures and maintenance practices necessary for the generation and delivery of Commercial Energy. The Consulting Engineer shall promptly issue a written report of the inspection (hereinafter referred to as the " Inspection Report") to Seller and Consumers. The cost of the inspection and Inspection Report shall be borne by Seller.

As soon as practicable, and in no event later than 730 days after receipt of the Inspection Report, Seller shall implement all recommendations in the report that have been approved by the MC-Facility management regarding equipment, structures, operating procedures and maintenance practices necessary for the generation and delivery of Commercial Energy. After the issuance of each Inspection Report and prior to the issuance of each subsequent report, Seller shall provide to Consumers a written summary of the status of previous Inspection Report recommendations and provide, upon Consumers' written request, verification of said status.

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If the Consulting Engineer withdraws its service, Seller shall retain a replacement Consulting Engineer as soon as reasonably possible. In such an instance or if Seller desires to replace the Consulting Engineer, Seller shall provide Consumers with a list of potential consulting engineering firms. Seller shall be entitled to select any of the consulting firms named on such list to which Consumers does not object within 10 days of receipt of such list.

13. Administrative Committee

From time to time various administrative and technical matters may arise in connection with the terms and conditions of this Agreement which will require the cooperation and consultation of the Parties and the exchange of information. As a means of providing for such cooperation, consultation and exchange, the Parties agree that an Administrative Committee shall be established. The purposes of the Administrative Committee shall include providing liaison between the Parties and exchanging information with respect to significant matters of design, construction, operation, and maintenance of the MC-Facility. Such Committee shall not diminish in any manner the authority or responsibility of either Party as set forth in this Agreement.

14. Force Majeure

14(a) Definition

The term “Force Majeure” means acts of God, including flood, earthquake, storm, or other natural calamity; war, insurrection, riot; curtailment, order, regulation or restriction imposed by governmental authority; or any other cause beyond the reasonable control of the Party affected, however, the phrase “any other cause beyond the reasonable control of the Party affected,” shall not include:

(i) shortages of fuel and supplies, other than fuel shortages occurring in time of calamity or unusual world events which are preventing major industrial users, including the Seller, from obtaining fuel for their operations;

(ii) mechanical breakdown of equipment of the Party affected;

(iii) strikes of employees of the Party affected; or,

(iv) explosions or fires on the site of the Party affected unless such explosions or fires are caused by criminal acts.

14(b) Obligations Under Force Majeure

If either Party is rendered unable, wholly or in part, by Force Majeure, to carry out its obligations under this Agreement, including but not limited to Seller’s ability to meet the minimum

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Contract Capacity Factor set forth in Section 11, then, during the continuance of such inability, the obligation of such Party shall be suspended. The Party relying on Force Majeure shall give written notice of Force Majeure to the other Party as soon as practicable after such event occurs. Upon the conclusion of Force Majeure, the Party heretofore relying on Force Majeure shall, with all reasonable dispatch, take all necessary steps to resume the obligation previously suspended. If Force Majeure has rendered Seller unable to meet the minimum Contract Capacity Factor set forth in Section 11, and such inability continues beyond the conclusion of Force Majeure, Seller may, at its option, terminate this Agreement without liability pursuant to Section 11.

14(c) Continued Payment Obligation

Any Party's obligation to make payments already owing shall not be suspended by Force Majeure.

15. Liability

Neither Party shall in any event be liable to the other for any special, incidental, exemplary, punitive or consequential damages such as, but not limited to, lost profits, revenue or good will, interest, loss by reason of shutdown or nonoperation of equipment or machinery, increased expense of operation of equipment or machinery, loss of use of equipment or machinery, cost of purchased or replacement power or services or claims by customers, whether such loss is based on contract, warranty, negligence, indemnity, strict liability or otherwise. Except for remedies specifically provided for elsewhere in this Agreement, no liability shall attach to a Party for failure to settle any strike or other labor problem in a manner not completely satisfactory to it.

16. Disagreements

16(a) Administrative Committee Procedure

If any disagreement arises on major matters concerning this Agreement, the disagreement shall be brought to the Administrative Committee, which shall attempt to timely resolve the disagreement. If the Administrative Committee can resolve the disagreement, such agreement shall be reported in writing to and shall be binding upon the Parties. If the Administrative Committee cannot resolve the disagreement within a reasonable time, the President of Consumers or the senior officer of Seller can, by written notice to the members of the Administrative Committee, withdraw the matter from consideration by the Administrative Committee and submit the same for resolution to the President of Consumers and the senior officer of Seller. If these representatives of the Parties agree to a resolution of the matter, such resolution shall be reported in writing to, and shall be binding upon, the Parties; but if said senior

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representatives fail to resolve the matter within seven days after its submission to them, then the matter shall proceed to legal or equitable dispute resolution.

16(b) Attorney Fees and Costs

If a Party to this Agreement files a complaint with the MPSC or initiates any other claim or litigation before a court or other tribunal of appropriate jurisdiction over the terms of, or performance under, this Agreement, that Party shall reimburse the other Party for all reasonable attorney fees and costs incurred in responding to or defending such complaint, claim or litigation which are associated with or related to claims which are denied or rejected by the MPSC, court, or other tribunal, as applicable.

16(c) Obligations to Perform Pending Dispute Resolution

If a disagreement should arise on any major matter which is not resolved by the Administrative Committee or the senior representatives of the Parties as provided in Subsection 16(a), then, pending the resolution of the disagreement by arbitration, Seller shall continue to operate the MC-Facility in a manner consistent with this Agreement and Consumers shall continue to pay all charges required in accordance with the applicable provisions of this Agreement.

17. Exculpation

Notwithstanding anything to the contrary contained in this Agreement, the liabilities and obligations of Seller arising out of, or in connection with, this Agreement or any other agreements entered into pursuant hereto shall not be enforced by any action or proceeding wherein damages or any money judgment or specific performance of any covenant in any such document and whether based upon contract, warranty, negligence, indemnity, strict liability or otherwise, shall be sought against the assets of the partners comprising Seller. By entering into this Agreement, Consumers waives any and all right to sue for, seek or demand any judgment against such partners and their affiliates, other than Seller, by reason of the liabilities and obligations of Seller arising out of, or in connection with, this Agreement or any other agreements entered into pursuant hereto, except to the extent such partners are legally required to be named in any action to be brought against Seller.

18. Billing

As soon as practicable after the end of each calendar month, Seller shall render a statement to Consumers which shall reflect any amounts owed by Consumers for Commercial

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Energy during such calendar month. The net amount due Seller shall be paid by Consumers within 20 days after the date of such statement. Any amounts not paid when due shall bear interest until paid at the lesser of (a) the per annum rate of interest equal to the prime lending rate as may be from time to time published in The Wall Street Journal under Money Rates on such day (or if not published on such day on the most recent preceding day on which published), plus one percent or (b) the maximum rate permitted by applicable law.

19. Purchase Option/Contract Extension

[Intentionally, this section is left blank.]

20. Service Contract

It is the intent of the Parties that this Agreement shall be treated as a service contract. The provisions of this Agreement shall be interpreted and applied in a manner consistent with the treatment of this Agreement as a service contract. The Parties shall make appropriate modifications to this Agreement in the event unanticipated events might otherwise cause this Agreement not to be treated as a service contract, provided, however, that no such modification shall be made without the concurrence of the Party whose rights would be affected thereby.

21. Successors and Assigns

This Agreement shall inure to the benefit of and be binding upon the successors and permitted assigns of the respective Parties hereto. Except as provided in this Section 21, this Agreement shall not be assigned, transferred or otherwise alienated without the other Party's written consent, which consent shall not be unreasonably withheld. No such assignment of this Agreement shall be valid unless the assignee assumes the obligation to pay Consumers any payments to which it may become entitled pursuant to Section 11. Notwithstanding the foregoing, Seller shall have the right, without obtaining Consumers' consent (and without relieving itself from liability hereunder), to assign all or a portion of its rights and/or obligations under this Agreement to any lender(s) providing financing to Seller as collateral security for obligations under financing documents entered into with such lender(s); provided, however, that any such lender(s) shall agree in writing to be bound by the terms and conditions hereof associated with the rights and/or obligations assigned.

22. Governing Law

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This Agreement shall be deemed to be a Michigan contract and shall be construed in accordance with and governed by the laws of Michigan.

23. Headings

The various headings set forth in this Agreement are for convenience only and shall not affect the construction or interpretation of this Agreement.

24. Notice to Parties

Unless otherwise provided in this Agreement, any notice, consent or other communication required to be made under this Agreement shall be in writing and shall be delivered to the address set forth below or such other address as the receiving Party may designate in writing:

Consumers Energy Company
1945 W. Parnall Road
Jackson, Michigan 49201
Attention: Electric Contract Strategies Manager, Contracts

Notice to Parties:
Midland Cogeneration Venture Limited Partnership
100 Progress Place
Midland, Michigan 48640
Attention: Chris Ganley, Director, Commercial Management &
Thomas Harrison, Commercial Manager
Email: cganley@capitalpower.com & tharrison@capitalpower.com
With a copy to: notices@capitalpower.com

All notices shall be effective when received. Notices of anticipated events required to be given by this Agreement shall be revised and reissued to reflect changes in the dates of the anticipated events. Upon notification of an assignment by Seller, Consumers shall also provide to assignee all notices required in this Agreement.

25. Compliance With Rules and Regulations

In the event an operational or scheduling term(s) of this Agreement or the practices or procedures conflict with any rule or regulation promulgated by MISO, the Federal Energy Regulatory Commission, North American Electric Reliability Corporation, ReliabilityFirst Corporation, Transmission Owner, or Transmission Provider, which rule or regulation applies to either Party or the MC-Facility, and which governs the operation of the MC-Facility or the scheduling of electric energy from the MC-Facility, the Parties shall conform this Agreement and/or the practices and procedures to such rule or regulation and in doing so, shall modify this Agreement to give effect to the original intent of the Parties to the extent practicable.

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26. Mobile-Sierra

It is the intent of the Parties that the rates and all other terms and conditions of the services provided hereunder shall not be subject to change under Sections 205 or 206 of the Federal Power Act of 1935, as amended, 16 U.S.C. § 791 *et seq.* (or any successor legislation), without the consent of both Parties. Each of the Parties hereto agrees not to unilaterally file with the FERC a change in the rates, terms or conditions of this Agreement. Moreover, absent agreement of the Parties to a proposed change, the standard of review for changes to any rate, term or condition of this Agreement proposed by a non-Party or the FERC or any other governing authority claiming jurisdiction and acting *sua sponte* shall be the "public interest" standard of review set forth in *United* Gas *Pipe Line* Co. *v. Mobile* Gas *Services Corp.,* 350 U.S. 332 (1956) and *Federal Power Commission v. Sierra Pacific Power* Co., 350 U.S. 348 (1956). To the extent that the FERC adopts specific language that parties must incorporate into agreements in order to bind FERC, third parties, governing authorities claiming jurisdiction and themselves to a public interest standard of review, the Parties hereby incorporate such language herein by reference.

27. Entire Agreement and Amendments

With respect to the subject matter hereof, this Agreement supersedes all previous representations, understandings, negotiations and agreements either written or oral between the Parties hereto or their representatives and constitutes the entire agreement of the Parties. I\Jo amendments or changes to this Agreement shall be binding unless made in writing and duly executed by both Parties.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement.

Signature to page to follow

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CONSUMERS ENERGY COMPANY

By: Signed by: GARRICK J ROCHOW 4CD782834A5E4D0...

Name: GARRICK J ROCHOW

Title: President & CEO

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

By: Signed by: F21D49EF2BA04A7...

Name: Avik Dey

Title: President & CEO

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

By: Signed by: Chris Ganley 643FA6C276784C3...

Name: Chris Ganley

Title: Director-Commercial

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POWER PURCHASE AGREEMENT
BETWEEN CONSUMERS ENERGY COMPANY
AND
MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

PAYMENTS BY SELLER TO CONSUMERS
FOR EARLY TERMINATION OF AGREEMENT

Payment for early termination pursuant to this Agreement shall be determined in accordance with the following formula.

ETP = (5256 x CC x CP x M)

Where:

ETP = Early Termination Payment, expressed in dollars.

CC = Contract Capacity, expressed in megawatts, in effect at time of termination.

CP = $7.57/MWh.

M = A factor based on the early termination year in accordance with the following table.

Year In Which Early Termination Occurs	"M" Factor
2030	1.0000
2031	1.0000
2032	1.0000
2033	0.70
2034	0.70
2036	0.70
2037	0.56
2038	0.42
2039	0.28
2040	0.14

Note: For example, if the Contract Capacity Factor is less than 0.10 for the years 2036 and 2037, then the factor to be used in the above stated formula is 0.42

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POWER PURCHASE AGREEMENT
BETWEEN CONSUMERS ENERGY COMPANY AND
MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

COST OF PRODUCTION DETERMINATION

Beginning with deliveries occurring on June 1, 2030 and continuing each month thereafter until this Agreement is terminated, Consumers shall, subject to Subsection 9(b), pay for Commercial Energy generated and delivered in each such month at the Cost of Production determined in accordance with this Exhibit B.

For the energy price associated with variable expenses, Consumers shall pay on Commercial Energy generated and delivered equal to:

COP = Gas Price x Heat Rate + Adders

Where COP = Cost of Production and the remaining terms in the above formula are defined below.

(a) Definitions

"Adders" means that portion of COP other than fuel by which Seller incurs a cost as a result of generating and delivering Commercial Energy and consists of the sum of the following items: (1) Demineralized Water Cost, (2) Maintenance Cost, and (3) NOx Cost. If new statutes are enacted or new regulations are promulgated that result in additional variable generation costs, such costs shall be added to the list of items above in a manner mutually agreed upon by the Parties and (or absent such agreement) as ordered by the MPSC.

"Business Day" means a calendar day other than a Saturday, Sunday, or a North American Electric Reliability Corporation (or any successor) holiday.

"Gas Price" means the price (in $/MMBtu and rounded to the nearest tenth of a cent) applicable to each hour of each calendar day equal to the "Midpoint" of the "Common Range" for the Consumers Energy city-gate location as published by Platts' *Gas Daily* in the Daily Price Survey (or its successor or substitute publication as mutually agreed to by the Parties for gas flow that begins that same calendar day plus variable firm gas transportation costs, including but not limited to, supplier premium, operational balancing fees, load balancing charges, nomination and settlement fees incurred through commercially reasonable decisions, in $/MMBtu in accordance with Consumers Energy's gas rate book. In the event that Platts does not publish a Gas Price for gas flow that begins on a calendar day, then the Gas Price for such a calendar day shall be the Gas Price in effect for the nearest previous calendar day. Seller shall use commercially reasonable efforts to secure the lowest cost applicable rate available in Consumers Energy's gas rate book as may be updated from time to time.

"Demineralized Water Cost" means the COP component (updated annually and made effective April 1 of each year) determined by the product of (1) the total annual thousands of gallons of demineralized water consumed during the prior calendar year adjusted to exclude the demineralized water attributable to the supply of process steam to DOW and the demineralized water attributable to the operation of the Boilers, and (2) the rate per thousand gallons for the month of January as determined under the MCV/DOW Demineralized Water Contract, divided by

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the total annual electric production for the prior calendar year adjusted to exclude electric production during the prior calendar year attributable to the Boilers.

"Emission Rate" means the MC-Facility's actual average (for the month two months prior to the month of generation and delivery of Commercial Energy to Consumers) NOx emission rate in lbs/MMBtu. The NOx emission rates used for the determination of COP will be those used by Seller in Seller's reporting to the U.S. Environmental Protection Agency ("EPA").

"Heat Rate" means the number of British Thermal Units ("BTU", or, if expressed in millions of BTU, "MMBTU") required to produce one incremental megawatt-hour of energy (operating in combined cycle mode) at the MC-Facility using the higher heating value of the fuel. The Heat Rate will be determined annually pursuant to Section (b) below and made effective on April 1 of each year.

"Maintenance Cost" means the COP component (updated annually and made effective April 1 of each year) determined by the product of (1) the total annual Gas Turbine Equivalent Operating Hours (or EOH) accumulated during the prior calendar year and (2) the rate per EOH as determined annually under the MCV/GE Service Agreement or any successor agreement, divided by the total annual electric production during the prior calendar year adjusted to exclude electric production during the prior calendar year attributable to the Boilers.

"Market Disruption Event" means, with respect to the Gas Price as published by Platts (or any successor), any of the following events: (a) the failure of Platts to announce or publish information necessary for determining the Gas Price at the Consumers Energy city-gate; (b) the failure of trading to commence or the permanent discontinuation or material suspension of trading of natural gas at the Consumers Energy city-gate; (c) the temporary or permanent discontinuance or unavailability of the information necessary for determining the Gas Price at the Consumers Energy city-gate; (d) the temporary or permanent closing of any exchange that supplies information to determine the Gas Price at the Consumers Energy city-gate; or (e) a material change in the formula for or the method of determining the Midpoint price of natural gas at the Consumers Energy city-gate. Notwithstanding the foregoing, a Market Disruption Event shall only apply to those calendar days that the Parties expect Gas Price information to be published.

"NOx Allowance(s)" means a right issued by the United States of America or the state of Michigan allowing the holder to emit one ton of nitrogen oxides ("NOx") during a particular period as more particularly described in Michigan's NOx State Implementation Plan (SIP) Call as administered by the EPA and/or under the Clean Air Interstate Rule (GAIR) program due to take effect in 2009.

"NOx Allowance Price" means the estimated sale price of NOx Allowances for the SIP, the GAIR NOx ozone season trading program and the GAIR annual trading program, as applicable, which is deemed to be equal to an average of at least two quotes obtained by Seller from brokers within seven days prior to the day the monthly NOx Cost is calculated hereunder.

"NOx Cost" means the COP component (updated monthly) determined by the product of (1) Emission Rate, (2) Heat Rate and (3) the NOx Allowance Price, divided by 2000 (i.e., NOx Cost = Emission Rate x Heat Rate x NOx Allowance Price / 2000).

(b) MC-Facility Heat Rate Determination

The Heat Rate for the yearly period that begins April 1 of each year and ends on March 31 of the following year will be determined in the following manner:

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1. The Heat Rate, before adjustment for start fuel, will be a fixed standard of 8.045 **MMBtu** per **MWh**.

2. The MC-Facility Heat Rate will be the standard Heat Rate plus the product of the number of Gas Turbine starts for the prior calendar year excluding those starts that were not associated with delivery of energy under the Commercial Energy schedules and 350 MMBtu per start divided by the energy delivered to Consumers under the Commercial Energy schedules expressed in MWhs during the prior calendar year. If the resulting calculated Heat Rate exceeds 8.500 MMBtu per MWh, the Heat Rate will be 8.500 MMBtu per MWh.

(c) Market Disruption Event

If a Market Disruption Event has occurred and is continuing for one or more calendar days, the Gas Price for each such day shall be determined pursuant to the Gas Price specified for the first calendar day thereafter on which no Market Disruption Event exists; provided, however, if the Gas Price is not so determined within three (3) Business Days after the first calendar day on which the Market Disruption Event occurred or existed, then the Parties shall negotiate in good faith to agree on a Gas Price (or a method for determining a Gas Price), and if the Parties have not so agreed on or before the twelfth (12th) Business Day following the first calendar day on which the Market Disruption Event occurred or existed, then the Gas Price shall be determined by each Party obtaining in good faith two dealer quotes obtained from leading dealers in the relevant market that are not an affiliate and averaging the four quotes.

(d) Rounding Conventions

- Heat Rate - MMBtu/MWh rounded to 3 decimal places
- NOx emission rate - pounds/MMBtu rounded to 3 decimal places
- Tons of NOx emissions - tons rounded to 0 decimal places
- Value of NOx emission allowances - dollars rounded to 0 decimal places
- MWh dispatched - MWh rounded to 3 decimal places

Docusign Envelope ID: 8E18DC22-7304-4BD9-BA32-30CC028FFC94

POWER PURCHASE AGREEMENT
BETWEEN CONSUMERS ENERGY COMPANY
AND
MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

FIXED ENERGY PRICE DETERMINATION

Beginning with deliveries occurring on June 1, 2030 and continuing each month thereafter until this Agreement is terminated, Consumers shall pay for Commercial Energy associated with fixed expenses in each such month at the energy price as set forth below:

For the energy price associated with fixed expenses, the Fixed Energy Price is equal to:

(On-Peak Hours) FEP = 1.03 x (Fixed Firm Gas Transportation Rate x Heat Rate + 13.51/MWh)
(Off-Peak Hours) FEP = 0.98 x (Fixed Firm Gas Transportation Rate x Heat Rate + 13.51/MWh)

Where:

FEP = The Fixed Energy Price, in dollars per megawatt hour, to be paid by Consumers to Seller for Commercial Energy during such Month. If new statutes are enacted or new regulations are promulgated that result in additional generation costs, such costs shall be added to the list of items above in a manner mutually agreed upon by the Parties and (or absent such agreement) as ordered by the MPSC.

Fixed Firm Gas Transportation Rate = means the fixed firm gas transportation rate (in $/MMBtu and rounded to the nearest tenth of a cent) applicable to each hour of each calendar day in accordance with Consumers' gas rate book. Seller shall use commercially reasonable efforts to secure the lowest cost applicable rate available in Consumers' gas rate book as may be updated from time to time. The Fixed Firm Gas Transportation rate shall include all gas transportation service costs charged by Consumers in accordance with Consumers' gas rate book and service agreements.

Heat Rate = means 8.335 MMBtu/MWh, as may be updated by mutual written agreement between the Parties.

Seller shall purchase 248,000 MMBtu / day of firm transportation, as may be updated by mutual written agreement between the Parties.

Docusign Envelope ID: 0C39F270-016A-8753-8254-0142AC48277A

AMENDMENT NO. 1 TO
THE POWER PURCHASE AGREEMENT BETWEEN
CONSMERS ENERGY COMPANY AND
MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

THIS AMENDMENT NO. 1, made and entered into as of the 25 day of June 2026, is between Consumers Energy Company, a Michigan corporation, herein called "Consumers" and Midland Cogeneration Venture Limited Partnership, herein called "Seller." Buyer and Seller are herein sometimes referred to individually as "Party" and collectively as "Parties" where appropriate.

WHEREAS, Consumers and Seller entered into a Power Purchase Agreement, as fully executed on September 17, 2025 [(the "Agreement"), providing for the purchase from Seller the electric energy generated by the MC-Facility; and

WHEREAS, the Parties desire to further amend the Agreement as hereinafter provide.

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein set forth, the Parties hereto agree as follows:

1. The second sentence in the first paragraph of Section 2(a) shall be deleted in its entirety and replaced with the following:

   "This Agreement shall be submitted by Consumers to the MPSC for approval under all applicable law no later than September 30, 2026"

2. The second paragraph of Section 2(a) shall be deleted in its entirety and replaced with the following:

   "In the event the MPSC does not issue an order, deemed satisfactory to Consumers, in Consumers' sole discretion, in the commercially reasonable discretion of each Party, regarding Consumers' request to approve this Agreement or any portion of the recovery requested in the application for approval of this Agreement, or the MPSC otherwise does not approve this Agreement as described herein within fourteen (14) months of Consumers' request for approval, this Agreement shall be void ab initio and neither party shall have any further liability hereunder."

Docusign Envelope ID: 0C39F270-016A-8753-8254-0142AC48277A

3. The Parties agree that the Agreement was fully executed on September 17, 2025.

4. Except as hereinabove amended, all the terms and conditions of the Agreement shall remain in full force and effect.

5. This Amendment No. 1 may be executed and delivered in counterparts, including by a facsimile or an electronic transmission thereof, each of which shall be deemed an original. Any document generated by the Parties with respect to this Amendment No. 1, including this Amendment No. 1, may be imaged and stored electronically and introduced as evidence in any proceeding as if original business records. Neither Party will object to the admissibility of such images as evidence in any proceeding on account of having been stored electronically.

The Agreement as amended by this Amendment No. 1 shall inure to the benefit of and be binding upon the successors and assigns of the respective parties.

CONSUMERS ENERGY COMPANY	Midland Cogeneration Venture Limited Partnership
By: Beth Skowronski	By: DocuSigned by: 013C244D8A354FD...
Name: Beth Skowronski	Name: Andrew Pearson
Title: Manager, Contracts	Title: SVP - US Commercial
Date: 6/26/26	Date: 6/26/2026

Exhibit A-4 (KGT-2)
CONFIDENTIAL
PLACEHOLDER

FILED UNDER SEAL WITH
THE MPSC

Project: **New MCV PPA**

Line No.	Origin of Requirement	General Filing Requirements	Witness	Testimony Section (s)	Exhibit Reference	Work Paper Reference	Applicable (Y/N)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Application Instructions for Certificate Necessity					
1	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	These filing instructions apply to an electric utility application for a certificate of necessity under the provisions of MCL 460.6s. The application shall be consistent with these instructions, with each item labeled as set forth below. Any additional information considered relevant by the applicant may also be included in the application.	Consumers Energy's application is submitted as an Integrated Resource Plan under MCL 460.6t and includes requests for Certificates of Necessity under MCL 460.6s, as applicable. The filing is organized and labeled consistently with the Commission's filing instructions and includes additional information relevant to the Commission's review.				Y
		Filing Announcement					
2	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	In order to facilitate the scheduling and preparation of certificate of necessity proceedings, a utility intending to file an application for a certificate of necessity shall file a filing announcement, in a new docket, at least 30 days prior to filing the application. The filing announcement, along with a proof of service, shall be served on the Commission and all parties granted intervention in the utility's last two general rate cases and its most recent integrated resource plan case. If the application for a certificate of necessity is not filed within 120 days after filing of the filing announcement, the filing announcement shall be considered withdrawn.	A filing announcement was made by the Company on August 4th announcing the Company's intent to file its 2026 Integrated Resource Plan and Certificates of Necessity on September 3, 2026 in docket U-22127 with proof of service attached.				Y
3	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The filing announcement shall include: 1. Statement of intent to file for a certificate(s) of necessity; 2. A brief description of the facilities or power purchase agreement for which the certificate(s) will be sought; and 3. Any additional information the utility finds relevant to provide notice.					Y
		Pre-Application Consultation Process					
4	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Prior to filing the application for a certificate of necessity, a pre-application consultation with the Commission Staff (Staff) is necessary. The purpose of the pre-application consultation is to assist the applicants in refining the project application, and to facilitate efficient regulatory review. Applicants should schedule pre-application consultation meetings with the Staff well in advance of filing an application with the Commission. The Staff recognizes that all projects are not the same and that the information needed for one project will not necessarily be appropriate for the next. For some projects, a complete application may require less information than for other projects. For this reason, a pre-application consultation with the Staff is important.	Pre-application consultations with the Commission Staff (Staff) occurred on April 8, 2026 and July 14, 2026. Sign-in sheets and presentation materials are included in docket U-22127				Y
5	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Early in the consultation process, the Staff will identify Staff contacts, and clarify the applicability of information requirements for the specific application. The pre-application consultation will be documented with a sign-in sheet indicating all meeting attendees. The sign-in sheet, along with any presentations provided by the utility during the pre-application consultation meeting, shall be uploaded to the docket containing the filing announcement.					Y
		I. Applicant Information **All applications shall contain the following information about the applicant utility:**					
6	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The name and address of the applicant utility seeking the certificate of necessity; and	The applicant utility is Consumers Energy Company, One Energy Plaza, Jackson, Michigan 49201.				Y
7	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A description of the applicant utility, and the name, title, and business address of a person to whom correspondence should be directed.	Consumers Energy Company is a Michigan public utility that provides electric service to customers throughout the state. The name, title, and business address of the person to whom correspondence should be directed are provided in the filing.				Y
		II. Alternate Standards and Criteria for Certain Projects					
8	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	An electric utility with more than one million retail customers in this state seeking a certificate of necessity for a project costing more than $100 million shall follow these instructions.	Consumers Energy Company is an electric utility serving more than one million retail customers in Michigan and is seeking a Certificate of Necessity for a project with an estimated cost exceeding $100 million. Accordingly, Consumers Energy has prepared its application in accordance with these filing instructions.				Y
9	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	An electric utility with less than one million retail customers in this state seeking a certificate of necessity for a project costing less than $100 million may propose different review criteria and approval standards in its application, under MCL 460.6s(2), including modification or waiver of these instructions for good cause shown. The justification for any such proposals shall be addressed in the application.	Not Applicable				N
10	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Project cost estimates submitted with the certificate of necessity application do not require final bidding and contracts for project engineering, procurement and construction. Project cost estimates may include cost estimates developed in an alternative manner, along with a proposed contract strategy for project development and implementation.	Not Applicable				N
		III. Confidential Information					
11	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Proprietary, confidential, and other nonpublic materials filed as part of the application shall be clearly identified and marked accordingly and presented in such a way that the proprietary and confidential nature of the materials is preserved pending the execution of any confidentiality agreements and issuance of protective orders. Availability of specific materials in the application may be contingent upon appropriate confidentiality agreements and protective orders.	Proprietary, confidential, and other nonpublic materials are clearly designated and filed confidentially under the applicable protective order. Publicly available information is used where practicable, and any confidentiality claims are supported by an appropriate justification.				Y
		IV. Integrated Resource Plan					
12	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	An integrated resource plan, as required by MCL 460.6s(11) or approved pursuant to MCL 460.6t, shall be included as an exhibit to the certificate of necessity application. The plan shall include the items listed in MCL 460.6s(11) and otherwise comply with the Commission's standards developed under that section. This subsection does not apply to an electric utility that has an approved integrated resource plan under MCL 460.6t.	Consumers Energy's Certificate of Necessity application is being submitted together with its Integrated Resource Plan. The Integrated Resource Plan is included with and incorporated into the filing as supporting documentation for the requested Certificate of Necessity.				Y
13	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The utility shall identify and explain any significant material changes that have occurred to actual and/or forecasted market energy, capacity, and fuel prices; load projections; capital and operating costs of resources; etc., from the time the integrated resource plan was approved.	Steven Q. McLean	Section I – Overall Testimony Summary			Y
		V. Certificate of Necessity Type					
14	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The certificate of necessity application shall identify the relief requested. An electric utility may seek one or more of the following certificates as described in MCL 460.6s(3):	Steven Q. McLean	Section I – Overall Testimony Summary; Section VIII – Description of Significant Proposals and Summary of Requested Relief			Y
15	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A certificate that the power to be supplied as a result of the proposed construction, investment, or purchase is needed;	Steven Q. McLean	Section V – Current Baseline Capacity Position; Section VII – Proposed Course of Action; Section VIII – Description of Significant Proposals and Summary of Requested Relief			Y
16	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A certificate that the size, fuel type, and other design characteristics of the existing or proposed electric generation facility or the terms of the power purchase agreement represent the most reasonable and prudent means of meeting that power need;	Steven Q. McLean	Section VI – New Resource Options; Section VII – Proposed Course of Action; Section VIII – Description of Significant Proposals and Summary of Requested Relief			Y
17	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A certificate that the price specified in the power purchase agreement will be recovered in rates from the electric utility's customers;	Steven Q. McLean	Section I – Overall Testimony Summary; Section VIII – Description of Significant Proposals and Summary of Requested Relief			Y
18	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A certificate that the estimated purchase or capital costs of, and the financing plan for, the existing or proposed electric generation facility, including, but not limited to, the costs of siting and licensing a new facility and the estimated cost of power from the new or proposed electric generation facility, will be recoverable in rates from the electric utility's customers subject to MCL 460.6s(4)(c).	Not Applicable				N
		VI. Certificate of Necessity That the Power to Be Supplied as a Result of the Proposed Construction, Investment, or Purchase Is Needed					
19	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A utility seeking a certificate of necessity that the power to be supplied as a result of the proposed construction, investment, or purchase is needed shall file an application that identifies projected resource requirements and the expected timing of the requirements.	Steven Q. McLean	Section V – Current Baseline Capacity Position; Section VII – Proposed Course of Action			Y

Line No.	Origin of Requirement	General Filing Requirements	Witness	Testimony Section (s)	Exhibit Reference	Work Paper Reference	Applicable (Y/N)
		Application Instructions for Certificate Necessity					
20	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The applicant shall either have an approved integrated resource plan, as specified in MCL 460.6t, or file, as a part of their application, an integrated resource plan that is consistent with MCL 460.6s(11) and that identifies a proposed course of action.	Steven Q. McLean	Section VII – Proposed Course of Action			Y
		VII. Certificate of Necessity That the Design Characteristics of a Proposed Electric Generation Facility or Investment in an Existing Electric Generation Facility or the Terms of a Power Purchase Agreement Represent the Most Reasonable and Prudent Means of Meeting Future Power Needs **An application seeking a certificate of necessity to construct a new electric generation facility or to make a significant investment in an existing facility or enter into a power purchase agreement shall include the following information:** **A. New or Existing Electric Generation Facility:**					
21	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A written description of the proposed or existing site, including identification of the municipality in which the facility will be constructed and the current use of that site;	Not Applicable				N
22	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, the age of the existing facility or facilities to be purchased or modified;	Not Applicable				N
23	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Expected generating technology and major systems (including major pollution control systems);	Not Applicable				N
24	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Expected nameplate capacity, availability, heat rates, expected life, and other significant operational characteristics;	Not Applicable				N
25	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Fuel type and sources, including the identification and justification of fuel price forecasts used over the study period;	Not Applicable				N
26	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The expected annual emissions of carbon dioxide and greenhouse gases, particulates, sulfur dioxides, volatile organic compounds, oxides of nitrogen, mercury, and other hazardous air pollutants over the life of the facility or contract, and an assessment of whether some or all of the anticipated emissions and their anticipated health impacts could be eliminated or reduced through the use of feasible and prudent alternatives.	Not Applicable				N
27	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Discussion of the rationale behind facility or investment technology, fuel, capacity, and other significant design characteristics;	Not Applicable				N
28	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A description of all major state, federal, and local permits required to construct and operate the proposed generation facility or the proposed facility upgrades in compliance with state and federal environmental standards, laws, and rules;	Keith G. Troyer	Section I: New MCV PPA- CON			Y
29	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, the status of any transmission interconnection study and identification of any expected or required transmission system modifications;	Not Applicable				N
30	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, natural gas infrastructure required for plant construction and operation not located on the proposed site but required for plant construction and operation;	Not Applicable				N
31	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, a description of modifications to existing road, rail, or waterway transportation facilities not located on the proposed site but required for plant construction and operation;	Keith G. Troyer	Section I: New MCV PPA- CON			Y
32	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, water and sewer infrastructure required for construction and operation not located on the proposed site but required for plant construction and operation;	Keith G. Troyer	Section I: New MCV PPA- CON			Y
33	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A basic schedule for development and construction, which include an estimated time between the start of construction and commercial operation of the facility or facility upgrades;	Not Applicable				N
34	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	An estimate of the proportion of the construction workforce that will be composed of residents of the state of Michigan;	Keith G. Troyer	Section I: New MCV PPA- CON			Y
35	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Descriptions of the alternatives that could defer, displace, or partially displace the proposed generation facility or significant investment in an existing facility, that were considered, including a "no-build" option, and the justification for the choice of the proposed project. Comparative costs of supply alternatives shall be included. The supply alternatives shall consider energy optimization, load management, demand response, energy storage and renewable energy;	Not Applicable				N
36	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Describe the effect of the proposed project on wholesale market competition;	Keith G. Troyer	Section I: New MCV PPA- CON			Y
37	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Any workpapers used in developing the application, supporting testimony, and any accompanying integrated resource plan. Such workpapers shall, whenever possible, be provided in electronic format with formulas intact.	Not Applicable				N
38	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Any modeling input or output files used in developing the application, supporting testimony, and any accompanying integrated resource plan. Such modeling input and output files shall, whenever possible, be provided in electronic format with formulas intact. The applicant shall also identify each modeling program used, and provide information for how interested parties can obtain access to such modeling program.	Not Applicable				N
39	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Any other information that the applicant considers relevant.	The filing includes any other information Consumers Energy considers relevant to support the requested Certificates of Necessity and facilitate the Commission's review.				Y
		VII.B. Power Purchase Agreement					
40	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, a written description of generation facilities covered by the power purchase agreement, the size of each facility, generator technology, expected nameplate capacity, availability, heat rates, expected life, fuel type, other significant operational characteristics and the location of the generation facilities, including identification of the municipalities in which the facilities are located;	Keith G. Troyer	Section I: New MCV PPA- CON	Exhibit A-3 (KGT-1)		Y
41	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The name and address of the power provider supplying contract products and services under the power purchase agreement;	Keith G. Troyer	Section I: New MCV PPA- CON	Exhibit A-3 (KGT-1)		Y
42	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	For power purchase agreements that are the result of a competitive solicitation, the following shall be included in the certificate of necessity application: (a) A copy of the request for proposal for electric capacity and/or energy and a description of how the request was issued to potential respondents; (b) Copies of responses to the request for proposal. Responses submitted as part of a certificate of necessity application may be presented in such a way that the identities of the respondents and other commercially sensitive information is protected; and (c) A description of the proposal selection process.	Not Applicable				N
43	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The date the resources covered by the power purchase agreement will be available, the term of the power purchase agreement, and a description of significant contract provisions that could result in early termination of the contract;	Keith G. Troyer	Section I: New MCV PPA- CON	Exhibit A-3 (KGT-1)		Y
44	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The price to be paid for capacity and energy contract products and services delivered under the power purchase agreement;	Keith G. Troyer	Section I: New MCV PPA- CON	Exhibit A-3 (KGT-1)		Y
45	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If the contract includes provisions which may result in an increase in cost due to the price of fuel, the fuel type and sources, including the identification and justification of fuel price forecasts used over the study period;	Keith G. Troyer	Section I: New MCV PPA- CON	Exhibit A-3 (KGT-1)		Y
46	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The annual expected emissions of carbon dioxide and greenhouse gases, particulates, sulfur dioxides, volatile organic compounds, oxides of nitrogen, mercury, and other hazardous air pollutants over the life of the facility or contract and an assessment of whether some or all of the anticipated emissions and their anticipated health impacts could be eliminated or reduced through the use of feasible and prudent alternatives;	Heather A. Breining Keith G. Troyer	Section VI: Environmental Considerations for the Proposed New MCV Contract Section I: New MCV PPA- CON	Exhibit A-49 (HAB-1)		Y
47	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Descriptions of the alternatives that could defer, displace, or partially displace the proposed power purchase agreement that were considered, and the justification for the choice of the proposed power purchase agreement. Comparative costs of supply alternatives shall be included. The supply alternatives shall consider energy optimization, load management, demand response, energy storage and renewable energy;	Adam J. Moritz	Section XIII: Resource Alternatives Analysis			Y
48	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Any workpapers used in developing the application, supporting testimony, and any accompanying integrated resource plan. Such workpapers shall, whenever possible, be provided in electronic format with formulas intact;	All workpapers used to develop the application, supporting testimony, and accompanying Integrated Resource Plan are included with the filing. Workpapers are provided electronically with formulas intact whenever practicable.				Y
49	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Any modeling input or output files used in developing the application, supporting testimony, and any accompanying integrated resource plan. Such modeling input and output files shall, whenever possible, be provided in electronic format with formulas intact. The applicant shall also identify each modeling program used, and provide information for how interested parties can obtain access to such modeling program;	All modeling input and output files used to develop the application, supporting testimony, and accompanying Integrated Resource Plan are included with the filing in electronic format whenever practicable. The filing identifies each modeling program used and provides information regarding how interested parties may obtain access to the program.				Y

Line No.	Origin of Requirement	General Filing Requirements	Witness	Testimony Section (s)	Exhibit Reference	Work Paper Reference	Applicable (Y/N)
		Application Instructions for Certificate Necessity					
50	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If a financial incentive is being requested, the requested amount and a certification that the applicant is not affiliated with the power provider.	Keith G. Troyer	Section I: New MCV PPA- CON			Y
51	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A copy of the proposed power purchase agreement.	Keith G. Troyer	Section I: New MCV PPA- CON	Exhibit A-3 (KGT-1)		Y
		VIII. Certificate of Necessity That the Estimated Capital or Purchase Costs of the New or Existing Electric Generation Facility or the Investment in an Existing Electric Generation Facility Will Be Recoverable in Rates From the Electric Utility's Customers. A. Construction of New Facility or Investment in Existing Facility:					
52	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	An application seeking a certificate of necessity to construct a new electric generation facility, to make a significant investment in an existing electric generation facility, or to purchase an existing electric generation facility shall provide an estimate of the costs required for the specified purchase or construction, as well as projected facility operation costs. Cost estimates filed with the certificate of necessity application shall include:	Not Applicable				N
53	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	To the extent applicable and available, engineering, procurement and construction costs, transmission interconnection costs, owner's costs, and project financing costs shall be included. Estimates filed with the application that are the result of competitively-bid engineering and procurement and construction contracts shall be separately identified. If the scope, scale, timing, or other aspects of the project, including legislative or regulatory uncertainty, make competitively-bid solicitations unlikely to produce reliable or timely project cost estimates, the application shall include cost estimates developed in an alternative manner, along with a proposed contract strategy for project development and implementation.	Not Applicable				N
54	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	For new construction, the certificate of necessity application shall include the expected typical annual costs associated with operating the facility including fuel, operations and maintenance, and environmental compliance.	Not Applicable				N
55	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	For investment and upgrades at an existing facility, the certificate of necessity application shall include an estimate of the incremental operating costs for the facility after upgrades are complete including fuel, operations and maintenance, and environmental compliance.	Not Applicable				N
56	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	To the extent applicable, the certificate of necessity application shall describe any definitive joint ownership plans for the proposed generation facility assets and the impact such plans will have on the costs for which a certificate of necessity is requested. For the purposes of a certificate of necessity application, changes in allocated costs among joint owners shall be considered an aspect of the estimated cost included in the filing.	Not Applicable				N
57	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A disclosure indicating the portion of investment included in the applicant's request for a certificate of necessity which was previously included in the applicant's rate base.	Not Applicable				N
		VIII.B. Purchase of Existing Facility					
58	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	As applicable, the estimated costs associated with purchasing the existing facility assets including the price to be paid for the assets, acquisition and transition costs, financing costs, and any significant financial liabilities that will accompany the asset transfer; and	Not Applicable				N
59	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The expected typical annual costs associated with operating the generation facility including fuel, operations and maintenance, and environmental compliance.	Not Applicable				N
		IX. Power Purchase Agreement Cost Recovery					
60	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A utility seeking rate recovery for future payments made pursuant to a power purchase agreement shall file a certificate of necessity application providing an estimate of the capacity and energy payments to be made for contract products and services pursuant to the agreement. The estimated payments shall be presented on a yearly basis in nominal dollars over the primary term of the contract.	Adam J. Moritz	Section VII: Supply-Side Resource Options Considered In The IRP	Confidential Exhibit A-28 (AJM-14)		Y

Project: **Clean PPA**

(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	**Origin of Requirement**	**General Filing Requirements**	**Witness**	**Testimony Section (s)**	**Exhibit Reference**	**Work Paper Reference**	**Applicable (Y/N)**
		Application Instructions for Certificate Necessity					
1	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	These filing instructions apply to an electric utility application for a certificate of necessity under the provisions of MCL 460.6s. The application shall be consistent with these instructions, with each item labeled as set forth below. Any additional information considered relevant by the applicant may also be included in the application.	Consumers Energy's application is submitted as an Integrated Resource Plan under MCL 460.6t and includes requests for Certificates of Necessity under MCL 460.6s, as applicable. The filing is organized and labeled consistently with the Commission's filing instructions and includes additional information relevant to the Commission's review.				Y
		Filing Announcement					
2	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	In order to facilitate the scheduling and preparation of certificate of necessity proceedings, a utility intending to file an application for a certificate of necessity shall file a filing announcement, in a new docket, at least 30 days prior to filing the application. The filing announcement, along with a proof of service, shall be served on the Commission and all parties granted intervention in the utility's last two general rate cases and its most recent integrated resource plan case. If the application for a certificate of necessity is not filed within 120 days after filing of the filing announcement, the filing announcement shall be considered withdrawn.	A filing announcement was made by the Company on August 4th announcing the Company's intent to file its 2026 Integrated Resource Plan and Certificates of Necessity on September 3, 2026 in docket U-22127 with proof of service attached.				Y
3	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The filing announcement shall include: 1. Statement of intent to file for a certificate(s) of necessity; 2. A brief description of the facilities or power purchase agreement for which the certificate(s) will be sought; and 3. Any additional information the utility finds relevant to provide notice.					Y
		Pre-Application Consultation Process					
4	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Prior to filing the application for a certificate of necessity, a pre-application consultation with the Commission Staff (Staff) is necessary. The purpose of the pre-application consultation is to assist the applicants in refining the project application, and to facilitate efficient regulatory review. Applicants should schedule pre-application consultation meetings with the Staff well in advance of filing an application with the Commission. The Staff recognizes that all projects are not the same and that the information needed for one project will not necessarily be appropriate for the next. For some projects, a complete application may require less information than for other projects. For this reason, a pre-application consultation with the Staff is important.	Pre-application consultations with the Commission Staff (Staff) occurred on April 8, 2026 and July 14, 2026. Sign-in sheets and presentation materials are included in docket U-22127				Y
5	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Early in the consultation process, the Staff will identify Staff contacts, and clarify the applicability of information requirements for the specific application. The pre-application consultation will be documented with a sign-in sheet indicating all meeting attendees. The sign-in sheet, along with any presentations provided by the utility during the pre-application consultation meeting, shall be uploaded to the docket containing the filing announcement.					Y
		I. Applicant Information **All applications shall contain the following information about the applicant utility:**					
6	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The name and address of the applicant utility seeking the certificate of necessity; and	The applicant utility is Consumers Energy Company, One Energy Plaza, Jackson, Michigan 49201.				Y
7	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A description of the applicant utility, and the name, title, and business address of a person to whom correspondence should be directed.	Consumers Energy Company is a Michigan public utility that provides electric service to customers throughout the state. The name, title, and business address of the person to whom correspondence should be directed are provided in the filing.				Y
		II. Alternate Standards and Criteria for Certain Projects					
8	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	An electric utility with more than one million retail customers in this state seeking a certificate of necessity for a project costing more than $100 million shall follow these instructions.	Consumers Energy Company is an electric utility serving more than one million retail customers in Michigan and is seeking a Certificate of Necessity for a project with an estimated cost exceeding $100 million. Accordingly, Consumers Energy has prepared its application in accordance with these filing instructions.				Y
9	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	An electric utility with less than one million retail customers in this state seeking a certificate of necessity for a project costing less than $100 million may propose different review criteria and approval standards in its application, under MCL 460.6s(2), including modification or waiver of these instructions for good cause shown. The justification for any such proposals shall be addressed in the application.	Not Applicable				N
10	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Project cost estimates submitted with the certificate of necessity application do not require final bidding and contracts for project engineering, procurement and construction. Project cost estimates may include cost estimates developed in an alternative manner, along with a proposed contract strategy for project development and implementation.	Not Applicable				N
		III. Confidential Information					
11	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Proprietary, confidential, and other nonpublic materials filed as part of the application shall be clearly identified and marked accordingly and presented in such a way that the proprietary and confidential nature of the materials is preserved pending the execution of any confidentiality agreements and issuance of protective orders. Availability of specific materials in the application may be contingent upon appropriate confidentiality agreements and protective orders.	Proprietary, confidential, and other nonpublic materials are clearly designated and filed confidentially under the applicable protective order. Publicly available information is used where practicable, and any confidentiality claims are supported by an appropriate justification.				Y
		IV. Integrated Resource Plan					
12	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	An integrated resource plan, as required by MCL 460.6s(11) or approved pursuant to MCL 460.6t, shall be included as an exhibit to the certificate of necessity application. The plan shall include the items listed in MCL 460.6s(11) and otherwise comply with the Commission's standards developed under that section. This subsection does not apply to an electric utility that has an approved integrated resource plan under MCL 460.6t.	Consumers Energy's Certificate of Necessity application is being submitted together with its Integrated Resource Plan. The Integrated Resource Plan is included with and incorporated into the filing as supporting documentation for the requested Certificate of Necessity.				Y
13	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The utility shall identify and explain any significant material changes that have occurred to actual and/or forecasted market energy, capacity, and fuel prices; load projections; capital and operating costs of resources; etc., from the time the integrated resource plan was approved.	Steven Q. McLean	Section I – Overall Testimony Summary			Y
		V. Certificate of Necessity Type					
14	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The certificate of necessity application shall identify the relief requested. An electric utility may seek one or more of the following certificates as described in MCL 460.6s(3):	Steven Q. McLean	Section I – Overall Testimony Summary; Section VIII – Description of Significant Proposals and Summary of Requested Relief			Y
15	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A certificate that the power to be supplied as a result of the proposed construction, investment, or purchase is needed;	Steven Q. McLean	Section V – Current Baseline Capacity Position; Section VII – Proposed Course of Action; Section VIII – Description of Significant Proposals and Summary of Requested Relief			Y
16	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A certificate that the size, fuel type, and other design characteristics of the existing or proposed electric generation facility or the terms of the power purchase agreement represent the most reasonable and prudent means of meeting that power need;	Steven Q. McLean	Section VI – New Resource Options; Section VII – Proposed Course of Action; Section VIII – Description of Significant Proposals and Summary of Requested Relief			Y
17	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A certificate that the price specified in the power purchase agreement will be recovered in rates from the electric utility's customers;	Steven Q. McLean	Section I – Overall Testimony Summary; Section VIII – Description of Significant Proposals and Summary of Requested Relief			Y
18	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A certificate that the estimated purchase or capital costs of, and the financing plan for, the existing or proposed electric generation facility, including, but not limited to, the costs of siting and licensing a new facility and the estimated cost of power from the new or proposed electric generation facility, will be recoverable in rates from the electric utility's customers subject to MCL 460.6s(4)(c).	Not Applicable				N
		VI. Certificate of Necessity That the Power to Be Supplied as a Result of the Proposed Construction, Investment, or Purchase Is Needed					

Line No.	Origin of Requirement	General Filing Requirements	Witness	Testimony Section (s)	Exhibit Reference	Work Paper Reference	Applicable (Y/N)
19	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A utility seeking a certificate of necessity that the power to be supplied as a result of the proposed construction, investment, or purchase is needed shall file an application that identifies projected resource requirements and the expected timing of the requirements.	Steven Q. McLean	Section V – Current Baseline Capacity Position; Section VII – Proposed Course of Action			Y
20	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The applicant shall either have an approved integrated resource plan, as specified in MCL 460.6t, or file, as a part of their application, an integrated resource plan that is consistent with MCL 460.6s(11) and that identifies a proposed course of action.	Steven Q. McLean	Section VII – Proposed Course of Action			Y
		VII. Certificate of Necessity That the Design Characteristics of a Proposed Electric Generation Facility or Investment in an Existing Electric Generation Facility or the Terms of a Power Purchase Agreement Represent the Most Reasonable and Prudent Means of Meeting Future Power Needs **An application seeking a certificate of necessity to construct a new electric generation facility or to make a significant investment in an existing facility or enter into a power purchase agreement shall include the following information:** **A. New or Existing Electric Generation Facility:**					
21	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A written description of the proposed or existing site, including identification of the municipality in which the facility will be constructed and the current use of that site;	Not Applicable				N
22	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, the age of the existing facility or facilities to be purchased or modified;	Not Applicable				N
23	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Expected generating technology and major systems (including major pollution control systems);	Not Applicable				N
24	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Expected nameplate capacity, availability, heat rates, expected life, and other significant operational characteristics;	Not Applicable				N
25	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Fuel type and sources, including the identification and justification of fuel price forecasts used over the study period;	Not Applicable				N
26	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The expected annual emissions of carbon dioxide and greenhouse gases, particulates, sulfur dioxides, volatile organic compounds, oxides of nitrogen, mercury, and other hazardous air pollutants over the life of the facility or contract, and an assessment of whether some or all of the anticipated emissions and their anticipated health impacts could be eliminated or reduced through the use of feasible and prudent alternatives.	Not Applicable				N
27	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Discussion of the rationale behind facility or investment technology, fuel, capacity, and other significant design characteristics;	Not Applicable				N
28	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A description of all major state, federal, and local permits required to construct and operate the proposed generation facility or the proposed facility upgrades in compliance with state and federal environmental standards, laws, and rules;	Keith G. Troyer	Confidential Section II			Y
29	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, the status of any transmission interconnection study and identification of any expected or required transmission system modifications;	Keith G. Troyer	Confidential Section II			Y
30	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, natural gas infrastructure required for plant construction and operation not located on the proposed site but required for plant construction and operation;	Not Applicable				N
31	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, a description of modifications to existing road, rail, or waterway transportation facilities not located on the proposed site but required for plant construction and operation;	Keith G. Troyer	Confidential Section II			Y
32	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, water and sewer infrastructure required for construction and operation not located on the proposed site but required for plant construction and operation;	Keith G. Troyer	Confidential Section II			Y
33	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A basic schedule for development and construction, which include an estimated time between the start of construction and commercial operation of the facility or facility upgrades;	Not Applicable				N
34	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	An estimate of the proportion of the construction workforce that will be composed of residents of the state of Michigan;	Keith G. Troyer	Confidential Section II			Y
35	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Descriptions of the alternatives that could defer, displace, or partially displace the proposed generation facility or significant investment in an existing facility, that were considered, including a "no-build" option, and the justification for the choice of the proposed project. Comparative costs of supply alternatives shall be included. The supply alternatives shall consider energy optimization, load management, demand response, energy storage and renewable energy;	Not Applicable				N
36	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Describe the effect of the proposed project on wholesale market competition;	Keith G. Troyer	Confidential Section II			Y
37	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Any workpapers used in developing the application, supporting testimony, and any accompanying integrated resource plan. Such workpapers shall, whenever possible, be provided in electronic format with formulas intact.	Not Applicable				N
38	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Any modeling input or output files used in developing the application, supporting testimony, and any accompanying integrated resource plan. Such modeling input and output files shall, whenever possible, be provided in electronic format with formulas intact. The applicant shall also identify each modeling program used, and provide information for how interested parties can obtain access to such modeling program.	Not Applicable				N
39	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Any other information that the applicant considers relevant.	The filing includes any other information Consumers Energy considers relevant to support the requested Certificates of Necessity and facilitate the Commission's review.				Y
		VII.B. Power Purchase Agreement					
40	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, a written description of generation facilities covered by the power purchase agreement, the size of each facility, generator technology, expected nameplate capacity, availability, heat rates, expected life, fuel type, other significant operational characteristics and the location of the generation facilities, including identification of the municipalities in which the facilities are located;	Keith G. Troyer	Confidential Section II	Confidential Exhibit A-4 (KGT-2)		Y
41	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The name and address of the power provider supplying contract products and services under the power purchase agreement;	Keith G. Troyer	Confidential Section II	Confidential Exhibit A-4 (KGT-2)		Y
42	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	For power purchase agreements that are the result of a competitive solicitation, the following shall be included in the certificate of necessity application: (a) A copy of the request for proposal for electric capacity and/or energy and a description of how the request was issued to potential respondents; (b) Copies of responses to the request for proposal. Responses submitted as part of a certificate of necessity application may be presented in such a way that the identities of the respondents and other commercially sensitive information is protected; and (c) A description of the proposal selection process.	Not Applicable				N
43	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The date the resources covered by the power purchase agreement will be available, the term of the power purchase agreement, and a description of significant contract provisions that could result in early termination of the contract;	Keith G. Troyer	Confidential Section II	Confidential Exhibit A-4 (KGT-2)		Y
44	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The price to be paid for capacity and energy contract products and services delivered under the power purchase agreement;	Keith G. Troyer	Confidential Section II	Confidential Exhibit A-4 (KGT-2)		Y
45	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If the contract includes provisions which may result in an increase in cost due to the price of fuel, the fuel type and sources, including the identification and justification of fuel price forecasts used over the study period;	Keith G. Troyer	Confidential Section II	Confidential Exhibit A-4 (KGT-2)		Y
46	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The annual expected emissions of carbon dioxide and greenhouse gases, particulates, sulfur dioxides, volatile organic compounds, oxides of nitrogen, mercury, and other hazardous air pollutants over the life of the facility or contract and an assessment of whether some or all of the anticipated emissions and their anticipated health impacts could be eliminated or reduced through the use of feasible and prudent alternatives;	Keith G. Troyer	Confidential Section II			Y

Line No.	Origin of Requirement	General Filing Requirements	Witness	Testimony Section (s)	Exhibit Reference	Work Paper Reference	Applicable (Y/N)
47	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Descriptions of the alternatives that could defer, displace, or partially displace the proposed power purchase agreement that were considered, and the justification for the choice of the proposed power purchase agreement. Comparative costs of supply alternatives shall be included. The supply alternatives shall consider energy optimization, load management, demand response, energy storage and renewable energy;	Adam J. Moritz	Section XIII: Resource Alternatives Analysis			Y
48	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Any workpapers used in developing the application, supporting testimony, and any accompanying integrated resource plan. Such workpapers shall, whenever possible, be provided in electronic format with formulas intact;	All workpapers used to develop the application, supporting testimony, and accompanying Integrated Resource Plan are included with the filing. Workpapers are provided electronically with formulas intact whenever practicable.				Y
49	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Any modeling input or output files used in developing the application, supporting testimony, and any accompanying integrated resource plan. Such modeling input and output files shall, whenever possible, be provided in electronic format with formulas intact. The applicant shall also identify each modeling program used, and provide information for how interested parties can obtain access to such modeling program;	All modeling input and output files used to develop the application, supporting testimony, and accompanying Integrated Resource Plan are included with the filing in electronic format whenever practicable. The filing identifies each modeling program used and provides information regarding how interested parties may obtain access to the program.				Y
50	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If a financial incentive is being requested, the requested amount and a certification that the applicant is not affiliated with the power provider.	Keith G. Troyer	Confidential Section II			Y
51	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A copy of the proposed power purchase agreement.	Keith G. Troyer	Confidential Section II	Confidential Exhibit A-4 (KGT-2)		Y
		VIII. Certificate of Necessity That the Estimated Capital or Purchase Costs of the New or Existing Electric Generation Facility or the Investment in an Existing Electric Generation Facility Will Be Recoverable in Rates From the Electric Utility's Customers. A. Construction of New Facility or Investment in Existing Facility:					
52	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	An application seeking a certificate of necessity to construct a new electric generation facility, to make a significant investment in an existing electric generation facility, or to purchase an existing electric generation facility shall provide an estimate of the costs required for the specified purchase or construction, as well as projected facility operation costs. Cost estimates filed with the certificate of necessity application shall include:	Not Applicable				N
53	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	To the extent applicable and available, engineering, procurement and construction costs, transmission interconnection costs, owner's costs, and project financing costs shall be included. Estimates filed with the application that are the result of competitively-bid engineering and procurement and construction contracts shall be separately identified. If the scope, scale, timing, or other aspects of the project, including legislative or regulatory uncertainty, make competitively-bid solicitations unlikely to produce reliable or timely project cost estimates, the application shall include cost estimates developed in an alternative manner, along with a proposed contract strategy for project development and implementation.	Not Applicable				N
54	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	For new construction, the certificate of necessity application shall include the expected typical annual costs associated with operating the facility including fuel, operations and maintenance, and environmental compliance.	Not Applicable				N
55	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	For investment and upgrades at an existing facility, the certificate of necessity application shall include an estimate of the incremental operating costs for the facility after upgrades are complete including fuel, operations and maintenance, and environmental compliance.	Not Applicable				N
56	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	To the extent applicable, the certificate of necessity application shall describe any definitive joint ownership plans for the proposed generation facility assets and the impact such plans will have on the costs for which a certificate of necessity is requested. For the purposes of a certificate of necessity application, changes in allocated costs among joint owners shall be considered an aspect of the estimated cost included in the filing.	Not Applicable				N
57	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A disclosure indicating the portion of investment included in the applicant's request for a certificate of necessity which was previously included in the applicant's rate base.	Not Applicable				N
		VIII.B. Purchase of Existing Facility					
58	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	As applicable, the estimated costs associated with purchasing the existing facility assets including the price to be paid for the assets, acquisition and transition costs, financing costs, and any significant financial liabilities that will accompany the asset transfer; and	Not Applicable				N
59	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The expected typical annual costs associated with operating the generation facility including fuel, operations and maintenance, and environmental compliance.	Not Applicable				N
		IX. Power Purchase Agreement Cost Recovery					
60	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A utility seeking rate recovery for future payments made pursuant to a power purchase agreement shall file a certificate of necessity application providing an estimate of the capacity and energy payments to be made for contract products and services pursuant to the agreement. The estimated payments shall be presented on a yearly basis in nominal dollars over the primary term of the contract.	Adam J. Moritz	Section VII: Supply-Side Resource Options Considered In The IRP	Confidential Exhibit A-28 (AJM-14)		Y

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan and Certificates of Necessity under MCL 460.6s and 460.6t, certain accounting approvals, and for other relief.	)))))))	Case No. U-22127

REDACTED

DIRECT TESTIMONY

OF

THOMAS P. CLARK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2026

Q. Please state your name and business address.

A. My name is Thomas P. Clark, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. In what capacity are you employed?

A. I am the Sr. Executive Director of the Electric Supply Development & Engineering Department.

Q. What is your educational background?

A. I received the degree of Bachelor of Science in Engineering from Western Michigan University in 2004. Since 2010, I have been a Registered Professional Engineer in the state of Michigan. In December 2016, I received the degree of Master of Business Administration from the Ross School of Business at the University of Michigan Ann Arbor.

Q. Please describe your business experience?

A. In August 2004, I joined Consumers Energy as an Electric System Owner. In 2005, I accepted a position as an Engineer in Transactions and Resource Planning responsible for administration of the Resource Conservation Plan and the Qualified Facility Reduced Dispatch Agreements. In this role, I assisted with proposal evaluation and the administration of power purchase contracts. In early 2009, I took on responsibilities associated with the Company's Renewable Energy Plan ("RE Plan"), including the calculation of the Transfer Price associated with renewable energy and capacity and Renewable Energy Credit tracking and forecasting. In June 2013, I was assigned to the Smart Energy Department where I was responsible for the development and

implementation of demand response programs associated with the Company's deployment of Advanced Metering Infrastructure. In March 2015, I accepted the role of Manager of the Company's Resource Planning Department where I was responsible for all the Company's short-, mid-, and long-term electric generation resource planning, including the development of the Company's Integrated Resource Plans ("IRP"). In July 2017, I added Real-Time and Day-Ahead Midcontinent Independent System Operator, Inc. ("MISO") Market Operations to my Resource Planning responsibilities. In March 2021, I was promoted to Executive Director of Electric Supply where I had responsibility for purchasing and transport functions for fuel for electric generation, interaction in the MISO markets, Power Supply Cost Recovery ("PSCR") activities, wholesale settlement and transaction functions, and contract strategy functions including distribution agreements, solicitations for energy and capacity, renewable energy compliance, and distributed generation programs. In December 2021, I was assigned the role of Executive Director of Clean Energy Development with responsibility for the engineering, development, and acquisition of all Company-owned renewable energy resources, including solar, wind, and storage projects. In August of 2025, I was promoted to Senior Executive Director of Electric Supply Development & Engineering and given responsibility for engineering, development, and acquisition of all Company-owned electric supply resources.

Q. Have you previously testified before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I provided testimony in the following cases:

- Case No. U-15675-R, the Company's 2009 PSCR Reconciliation;
- Case No. U-16300, the Company's 2009 Renewable Cost Reconciliation;
- Case No. U-16543, the Company's RE Plan Amendment;

- Case No. U-16045-R, the Company's 2010 PSCR Reconciliation;
- Case No. U-16301, the Company's 2010 Renewable Cost Reconciliation;
- Case No. U-16581, the Company's Biennial RE Plan Review;
- Case No. U-16432-R, the Company's 2011 PSCR Reconciliation;
- Case No. U-16655, the Company's 2011 Renewable Cost Reconciliation;
- Case No. U-17301, the Company's 2013 Biennial RE Plan Review;
- Case No. U-17321, the Company's 2012 Renewable Cost Reconciliation;
- Case No. U-18250, the Company's application for a financing order approving the securitization of qualified costs and related approval;
- Case No. U-18322, the Company's 2017 Electric Rate Case;
- Case No. U-20165, the Company's 2018 IRP;
- Case No. U-20963, the Company's 2021 Electric Rate Case;
- Case No. U-21090, the Company's 2021 IRP;
- Case No. U-21224, the Company's 2022 Electric Rate Case;
- Case No. U-21389, the Company's 2023 Electric Rate Case;
- Case No. U-21585, the Company's 2024 Electric Rate Case;
- Case No. U-21816, the Company's RE Plan Amendment;
- Case No. U-21870, the Company's 2025 Electric Rate Case; and
- Case No. U-22070, the Company's 2026 Electric Rate Case.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony can be divided into three distinct purposes.

First, my testimony presents the supply-side input assumptions utilized in the Company's IRP modeling. Specifically, I support the technical, cost, performance, and operational assumptions for certain supply-side generation resources evaluated in the

Aurora capacity expansion modeling. These assumptions were provided for use in the modeling process described by Company witness Adam J. Moritz.

Second, my testimony supports the Company's Proposed Course of Action ("PCA") identified in this IRP and demonstrates that the supply-side resources identified in the PCA can be executed consistent with the underlying assumptions in the plan. In so doing, I describe how the Company will meet its proportional share of the 2,500 MW statewide energy storage target established under MCL 460.1101(1), calculated using the methodology approved by the Commission in Case No. U-21751. My testimony also addresses execution-related considerations for solar, wind, and battery energy storage development, including the statewide energy storage target and procurement plan, socioeconomic impacts, decommissioning considerations, implementation activities, Michigan workforce and material sourcing considerations, and applicable labor standards.

Finally, my testimony supports the Company's Certificates of Necessity ("CON") to construct and operate the D.E. Karn ("Karn") 5 & 6 Generating Station ("Proposed Karn Project") and Thetford 10, 11, 12, and 13 Generating Station ("Proposed Thetford Project") natural gas-fueled electric generating facilities including a summary of information presented by Company witnesses Nathan J. Washburn, Steven A. Sulzman, Erin M. Busby, Angela K. Rissman, Heather A. Breining, Sang H. Gang, and Daniel J. Azukas and supports the assumptions associated with the Proposed Karn and Thetford Projects that were evaluated during the Company's executable portfolio analysis.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-6 (TPC-1)	2026 IRP New Gas-Fueled Technologies Real and Nominal Overnight Cost Projections;
Exhibit A-7 (TPC-2)	2026 IRP New Nuclear Technology Real and Nominal Overnight Cost Projections;
Exhibit A-8 (TPC-3)	2026 IRP Solar Generation Capital Cost Assumptions;
Exhibit A-9 (TPC-4)	2026 IRP Wind Generation Capital Cost Assumptions;
Exhibit A-10 (TPC-5)	2026 IRP Battery Technology Capital Cost Assumptions;
Confidential Exhibit A-11 (TPC-6)	2026 IRP Confidential Battery Technology Capital Cost Assumptions;
Exhibit A-12 (TPC-7)	2026 IRP Karn and Thetford Capital Cost Assumptions;
Exhibit A-13 (TPC-8)	Karn CON Application Requirements Reference Table; and
Exhibit A-14 (TPC-9)	Thetford CON Application Requirements Reference Table.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. How is your testimony organized?

A. My testimony is organized into three parts:

Part I – IRP Modeling Assumptions

- Modeling Assumptions Overview
- Gas Fueled Technology Modeling Input Assumptions
- Nuclear Technology Modeling Input Assumptions
- Solar Technology Modeling Input Assumptions

- Wind Technology Modeling Input Assumptions
- Energy Storage Technology Modeling Input Assumptions

Part II – Execution of the PCA

- Supply-Side Resources
- Overview of Development
- Solar Development
- Wind Development
- Energy Storage Development, Target, and Procurement Plan
- Natural Gas Development
- Socioeconomic Impacts and Decommissioning

Part III – Certificates of Necessity

- Natural Gas Simple Cycle Generating Facilities
  - Proposed Karn Project
  - Proposed Thetford Project

PART I: IRP MODELING ASSUMPTIONS

Modeling Assumptions Overview

Q. Please describe your responsibilities related to the Company's IRP modeling.

A. My responsibilities included development, review, and support of the supply-side input assumptions utilized in the Company's IRP modeling. Specifically, I am supporting the technical, cost, performance, and operational assumptions for certain supply-side generation resources evaluated in the Aurora capacity expansion modeling. These assumptions were provided for use in the modeling process described by Company witness Moritz.

Q. How were the assumptions you supported used within the IRP modeling process?

A. As explained by Company witness Moritz, Aurora was used during the planning-information phase of the IRP to evaluate a range of eligible supply-side and demand-side resource options and identify recurring patterns in the resources selected across scenarios and sensitivities. I supported the development of assumptions for supply-side resources that were made available to Aurora for evaluation as part of that process. Aurora then utilized those assumptions, together with its optimization framework and planning constraints, to determine the types, timing, and approximate amounts of resources selected in the model results.

Q. What types of resources were evaluated using the assumptions you supported?

A. The assumptions I supported were associated with supply-side generation technologies including natural gas combined cycle ("CC"), simple cycle combustion turbine ("Natural Gas CTGs"), and reciprocating internal combustion engine ("RICE"), nuclear, wind, solar, and battery energy storage system ("BESS") generating resources. These inputs included assumptions necessary for Aurora to evaluate the relative economics, performance characteristics, and operational capabilities of the resource options available for selection by the model.

Q. Are the cost and operating assumptions reasonable for purposes of the IRP?

A. Yes. As described by Company witness Moritz, the Company's modeling proceeded in two analytically distinct phases, a planning-information phase and an executable portfolio evaluation. The Company believes the assumptions presented in Exhibits A-6 (TPC-1) to Confidential Exhibit A-11 (TPC-6) are reasonable because they represent generic

candidate resource options that were developed specifically for the planning-information phase of analysis and were not intended to represent project specific costs.

Q. Please explain what is meant by "generic candidate resource options."

A. As described by Company witness Moritz, the initial planning-information phase of the IRP utilized generic candidate resource options to evaluate the types of resources that may be economically and operationally attractive under a range of future conditions. These generic candidate resource options were not intended to represent specific executable projects. Rather, they were used to provide directional guidance regarding the types, timing, and approximate amounts of resources likely to be needed across the scenarios and sensitivities evaluated in the IRP.

Q. How were these assumptions developed?

A. This information was developed using recognized third-party engineering data, publicly available industry benchmarks, and standard internal cost-estimating practices. The assumptions were developed specifically for use in long-term resource planning and were designed to provide a consistent basis for comparing multiple resource technologies within Aurora. The primary source for the Company's assumptions was the National Renewable Energy Laboratory's ("NREL") 2024 Annual Technology Baseline ("ATB") report.

Q. Please explain the NREL 2024 ATB report.

A. On an annual basis, NREL publishes the ATB, which provides projected cost and operating performance parameters for a range of electricity generation and storage technologies. The report is publicly available on NREL's website and includes a full narrative discussion on the underlying assumptions, data sources, and justifications supporting the projections provided. The ATB presents cost projections under three defined scenarios: advanced,

moderate and conservative. These scenarios allow utilities and planning entities to evaluate technology costs across a range of future outcomes consistent with industry-accepted planning practices.

Q. How does the Company address unit lifetime for accounting book purposes and engineering design purposes in the IRP modeling assumptions?

A. The operating life assumptions used in the IRP modeling reflect the expected productive life of each modeled resource technology for planning purposes. These assumptions are used to evaluate resource economics over the IRP planning period and do not, by themselves, establish the accounting book life for any specific project. Accounting book lives are established through the Company's depreciation studies and are subject to review and approval in depreciation and rate case proceedings. Engineering design life reflects the period over which a resource is expected to be capable of operating based on technical design, maintenance, inspections, component replacement, and applicable operating requirements. Accounting book life and engineering design life may differ because accounting lives are used for depreciation and ratemaking purposes, while engineering design lives reflect technical operating capability and expected asset performance. The design life for each asset type is discussed below. For the accounting life assumed, see tabs 8a through 8e in the work paper of Company witness Moritz (WP-AJM-1).

Gas-Fueled Technology Modeling Input Assumptions

Q. What natural gas-fueled technologies were considered as utility-scale prototype units in the IRP modeling data assumptions?

A. The Company considered the following natural gas-fueled generation prototypes for evaluation in the IRP:

- 2x1 H-Class CC with carbon capture and sequestration ("CCS");
- 2x1 H-Class CC;
- 1x1 H-Class CC;
- 1x0 F-Class Natural Gas CTG; and
- 5x0 RICE.

Q. What primary industry source(s) was utilized as the basis for defining the transmission connected utility-scale natural gas prototype units in the IRP modeling data assumptions?

A. The Company used the NREL 2024 ATB report.

Q. What are the cost assumptions utilized for the various new sources of gas-fueled technologies in the Company's IRP?

A. Exhibit A-6 (TPC-1) provides the capital and operation and maintenance ("O&M") cost estimates, together with the operating performance characteristics, utilized for the various gas-fueled technology resource options offered for selection in Aurora.

Q. How did the Company develop its cost estimates for the various gas-fueled technologies?

A. The Company's engineering, planning, and cost-estimating teams developed cost estimates for the gas-fueled technologies identified above, including the 2x1 H-Class CCS, 2x1 H-Class CC, 1x1 H-Class CC, 1x0 F-Class CTG, and 5x0 RICE resource options based on the NREL 2024 ATB report, Conservative Cost Scenario. The Company escalated those cost assumptions to 2025 dollars and applied standard Consumers Energy loadings, including applicable overheads and Allowance for Funds Used During Construction ("AFUDC"), to develop fully burdened capital cost estimates. The resulting cost

assumptions were entered into the Company's assumptions book and used as direct inputs into the Aurora modeling.

Q. What first year available assumptions were used for the gas-fueled resource options?

A. The Company assumed that the 2x1 H-Class CCS, 2x1 H-Class CC, and 1x1 H-Class CC resource options first become available in 2033. The Company assumed that the 1x0 F-Class combustion turbine and 5x0 RICE resource options first become available in 2031.

Q. What operating life assumptions were used for the gas-fueled resource options?

A. The Company assumed an operating life of 50 years for the 2x1 H-Class CCS, 2x1 H-Class CC, 1x1 H-Class CC, and 1x0 F-Class combustion turbine resource options. The Company assumed an operating life of 30 years for the 5x0 RICE resource option.

Q. What capital cost assumptions were used for the gas-fueled resource options?

A. For the base modeling assumptions, the Company assumed 2025 nominal capital costs of $3,293 per kW for 2x1 H-Class CCS, $1,744 per kW for 2x1 H-Class CC, $2,056 per kW for 1x1 H-Class CC, $1,653 per kW for 1x0 F-Class combustion turbine, and $3,244 per kW for the 5x0 RICE configuration.

Q. What capital cost escalation assumptions were used for the gas-fueled resource options?

A. Escalation rates were tied to publicly available data from the NREL 2024 ATB report. The Company assumed nominal capital cost escalation rates, as defined in the NREL 2024 ATB report, of 1.34% for 2x1 H-Class CCUS, 1.74% for 2x1 H-Class CC, 1.74% for 1x1 H-Class CC, 1.58% for 1x0 F-Class combustion turbine, and 1.58% for the 5x0 RICE configuration. The same nominal capital cost escalation rates were assumed for base and sensitivity modeling assumptions.

Q. What fixed O&M assumptions were used for the gas-fueled resource options?

A. For the base modeling assumptions, the Company relied on the NREL 2024 ATB report. The Company assumed fixed O&M costs, expressed in 2025 nominal dollars, of $67.09 per kW-year for 2x1 H-Class CCUS, $35.75 per kW-year for 2x1 H-Class CC, $42.00 per kW-year for 1x1 H-Class CC, $27.68 per kW-year for 1x0 F-Class combustion turbine, and $55.00 per kW-year for the 5x0 RICE configuration. The nominal fixed O&M escalation rates assumed were 0.93%, 1.58%, 1.69%, 1.86%, and 1.86%, respectively.

Q. What variable O&M assumptions were used for the gas-fueled resource options?

A. For the base modeling assumptions, the Company relied on the NREL 2024 ATB report. The Company assumed variable O&M costs, expressed in 2025 nominal dollars, of $5.02 per MWh for 2x1 H-Class CCUS, $2.28 per MWh for 2x1 H-Class CC, $2.68 per MWh for 1x1 H-Class CC, $7.47 per MWh for 1x0 F-Class combustion turbine, and $7.50 per MWh for the 5x0 RICE configuration. The nominal variable O&M escalation rates assumed were 1.4%, 1.79%, 1.86%, 2.5%, and 2.5%, respectively.

Q. Were any tax credit assumptions included for the gas-fueled resource options?

A. Yes. The Company assumed a tax credit would be available for the 2x1 H-Class CCS configuration. Tax credits were assumed available for a project achieving commercial operation by the end of year 2035. The remaining gas-fueled resource options do not qualify for tax credits and are shown as "n/a" for tax credit end year in Exhibit A-6 (TPC-1).

Q. Were any transmission upgrade assumptions included for the gas-fueled resource options?

A. Yes. Exhibit A-6 (TPC-1) reflects a transmission network upgrade cost of $117.45 per kW, expressed in 2025 dollars.

Q. Were any indirect costs included in the cost estimates provided?

A. Yes. Indirect costs are included in the cost estimates and were developed using the Company's standard internal cost-estimating methodologies consistent with utility practice.

Nuclear Technology Modeling Input Assumptions

Q. Are you sponsoring the nuclear technology assumptions used in the Company's IRP modeling?

A. Yes. I am sponsoring the nuclear technology cost and operating parameter assumptions reflected in Exhibit A-7 (TPC-2), which were used as inputs into the Company's IRP modeling.

Q. What are the cost assumptions utilized for the nuclear resource option in the Company's IRP?

A. Exhibit A-7 (TPC-2) provides the capital cost estimate, O&M cost estimates, and operating performance characteristics utilized for the nuclear resource option offered for economic selection in Aurora. These assumptions are based on NREL 2024 ATB unless otherwise noted in the exhibit.

Q. What first-year-available and operating life assumptions were used for the nuclear resource option?

A. The Company assumed that the first year available for the nuclear resource option is 2040 and that the operating life is 60 years.

Q. What capacity and operating range assumptions were used for the nuclear resource option?

A. The Company modeled the nuclear resource option with a maximum capacity of 300 MW and a minimum operating level of 15%, which results in a minimum capacity of 45 MW.

Q. What fixed O&M assumptions were used for the nuclear resource option?

A. Consistent with the NREL 2024 ATB report, the Company assumed fixed O&M costs of $219.69 per kW-year, expressed in 2025 nominal dollars, with a nominal escalation rate of 2.5%.

Q. What variable O&M assumptions were used for the nuclear resource option?

A. Consistent with the NREL 2024 ATB report, the Company assumed variable O&M costs of $3.66 per MWh, expressed in 2025 nominal dollars, with a nominal escalation rate of 2.5%.

Q. What capital cost assumptions were used for the nuclear resource option?

A. The Company assumed a capital cost of $15,901 per kW, expressed in 2025 nominal dollars, together with a nominal capital cost escalation rate of 1.47% and including Company overheads.

Q. Were any tax credit or transmission upgrade assumptions included for the nuclear resource option?

A. While nuclear generation projects can technically qualify for tax credits, the Company determined that to qualify the project would need to achieve commercial operation by 2037. Given the assumption that the first year new nuclear generation could be delivered is 2040, the Company did not assume tax credit benefits for new nuclear generation. The Company assumed a transmission network upgrade cost of $117.45 per kW, expressed in 2025 dollars.

Q. Were any indirect costs included in the nuclear cost estimates?

A. Yes. The Company included applicable overhead loadings as part of the nuclear modeling assumptions.

Solar Technology Modeling Input Assumptions

Q. Are you sponsoring the solar technology assumptions used in the Company's IRP modeling?

A. Yes, Exhibit A-8 (TPC-3) contains the Company's utility-scale solar technology cost projections together with the associated scheduling and operating assumptions used in the IRP. The solar assumptions reflect annual availability beginning in 2029. For modeling purposes, assumptions include 1,000 MW per year of solar was made available from 2029 through 2050.

Q. What primary industry source was utilized as the basis for defining the utility-scale solar prototype units in the IRP modeling data assumptions?

A. The Company used the NREL 2024 ATB report as the primary source for utility-scale prototype cost and performance assumptions. The Company selected the Conservative Cost Scenario and Conservative Class 9 resource designation.

Q. Why did the Company select the Conservative Cost Scenario from the NREL ATB?

A. The Conservative Cost Scenario provides a reasonable cost outlook among the NREL ATB scenarios and is appropriate for long-term resource planning where future technology cost reductions are uncertain. Using that scenario provides a reasonable and consistent basis for comparing solar resources with other resource options evaluated in Aurora.

Q. Why did the Company select the NREL ATB Conservative Class 9 resource designation for utility-scale solar?

A. The Company selected Conservative Class 9 because of the net capacity factors (22.2%) and solar irradiance characteristics associated with that resource class most closely aligns with actual conditions observed in Michigan. This approach ensures that the modeled cost and performance assumptions reflect resource quality representative of the Company's service territory rather than national averages or more favorable solar resource regions.

Q. Please explain how the data from NREL was used to develop the utility-scale solar prototype units modeling assumptions.

A. The data was used as the foundation for the solar prototype assumptions, including net capacity factor, overnight capital cost, and fixed O&M. To develop fully burdened capital cost estimates, the Company's internal cost-estimating team applied standard Consumers Energy utility overhead loadings to the NREL overnight capital cost values. Those loadings include a variable overhead equal to 7.94% of the NREL overnight cost and fixed overhead costs of $41.45/kW. The resulting cost and operating assumptions were then incorporated into the IRP modeling framework for use in Aurora.

Q. What operating life was assumed?

A. The Company assumed an operating life of 35 years. This operating life reflects the expected productive life of the modeled utility scale solar.

Q. What are the capital, annual fixed O&M, and annual variable O&M costs assumed for utility-scale solar resources?

A. The assumed capital cost for solar in 2026 is $1,472/kW declining at a 2.5% annual rate. The fixed annual O&M for solar in 2026 is $21.15/kW-yr declining at a 1.4% annual rate. There is no variable O&M for solar.

Q. How were Production Tax Credits treated for solar resources in the IRP?

A. Solar resources were assumed to be eligible for the federal Production Tax Credit if they achieved commercial operation in 2029. Additional discussion of the legal and tax framework for federal tax credits is provided in the direct testimony of Company witness Brian J. VanBlarcum.

Wind Technology Modeling Input Assumptions

Q. Are you sponsoring the wind technology assumptions used in the Company's IRP modeling?

A. Yes. Exhibit A-9 (TPC-4) contains the Company's wind technology cost projections together with the associated scheduling and operating assumptions used in the IRP. The exhibit includes assumptions for both land based and offshore wind resources. The land based wind prototype reflects wind resources located in Michigan, while the offshore wind prototype reflects wind resources located in and along the great lakes surrounding the Lower Peninsula of Michigan. For modeling purposes, wind resources were assumed to be first available for selection beginning in 2029, with modeled project sizes ranging from 100 MW to 300 MW with 500 MW per year of wind made available from 2029 through 2035, followed by 100 MW per year from 2036 through 2040. The expectation with these assumptions was that new resources would continue to be generally available through

2035. Beyond 2035, the incremental new capacity is assumed to come from repowering existing wind resources.

Q. What primary industry source was utilized as the basis for defining the land based prototype units in the IRP modeling data assumptions?

A. The Company used the NREL 2024 ATB report as the primary source for utility-scale prototype cost and performance assumptions. The Company selected the Conservative Class 9 Cost Scenario and average of Conservative Class 9 and 10 resource designation for land based wind and Conservative Class 6 for offshore wind resource values and Conservative Class 4 for cost assumption values.

Q. Why did the Company select the Conservative Cost Scenario from the NREL ATB?

A. The Conservative Cost Scenario provides a reasonable cost outlook among the NREL ATB scenarios and is appropriate for long-term resource planning where future technology cost reductions are uncertain. Using that scenario provides a reasonable and consistent basis for comparing wind resources with other resource options evaluated in Aurora.

Q. Why did the Company select the average of NREL ATB Conservative Class 9 and 10 resource designation for land based wind?

A. The Company selected an average of Conservative Class 9 and 10 because of the net capacity factors of 30% and wind speed characteristics associated with that resource class most closely aligns with actual conditions observed in Michigan. This approach ensures that the modeled cost and performance assumptions reflect resource quality representative of the Company's service territory rather than national averages or more favorable wind resource regions.

Q. Why did the Company select the NREL ATB Class 6 resource designation for offshore wind?

A. The Company selected Class 6 because of the net capacity factor of 35% and wind speed characteristics associated with that resource class most closely aligns with actual conditions expected in Michigan. This approach ensures that the modeled cost and performance assumptions reflect resource quality representative of the Company's service territory rather than national averages or more favorable wind resource regions.

Q. What operating life was assumed for wind resources?

A. The Company assumed an operating life of 30 years for both in-state and offshore wind resources. This operating life reflects the expected productive life of the modeled wind resources for IRP planning purposes.

Q. Please explain how the NREL data was used to develop the wind prototype assumptions.

A. The data was used as a basis for the wind prototype assumptions, including capital cost, fixed O&M, capacity factor, and other operating parameters. To develop fully burdened capital cost estimates, the Company's internal cost-estimating team applied standard Consumers Energy utility overhead loadings to the NREL overnight capital cost values. Those loadings include a variable overhead equal to 19.81% of the NREL overnight cost and fixed overhead costs of $37.65/kW. The resulting cost and operating assumptions were then incorporated into the IRP modeling framework for use in Aurora.

Q. What are the capital costs, annual fixed O&M, and annual variable O&M assumed for land based wind resources?

A. The assumed capital cost for wind in 2026 is $1,844/kW declining at a 0.8% annual real rate. The fixed annual O&M for wind in 2026 is $40.25/kW-yr declining at a 0.4% annual real rate. There is no variable O&M for wind resources.

Q. What are the capital costs, annual fixed O&M, and annual variable O&M assumed for offshore wind resources?

A. The assumed capital cost for wind in 2026 is $6,838/kW declining at a 2.8% annual real rate. The fixed annual O&M for wind in 2026 is $89.24/kW-yr declining at a 0.4% annual real rate. There is no variable O&M for wind resources.

Q. How were Production Tax Credits treated for wind resources in the IRP?

A. Wind resources were assumed to be eligible for the federal Production Tax Credit if they achieve commercial operation by 2029.

Energy Storage Technology Modeling Input Assumptions

Q. Are you sponsoring the battery energy storage technology assumptions used in the Company's IRP modeling?

A. Yes. Exhibit A-10 (TPC-5) contains the Company's battery energy storage technology cost projections together with the associated scheduling and operating assumptions used in the IRP. The exhibit includes assumptions for battery energy storage resources, including duration, operating characteristics, capital cost, fixed O&M, and utility loading assumptions used in the Company's IRP modeling.

Q. What battery energy storage resources were modeled in the IRP?

A. The Company modeled utility scale battery energy storage resources, including four hour (Lithium-ion), 10 hour and 100 hour duration battery storage resources. Project sizes considered were 1 MW to 1,000 MW depending on duration with 1,000 MW assumed to be available to be added each year starting 2029 through 2050.

Q. What primary sources of industry data were used to develop the battery energy storage prototype assumptions?

A. The Company used the NREL 2024 ATB report as the primary source for utility-scale energy storage prototype cost and performance assumptions except for the 100 hour battery energy storage resource which was sourced from a confidential source and can be seen in Confidential Exhibit A-11 (TPC-6).

Q. Why did the Company select the Conservative Cost Scenario from the NREL ATB?

A. The Conservative Cost Scenario provides a reasonable cost outlook among the NREL ATB scenarios and is appropriate for long-term resource planning where future technology cost reductions are uncertain. Using that scenario provides a reasonable and consistent basis for comparing energy storage resources with other resource options evaluated in Aurora.

Q. Please explain how the data was used to develop the energy storage prototype assumptions.

A. The data was used as the foundation for the energy storage prototype assumptions, including round trip efficiency (85%), capacity factor, overnight capital cost, and fixed O&M. To develop fully burdened capital cost estimates, the Company's internal cost-estimating team applied standard Consumers Energy utility overhead loadings to the NREL overnight capital cost values. Those loadings include a variable overhead equal to 7.94%

of the NREL overnight cost and fixed overhead costs of $41.45/kW. The resulting cost and operating assumptions were then incorporated into the IRP modeling framework for use in Aurora.

Q. What are the capital costs, annual fixed O&M, and annual variable O&M assumed for battery energy storage resources?

A. The assumed capital cost for battery energy storage with four hour duration in 2026 is $2,103/kW declining at a 1.3% annual real rate. The fixed annual O&M for battery energy storage in 2026 is $47.74/kW-yr declining at a 1.3% annual real rate. The assumed capital cost for battery energy storage with 10 hour duration in 2026 is $4,599/kW declining at a 1.4% annual real rate. The fixed annual O&M for battery energy storage in 2026 is $105.57/kW-yr declining at a 1.4% annual real rate. The fixed annual O&M for battery energy storage in 2026 is $17.50/kW-yr with 0% escalation. There is no variable O&M for battery energy storage resources. As noted above, modeling information for the 100 hour battery was sourced from a confidential source and can be seen in Confidential Exhibit A-11 (TPC-6).

Q. What operating life was assumed for battery energy storage resources?

A. The Company assumed an operating life of 20 years for battery energy storage resources. This operating life reflects the expected productive life of the modeled storage resource for IRP planning purposes.

Q. How were federal tax credits treated for battery energy storage resources in the IRP?

A. Battery energy storage resources were assumed to be eligible for the federal Investment Tax Credit if commercial operation is achieved by 2037.

Sensitivity Analysis

Q. Did the Company conduct sensitivity analyses as part of the resource planning process, and if so, why?

A. Yes. Following completion of the planning-information phase modeling, which utilized NREL cost assumptions, the Company performed sensitivity analyses to evaluate whether the preferred resource selections remained reasonable under alternative market conditions. These sensitivities were designed to test the robustness of the original modeling results and assess the impact of changes in resource costs that could reasonably occur during project development and procurement activities.

Q. What assumptions were updated as part of the sensitivity analyses?

A. The Company evaluated two sensitivity cases. The first sensitivity updated the capital cost assumptions for gas-fired generation resources using turbine pricing obtained through competitive solicitations and project development activities. The second sensitivity incorporated those updated gas-fired generation costs and additionally increased renewable and battery storage capital costs by 40%. These sensitivity analyses were performed between June and September 2025 following completion of the initial Aurora modeling. The Gas-Fueled Technology Assumptions: Based on turbine pricing obtained and evaluated during project development, the 2025 nominal capital cost assumptions were updated as follows:

- 2x1 H-Class CC with CCS: $4,021/kW
- 2x1 H-Class CC: $2,471/kW
- 1x1 H-Class CC: $2,914/kW
- 1x0 F-Class Combustion Turbine: $2,208/kW
- 5x0 Reciprocating Engine: $4,173/kW

PART II: EXECUTION OF THE PCA

Supply-Side Resources

Q. What supply-side resources are included in the PCA?

A. The PCA includes a balanced portfolio of supply-side resources, including renewable generation, battery energy storage, and firm dispatchable resources. Specifically, the PCA includes additions of 8,823 MW of solar resources, 3,208 MW of wind resources, and 3,269 MW of four hour battery energy storage resources through 2040, combined with 3,307 MW of firm and dispatchable capacity resources needed to supplement intermittent and energy limited resources to support reliability.

Q. What amount of the supply-side capacity included in the PCA is associated with specific projects presented for approval in the IRP?

A. [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] As discussed in the testimony of Company witness Moritz, a number of solar, wind, and storage projects expected to achieve commercial operation prior to 2029 are included in the Company's plan, but those projects are not included in the incremental capacity additions identified above and are not included in this proceeding for approval.

Q. How does the Company expect to develop or procure supply-side resources included in the PCA that have not been specifically identified above?

A. The Company utilizes a wide array of methods to secure supply-side resources including i) direct Company development, ii) acquisition through Build Transfer Agreements

("BTAs"), Development Asset Acquisitions ("DAAs"), and Power Purchase Agreements ("PPAs"), and iii) other competitive procurement structures where appropriate. Direct development sets up the Company with strong supplier relationships, a deep understanding of competitive pricing for resources, and the ability to more directly influence when resources are made available. It also ensures that a minimum amount of new resources will be available to customers to meet future supply needs. Acquisition through BTAs, DAAs, and PPAs ensures a competitive marketplace for supply-side resources and diversifies the execution risks because the competitive procurement process allows evaluation of project economics, ownership structure, location, interconnection requirements, development risk, customer value, and system need before committing to specific resources. The majority of BTAs, DAAs, and PPAs result from the Company's competitive procurement process. Details about the Company's competitive procurement process can be found in the testimony of Company witness Beth A. Skowronski.

Q. How were the supply-side resource assumptions updated between the planning-information phase and the executable portfolio evaluation?

A. As discussed by Company witness Moritz, the modeling process consisted of two distinct phases. To support the second "executable portfolio evaluation" phase, the Company updated supply-side resource assumptions, where applicable, based on project-specific information that became available during the planning process, including storage information obtained through the all-source RFP, vendor- and site-specific information for the Karn and Thetford combustion turbines, the availability and terms of the MCV and [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] PPAs, and other material assumptions updates from further due diligence. The supply-side resource assumptions are

reasonable for IRP purposes because they are based on recognized industry sources, Company-specific cost-estimating practices, and resource-specific development considerations.

Each renewable technology was specifically updated to reflect the reasonable and prudent cost as observed within solicitation results. For instance, solar prototype assumptions were not updated from NREL data because the observed Levelized Cost of Energy ("LCOE") results from recent solicitations closely aligned with evaluated LCOEs of the NREL data. Wind resource costs were not updated due to a lack of wind resources submitted into the recent solicitations. Storage costs for 4 hour duration were updated to reflect actual results from the solicitations. Costs for the natural gas prototype were unchanged from the sensitivity analysis.

Q. What cost assumptions were updated for the executable portfolio evaluation?

A. As stated previously, the solar, wind, nuclear, and natural gas cost assumptions were unchanged from the sensitivity analysis or the base assumptions. The assumed 2026 capital cost for a four-hour BESS was updated to $1,366/kW, with costs declining at a real annual rate of 1.2% over the study period. The associated fixed O&M expense was updated to $30.98/kW-year in 2026 and was also assumed to decline at a real annual rate of 1.2%.

These updated cost assumptions were evaluated to assess the impact of current market pricing on resource selection and to validate the conclusions reached in the original Aurora modeling.

Overview of Development

Q. Please describe how the Company develops new generation resources.

A. The Company develops new generation resources through a structured development lifecycle consisting of early development, late development, and construction/execution. The development team works closely across the organization throughout each stage of that lifecycle to advance projects from initial concept through commercial operation. During early development, the Company identifies and screens potential locations for generation, secures site control, advances conceptual design, initiates the interconnection process, and begins permitting activities. During late development, the Company advances engineering and design, secures permits, progresses interconnection studies and agreements, conducts long-lead procurement and contracting activities, and prepares the project for execution. During the execution phase, the Company completes site preparation, installs major equipment, enters into agreements for the construction of interconnection facilities and network upgrades as required, performs commissioning and testing, and brings the project into commercial operation. This phased approach helps the Company manage cost, schedule, and project risk in a disciplined and consistent manner.

Q. How does the Company address lead time assumptions for engineering, permitting and licensing, design, construction, and pre-commercial operation testing?

A. Lead time assumptions vary by resource type, project location, procurement structure, interconnection path, permitting requirements, and equipment availability. To evaluate lead time for a specific project, the Company relies on previous experience, industry benchmarks, and input from contractors and equipment suppliers. Engineering and design schedules are informed by engineering contractors' feedback and project specific

requirements. Permitting lead times are developed based on applicable regulatory processes and feedback from permitting authorities. Construction and pre-commercial operations testing schedules are informed by industry experience, lessons learned from prior projects, and contractor input. Equipment lead times are determined through direct conversations with the suppliers that the Company is working with to support the projects. In evaluating whether resources can be developed or procured in time to support the PCA, the Company builds schedules that are informed by the lead time for each item discussed above, determines the critical path, and identifies when the project can be commercially operational.

Solar Development

Q. Please summarize the Company's plan for solar resources as part of its PCA.

A. Under the PCA, the Company will continue acquiring solar capacity additions through its annual competitive solicitation process. The PCA includes the addition of approximately 8,800 MW of solar generation through 2040. As discussed by Company witness Steven Q. McLean, the PCA reflects a balanced portfolio that incorporates continued expansion of clean, renewable resources at levels consistent with or exceeding those reflected in the Company's previously approved IRP, including the lessons learned from the Company's solar development glidepath.

The solar glidepath provides a measured pace of deployment that supports the Company's commitment to achieve net-zero carbon emissions by 2040. It allows time for the Company to operate and assess system performance under increasing levels of solar generation, mitigates execution risk associated with large-scale solar buildout, including supply chain, labor, interconnection, and land acquisition risks, supports a more gradual

impact on customer rates, and aligns solar additions with the Company's forecasted customer demand and capacity needs.

Q. What type of solar facility would the Company expect to pursue?

A. The Company plans to pursue industry standard utility scale projects that use bifacial photovoltaic ("PV") modules mounted on single axis trackers that feed central inverters. This configuration is consistent with the NREL 2024 ATB representative utility-scale solar plant upon which the Company's cost assumptions are based. The Company acknowledges solar PV technology will continue advancing over time. When developing and procuring future solar projects, the Company will evaluate available technologies based on factors including capital costs, energy production, reliability, ongoing maintenance, and operational costs to ensure the selected technology provides the best value to customers.

Q. Is this consistent with the solar units modeled in the IRP?

A. Yes. As discussed above, the modeling inputs for IRP modeling for utility-scale solar reflect bifacial modules mounted on single-axis trackers which are connected with central inverters. As discussed by Company witness Moritz the modeling also reflects MISO's Direct Loss of Load framework for solar resources used to determine accreditation toward the Company's Planning Reserve Margin Requirement.

Q. How does the Company propose to develop the solar included in the PCA?

A. The PCA proposes to procure solar generation through one or more of the following approaches: competitively bid BTAs, Company self-developed projects, DAAs, or PPAs. Under the PCA, solar capacity – whether developed by the Company, acquired from third-party developers, or purchased through PPAs – will be awarded based upon a competitive

solicitation process. The Company's annual competitive solicitation process is explained in detail by Company witness Skowronski.

Q. How does the Company propose to develop and submit bids in the competitive solicitation for self-developed projects?

A. The Company will perform early-stage development activities, as discussed above, sufficient to support a competitive bid. Upon completion of early development activities, the Company will submit its bid into the competitive procurement process on the same basis as other third-party bidders.

Q. Can the Company feasibly develop or acquire the amount of solar in the PCA?

A. Yes. The Company believes the amount of solar identified in the PCA is achievable. By leveraging both Company-developed and third-party developed resources, the Company maintains sufficient flexibility, ensures competitive pricing, and reduces execution risk with multiple development pathways, while preserving internal expertise and optionality with Company-developed projects. This balanced approach increases the Company's ability to successfully deploy the amount of solar capacity included in the PCA while maintaining cost-effective outcomes for customers.

Q. Is the Company intending to constrain the solar development to 1,000 MW per year as identified in the PCA?

A. The PCA reflects a planned annual solar procurement target of approximately 1,000 MW; however, the Company does not intend for that amount to operate as a rigid annual constraint. The annual limit of 1,000 MW is intended to restrict the amount of solar consistent with workforce availability and practical project execution limitations. As discussed by Company witness Skowronski, the Company is proposing improvements to

the annual competitive procurement process that would provide greater flexibility in the amount of capacity acquired in any given solicitation. Under that approach, the Company may procure more or less than 1,000 MW of solar in a particular year based on the results of the competitive solicitation process, project economics, customer value, and the Company's overall resource needs. This flexible approach allows the Company to pursue the most economic and valuable projects for customers while continuing to work toward the solar capacity reflected in the PCA over the planning period.

Q. How long does it typically take to develop and construct a solar facility?

A. Whether a solar facility is owned by the Company or developed by a third party, the typical solar development and construction process takes approximately seven to nine years from initial project identification through commercial operation. While actual schedules vary by project, this timeframe reflects the current development environment and is consistent with information gathered in the Company's competitive solicitation process, including the 2025 All Source RFP discussed by Company witness Skowronski.

At a high level, the development phase, which typically takes approximately five to seven years, involves site selection, land acquisition, community engagement and education, environmental impact studies, permitting, submitting into and working through the electrical interconnection process, engineering, regulatory reviews and approvals, and contracting for equipment and construction services before construction begins. The construction phase, which typically takes approximately two years, involves site preparation, installation of solar racking, modules, and inverters, substation construction and generator step-up transformer installation, performance testing and acceptance, site restoration, revegetation, and transmission system network upgrades. One of the main

drivers of the development timeline is the transmission interconnection process which, between the studies that have to be conducted, and the construction of the network upgrades, can take five to eight or more years depending on the specific project.

Q. What kind of land resources will be necessary for the Company to execute the build of solar capacity identified in the PCA?

A. Real estate is a critical resource for solar development, particularly at the projected scale of solar deployment under the PCA. A utility scale solar facility typically requires approximately eight to eleven acres per megawatt of capacity. Based on the PCA's approximately 8,800 MW of solar deployment through 2040, the total real estate dedicated to solar development is estimated at approximately 70,000 to 97,000 acres.

The Company expects these land resources will need to be geographically diverse across its service territory and surrounding regions to reduce potential electric system disruptions caused by localized weather conditions, providing access to multiple transmission interconnection opportunities, and increasing flexibility in project siting. Geographic diversity may also help mitigate potential community concerns regarding concentration of solar development in any single area and provide additional siting optionality to balance project economics, energy value for customers, and system resiliency.

Q. Has the Company evaluated whether sufficient land resources are available to support the solar development identified in the PCA?

A. Yes. The Company evaluated the availability of land in the Lower Peninsula of Michigan suitable for utility scale solar development. That evaluation considered land without significant forest cover, urban development, or other physical impediments to solar

deployment, and focused on parcels large enough to support utility scale solar development. The Company's land availability analysis indicates that the Lower Peninsula contains substantial land suitable for solar development, and the acreage required for the PCA represents only a small percentage of that available land base.

Q. What opportunities does the Company see for utilizing existing or previously developed properties to support future solar development?

A. The Company is committed to the best land use practices for Michigan in its development processes. The Company will continue to evaluate the technical and economic feasibility of using previously developed, underutilized, or brownfield sites for solar. This includes repurposing retired or decommissioned Company-owned facilities, former industrial sites, and other previously disturbed land. Utilizing existing sites reduces the need for new greenfield development, minimizes community and environmental impact, and may offer advantages such as existing electrical infrastructure and interconnection access. The Company expects the evaluation of existing previously developed properties to remain an important component of its overall solar development strategy.

Q. Would the use of third-party developers impact the land acquisition necessary for solar development?

A. Yes. Third-party developers enter the competitive solicitation process with land already secured through ownership or long-term easements, reducing the total acreage the Company would need to independently acquire. The Company anticipates that a combination of Company-developed and third-party-developed projects will provide the most effective approach to meeting the PCA's solar land requirements.

Q. Please describe the labor, equipment, and material procurement process the Company will need to undertake for the potential construction of the solar facilities in the PCA.

A. Evaluation of construction procurement risk will be an important factor in the project selection and execution process. Given the scale of solar development anticipated in the PCA, supply chain reliability will be critical for both the Company and third-party developers constructing solar resources in Michigan.

The primary procurement needs for solar facilities include major equipment such as solar PV modules, single axis tracker systems, inverters, substation equipment, and generator step-up transformers; construction materials such as racking hardware, cabling, fencing, and related balance of plant materials; and skilled construction labor for civil, structural, electrical, commissioning, and site restoration activities.

To manage these procurement needs, the Company anticipates using competitive bidding processes to secure equipment, materials, construction services, and, where appropriate, strategic supplier or contractor arrangements. These processes are intended to support access to qualified labor, reliable equipment, competitive pricing, and sufficient material availability over the PCA implementation period. Third-party developers participating in the competitive solicitation process will also be expected to demonstrate that they have the procurement capability, supplier relationships, and construction resources necessary to deliver projects on the proposed schedule.

The Company will continue to monitor equipment availability, material lead times, labor market conditions, and other supply chain risks, and will incorporate those considerations into project evaluation, contracting, and execution decisions.

Q. How will the new solar facilities interconnect to the grid?

A. Interconnection of new solar facilities will depend on project location and the available electrical infrastructure near each site. As part of the competitive procurement and project development process, the Company will consider proximity to existing high voltage distribution and transmission infrastructure when evaluating potential solar projects. Locating projects near existing grid infrastructure can reduce interconnection costs, minimize required equipment and construction, and reduce electrical line losses. Transmission connected projects will generally proceed through the MISO generator interconnection process, while any distribution connected projects would be evaluated through the Company's distribution interconnection process. Geographic diversity in siting, mentioned previously, will also support reliable integration of solar resources into the electric system by spreading the new generation assets across the region.

Q. What challenges are there toward the implementation of a large solar build?

A. There are three broad challenges to plan for:

(i) Cost: Industry projections used in the Company's analyses assume solar costs decline during the early years of the plan; however, actual costs may vary from those projections. The Company intends to use its competitive procurement process to procure economic projects that provide value for customers. Strategic arrangements formed through competitive bidding may help manage key parts of the solar supply chain, including solar PV modules, major equipment, materials, and construction labor. These arrangements may provide greater cost certainty for portions of the PCA timeframe while allowing the Company and developers to capture technology driven cost declines.

(ii) Permitting: Permitting remains a key challenge for utility scale solar projects. Development of solar involves many landowners, community members, local governments, and other stakeholders. The Company is committed to working with local communities throughout the development process to address project-specific considerations, understand community priorities, and seek locally supported permitting outcomes whenever possible. Public Act 233 provides a state siting process for qualifying projects, but local engagement, technical studies, environmental review, and other project-specific permitting

work remain an important part of the process. As a result, early and ongoing collaboration with local stakeholders remains critical to successful development of solar projects.

(iii) Interconnection: Timelines for interconnection remain highly uncertain. While MISO has implemented reforms and continues to make progress advancing interconnection studies, the sheer volume of interconnection requests submitted over the past five years has created a substantial backlog of work required to bring new resources onto the system. In addition, projects entering later queue cycles and increased saturation of the existing electric grid mean significant network upgrades will need to be completed to enable new resources to come online and operate without restriction.

Q. Please describe the Michigan workforce and economic benefits associated with the development of solar in the PCA.

A. The development of solar resources under the PCA is expected to support the Michigan workforce and provide significant economic benefits while advancing the Company's transition to a cleaner generation portfolio. As discussed by Company witness McLean, the PCA reflects a balanced plan across People, Planet, and Prosperity, continues the expansion of clean, renewable resources, and supports the Company's commitment to achieve net-zero carbon emissions by 2040.

Solar development supports local economic activity through sourcing of materials, construction work, O&M opportunities, landowner payments, property tax revenues, and potential community benefits in the areas where projects are located. It also creates workforce opportunities through new job skill development, reskilling, and potential reassignment of Company employees as the Company's generation portfolio transitions from retiring legacy assets to new renewable resources. This approach supports the prosperity of Michigan communities by aligning renewable resource development with local economic activity, workforce transition opportunities, and the broader resource additions reflected in the PCA.

Wind Development

Q. Please summarize the Company's plan for wind resources as part of its PCA.

A. The PCA includes the addition of approximately 3,200 MW of wind resources through 2040. Wind resources provide renewable energy diversity within the Company's resource portfolio and complement the solar, storage, and dispatchable resources reflected in the PCA. The Company modeled both in-state land based wind and in-state offshore wind. Out-of-state wind was not explicitly modeled; however, the LCOE of in-state land based wind was confirmed in the Company's 2025 All Source RFP to be similarly priced to out-of-state wind resources.

Q. How does the Company propose to develop or acquire wind resources included in the PCA?

A. Wind resources included in the PCA would be procured through the Company's competitive procurement process, which may include Company-developed projects, BTAs, DAAs, or PPAs. The competitive procurement process allows the Company to evaluate ownership structure, project economics, location, interconnection requirements, permitting and siting considerations, and customer value before selecting specific resources.

Q. How long does it typically take to develop and construct a wind facility?

A. The development and construction timeline for a wind facility can vary based on project size, location, permitting, interconnection requirements, land acquisition, and supply chain conditions and typically takes approximately seven to nine years from initial project identification through commercial operation. This timeframe reflects the current development environment and is consistent with information gathered in the Company's

competitive solicitation process. At a high level, wind development requires site identification, wind resource assessment, obtaining land control, community engagement, environmental studies, permitting and siting approvals, interconnection studies, engineering, procurement, and construction. Construction includes turbine foundation installation, access roads, collection systems, substation work, turbine erection, commissioning, and performance testing. These activities may overlap, and the schedule for any specific project will depend on project-specific conditions and the applicable procurement structure.

Q. What land resources are necessary for wind development?

A. Wind projects require roughly 40-60 acres per MW to support turbine siting, access roads, collection lines, substations, setbacks, and other project infrastructure. Wind development typically relies on long-term land easements with participating landowners rather than purchases of land within a project area. Agricultural and other existing land uses may continue around turbine locations, subject to project design and landowner agreements. The amount and configuration of land required will depend on turbine size, project layout, wind resource quality, interconnection location, and applicable siting requirements.

Q. How will wind resources interconnect to the grid?

A. Interconnection of wind resources will depend on project location and the available transmission infrastructure near each site. As part of the competitive procurement and project development process, the Company will consider proximity to existing high voltage distribution and transmission infrastructure when evaluating potential wind projects. Locating projects near existing grid infrastructure can reduce interconnection costs. Transmission connected wind projects proceed through the MISO generator

interconnection process, which determines the scope and cost of any required interconnection facilities or network upgrades. Distribution connected projects would be evaluated through the Company's distribution interconnection process.

Q. What siting and permitting challenges are associated with wind development?

A. Permitting remains a key challenge for wind projects. Wind development involves many landowners, community members, local governments, and other stakeholders. The Company is committed to working with local communities throughout the development process to address project-specific considerations, understand community priorities, and seek locally supported permitting outcomes whenever possible. Public Act 233 provides a state siting process for qualifying projects, but local engagement, technical studies, environmental review, and other project-specific permitting work remain an important part of the process. As a result, early and ongoing collaboration with local stakeholders remains critical to successful development of wind projects.

Energy Storage Development, Target, and Procurement Plan

Q. Please summarize the Company's plan for BESS resources as part of its PCA.

A. The PCA includes the addition of approximately 3,300 MW of four-hour BESS resources through 2040. BESS provides flexible, dispatchable capability that complements the solar, wind, and dispatchable resources reflected in the PCA. Storage resources can charge during lower cost or higher renewable output periods and discharge during periods of higher system need, supporting reliability, renewable integration, and overall portfolio flexibility.

As the Company adds increasing amounts of solar and wind generation to its portfolio, BESS will play an important role in helping balance supply and demand

throughout the day. Storage resources can shift energy from periods of high renewable production to periods of peak customer demand, improving the utilization and value of renewable resources. BESS also provides operational flexibility that can help manage changing system conditions, respond quickly to fluctuations in load and generation, and support reliability during peak demand events. These capabilities make storage an important component of a diverse resource portfolio and help the Company maintain reliable electric service while implementing the PCA.

Q. How does the Company propose to develop or acquire BESS resources included in the PCA?

A. BESS resources included in the PCA will be procured through the Company's competitive procurement process. Sources of BESS are expected to include Company developed projects, BTAs, DAAs, and/or PPAs. The competitive procurement process allows the Company to evaluate ownership structure, project economics, location, interconnection requirements, technology performance, safety considerations, permitting and siting requirements, and customer value before selecting specific resources.

Q. What site characteristics are important for BESS development?

A. BESS facilities require less land than renewable generation facilities, but site selection remains important. The Company will consider proximity to existing transmission or distribution infrastructure, interconnection feasibility, site access, zoning and permitting requirements, safety setbacks, environmental conditions, fire protection requirements, and the ability to integrate the storage resource into the electric system. Co-locating storage with renewable resources or siting storage near existing electric infrastructure typically provides operational or cost advantages, depending on project-specific circumstances.

Q. How will BESS resources interconnect to the grid?

A. Interconnection of BESS resources will depend on project location and the available electrical infrastructure near each site. Transmission connected battery storage projects proceed through the MISO generator interconnection process, while distribution connected projects would be evaluated through the Company's distribution interconnection process. Interconnection cost, network upgrade requirements, deliverability, and operational flexibility will be important considerations in evaluating storage projects.

Q. What safety considerations apply to BESS development?

A. Safety is an important consideration in the development and operation of BESS resources. The Company will evaluate project designs for compliance with applicable safety standards, fire protection requirements, emergency response needs, while verifying the projects include the appropriate equipment certification, monitoring systems, and operational controls. These considerations will be addressed through project development, engineering, procurement, permitting, construction, and operating processes for each project.

Q. How long does it typically take to develop and construct a battery energy storage facility?

A. The development and construction timeline for a BESS facility can vary significantly depending on the interconnection path. An independently sited BESS project will typically take seven to nine years while a BESS utilizing the interconnection of a retiring generation facility, also called a replacement interconnection, or a BESS utilizing an interconnection currently in use by another generation asset, known as a surplus interconnection, could range from two to four years depending on the specifics of the project.

Development activities generally include site identification, real estate control, engineering, permitting, interconnection studies, equipment procurement, safety reviews, and contracting for engineering, procurement, and construction services. Construction activities generally include site preparation, installation of foundations, installation of battery enclosures, inverters, transformers, controls and communication systems, substation work, commissioning, performance testing, and project acceptance. These activities may overlap, and the schedule for each project will depend on project-specific conditions.

Q. What considerations will the Company need to manage as it implements its battery energy storage strategy?

A. The Company will need to manage several important considerations as it implements the BESS resources included in the PCA. Cost remains an important consideration, as project economics can be affected by market conditions, supply chain constraints, labor costs, equipment pricing, interconnection requirements, and project-specific factors. Monitoring technology and performance risk also remain important, including items such as battery degradation, availability, safety performance, warranty terms, and the ability of storage resources to meet system needs during high-need periods. Permitting and siting requirements must also be managed, including local engagement, safety standards, fire protection, emergency response coordination, and compliance with applicable siting requirements.

Q. How do battery energy storage resources support the Company's overall resource plan?

A. Battery energy storage resources support the Company's overall resource plan by providing flexible capacity that can respond to system needs, support renewable integration, and reduce reliance on market purchases during certain periods. Storage resources complement solar and wind by allowing energy to be shifted from periods of lower system need to periods of higher system need. This flexibility supports the PCA's balanced portfolio approach.

Q. What statewide energy storage target applies to the Company?

A. Public Act 235 of 2023 establishes a statewide energy storage target of 2,500 MW. The Commission implemented the energy storage target provisions in Case No. U-21571 and requires each load-serving entity's proportional share of that statewide target to be calculated using the Commission-approved methodology.

Q. What is the Company's proportional share of the statewide energy storage target?

A. Based on the Commission-approved allocation methodology, the Company's proportional share of Michigan's statewide 2,500 MW energy storage target is 817.3 MW. The Company will continue to monitor updated annual calculations because the proportional share is subject to recalculation under the Commission's approved methodology.

Q. How does the Company plan to meet its proportional share of the statewide energy storage target?

A. The Company expects to meet its proportional share of the statewide energy storage target through existing and planned energy storage resources. In 2026, the Company's operating storage resources that count toward this allocation total approximately 302 MW. Planned

storage additions, including contracted and Company-owned resources, are expected to increase eligible storage capacity to approximately 930 MW by 2029, which exceeds the Company's approximate 817 MW proportional share of the statewide target. The table below presents 925 MW of existing and planned utility scale energy storage projects which were previously approved by the Commission.

BESS	Size	Ownership	COD	Case #
Tibbits Battery Storage	100	PPA	5/31/2025	U-21090
Century Oaks Battery Storage	200	PPA	4/1/2026	U-21090
Voyager I Battery Storage	100	PPA	5/31/2027	U-21090
Grand Basin Battery Storage	100	PPA	5/31/2027	U-21090
Lakeside Battery Storage	100	PPA	5/31/2028	U-21090
Voyager II Battery Storage	150	PPA	5/31/2028	U-21090
Hacket Battery Storage	100	PPA	5/31/2028	U-21090
Weadock	45	Self-Development	12/21/2026	U-21870
Iosco	30	Self-Development	February-April 2027	U-21870

Q. Please discuss the status of the approved energy storage projects which have not yet reached Commercial Operation Date ("COD").

A. The Company has become aware of a potential delay in the CODs for Voyager II, Lakeside and Hacket Battery Storage, each of which were originally scheduled to reach COD by May 31, 2028. In order to continue to provide reliable electric service to its customers, these projects remain part of the Company's IRP, consistent with the availability cost cap presented by Company witness Skowronski. The Company intends to request ex parte approval of several recently solicited replacement energy storage projects which can achieve a May 31, 2028, COD.

Q. Please elaborate regarding the change in CODs for the Voyager II, Lakeside, and Hacket Battery Storage Projects.

A. The Voyager II, Lakeside, and Hacket Battery Storage Projects CODs have shifted from May 31, 2028 to May 31, 2030. Each project was selected through the Company's 2024 Clean RFP and was previously approved by the Commission in Case No. U-21090. Each project is structured as a 20-year PPA under which the Company receives energy, capacity, and Incentive Storage RECs in exchange for a fixed, availability-based energy payment of $14.50/MWh. The projects support the Company's long-term capacity needs, provide flexible storage capability to complement renewable resources, and help the Company meet its clean energy and reliability obligations under Public Act 235 of 2023. Because these projects are no longer expected to achieve the original May 31, 2028 COD, the Company intends to request ex parte approval of recently solicited replacement energy storage projects that can achieve that date. The Company will update the Commission regarding any changes as appropriate.

Q. Please discuss the Voyager II Battery Storage Project.

A. Voyager II is a 150 MW Alternating Current ("AC") electrochemical BESS located in Saline, Michigan, with a Point of Delivery at the Dorset Substation at 120 kV. The project has a maximum available energy quantity of 1,314,000 MWh, a guaranteed round-trip efficiency of 85%, a target COD of May 31, 2030, an early COD of May 31, 2027, and an expected termination date of May 31, 2050. The Voyager II PPA was executed effective June 6, 2025, and was included in the Company's application filed December 3, 2025, in Case No. U-21090. The Voyager II PPA has estimated supplier payments of approximately $530 million and approximately $46 million in financial compensation mechanism costs

over the 20-year term, resulting in a total forecast cost of approximately $577 million.[1] The projected total value of the Voyager II PPA is approximately $610 million. The Company requested Commission approval of the Voyager II PPA on an ex parte basis; and the Commission subsequently issued an order granting conditional approval of the PPA on February 19, 2026, in Case No. U-21090.

Q. Please discuss the Lakeside Battery Storage Project.

A. Lakeside is a 100 MW battery energy storage project selected through the 2024 Clean RFP. The Lakeside PPA provides the Company with energy, capacity, and Incentive Storage RECs over a 20-year term, with deliveries expected to commence by May 31, 2030, and an expected termination date of May 31, 2050. The Lakeside PPA was executed effective June 6, 2025, and was included in the Company's application filed July 3, 2025, in Case No. U-21090. The Lakeside PPA has estimated supplier payments of approximately $354 million and approximately $31 million in financial compensation mechanism costs over the 20-year term, resulting in a total forecast cost of approximately $384 million. The projected total value of the Lakeside PPA is approximately $405 million. The Company requested Commission approval of the Lakeside PPA on an ex parte basis. The Commission approved the PPA on August 7, 2025, in Case No. U-21090.

Q. Please discuss the Hackett Battery Storage Project.

A. Hacket is a 100 MW AC electrochemical BESS located in Tittabawassee, Michigan, with a Point of Delivery at the Linebreak-Bullock to Saginaw 138 kV interconnection. The project has a maximum available energy quantity of 876,000 MWh, a guaranteed round-trip efficiency of 85%, a target COD of May 31, 2030, an early COD of May 31, 2027, and

[1] Consumers Energy has included the full amount of the FCM that it requested in Case No. U-21090 pending its appeal of the Commission's February 19, 2026 Order in that case.

an expected termination date of May 31, 2050. The Hacket PPA was executed effective June 6, 2025, and was included in the Company's application filed July 3, 2025, in Case No. U-21090. The Hacket PPA has estimated supplier payments of approximately $354 million and approximately $31 million in financial compensation mechanism costs over the 20-year term, resulting in a total forecast cost of approximately $384 million. The projected total value of the Hacket PPA is approximately $405 million. The Company requested Commission approval of the Hacket PPA on an ex parte basis. The Commission approved the PPA on August 7, 2025, in Case No. U-21090.

Q. Please summarize the Voyager II, Lakeside, and Hacket Battery Storage Projects.

A. Each project is a 100 MW or greater utility-scale battery energy storage resource that will support reliability, renewable integration, and the Company's ability to meet customer needs over the planning period. Voyager II Battery Storage is a 150 MW battery energy storage project, while Lakeside Battery Storage and Hacket Battery Storage are each 100 MW battery energy storage projects. Each project is structured as a PPA and is expected to provide four-hour duration battery storage capability. The projects will be designed to charge during periods of lower-cost or higher renewable generation and discharge during periods of higher system need, thereby providing flexible capacity and supporting the integration of renewable resources. The projects continue to provide value as part of the Company's broader energy storage portfolio and remain consistent with the PCA, which includes significant battery energy storage additions through 2050.

Q. Is the Company seeking approval of additional energy storage resources in this IRP?

A. Yes. The PCA includes significant battery energy storage additions, including approximately 3,300 MW of four-hour battery energy storage resources through 2040. The

Company's planned and selected storage resources support compliance with the statewide storage target while also providing flexible capacity, renewable integration, and reliability benefits over the IRP planning period. As previously mentioned, Company witness Skowronski presents the Company's proposal for future approval of these energy storage additions as they are identified.

Q. How does the PCA storage build compare to the Company's proportional share of the statewide storage target?

A. The PCA storage build exceeds the Company's approximate proportional share of the statewide energy storage target. The Company's approximate proportional share is 817 MW, while planned eligible storage capacity is expected to reach approximately 930 MW by 2029. The PCA further includes approximately 3,300 MW of four-hour battery energy storage resources through 2040, which supports the Company's broader reliability, renewable integration, and resource flexibility objectives. The combination will bring the Company's total energy storage capacity to a total of 4,230 MW by 2040, far exceeding the Company's required 817 MW share of the statewide energy storage target.

Q. What types of energy storage resources are included in the Company's procurement plan?

A. The Company's PCA assumes utility scale battery energy storage resources providing 4 hours of continuous discharge; however, the procurement and development of these storage systems will consider the costs and benefits provided by each system and is not limited to just four-hour duration systems. These resources are expected to provide flexible capacity that can charge during lower cost or higher renewable output periods and discharge during periods of higher system need.

Q. How will the Company procure the storage resources needed to meet the target and support the PCA?

A. Battery energy storage resources may be developed or acquired through Company self development, BTAs, DAAs, PPAs, or other competitive procurement structures where appropriate. The Company will evaluate project economics, ownership structure, interconnection requirements, technology performance, safety considerations, permitting and siting requirements, and customer value before selecting specific storage resources. The capital and O&M cost assumptions for battery energy storage resources are addressed in Part I of my testimony and reflected in Exhibit A-10 (TPC-5) and Confidential Exhibit A-11 (TPC-6), with updated four-hour BESS cost assumptions used in the later portfolio evaluation that supported development of the PCA. This procurement approach is consistent with the broader competitive procurement framework addressed in the Company's IRP testimony.

Q. Does the Company's storage procurement plan include long-duration or multi-day storage resources?

A. No. As mentioned above, the PCA includes 4,230 MW of four-hour duration energy storage, 930 MW of which has already been procured and is or will be online by 2029. None of the current long-duration (greater than 10 hour duration) or multi-day energy storage technologies were determined to be economically viable at this time. That said, the procurement of the future 3,300 MW of energy storage will not be limited to four-hour duration systems. Rather, the four-hour duration will serve as a minimum duration threshold. Any economically viable longer duration storage system would be selected through the Company's competitive procurement process.

Natural Gas Development

Q. Please summarize the Company's plan for Natural Gas resources as part of its PCA.

A. The Company's PCA includes approximately 3,307 MW of firm and dispatchable natural gas generation resources to support reliability and resource adequacy as the Company adds significant renewable generation and battery energy storage resources. Specifically, the PCA includes approximately 1,233 MW of CC generation with CCS, 1,375 MW from the Proposed Karn and Thetford Projects, and 699 MW of generic combustion turbine capacity. As described by Company witness Moritz, these resources provide the firm and dispatchable capacity necessary to complement intermittent and energy-limited resources and ensure the Company can continue to meet customer energy and capacity needs under a wide range of future operating conditions. The natural gas resources included in the PCA are intended to work alongside the Company's solar, wind, battery storage, demand-side, and other supply-side resources to maintain reliability while supporting the Company's long-term generation transition strategy.

Q. How do the Proposed Karn and Thetford Projects relate to the natural gas resource additions included in the PCA?

A. The initial phase of the Company's IRP modeling identified a need for approximately 1,500 MW of new simple-cycle natural gas generation capacity to be commercially available by June 2031. The Company identified the Proposed Karn Project and Proposed Thetford Project to meet a substantial portion of that need, and together those projects are expected to provide approximately 1,375 MW of firm, dispatchable natural gas-fueled simple-cycle capacity. The Company is requesting CON for both projects in this proceeding.

Q. Why did the Company begin development of the Karn and Thetford Projects at this stage of the process?

A. The Company began advancing the Proposed Karn and Thetford Projects because natural gas generation projects require substantial development work and investment well in advance of their anticipated in-service dates. Development timelines for natural gas generation have increased in recent years due to growing demand for gas-fired generation resources and corresponding constraints on equipment manufacturing, engineering, and construction capacity.

A key distinction between natural gas generation projects and renewable energy or storage projects is the timing of major capital commitments. Natural gas generation facilities require specialized long-lead equipment, including combustion turbines, and related major components, for which lead times can exceed four years. As a result, significant investment decisions often must be made years before construction starts in order to secure equipment and maintain project schedules. By comparison, renewable energy and energy storage projects generally require less investment during the early stages of development, with many of the largest capital commitments occurring closer to the start of construction.

As a result, project development must begin early to support engineering, transmission interconnection activities, permitting, fuel supply evaluation, major equipment procurement, and construction planning. Transmission, interconnection activities require significant time as well because they require extensive study, engineering evaluation, coordination with MISO and the applicable transmission owners, and identification of any interconnection facilities or network upgrades needed to reliably

integrate the resource. In addition, natural gas infrastructure improvements may require several years of planning, engineering, permitting, property rights acquisition, and construction by the fuel supplier. These factors require the Company to make material development and procurement-related investments early in the process to maintain project schedules and preserve access to critical equipment and construction resources.

Accordingly, the Proposed Karn and Thetford Projects have progressed beyond generic resource assumptions and have been developed as specific, executable projects. The projects were evaluated as part of the Company's portfolio analysis supporting the PCA, and are the subject of the Company's request for CON in this proceeding.

Q. How long does it typically take to develop and construct a natural gas generation facility?

A. The development and construction of a natural gas generation facility is a multi-year effort that typically spans seven to nine years from project initiation to commercial operation. While physical construction may generally require only 24 to 48 months, substantial time is needed beforehand for project development activities, including permitting, environmental studies, transmission interconnection, fuel supply evaluation, engineering, and procurement of major equipment.

Q. How does the Company plan to procure additional resources required not provided by Karn and Thetford Projects?

A. Additional resources may be procured through PPAs, bilateral transactions, competitive procurement processes, or the development of new natural gas generation assets. The Company will evaluate those alternatives based on reliability need, project economics,

deliverability, interconnection requirements, fuel supply, development timeline, and customer value.

Q. What site conditions are necessary for a successful Natural Gas Generation Project?

A. Key site considerations for a natural gas generation project include access to transmission infrastructure, a reliable natural gas supply, sufficient developable land, favorable constructability conditions, permitting feasibility, and the ability to support the long-term O&M of the facility. Existing or previously developed brownfield generation sites may provide additional advantages because they can allow the Company to leverage existing infrastructure and reduce certain development risk and schedule uncertainty.

Q. What siting and permitting challenges are associated with natural gas generation development?

A. Permitting remains a key challenge for natural gas generation projects and all new generation projects, as development requires coordination with local governments, regulatory agencies, utilities, landowners, transmission owners, natural gas infrastructure providers, and other stakeholders. The Company is committed to working with local communities throughout the development process to understand community priorities, address project-specific considerations, and support responsible project execution. Successful development also depends on identifying sites that can support the required infrastructure, including electric transmission interconnection, natural gas supply, and other characteristics necessary for long-term operation.

Q. How will natural gas resources interconnect to the grid?

A. Utility-scale natural gas generation facilities require interconnection to the MISO transmission system through high-voltage transmission infrastructure. Due to the size and

output of these facilities, interconnection is typically made to the 345-kV transmission system.

The interconnection process requires transmission studies, engineering evaluations, and coordination with MISO and the applicable transmission owners to determine any upgrades necessary to reliably integrate the resource into the transmission system. These activities require significant time and investment, which is one of the reasons natural gas generation projects must begin development activities well in advance of their required in-service date.

Q. What fuel supply considerations apply to natural gas generation development?

A. Natural gas generation projects require access to reliable natural gas supply infrastructure capable of supporting the operating requirements of the facility. Fuel supply considerations include the availability and proximity of natural gas pipeline infrastructure, delivered fuel cost, suitable gas pressures, and the ability to support reliable operation.

These considerations are evaluated early in the development process because they can affect site selection, project feasibility, cost, schedule, and long-term operation. The Company also considers whether additional on-site or off-site infrastructure may be required to deliver natural gas to the facility at the pressure and volume needed for reliable operation.

Q. What are the primary development risks associated with natural gas resources?

A. The primary development risks associated with natural gas resources include major equipment availability, Engineering, Procurement and Construction contractor availability, transmission interconnection requirements, fuel supply requirements, permitting, cost escalation, and schedule execution. These projects require significant early coordination

across engineering, procurement, interconnection, fuel supply, permitting, and construction activities. The Company manages these risks through early-stage development activities, proactive procurement and contracting strategies, interconnection and fuel supply planning, disciplined project governance, and ongoing evaluation of project cost, schedule, and execution risk.

Q. Please describe the labor, equipment, and material procurement process the Company will need to undertake for the construction of the natural gas generation facilities in the PCA.

A. Managing construction procurement risk will be very important in the development and execution of natural gas generation resources included in the PCA. Natural gas generation projects require the procurement of specialized long-lead equipment, and supply chain reliability will be critical to successful project execution.

The primary procurement needs for natural gas generation facilities include major equipment such as combustion turbines, generators, generator step-up transformers, emissions control systems, substation equipment, and other major balance-of-plant systems. Construction materials include structural steel, electrical equipment, piping systems, control systems, and other supporting infrastructure. Development and construction also require skilled labor across engineering, civil, mechanical, electrical, commissioning, and construction disciplines.

A key consideration for natural gas generation projects is that major equipment procurement often must occur years before a facility is placed into service. Combustion turbines and certain high-voltage electrical equipment can have extended manufacturing

and delivery schedules, making early-stage planning and procurement necessary to maintain project schedules and achieve the required in-service dates.

To manage these procurement needs, the Company will utilize competitive procurement processes and strategic supplier relationships to execute engineering, procurement, and construction contracting arrangements, to support the projects. These processes are intended to secure access to qualified labor, reliable equipment, competitive pricing, and sufficient material availability throughout implementation of the PCA.

The Company will continue to monitor equipment availability, material lead times, labor market conditions, and other supply chain risks and will incorporate those considerations into project planning, contracting, and execution decisions to support the successful development of natural gas generation resources needed to maintain system reliability and resource adequacy.

Socioeconomic Impacts and Decommissioning

Q. Why is the Company addressing socioeconomic impacts and decommissioning for new supply side resources in this IRP?

A. The Company considers socioeconomic impacts and decommissioning as part of its overall evaluation of new supply side resources. The PCA includes significant additions of solar, wind, battery energy storage, and natural gas resources, and those resources will require development, construction, operation, maintenance, and eventual decommissioning. Addressing these topics helps demonstrate that the Company has considered not only the cost and performance of the resources, but also how development may affect local communities, landowners, employees, contractors, and the long-term use of project sites. For natural gas resources, the Company has addressed the socioeconomic impacts and

decommissioning in the detailed testimony supporting the request for CONs for the Proposed Karn Project and the Proposed Thetford Project.

Q. What types of socioeconomic impacts are associated with the new renewable and storage resources included in the PCA?

A. The development of solar, wind, and battery energy storage resources can provide several socioeconomic benefits in Michigan. These benefits may include construction employment, long term operations and maintenance work, landowner payments, local tax revenues, local vendor participation where available, and workforce development opportunities. For Company-owned resources, these projects may also support the transition of the Company's generation workforce by creating opportunities for reskilling, reassignment, and new job skill development as the Company's generation portfolio evolves.

Q. How do solar resources included in the PCA support Michigan workforce and economic benefits?

A. The PCA includes significant solar additions in Michigan, primarily in the Lower Peninsula within MISO Zone 7. Developing solar resources in Michigan supports local economic activity through construction work, equipment installation, operations and maintenance, landowner payments, property tax revenues, and potential host community benefits. Solar development also creates opportunities for new job skill development and workforce transition as the Company adds renewable resources to replace retiring Company owned generating resources.

Q. How do wind resources included in the PCA support Michigan workforce and economic benefits?

A. In-state wind development can support Michigan economic activity through construction employment, long term operations and maintenance work, landowner payments, property tax revenues, and local supplier participation where available. To the extent wind resources are developed or acquired within Michigan, those resources can provide local economic benefits while contributing to the renewable resource additions reflected in the PCA. Out-of-state wind resources may provide higher production characteristics, but they do not provide the same level of Michigan based siting, construction, tax, and landowner benefits as in-state resources.

Q. How do battery energy storage resources included in the PCA support Michigan workforce and economic benefits?

A. Battery energy storage development can support Michigan economic activity through construction employment, electrical and civil construction work, equipment installation, commissioning, and long-term operations and maintenance support. Storage resources located in Michigan may also support local vendor participation, property tax revenues, and skilled workforce development. In addition, battery energy storage supports the broader transition of the Company's resource portfolio by providing flexible resources that complement solar and wind additions reflected in the PCA.

Q. Will third-party development affect the socioeconomic benefits associated with PCA resources?

A. Yes. Third-party developers are expected to be an important part of developing and deploying the renewable and storage resources reflected in the PCA. Their participation

can provide additional development capability, geographic diversity, access to project sites, and competitive pricing. Third-party development will provide local economic benefits through construction activity, landowner payments, property tax revenues, and community benefit arrangements. The specific benefits will depend on the project location, ownership structure, procurement approach, and terms of the applicable agreements.

Q. How will the Company consider Michigan workforce and materials in developing new resources?

A. The Company will seek to use Michigan-based labor and suppliers as it develops new resources. The extent to which Michigan workforce and suppliers can be used will depend on project-specific needs, labor availability, supply chain conditions, technology requirements, and overall project economics. These considerations will be evaluated through the Company's project development and procurement processes.

Q. How will the Company address applicable labor standards for new generation capacity and rehabilitation of existing capacity resources?

A. The Company has a long-standing relationship with union labor and skilled trades throughout the state of Michigan and recognizes the important role that a qualified workforce plays in the successful development and construction of energy infrastructure. The Company will ensure applicable labor standards established under PA 231, including the requirements set forth in Section 6t(8)(c). The Company will address these requirements through its project development, procurement, construction, and contracting processes. For Company-developed resources, applicable labor standards including apprenticeship, prevailing wage, and other applicable workforce requirements will be

incorporated into project contracting requirements consistent with PA 231 and Commission requirements.

Q. Why is decommissioning important for renewable and storage resources?

A. Decommissioning is important because renewable and storage facilities have finite operating lives and must be responsibly removed, repowered, replaced, or otherwise addressed at the end of their useful life. Decommissioning planning helps ensure that project sites will be restored in a manner consistent with landowner agreements, applicable local permits, state siting requirements, and environmental standards. It also provides assurance that materials will be handled appropriately and that potential salvage or recycling opportunities are considered.

Q. Please describe the expected decommissioning process for utility scale solar, wind, and BESS resources.

A. Utility scale solar, wind, and BESS facilities are generally designed for an operating life of approximately 35, 30, and 20 years, respectively. At the end of their useful lives, facilities may be decommissioned, repowered, or otherwise addressed based on project specific circumstances and applicable approvals. Decommissioning generally includes the removal of major above-ground equipment and infrastructure. For solar facilities, this includes solar modules, tracker systems, inverters, transformers, cabling, racking hardware, substation equipment, and related equipment. Wind facility decommissioning includes removal of towers nacelles, blades, transformers, collection equipment, substation equipment, and related infrastructure. BESS decommissioning involves removal of battery enclosures, inverters, transformers, cabling, controls and associated equipment. Site restoration for all three technologies typically includes removal of foundations in whole or

to an approved depth, restoration of soil conditions, and revegetation to return the site to a productive condition consistent with landowner agreements and applicable requirements.

Q. How will the Company consider material salvage, recycling, and disposal during decommissioning?

A. The Company will evaluate material salvage, recycling, reuse, and disposal options available at the time of decommissioning. Solar facilities include materials such as glass, aluminum, steel, copper, and semiconductor materials that may have recycling or salvage value. Wind facilities include steel, copper, and other metals that may be recoverable, while battery energy storage facilities include metals and battery components that may be recyclable or reusable depending on technology and market conditions. The Company will seek to maximize material recovery and minimize waste, consistent with applicable environmental and safety requirements.

Q. How will decommissioning costs be addressed?

A. Decommissioning costs will depend on project specific factors, including technology type, project size, site conditions, material salvage value, recycling markets, landowner agreements, and applicable regulatory requirements at the time of decommissioning. The Company will consider industry benchmarks, project specific estimates, expected salvage values, and applicable siting or permitting requirements when evaluating decommissioning costs. For third-party developed projects, decommissioning obligations will be addressed through the applicable project agreements, landowner arrangements, and regulatory requirements.

Q. How will decommissioning costs be addressed for Company-owned projects?

A. For Company owned projects, estimated decommissioning costs will be addressed in future depreciation rate case proceedings. As resources are placed in service, the Company will evaluate decommissioning cost estimates through its depreciation studies, along with asset life, net salvage, and other depreciation-related assumptions. This allows decommissioning costs to be reviewed and addressed through the Commission-approved depreciation process.

Q. How will the Company provide assurance for proper decommissioning and disposal?

A. The Company will address decommissioning assurance through appropriate mechanisms based on project ownership, siting requirements, landowner agreements, and applicable regulatory obligations. These mechanisms may include decommissioning plans, financial assurance requirements, contractual obligations, landowner agreement provisions, or other methods consistent with Commission requirements and industry practice. Third-party developer projects will be subject to decommissioning obligations reflected in their agreements and applicable siting requirements, including requirements that may apply under PA 233 of 2023 for qualifying renewable energy and storage projects.

Q. How does decommissioning planning support local communities and landowners?

A. Decommissioning planning supports local communities and landowners by providing assurances and a framework for removing facilities at the end of their useful life and restoring project sites consistent with applicable agreements and requirements. This planning helps address long term land use considerations, reduces uncertainty for landowners and local communities, and supports responsible development of the renewable and storage resources included in the PCA.

Q. Does the Company expect decommissioning requirements to evolve over time?

A. Yes. Decommissioning requirements, recycling markets, battery handling standards, and renewable equipment disposal practices are expected to continue to evolve and mature over the planning period. The Company will monitor developments in decommissioning practices, recycling technologies, safety standards, and financial assurance requirements and will incorporate those considerations into project specific development, contracting, and decommissioning planning as appropriate.

Part III: Certificates of Necessity

Q. Please provide an overview of the proposed Karn and Thetford projects for which the Company is requesting CON.

A. The Company is requesting CON for two new natural gas-fueled simple-cycle generating facilities: the Proposed Karn 5 and 6 Generating Station Project and the Proposed Thetford 10, 11, 12, and 13 Generating Station Project. The Proposed Karn Project is expected to provide approximately 456 MW of maximum net output at the existing Karn-Weadock Generating Complex in Essexville, Michigan, and the Proposed Thetford Project is expected to provide approximately 919 MW of maximum net output at the Company-owned Thetford site in Thetford Township, Michigan. Together, the projects are expected to provide approximately 1,375 MW of simple-cycle gas turbine generating capacity to support the Company's PCA and the resource need identified in the Company's IRP modeling.

Q. The Company identified 1,500 MW of capacity as needed. How does this meet that requirement?

A. The approximately 1,500 MW identified in the Company's IRP modeling was an initial planning target used to evaluate resource options and develop an executable portfolio. The Proposed Karn and Thetford Projects are expected to provide approximately 1,375 MW of simple-cycle generation capacity, reflecting the final equipment selection, site-specific design, and operating conditions. While this capacity is less than the initial planning target, the final project configurations were validated through the Company's executable portfolio evaluation modeling and determined to satisfy the reliability and resource adequacy needs underlying the Company's PCA.

Q. Which Company witnesses provide testimony in support of the Company's request for CON for the Proposed Karn and Thetford Projects?

A. Several Company witnesses provide testimony in support of the Company's request for CON for the Proposed Karn and Thetford Projects. My testimony provides the overall project and development overview, explains how the Proposed Projects fit within the Company's IRP and PCA, and summarizes the roles of the witnesses supporting the Company's request. I also sponsor Exhibit A-13 (TPC-8), the Proposed Karn Project CON Filing Requirements Matrix, and Exhibit A-14 (TPC-9), the Proposed Thetford Project CON Filing Requirements Matrix. These exhibits identify the applicable CON filing requirements for each project and the Company witness testimony that addresses each requirement.

- **Steven Q. McLean** addresses the overall IRP and statutory framework supporting the CON. His testimony explains the Company's request under MCL 460.6s, including the requested findings that the power to be supplied by the Proposed Projects is needed, that the size, fuel type, and design

characteristics of the projects are reasonable and prudent, and that the estimated capital costs, financing plan, and recovery of approved costs in rates are appropriate. Company witness McLean also supports inclusion of the IRP as an exhibit to the CON application.

- **Adam J. Moritz** supports the modeling and economic analysis underlying the CON request. Company witness Moritz addresses the alternatives analysis that was conducted as part of the Company's broader IRP including alternatives, the no-build option, comparative costs of supply alternatives, and the effect of the Proposed Projects on wholesale market competition. His testimony also explains how the Proposed Projects were evaluated within the Company's IRP modeling and executable portfolio analysis.

- **Erin M. Busby** addresses the project development, site, permitting, schedule, and construction-related requirements for the Proposed Projects. Her testimony addresses the site descriptions, current site use, local land use considerations, major state, federal, and local permits required to construct and operate the Proposed Projects in compliance with applicable environmental standards, laws, and rules, off-site transportation considerations, water and sewer infrastructure requirements, development and construction schedules, and the estimated proportion of the construction workforce expected to be composed of Michigan residents.

- **Daniel J. Azukas** (Sargent & Lundy) addresses the site selection analysis for the Proposed Projects. His testimony addresses the Simple Cycle Generation Siting Study, including the site evaluation criteria, scoring methodology, and rationale for selecting the Karn and Thetford sites for the proposed simple-cycle natural gas generation resources.

- **Sang H. Gang** (Sargent & Lundy) addresses the transmission interconnection requirements for the Proposed Projects. His testimony addresses the status of the applicable transmission interconnection studies, identifies any expected or required transmission system modifications, and describes the applicable MISO interconnection processes.

- **Nathan J. Washburn** addresses the project cost estimates and cost-development methodology for the Proposed Karn and Thetford Projects. His testimony addresses the estimated costs required for construction of the Proposed Projects, projected facility operation costs, and the expected typical annual costs associated with operating the facilities, including fuel, operations and maintenance, and environmental compliance where applicable. Company witness Washburn also addresses engineering, procurement and construction costs, owner's costs, project financing costs, the status of competitively bid cost information, and the use of alternative cost-estimating methods and proposed contract strategy where final bidding and executed engineering, procurement, and construction contracts are not yet available.

- **Steven A. Sulzman** addresses the technology, design, and operational characteristics of the Proposed Projects. His testimony addresses the expected generating technology and major systems, including major pollution control systems, expected nameplate capacity, availability, heat rates, expected life, and other significant operating characteristics. Company witness Sulzman also explains the rationale for the selected technology, fuel type, capacity, and other significant design characteristics of the Proposed Projects.

- **Angela K. Rissman** addresses the fuel-related requirements for the Proposed Projects, including fuel type and sources, the identification and justification of fuel price forecasts used over the study period, and any natural gas infrastructure required to support plant construction and operation.

- **Heather A. Breining** addresses the emissions-related requirements for the Proposed Projects. Her testimony addresses expected facility emissions over the life of the facilities, anticipated health impacts associated with those emissions, and whether emissions could be eliminated or reduced through feasible and prudent alternatives.

Q. What benefits can the Company's customers realize from adding the Proposed Karn and Thetford Projects to Consumers Energy's supply portfolio?

A. The Proposed Karn and Thetford Projects are expected to provide customers with reliable, firm, and dispatchable capacity that supports the Company's ability to meet future capacity and energy needs. The Company's IRP modeling identified as the most cost effective solution a need for 1,500 MW of simple-cycle natural gas generation capacity to be commercially available by June 2031, and the Proposed Karn and Thetford Projects are intended to help meet that need. The Proposed Karn and Thetford Projects not only provide the firm, dispatchable capacity needed to support reliability, but were also identified through the Company's Aurora modeling as the most economical approach to meeting a significant portion of the Company's future energy and capacity requirements. As explained by Company witness Moritz, the projects were selected through the optimization process after evaluating a broad range of resource alternatives and therefore represent a cost-effective component of the Company's PCA.

The projects also support the Company's transition to a cleaner generation portfolio by complementing the renewable generation, battery storage, demand-side resources, and other supply-side resources included in the PCA. As the Company adds increasing levels of intermittent and energy-limited resources, firm dispatchable resources provide operational flexibility and help maintain reliability during periods when renewable output, storage availability, or market purchases may not be sufficient to meet customer needs.

The Proposed Karn Project is expected to provide approximately 456 MW of natural gas-fueled simple-cycle capacity at the existing Karn-Weadock Generating Complex, and the Proposed Thetford Project is expected to provide approximately 919 MW of natural gas-fueled simple-cycle capacity at the Company-owned Thetford site. Together, the projects provide approximately 1,375 MW of capacity to support resource adequacy and reliability as the Company's portfolio evolves.

Q. Why is natural gas simple-cycle generation the appropriate resource choice for these projects?

A. The Company's IRP modeling identified a need for firm, dispatchable capacity that can be relied upon during peak demand, contingency events, and periods of low renewable output. Natural gas simple-cycle generation provides fast-starting, flexible, dispatchable capacity that supports reliability and resource adequacy while complementing the Company's significant additions of renewable and storage resources. The rationale for the specific selected technology and configuration is further addressed by Company witness Sulzman.

Q. Are the projected costs for the Karn and Thetford Projects reasonable?

A. Yes. The projected capital and operating costs were developed using engineering studies, vendor pricing, and Company cost-estimating practices, and reflect the scope necessary to

construct and operate the facilities. The development and reasonableness of the cost estimates are addressed in detail by Company witness Washburn. As discussed in Part II of my testimony, project specific Karn and Thetford costs were provided for the executable portfolio evaluation. The costs, presented in Exhibit A-12 (TPC-7) were derived from the information presented by Company witness Washburn.

The project cost estimates include financing costs during construction developed using AFUDC assumptions. Company witness Marc R. Bleckman requests Construction Work In Progress ("CWIP") treatment on the two near-term gas plants. If approved, this would allow recovery of construction financing costs as they are incurred by including CWIP in rate base rather than recovering these costs over the life of the asset via AFUDC. While CWIP and AFUDC differ in timing of recovery of construction financing costs, the LCOE of the project is unaffected by the choice as the AFUDC rate and the discount rate utilized in the LCOE analysis is the same.

Q. What are the primary risks associated with the projects, and how is the Company managing them?

A. The primary risks include cost, schedule, procurement, permitting, and interconnection risks. The Company is managing these risks through its project governance and lifecycle processes, its contracting and procurement strategy, early procurement of long-lead equipment, and ongoing engagement with MISO and permitting agencies. These matters are addressed further in the testimony of Company witnesses Washburn, Sulzman, Busby, and Gang.

Q. Do the projects have identified interconnection and fuel supply paths?

A. Yes. The interconnection status and applicable MISO study processes are addressed by Company witnesses Sulzman and Gang, and the fuel supply arrangements and delivered natural gas price forecasts are addressed by Company witness Rissman. Both the transmission interconnection and natural gas supply paths support the feasibility of the projects at the selected sites.

Q. How do the projects address environmental and community considerations?

A. The projects are designed to comply with applicable environmental regulations and include modern emissions control technologies. Environmental regulations, emissions, environmental justice, and permitting considerations are addressed by Company witness Breining, and community, workforce, and local economic considerations are addressed by Company witness Busby and in my testimony.

Q. Please summarize the Company's request with respect to the Proposed Karn Project.

A. The Company requests that the Commission grant a CON under MCL 460.6s to construct and operate the Karn 5 and 6 Generating Station, referred to as the Proposed Karn Project. The Proposed Karn Project is a 456 MW natural gas-fueled simple-cycle generating facility located at the existing Karn-Weadock Generating Complex in Essexville, Hampton Charter Township, Bay County, Michigan.

The project is included in the Company's PCA to provide firm, dispatchable capacity that supports reliability and resource adequacy as the Company's generation portfolio evolves. My testimony supports the Company's request by explaining how the Proposed Karn Project fits within the PCA, summarizing the supporting testimony of other

Company witnesses, and supporting the assumptions associated with the project that were evaluated in the Company's executable portfolio analysis.

The Company also requests that the Commission make the findings required under MCL 460.6s, including that the power to be supplied by the Proposed Karn Project is needed, that the project's size, fuel type, and design characteristics are reasonable and prudent, and that the associated $1.2 billion of capital costs, financing plan, and recovery of approved costs in rates are appropriate.

Q. Please summarize the Company's request with respect to the Proposed Thetford Project.

A. The Company requests that the Commission grant a CON under MCL 460.6s to construct and operate the Thetford 10, 11, 12, and 13 Generating Station, referred to as the Proposed Thetford Project. The Proposed Thetford Project is a 919 MW natural gas-fueled simple-cycle generating facility located on a Company-owned site in Thetford Township, Genesee County, Michigan.

The project is included in the Company's PCA to provide firm, dispatchable capacity that supports reliability and resource adequacy as the Company's generation portfolio evolves. My testimony supports the Company's request by explaining how the Proposed Thetford Project fits within the PCA, summarizing the supporting testimony of other Company witnesses, and supporting the assumptions associated with the project that were evaluated in the Company's executable portfolio analysis.

The Company also requests that the Commission make the findings required under MCL 460.6s, including that the power to be supplied by the Proposed Thetford Project is needed, that the project's size, fuel type, and design characteristics are reasonable and

prudent, and that the associated $2.4 billion of capital costs, financing plan, and recovery of approved costs in rates are appropriate.

Q. Does this conclude your direct testimony?

A. Yes.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan and Certificates of Necessity under MCL 460.6s and 460.6t, certain accounting approvals, and for other relief.	)))))))	Case No. U-22127

REDACTED

EXHIBITS

OF

THOMAS P. CLARK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2026

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

2026 IRP New Gas-Fueled Technologies Real and Nominal Overnight Cost Projections

Case No.: U-22127
Exhibit No.: A-6 (TPC-1)
Page: 1 of 1
Witness: TPClark
Date: September 2026

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
			Base Modeling Assumptions					**Sensitivity Modeling Assumptions**				
Line No.	New Generation Technologies - Schedules and Operating Parameters		2x1 H-Class CCS	2x1 H-Class CC	1x1 H-Class CC	1x0 F-Class CT	5x0 Reciprocating Engine (6, 7, 8)	2x1 H-Class CCS	2x1 H-Class CC	1x1 H-Class CC	1x0 F-Class CT	5x0 Reciprocating Engine (6, 7, 8)
1	First Year Available (2)	(1/1/20xx)	2033	2033	2033	2031	2031					
2	Maximum Capacity (3)	(MW)	1,233	1,450	649	233	85					
3	Minium Plant Load	(%)	50%	50%	50%	16%	14%					
4	Minimum Capacity	(MW)	616	725	325	37	12					
5	Operating Life	(Yrs)	50	50	50	50	30					
6	Fixed O&M	($/kW-yr, 2025 nominal)	67.09	35.75	42	27.68	55					
7	FOM Esclation Rate (nominal)	(%)	0.93%	1.58%	1.69%	1.86%	1.86%					
8	Variable O&M	($/MWh, 2025 nominal)	5.02	2.28	2.68	7.47	7.5					
9	VOM Escalation Rate (nominal)	(%)	1.40%	1.79%	1.86%	2.50%	2.50%					
10	Tax Credit End Year		2035			n/a						
11	Transmission Network Upgrade (4)	($/kW, 2025$)			117.45							
12	Capital Cost	($/kW, 2025 nominal)	3,293	1,744	2,056	1,653	3,244	4,021	2,471	2,914	2,208	4,173
13	Capital Cost Escalation Rate (nominal)	(%)	1.34%	1.74%	1.74%	1.58%	1.58%	1.34%	1.74%	1.74%	1.58%	1.58%
14	Annual Forced Outage Rate	(%)	5%	5%	5%	5%	2%					
15	Annual Maintenance	(%)	10%	10%	10%	7%	3%					
16	Full Load Heat Rate	(Btu/kWh)	7,220	6,196	6,068	9,717	8,102					
17	SO_2 Emission Rate	(lb/MMBtu)	0.001	0.001	0.001	0.001	0.001					
18	NOx Emission Rate	(lb/MMBtu)	0.04	0.04	0.04	0.04	0.018					
19	CO2 Emission Rate	(lb/MMBtu)	6	119	119	119	117					
20	Cold Start Heat Input (5)	(MMBtu/MW/Start)	8.875	8.875	8.875	2.423	0.215					
21	Minimum Up Time (5)	(Hours)	7	7	7	1	1					
22	Minimum Down Time (5)	(Hours)	5	5	5	1	1					

No change from base modeling

New Generation Technologies - Schedules and Operating Parameters Notes:

1. Unless otherwise noted, all parameters are sourced from the 2024 NREL ATB
2. First year available is a function of when planned resources are able to come online and when new generic resources are able to be added to the model
3. Maximum capacity of 2x1 H-Class CCS and CC assumed based project specific evaluations
4. See WP-AJM-1 for more detail
5. Cold state heat input, minimum up, and minimum down time based on Zeeland CC and CTs for natural gas based new resources.
6. Not from NREL
7. RICE FOM includes LTSA Fixed Payments including recovery fee, staff labor, general maintenance and minor repairs, asset management, administrative and general costs, property taxes, insurance, and firm gas costs
8. RICE VOM includes LTSA hours-based maintenance contract costs, consumables including lube oil, waste disposal and other operationally dependent operations and maintenance costs.

Case No.: U-22127
Exhibit No.: A-7 (TPC-2)
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Date: September 2026

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

2026 IRP New Nuclear Technology Real and Nominal Overnight Cost Projections

	(a)	(b)	(c)	
			Base Modeling Assumptions	
Line No.	New Generation Technologies - Schedules and Operating Parameters		Nuclear	**Sensitivity Modeling Assumptions**
				Nuclear
1	First Year Available (2)	(1/1/20xx)	2040	
2	Maximum Capacity (3)	(MW)	300	
3	Minium Plant Load	(%)	15%	
4	Minimum Capacity	(MW)	45	
5	Operating Life	(Yrs)	60	
6	Fixed O&M	($/kW-yr, 2025 nominal)	219.69	
7	FOM Esclation Rate (nominal)	(%)	2.50%	
8	Variable O&M	($/MWh, 2025 nominal)	3.66	
9	VOM Escalation Rate (nominal)	(%)	2.50%	
10	Tax Credit End Year		2032	
11	Transmission Network Upgrade (4)	($/kW, 2025$)	117.45	
12	Capital Cost	($/kW, 2025 nominal)	15,901	No cost increase modeled
13	Capital Cost Escalation Rate (nominal)	(%)	1.47%	
14	Annual Forced Outage Rate	(%)	3%	
15	Annual Maintenance	(%)	6%	
16	Full Load Heat Rate	(Btu/kWh)	10,497	
17	SO_2 Emission Rate	(lb/MMBtu)	0	
18	NOx Emission Rate	(lb/MMBtu)	0	
19	CO2 Emission Rate	(lb/MMBtu)	0	
20	Cold Start Heat Input (5)	(MMBtu/MW/Start)	n/a	
21	Minimum Up Time (5)	(Hours)	n/a	
22	Minimum Down Time (5)	(Hours)	n/a	

New Generation Technologies - Schedules and Operating Parameters Notes:

1. Unless otherwise noted, all parameters are sourced from the 2024 NREL ATB
2. First year available is a function of when planned resources are able to come online and when new generic resources are able to be added to the model
3. NREL 2024 ATB SMR
4. See WP-AJM-1 for more detail
5. Nuclear is must-run.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

2026 IRP Solar Generation Capital Cost Assumptions

Case No.: U-22127
Exhibit No.: A-8 (TPC-3)
Page: 1 of 1
Witness: TPClark
Date: September 2026

Line No.	(a) Scenario	(b)	(c) 2026	(d) 2027	(e) 2028	(f) 2029	(g) 2030	(h) 2031	(i) 2032	(j) 2033	(h) 2034	(i) 2035	(j) 2036	(k) 2037	(l) 2038	(m) 2039	(n) 2040	(o) 2041	(p) 2042	(q) 2043	(r) 2044	(s) 2045	(t) 2046	(u) 2047	(v) 2048	(w) 2049	(x) 2050
	Solar, Utlity-Scale, Transmission Connected, Tracking																										
1	Total available by year[1]	(MW)	-	-	-	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
2	Cumulative total available	(MW)	-	-	-	1,000	2,000	3,000	4,000	5,000	6,000	7,000	8,000	9,000	10,000	11,000	12,000	13,000	14,000	15,000	16,000	17,000	18,000	19,000	20,000	21,000	22,000
3	Max Size	(MW)	500																								
4	Min Size	(MW)	50																								
5	Capacity Factor	(%)	22.20%																								
6	Operating Life	(yrs)	35																								
7	First year available	-	2029																								
8	Fixed O&M (2022$)[2]	($/kW-yr)	$21.15	$20.79	$20.43	$20.08	$19.72	$19.37	$19.02	$18.67	$18.31	$17.96	$17.76	$17.57	$17.37	$17.17	$16.98	$16.78	$16.58	$16.39	$16.19	$16.00	$15.80	$15.61	$15.41	$15.22	$15.02
9	FOM Escalation Rate (real)	(%)	-1.4%																								
10	Capital Cost (2022$)[3]	($/kW)	$1,326	$1,289	$1,253	$1,216	$1,180	$1,144	$1,107	$1,071	$1,035	$998	$979	$960	$941	$922	$904	$885	$866	$847	$828	$809	$790	$771	$752	$733	$714
11	Capital Cost Escalation Rate (real)	(%)	-2.5%																								
12	Capital Cost with Utility loading (2022$)	($/kW)	$1,472	$1,433	$1,394	$1,354	$1,315	$1,276	$1,237	$1,197	$1,158	$1,119	$1,098	$1,078	$1,058	$1,037	$1,017	$996	$976	$955	$935	$915	$894	$874	$853	$833	$813

[1]REP/RFP built through 2028 already included in plan

[2]Fixed operating and maintenance expense includes insurance, property taxes, site security, legal and administrative fees and other fixed costs, component replacement cost over technical life, maintenance, transformers, etc.

[3]Capital costs include cost of land

Source: NREL 2024 ATB

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

2026 IRP Wind Generation Capital Cost Assumptions

Case No.: U-22127
Exhibit No.: A-9 (TPC-4)
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Witness: TPClark
Date: September 2026

Line No.	(a)	(b)	(c) 2026	(d) 2027	(e) 2028	(f) 2029	(g) 2030	(h) 2031	(i) 2032	(j) 2033	(h) 2034	(i) 2035	(j) 2036	(k) 2037	(l) 2038	(m) 2039	(n) 2040	(o) 2041	(p) 2042	(q) 2043	(r) 2044	(s) 2045	(t) 2046	(u) 2047	(v) 2048	(w) 2049	(x) 2050
	Wind, Land Based																										
1	Total available by year[1]	(MW)	-	-	-	500	500	500	500	500	500	500	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
2	Cumulative total available	(MW)	-	-	-	500	1,000	1,500	2,000	2,500	3,000	3,500	3,600	3,700	3,800	3,900	4,000	4,100	4,200	4,300	4,400	4,500	4,600	4,700	4,800	4,900	5,000
3	Max Size	(MW)	300																								
4	Min Size	(MW)	100																								
5	Capacity Factor	(%)	30.00%																								
6	Operating Life	(yrs)	30																								
7	First year available	-	2029																								
8	Fixed O&M (2022$)[2]	($/kW-yr)	$40.25	$40.01	$39.76	$39.52	$39.28	$39.12	$38.96	$38.80	$38.65	$38.49	$38.33	$38.17	$38.01	$37.86	$37.70	$37.54	$37.38	$37.23	$37.07	$36.91	$36.75	$36.60	$36.44	$36.28	$36.12
9	FOM Escalation Rate (real)	(%)	-0.4%																								
10	Capital Cost (2022$)[3]	($/kW)	$1,508	$1,501	$1,494	$1,486	$1,479	$1,468	$1,456	$1,445	$1,434	$1,422	$1,411	$1,400	$1,388	$1,377	$1,365	$1,354	$1,343	$1,331	$1,320	$1,309	$1,297	$1,286	$1,275	$1,263	$1,252
11	Capital Cost Escalation Rate (real)	(%)	-0.8%																								
12	Capital Cost with Utility loading (2022$)	($/kW)	$1,844	$1,836	$1,827	$1,818	$1,810	$1,796	$1,782	$1,769	$1,755	$1,742	$1,728	$1,714	$1,701	$1,687	$1,674	$1,660	$1,646	$1,633	$1,619	$1,606	$1,592	$1,578	$1,565	$1,551	$1,537
	Wind, Offshore																										
1	Total available by year[1]	(MW)	-	-	-	500	500	500	500	500	500	500	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
2	Cumulative total available	(MW)	-	-	-	500	1,000	1,500	2,000	2,500	3,000	3,500	3,600	3,700	3,800	3,900	4,000	4,100	4,200	4,300	4,400	4,500	4,600	4,700	4,800	4,900	5,000
3	Max Size	(MW)	300																								
4	Min Size	(MW)	100																								
5	Capacity Factor	(%)	35.00%																								
6	Operating Life	(yrs)	30																								
7	First year available	-	2029																								
8	Fixed O&M (2022$)[2]	($/kW-yr)	$89.24	$88.88	$88.55	$88.23	$87.93	$87.10	$86.39	$85.77	$85.22	$84.73	$84.40	$84.09	$83.80	$83.53	$83.27	$83.03	$82.80	$82.58	$82.37	$82.17	$81.98	$81.79	$81.62	$81.45	$81.28
9	FOM Escalation Rate (real)	(%)	-0.4%																								
10	Capital Cost (2022$)[3]	($/kW)	$5,676	$5,656	$5,637	$5,619	$5,206	$4,763	$4,327	$3,896	$3,469	$3,045	$3,027	$3,009	$2,993	$2,978	$2,964	$2,950	$2,937	$2,925	$2,913	$2,902	$2,891	$2,881	$2,871	$2,862	$2,853
11	Capital Cost Escalation Rate (real)	(%)	-2.8%																								
12	Capital Cost with Utility loading (2022$)	($/kW)	$6,838	$6,814	$6,791	$6,770	$6,275	$5,745	$5,222	$4,706	$4,194	$3,686	$3,664	$3,643	$3,624	$3,606	$3,588	$3,572	$3,557	$3,542	$3,528	$3,515	$3,502	$3,489	$3,478	$3,466	$3,455

[1]REP/RFP built through 2028 already included in plan

[2]Fixed operating and maintenance expense includes insurance, property taxes, site security, legal and administrative fees and other fixed costs, component replacement cost over technical life, maintenance, transformers, etc.

[3]Capital costs include cost of land

Source: NREL 2024 ATB

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

2026 IRP Battery Technology Capital Cost Assumptions

Case No.: U-22127
Exhibit No.: A-10 (TPC-5)
Page: 1 of 1
Witness: TPClark
Date: September 2026

Line No.	(a)	(b)	(c) 2026	(d) 2027	(e) 2028	(f) 2029	(g) 2030	(h) 2031	(i) 2032	(j) 2033	(h) 2034	(i) 2035	(j) 2036	(k) 2037	(l) 2038	(m) 2039	(n) 2040	(o) 2041	(p) 2042	(q) 2043	(r) 2044	(s) 2045	(t) 2046	(u) 2047	(v) 2048	(w) 2049	(x) 2050
1	Total available by year[1]	(MW)	-	-	-	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
2	Cumulative total available	(MW)	-	-	-	1,000	2,000	3,000	4,000	5,000	6,000	7,000	8,000	9,000	10,000	11,000	12,000	13,000	14,000	15,000	16,000	17,000	18,000	19,000	20,000	21,000	22,000
	Battery Storage, 4 hour																										
3	Max Size	(MW)	1,000																								
4	Min Size	(MW)	50																								
5	Round-trip efficiency	(%)	85.00%																								
6	Operating Life	(yrs)	20																								
7	Duration	(hrs)	4																								
8	First year available	-	2029																								
9	Fixed O&M (2022$)[2]	($/kW-yr)	$47.74	$45.88	$44.02	$42.17	$40.31	$40.03	$39.76	$39.48	$39.20	$38.93	$38.65	$38.38	$38.10	$37.82	$37.55	$37.27	$37.00	$36.72	$36.44	$36.17	$35.89	$35.62	$35.34	$35.06	$34.79
10	FOM Escalation Rate (real)	(%)	-1.3%																								
11	Capital Cost (2022$)[3]	($/kW)	$1,910	$1,835	$1,761	$1,687	$1,612	$1,601	$1,590	$1,579	$1,568	$1,557	$1,546	$1,535	$1,524	$1,513	$1,502	$1,491	$1,480	$1,469	$1,458	$1,447	$1,436	$1,425	$1,414	$1,403	$1,392
12	Capital Cost Escalation Rate (real)	(%)	-1.3%																								
13	Capital Cost with Utility loading (2022$)	($/kW)	$2,103	$2,022	$1,942	$1,862	$1,782	$1,770	$1,758	$1,746	$1,734	$1,722	$1,710	$1,698	$1,686	$1,675	$1,663	$1,651	$1,639	$1,627	$1,615	$1,603	$1,591	$1,579	$1,567	$1,555	$1,543
	Battery Storage, 10 hour																										
14	Max Size	(MW)	1,000																								
15	Min Size	(MW)	1																								
16	Round-trip efficiency	(%)	85.00%																								
17	Operating Life	(yrs)	20																								
18	Duration	(hrs)	10																								
19	First year available	-	2029																								
20	Fixed O&M (2022$)[2]	($/kW-yr)	$105.57	$101.19	$96.82	$92.46	$88.10	$87.49	$86.89	$86.29	$85.68	$85.08	$84.48	$83.87	$83.27	$82.67	$82.06	$81.46	$80.86	$80.25	$79.65	$79.05	$78.45	$77.84	$77.24	$76.64	$76.03
21	FOM Escalation Rate (real)	(%)	-1.4%																								
22	Capital Cost (2022$)[3]	($/kW)	$4,223	$4,048	$3,873	$3,698	$3,524	$3,500	$3,476	$3,451	$3,427	$3,403	$3,379	$3,355	$3,331	$3,307	$3,283	$3,258	$3,234	$3,210	$3,186	$3,162	$3,138	$3,114	$3,090	$3,065	$3,041
23	Capital Cost Escalation Rate (real)	(%)	-1.4%																								
24	Capital Cost with Utility loading (2022$)	($/kW)	$4,599	$4,411	$4,222	$4,033	$3,845	$3,819	$3,793	$3,767	$3,741	$3,715	$3,689	$3,663	$3,637	$3,611	$3,585	$3,559	$3,533	$3,507	$3,480	$3,454	$3,428	$3,402	$3,376	$3,350	$3,324
	Battery Storage, 4 hour, Updated for RFP Pricing																										
25	Max Size	(MW)	1,000																								
26	Min Size	(MW)	50																								
27	Round-trip efficiency	(%)	85.00%																								
28	Operating Life	(yrs)	20																								
29	Duration	(hrs)	4																								
30	First year available	-	2029																								
31	Fixed O&M (2022$)[2]	($/kW-yr)	$30.97	$30.98	$29.72	$28.47	$27.22	$27.03	$26.84	$26.66	$26.47	$26.28	$26.10	$25.91	$25.73	$25.54	$25.35	$25.17	$24.98	$24.79	$24.61	$24.42	$24.23	$24.05	$23.86	$23.68	$23.49
32	FOM Escalation Rate (real)	(%)	-1.2%																								
33	Capital Cost (2022$)[3]	($/kW)	$1,240	$1,239	$1,189	$1,139	$1,089	$1,081	$1,074	$1,066	$1,059	$1,051	$1,044	$1,036	$1,029	$1,022	$1,014	$1,007	$999	$992	$984	$977	$969	$962	$954	$947	$940
34	Capital Cost Escalation Rate (real)	(%)	-1.2%																								
35	Capital Cost with Utility loading (2022$)	($/kW)	$1,366	$1,366	$1,311	$1,257	$1,203	$1,195	$1,187	$1,179	$1,171	$1,163	$1,155	$1,147	$1,139	$1,131	$1,123	$1,115	$1,107	$1,098	$1,090	$1,082	$1,074	$1,066	$1,058	$1,050	$1,042

[1]REP/RFP built through 2028 already included in plan

[2]Fixed operating and maintenance expense includes insurance, property taxes, site security, legal and administrative fees and other fixed costs, component replacement cost over technical life, maintenance, transformers, etc.

[3]Capital costs include cost of land, but do not include investment tax credit reductions

Source: NREL 2024 ATB

Exhibit A-11 (TPC-6)
CONFIDENTIAL
PLACEHOLDER

FILED UNDER SEAL WITH
THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2026 IRP Karn and Thetford Capital Cost Assumptions

Case No.: U-22127
Exhibit No.: A-12 (TPC-7)
Page: 1 of 1
Witness: TPClark
Date: September 2026

New Generation Technologies - Schedules and Operating Parameters

Line No.	(a)	(b)	(c) Thetford CT	(d) Karn CT
1	First Year Available (2)	(6/1/20xx)	2031	2031
2	Maximum Capacity (3)	(MW)	919	456
3	Minium Plant Load (4)	(%)	31%	31%
4	Minimum Capacity (4)	(MW)	285	141
5	Operating Life (5)	(Yrs)	50	50
6	Fixed O&M	($/kW-yr, 2025 nominal)	27.68	27.68
7	FOM Esclation Rate (nominal)	(%)	1.86%	1.86%
8	Variable O&M	($/MWh, 2025 nominal)	7.47	7.47
9	VOM Escalation Rate (nominal)	(%)	2.50%	2.50%
10	Tax Credit End Year (6)		n/a	
11	Transmission Network Upgrade (7)	($/kW, 2025$)	163.6	0
12	Capital Cost (upper range) (11)	($/kW, 2031 nominal)	2,612	2,632
13	Capital Cost (lower range) (11)	($/kW, 2031 nominal)	2,295	2,310
14	Capital Cost Escalation Rate (nominal)	(%)	N/A	N/A
15	Annual Forced Outage Rate	(%)	5%	5%
16	Annual Maintenance	(%)	7%	7%
17	Full Load Heat Rate (8)	(Btu/kWh)	9,940	9,905
18	SO_2 Emission Rate (9)	(lb/MMBtu)	0.001	0.001
19	NOx Emission Rate (9)	(lb/MMBtu)	0.034	0.034
20	CO2 Emission Rate (9)	(lb/MMBtu)	117.5	117.5
21	Cold Start Heat Input (10)	(MMBtu/MW/Start)	2.440	2.440
22	Minimum Up Time (10)	(Hours)	1	1
23	Minimum Down Time (10)	(Hours)	1	1

New Generation Technologies - Karn and Thetford Notes:

1. Unless otherwise noted, all parameters are sourced from the 2024 NREL ATB
2. First year available is the planned COD for Thetford and Karn
3. Maximum capacity of 1x0 7F.05 GE turbine at Winter 100% capacity conditions
4. Minimum capacity of 1x0 7F.05 GE turbine at Average Annual MECL capacity conditions
5. Operating life based on expected life of the Thetford and Karn units with proper maintenance.
6. No tax credit applicable
7. Transmission network upgrade cost from MISO DPP 2025 Phase 1 Results. Subject to change pending further progress in DPP process. Costs are reimbursable per tariff
8. Full Load Heat Rate at Annual Average maximum output
9. Emmisions rates at Average Annual full load
10. Estimated from heat balances and GE provided startup/shutdown curves.
11. Gas infrastructure improvement costs embedded in capital

Project: **Karn**

(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	**Origin of Requirement**	**General Filing Requirements**	**Witness**	**Testimony Section (s)**	**Exhibit Reference**	**Work Paper Reference**	**Applicable (Y/N)**
		Application Instructions for Certificate Necessity					
1	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	These filing instructions apply to an electric utility application for a certificate of necessity under the provisions of MCL 460.6s. The application shall be consistent with these instructions, with each item labeled as set forth below. Any additional information considered relevant by the applicant may also be included in the application.	Consumers Energy's application is submitted as an Integrated Resource Plan under MCL 460.6t and includes requests for Certificates of Necessity under MCL 460.6s, as applicable. The filing is organized and labeled consistently with the Commission's filing instructions and includes additional information relevant to the Commission's review.				Y
		Filing Announcement					
2	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	In order to facilitate the scheduling and preparation of certificate of necessity proceedings, a utility intending to file an application for a certificate of necessity shall file a filing announcement, in a new docket, at least 30 days prior to filing the application. The filing announcement, along with a proof of service, shall be served on the Commission and all parties granted intervention in the utility's last two general rate cases and its most recent integrated resource plan case. If the application for a certificate of necessity is not filed within 120 days after filing of the filing announcement, the filing announcement shall be considered withdrawn.	A filing announcement was made by the Company on August 4th announcing the Company's intent to file its 2026 Integrated Resource Plan and Certificates of Necessity on September 3, 2026 in docket U-22127 with proof of service attached.				Y
3	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The filing announcement shall include: 1. Statement of intent to file for a certificate(s) of necessity; 2. A brief description of the facilities or power purchase agreement for which the certificate(s) will be sought; and 3. Any additional information the utility finds relevant to provide notice.					Y
		Pre-Application Consultation Process					
4	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Prior to filing the application for a certificate of necessity, a pre-application consultation with the Commission Staff (Staff) is necessary. The purpose of the pre-application consultation is to assist the applicants in refining the project application, and to facilitate efficient regulatory review. Applicants should schedule pre-application consultation meetings with the Staff well in advance of filing an application with the Commission. The Staff recognizes that all projects are not the same and that the information needed for one project will not necessarily be appropriate for the next. For some projects, a complete application may require less information than for other projects. For this reason, a pre-application consultation with the Staff is important.	Pre-application consultations with the Commission Staff (Staff) occurred on April 8, 2026 and July 14, 2026. Sign-in sheets and presentation materials are included in docket U-22127				Y
5	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Early in the consultation process, the Staff will identify Staff contacts, and clarify the applicability of information requirements for the specific application. The pre-application consultation will be documented with a sign-in sheet indicating all meeting attendees. The sign-in sheet, along with any presentations provided by the utility during the pre-application consultation meeting, shall be uploaded to the docket containing the filing announcement.					Y
		I. Applicant Information **All applications shall contain the following information about the applicant utility:**					
6	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The name and address of the applicant utility seeking the certificate of necessity; and	The applicant utility is Consumers Energy Company, One Energy Plaza, Jackson, Michigan 49201.				Y
7	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A description of the applicant utility, and the name, title, and business address of a person to whom correspondence should be directed.	Consumers Energy Company is a Michigan public utility that provides electric service to customers throughout the state. The name, title, and business address of the person to whom correspondence should be directed are provided in the filing.				Y
		II. Alternate Standards and Criteria for Certain Projects					
8	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	An electric utility with more than one million retail customers in this state seeking a certificate of necessity for a project costing more than $100 million shall follow these instructions.	Consumers Energy Company is an electric utility serving more than one million retail customers in Michigan and is seeking a Certificate of Necessity for a project with an estimated cost exceeding $100 million. Accordingly, Consumers Energy has prepared its application in accordance with these filing instructions.				Y
9	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	An electric utility with less than one million retail customers in this state seeking a certificate of necessity for a project costing less than $100 million may propose different review criteria and approval standards in its application, under MCL 460.6s(2), including modification or waiver of these instructions for good cause shown. The justification for any such proposals shall be addressed in the application.	Not Applicable				N
10	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Project cost estimates submitted with the certificate of necessity application do not require final bidding and contracts for project engineering, procurement and construction. Project cost estimates may include cost estimates developed in an alternative manner, along with a proposed contract strategy for project development and implementation.	Nathan J. Washburn	Part I- Methodology for Cost Estimates, Contracting Strategy, and Major Procurements; Part III Karn Generating Station Proposed Projects Costs		WP-NJW-1	Y
		III. Confidential Information					
11	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Proprietary, confidential, and other nonpublic materials filed as part of the application shall be clearly identified and marked accordingly and presented in such a way that the proprietary and confidential nature of the materials is preserved pending the execution of any confidentiality agreements and issuance of protective orders. Availability of specific materials in the application may be contingent upon appropriate confidentiality agreements and protective orders.	Proprietary, confidential, and other nonpublic materials are clearly designated and filed confidentially under the applicable protective order. Publicly available information is used where practicable, and any confidentiality claims are supported by an appropriate justification.				Y
		IV. Integrated Resource Plan					
12	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	An integrated resource plan, as required by MCL 460.6s(11) or approved pursuant to MCL 460.6t, shall be included as an exhibit to the certificate of necessity application. The plan shall include the items listed in MCL 460.6s(11) and otherwise comply with the Commission's standards developed under that section. This subsection does not apply to an electric utility that has an approved integrated resource plan under MCL 460.6t.	Consumers Energy's Certificate of Necessity application is being submitted together with its Integrated Resource Plan. The Integrated Resource Plan is included with and incorporated into the filing as supporting documentation for the requested Certificate of Necessity.				Y
13	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The utility shall identify and explain any significant material changes that have occurred to actual and/or forecasted market energy, capacity, and fuel prices; load projections; capital and operating costs of resources; etc., from the time the integrated resource plan was approved.	Steven Q. McLean	Section I – Overall Testimony Summary; Section II - Statutory and Regulatory Background			Y
		V. Certificate of Necessity Type					
14	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The certificate of necessity application shall identify the relief requested. An electric utility may seek one or more of the following certificates as described in MCL 460.6s(3):	Steven Q. McLean	Section I – Overall Testimony Summary; Section VIII – Description of Significant Proposals and Summary of Requested Relief			Y
15	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A certificate that the power to be supplied as a result of the proposed construction, investment, or purchase is needed;	Steven Q. McLean	Section V – Current Baseline Capacity Position; Section VII – Proposed Course of Action; Section VIII – Description of Significant Proposals and Summary of Requested Relief			Y
16	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A certificate that the size, fuel type, and other design characteristics of the existing or proposed electric generation facility or the terms of the power purchase agreement represent the most reasonable and prudent means of meeting that power need;	Steven Q. McLean	Section VI – New Resource Options; Section VII – Proposed Course of Action; Section VIII – Description of Significant Proposals and Summary of Requested Relief			Y

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	**Origin of Requirement**	**General Filing Requirements**	**Witness**	**Testimony Section (s)**	**Exhibit Reference**	**Work Paper Reference**	**Applicable (Y/N)**
17	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A certificate that the price specified in the power purchase agreement will be recovered in rates from the electric utility's customers;	Not Applicable				N
18	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A certificate that the estimated purchase or capital costs of, and the financing plan for, the existing or proposed electric generation facility, including, but not limited to, the costs of siting and licensing a new facility and the estimated cost of power from the new or proposed electric generation facility, will be recoverable in rates from the electric utility's customers subject to MCL 460.6s(4)(c).	Steven Q. McLean	Section I – Overall Testimony Summary; Section VII – Description of Significant Proposals and Summary of Requested Relief			Y
		VI. Certificate of Necessity That the Power to Be Supplied as a Result of the Proposed Construction, Investment, or Purchase Is Needed					
19	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A utility seeking a certificate of necessity that the power to be supplied as a result of the proposed construction, investment, or purchase is needed shall file an application that identifies projected resource requirements and the expected timing of the requirements.	Steven Q. McLean	Section V – Current Baseline Capacity Position; Section VII – Proposed Course of Action			Y
20	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The applicant shall either have an approved integrated resource plan, as specified in MCL 460.6t, or file, as a part of their application, an integrated resource plan that is consistent with MCL 460.6s(11) and that identifies a proposed course of action.	Steven Q. McLean	Section VII – Proposed Course of Action			Y
		VII. Certificate of Necessity That the Design Characteristics of a Proposed Electric Generation Facility or Investment in an Existing Electric Generation Facility or the Terms of a Power Purchase Agreement Represent the Most Reasonable and Prudent Means of Meeting Future Power Needs **An application seeking a certificate of necessity to construct a new electric generation facility or to make a significant investment in an existing facility or enter into a power purchase agreement shall include the following information:** **A. New or Existing Electric Generation Facility:**					
21	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A written description of the proposed or existing site, including identification of the municipality in which the facility will be constructed and the current use of that site;	Erin M. Busby	Part III – Proposed Karn Generating Station Project			Y
22	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, the age of the existing facility or facilities to be purchased or modified;	Not Applicable				N
23	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Expected generating technology and major systems (including major pollution control systems);	Steven A. Sulzman	Part I – Rationale for Investment Technology; Part II – Proposed Karn Generating Station Project Generating Technology			Y
24	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Expected nameplate capacity, availability, heat rates, expected life, and other significant operational characteristics;	Steven A. Sulzman	Part I – Rationale for Investment Technology; Part II – Proposed Karn Generating Station Project Generating Technology			Y
25	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Fuel type and sources, including the identification and justification of fuel price forecasts used over the study period;	Angie K. Rissman	Section IV: Delivered Fuel Prices to Existing and New Generating Plants; Section VI: Expected Fuel Type, Supply, Costs, and Contractual Arrangements Associated with the PCA			Y
26	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The expected annual emissions of carbon dioxide and greenhouse gases, particulates, sulfur dioxides, volatile organic compounds, oxides of nitrogen, mercury, and other hazardous air pollutants over the life of the facility or contract, and an assessment of whether some or all of the anticipated emissions and their anticipated health impacts could be eliminated or reduced through the use of feasible and prudent alternatives.	Heather A. Breining	Section V: Environmental Considerations for the Proposed Karn Facility			Y
27	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Discussion of the rationale behind facility or investment technology, fuel, capacity, and other significant design characteristics;	Steven A. Sulzman	Part I – Rationale for Investment Technology			Y
28	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A description of all major state, federal, and local permits required to construct and operate the proposed generation facility or the proposed facility upgrades in compliance with state and federal environmental standards, laws, and rules;	Erin M. Busby	Part III – Proposed Karn Generating Station Project			Y
29	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, the status of any transmission interconnection study and identification of any expected or required transmission system modifications;	Sang H. Gang	Part II – Overview of the Karn Replacement Study; Part III – Karn Replacement Study Results	Exhibit A-66 (SHG-1)		Y
30	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, natural gas infrastructure required for plant construction and operation not located on the proposed site but required for plant construction and operation;	Angie K. Rissman	Section IV: Delivered Fuel Prices to Existing and New Generating Plants			Y
31	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, a description of modifications to existing road, rail, or waterway transportation facilities not located on the proposed site but required for plant construction and operation;	Erin M. Busby	Part III – Proposed Karn Generating Station Project			Y
32	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, water and sewer infrastructure required for construction and operation not located on the proposed site but required for plant construction and operation;	Erin M. Busby	Part III – Proposed Karn Generating Station Project			Y
33	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A basic schedule for development and construction, which include an estimated time between the start of construction and commercial operation of the facility or facility upgrades;	Erin M. Busby	Part III – Proposed Karn Generating Station Project	Exhibit A-62 (EB-2)		Y
34	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	An estimate of the proportion of the construction workforce that will be composed of residents of the state of Michigan;	Erin M. Busby	Part III – Proposed Karn Generating Station Project			Y
35	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Descriptions of the alternatives that could defer, displace, or partially displace the proposed generation facility or significant investment in an existing facility, that were considered, including a "no-build" option, and the justification for the choice of the proposed project. Comparative costs of supply alternatives shall be included. The supply alternatives shall consider energy optimization, load management, demand response, energy storage and renewable energy;	Adam J. Moritz	Section XIII: Resource Alternatives Analysis			Y
36	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Describe the effect of the proposed project on wholesale market competition;	Adam J. Moritz	Section XIII: Resource Alternatives Analysis			Y

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	**Origin of Requirement**	**General Filing Requirements**	**Witness**	**Testimony Section (s)**	**Exhibit Reference**	**Work Paper Reference**	**Applicable (Y/N)**
37	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Any workpapers used in developing the application, supporting testimony, and any accompanying integrated resource plan. Such workpapers shall, whenever possible, be provided in electronic format with formulas intact.	All workpapers used to develop the application, supporting testimony, and accompanying Integrated Resource Plan are included with the filing. Workpapers are provided electronically with formulas intact whenever practicable.				Y
38	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Any modeling input or output files used in developing the application, supporting testimony, and any accompanying integrated resource plan. Such modeling input and output files shall, whenever possible, be provided in electronic format with formulas intact. The applicant shall also identify each modeling program used, and provide information for how interested parties can obtain access to such modeling program.	All modeling input and output files used to develop the application, supporting testimony, and accompanying Integrated Resource Plan are included with the filing in electronic format whenever practicable. The filing identifies each modeling program used and provides information regarding how interested parties may obtain access to the program.				Y
39	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Any other information that the applicant considers relevant.	The filing includes any other information Consumers Energy considers relevant to support the requested Certificates of Necessity and facilitate the Commission's review.				Y
		VII.B. Power Purchase Agreement					
40	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, a written description of generation facilities covered by the power purchase agreement, the size of each facility, generator technology, expected nameplate capacity, availability, heat rates, expected life, fuel type, other significant operational characteristics and the location of the generation facilities, including identification of the municipalities in which the facilities are located;	Not Applicable				N
41	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The name and address of the power provider supplying contract products and services under the power purchase agreement;	Not Applicable				N
42	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	For power purchase agreements that are the result of a competitive solicitation, the following shall be included in the certificate of necessity application: (a) A copy of the request for proposal for electric capacity and/or energy and a description of how the request was issued to potential respondents; (b) Copies of responses to the request for proposal. Responses submitted as part of a certificate of necessity application may be presented in such a way that the identities of the respondents and other commercially sensitive information is protected; and (c) A description of the proposal selection process.	Not Applicable				N
43	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The date the resources covered by the power purchase agreement will be available, the term of the power purchase agreement, and a description of significant contract provisions that could result in early termination of the contract;	Not Applicable				N
44	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The price to be paid for capacity and energy contract products and services delivered under the power purchase agreement;	Not Applicable				N
45	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If the contract includes provisions which may result in an increase in cost due to the price of fuel, the fuel type and sources, including the identification and justification of fuel price forecasts used over the study period;	Not Applicable				N
46	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The annual expected emissions of carbon dioxide and greenhouse gases, particulates, sulfur dioxides, volatile organic compounds, oxides of nitrogen, mercury, and other hazardous air pollutants over the life of the facility or contract and an assessment of whether some or all of the anticipated emissions and their anticipated health impacts could be eliminated or reduced through the use of feasible and prudent alternatives;	Not Applicable				N
47	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Descriptions of the alternatives that could defer, displace, or partially displace the proposed power purchase agreement that were considered, and the justification for the choice of the proposed power purchase agreement. Comparative costs of supply alternatives shall be included. The supply alternatives shall consider energy optimization, load management, demand response, energy storage and renewable energy;	Not Applicable				N
48	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Any workpapers used in developing the application, supporting testimony, and any accompanying integrated resource plan. Such workpapers shall, whenever possible, be provided in electronic format with formulas intact;	Not Applicable				N
49	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Any modeling input or output files used in developing the application, supporting testimony, and any accompanying integrated resource plan. Such modeling input and output files shall, whenever possible, be provided in electronic format with formulas intact. The applicant shall also identify each modeling program used, and provide information for how interested parties can obtain access to such modeling program;	Not Applicable				N
50	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If a financial incentive is being requested, the requested amount and a certification that the applicant is not affiliated with the power provider.	Not Applicable				N
51	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A copy of the proposed power purchase agreement.	Not Applicable				N
		VIII. Certificate of Necessity That the Estimated Capital or Purchase Costs of the New or Existing Electric Generation Facility or the Investment in an Existing Electric Generation Facility Will Be Recoverable in Rates From the Electric Utility's Customers. A. Construction of New Facility or Investment in Existing Facility:					
52	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	An application seeking a certificate of necessity to construct a new electric generation facility, to make a significant investment in an existing electric generation facility, or to purchase an existing electric generation facility shall provide an estimate of the costs required for the specified purchase or construction, as well as projected facility operation costs. Cost estimates filed with the certificate of necessity application shall include:	Nathan J. Washburn	Part III – Proposed Karn Generating Station Project Costs		WP-NJW-1	Y
53	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	To the extent applicable and available, engineering, procurement and construction costs, transmission interconnection costs, owner's costs, and project financing costs shall be included. Estimates filed with the application that are the result of competitively-bid engineering and procurement and construction contracts shall be separately identified. If the scope, scale, timing, or other aspects of the project, including legislative or regulatory uncertainty, make competitively-bid solicitations unlikely to produce reliable or timely project cost estimates, the application shall include cost estimates developed in an alternative manner, along with a proposed contract strategy for project development and implementation.	Nathan J. Washburn	Part I – Methodology for Cost Estimates, Contracting Strategy, and Major Procurement;Part II – Status of Procurement;Section III – Proposed Karn Generating Station Project Costs		WP-NJW-1	Y
54	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	For new construction, the certificate of necessity application shall include the expected typical annual costs associated with operating the facility including fuel, operations and maintenance, and environmental compliance.	Nathan J. Washburn; Angie K. Rissman	**Washburn:** Part III – Proposed Karn Generating Station Project Costs **Rissman:** Section VI-Expected Fuel Type, Supply,Costs, and Contractural Arrangements Associated with the PCA.	Rissman: Exhibit A-86(AKR-9)	WP-NJW-1	Y
55	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	For investment and upgrades at an existing facility, the certificate of necessity application shall include an estimate of the incremental operating costs for the facility after upgrades are complete including fuel, operations and maintenance, and environmental compliance.	Not Applicable				N
56	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	To the extent applicable, the certificate of necessity application shall describe any definitive joint ownership plans for the proposed generation facility assets and the impact such plans will have on the costs for which a certificate of necessity is requested. For the purposes of a certificate of necessity application, changes in allocated costs among joint owners shall be considered an aspect of the estimated cost included in the filing.	Not Applicable				N
57	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A disclosure indicating the portion of investment included in the applicant's request for a certificate of necessity which was previously included in the applicant's rate base.	Steven Q. McLean	Section VII – Description of Significant Proposals and Summary of Requested Relief			Y
		VIII.B. Purchase of Existing Facility					
58	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	As applicable, the estimated costs associated with purchasing the existing facility assets including the price to be paid for the assets, acquisition and transition costs, financing costs, and any significant financial liabilities that will accompany the asset transfer; and	Not Applicable				N
59	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The expected typical annual costs associated with operating the generation facility including fuel, operations and maintenance, and environmental compliance.	Not Applicable				N
		IX. Power Purchase Agreement Cost Recovery					
60	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A utility seeking rate recovery for future payments made pursuant to a power purchase agreement shall file a certificate of necessity application providing an estimate of the capacity and energy payments to be made for contract products and services pursuant to the agreement. The estimated payments shall be presented on a yearly basis in nominal dollars over the primary term of the contract.	Not Applicable				N

Project: **Thetford**

(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	**Origin of Requirement**	**General Filing Requirements**	**Witness**	**Testimony Section (s)**	**Exhibit Reference**	**Work Paper Reference**	**Applicable (Y/N)**
		Application Instructions for Certificate Necessity					
1	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	These filing instructions apply to an electric utility application for a certificate of necessity under the provisions of MCL 460.6s. The application shall be consistent with these instructions, with each item labeled as set forth below. Any additional information considered relevant by the applicant may also be included in the application.	Consumers Energy's application is submitted as an Integrated Resource Plan under MCL 460.6t and includes requests for Certificates of Necessity under MCL 460.6s, as applicable. The filing is organized and labeled consistently with the Commission's filing instructions and includes additional information relevant to the Commission's review.				Y
		Filing Announcement					
2	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	In order to facilitate the scheduling and preparation of certificate of necessity proceedings, a utility intending to file an application for a certificate of necessity shall file a filing announcement, in a new docket, at least 30 days prior to filing the application. The filing announcement, along with a proof of service, shall be served on the Commission and all parties granted intervention in the utility's last two general rate cases and its most recent integrated resource plan case. If the application for a certificate of necessity is not filed within 120 days after filing of the filing announcement, the filing	A filing announcement was made by the Company on August 4th announcing the Company's intent to file its 2026 Integrated Resource Plan and Certificates of Necessity on September 3, 2026 in docket U-22127 with proof of service attached.				Y
3	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The filing announcement shall include: 1. Statement of intent to file for a certificate(s) of necessity; 2. A brief description of the facilities or power purchase agreement for which the certificate(s) will be sought; and 3. Any additional information the utility finds relevant to provide notice.					Y
		Pre-Application Consultation Process					
4	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Prior to filing the application for a certificate of necessity, a pre-application consultation with the Commission Staff (Staff) is necessary. The purpose of the pre-application consultation is to assist the applicants in refining the project application, and to facilitate efficient regulatory review. Applicants should					Y
5	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Early in the consultation process, the Staff will identify Staff contacts, and clarify the applicability of information requirements for the specific application. The pre-application consultation will be documented with a sign-in sheet indicating all meeting attendees. The sign-in sheet, along with any presentations provided by the utility during the pre-application consultation meeting, shall be uploaded to the docket containing the filing announcement.	Pre-application consultations with the Commission Staff (Staff) occurred on April 8, 2026 and July 14, 2026. Sign-in sheets and presentation materials are included in docket U-22127				Y
		I. Applicant Information **All applications shall contain the following information about the applicant utility:**					
6	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The name and address of the applicant utility seeking the certificate of necessity; and	The applicant utility is Consumers Energy Company, One Energy Plaza, Jackson, Michigan 49201.				Y
7	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A description of the applicant utility, and the name, title, and business address of a person to whom correspondence should be directed.	Consumers Energy Company is a Michigan public utility that provides electric service to customers throughout the state. The name, title, and business address of the person to whom correspondence should be directed are provided in the filing.				Y
		II. Alternate Standards and Criteria for Certain Projects					
8	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	An electric utility with more than one million retail customers in this state seeking a certificate of necessity for a project costing more than $100 million shall follow these instructions.	Consumers Energy Company is an electric utility serving more than one million retail customers in Michigan and is seeking a Certificate of Necessity for a project with an estimated cost exceeding $100 million. Accordingly, Consumers Energy has prepared its application in accordance with these filing instructions				Y
9	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	An electric utility with less than one million retail customers in this state seeking a certificate of necessity for a project costing less than $100 million may propose different review criteria and approval standards in its application, under MCL 460.6s(2), including modification or waiver of these instructions for good cause shown. The justification for any such proposals shall be addressed in the application.	Not Applicable				N
10	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Project cost estimates submitted with the certificate of necessity application do not require final bidding and contracts for project engineering, procurement and construction. Project cost estimates may include cost estimates developed in an alternative manner, along with a proposed contract strategy for project development and implementation.	Nathan J. Washburn	Part I- Methodology for Cost Estimates, Contracting Strategy, and Major Procurements; Part IV Thetford Generating Station Proposed Projects Costs		WP-NJW-1	Y
		III. Confidential Information					
11	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Proprietary, confidential, and other nonpublic materials filed as part of the application shall be clearly identified and marked accordingly and presented in such a way that the proprietary and confidential nature of the materials is preserved pending the execution of any confidentiality agreements and issuance of protective orders. Availability of specific materials in the application may be contingent upon appropriate confidentiality agreements and protective orders.	Proprietary, confidential, and other nonpublic materials are clearly designated and filed confidentially under the applicable protective order. Publicly available information is used where practicable, and any confidentiality claims are supported by an appropriate justification.				Y
		IV. Integrated Resource Plan					
12	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	An integrated resource plan, as required by MCL 460.6s(11) or approved pursuant to MCL 460.6t, shall be included as an exhibit to the certificate of necessity application. The plan shall include the items listed in MCL 460.6s(11) and otherwise comply with the Commission's standards developed under that section. This subsection does not apply to an electric utility that has an approved integrated resource plan under MCL 460.6t.	Consumers Energy's Certificate of Necessity application is being submitted together with its Integrated Resource Plan. The Integrated Resource Plan is included with and incorporated into the filing as supporting documentation for the requested Certificate of Necessity.				Y
13	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The utility shall identify and explain any significant material changes that have occurred to actual and/or forecasted market energy, capacity, and fuel prices; load projections; capital and operating costs of resources; etc., from the time the integrated resource plan was approved.	Steven Q. McLean	Section I – Overall Testimony Summary; Section II - Statutory and Regulatory Background			Y
		V. Certificate of Necessity Type					
14	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The certificate of necessity application shall identify the relief requested. An electric utility may seek one or more of the following certificates as described in MCL 460.6s(3):	Steven Q. McLean	Section I – Overall Testimony Summary; Section VIII – Description of Significant Proposals and Summary of Requested Relief			Y
15	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A certificate that the power to be supplied as a result of the proposed construction, investment, or purchase is needed;	Steven Q. McLean	Section V – Current Baseline Capacity Position; Section VII – Proposed Course of Action; Section VII – Description of Significant Proposals and Summary of Requested Relief			Y
16	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A certificate that the size, fuel type, and other design characteristics of the existing or proposed electric generation facility or the terms of the power purchase agreement represent the most reasonable and prudent means of meeting that power need;	Steven Q. McLean	Section VI – New Resource Options; Section VII – Proposed Course of Action; Section VIII – Description of Significant Proposals and Summary of Requested Relief			Y

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	**Origin of Requirement**	**General Filing Requirements**	**Witness**	**Testimony Section (s)**	**Exhibit Reference**	**Work Paper Reference**	**Applicable (Y/N)**
17	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A certificate that the price specified in the power purchase agreement will be recovered in rates from the electric utility's customers;	Not Applicable				N
18	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A certificate that the estimated purchase or capital costs of, and the financing plan for, the existing or proposed electric generation facility, including, but not limited to, the costs of siting and licensing a new facility and the estimated cost of power from the new or proposed electric generation facility, will be recoverable in rates from the electric utility's customers subject to MCL 460.6s(4)(c).	Steven Q. McLean	Section I – Overall Testimony Summary; Section VII – Description of Significant Proposals and Summary of Requested Relief			Y
		VI. Certificate of Necessity That the Power to Be Supplied as a Result of the Proposed Construction, Investment, or Purchase Is Needed					
19	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A utility seeking a certificate of necessity that the power to be supplied as a result of the proposed construction, investment, or purchase is needed shall file an application that identifies projected resource requirements and the expected timing of the requirements.	Steven Q. McLean	Section V – Current Baseline Capacity Position; Section VII – Proposed Course of Action			Y
20	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The applicant shall either have an approved integrated resource plan, as specified in MCL 460.6t, or file, as a part of their application, an integrated resource plan that is consistent with MCL 460.6s(11) and that identifies a proposed course of action.	Steven Q. McLean	Section VII – Proposed Course of Action			Y
		VII. Certificate of Necessity That the Design Characteristics of a Proposed Electric Generation Facility or Investment in an Existing Electric Generation Facility or the Terms of a Power Purchase Agreement Represent the Most Reasonable and Prudent Means of Meeting Future Power Needs **An application seeking a certificate of necessity to construct a new electric generation facility or to make a significant investment in an existing facility or enter into a power purchase agreement shall include the following information:** **A. New or Existing Electric Generation Facility:**					
21	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A written description of the proposed or existing site, including identification of the municipality in which the facility will be constructed and the current use of that site;	Erin M. Busby	Part IV – Proposed Thetford Generating Station Project			Y
22	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, the age of the existing facility or facilities to be purchased or modified;	Not Applicable				N
23	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Expected generating technology and major systems (including major pollution control systems);	Steven A. Sulzman	Part I – Rationale for Investment Technology; Part III– Proposed Thetford Generating Station Project Generating Technology			Y
24	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Expected nameplate capacity, availability, heat rates, expected life, and other significant operational characteristics;	Steven A. Sulzman	Part I – Rationale for Investment Technology; Part III– Proposed Thetford Generating Station Project Generating Technology			Y
25	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Fuel type and sources, including the identification and justification of fuel price forecasts used over the study period;	Angie K. Rissman	Section IV: Delivered Fuel Prices to Existing and New Generating Plants; Section VI: Expected Fuel Type, Supply, Costs, and Contractual Arrangements Associated with the PCA			Y
26	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The expected annual emissions of carbon dioxide and greenhouse gases, particulates, sulfur dioxides, volatile organic compounds, oxides of nitrogen, mercury, and other hazardous air pollutants over the life of the facility or contract, and an assessment of whether some or all of the anticipated emissions and their anticipated health impacts could be eliminated or reduced through the use of feasible and prudent alternatives.	Heather A. Breining	Section IV: Environmental Considerations for the Proposed Thetford Facility			Y
27	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Discussion of the rationale behind facility or investment technology, fuel, capacity, and other significant design characteristics;	Steven A. Sulzman	Part I – Rationale for Investment Technology			Y
28	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A description of all major state, federal, and local permits required to construct and operate the proposed generation facility or the proposed facility upgrades in compliance with state and federal environmental standards, laws, and rules;	Erin M. Busby	Part IV – Proposed Thetford Generating Station Project			Y
29	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, the status of any transmission interconnection study and identification of any expected or required transmission system modifications;	Sang H. Gang	Part IV – Overview of the Thetford System Impact Study; Part V – Thetford System Impact Study Results	Exhibit A-67 (SHG-2)		Y
30	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, natural gas infrastructure required for plant construction and operation not located on the proposed site but required for plant construction and operation;	Angie K. Rissman	Section IV: Delivered Fuel Prices to Existing and New Generating Plants			Y
31	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, a description of modifications to existing road, rail, or waterway transportation facilities not located on the proposed site but required for plant construction and operation;	Erin M. Busby	Part IV – Proposed Thetford Generating Station Project			Y
32	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, water and sewer infrastructure required for construction and operation not located on the proposed site but required for plant construction and operation;	Erin M. Busby	Part IV – Proposed Thetford Generating Station Project			Y
33	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A basic schedule for development and construction, which include an estimated time between the start of construction and commercial operation of the facility or facility upgrades;	Erin M. Busby	Part IV – Proposed Thetford Generating Station Project	Exhibit A-64 (EB-4)		Y
34	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	An estimate of the proportion of the construction workforce that will be composed of residents of the state of Michigan;	Erin M. Busby	Part IV – Proposed Thetford Generating Station Project			Y
35	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Descriptions of the alternatives that could defer, displace, or partially displace the proposed generation facility or significant investment in an existing facility, that were considered, including a "no-build" option, and the justification for the choice of the proposed project. Comparative costs of supply alternatives shall be included. The supply alternatives shall consider energy optimization, load management, demand response, energy storage and renewable energy;	Adam J. Moritz	Section XIII: Resource Alternatives Analysis			Y
36	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Describe the effect of the proposed project on wholesale market competition;	Adam J. Moritz	Section XIII: Resource Alternatives Analysis			Y
37	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Any workpapers used in developing the application, supporting testimony, and any accompanying integrated resource plan. Such workpapers shall, whenever possible, be provided in electronic format with formulas intact.	All workpapers used to develop the application, supporting testimony, and accompanying Integrated Resource Plan are included with the filing. Workpapers are provided electronically with formulas intact whenever practicable.				Y
38	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Any modeling input or output files used in developing the application, supporting testimony, and any accompanying integrated resource plan. Such modeling input and output files shall, whenever possible, be provided in electronic format with formulas intact. The applicant shall also identify each modeling program used, and provide information for how interested parties can obtain access to such modeling program.	All modeling input and output files used to develop the application, supporting testimony, and accompanying Integrated Resource Plan are included with the filing in electronic format whenever practicable. The filing identifies each modeling program used and provides information regarding how interested parties may obtain access to the program.				Y
39	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Any other information that the applicant considers relevant.	The filing includes any other information Consumers Energy considers relevant to support the requested Certificates of Necessity and facilitate the Commission's review.				Y
		VII.B. Power Purchase Agreement					
40	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If applicable, a written description of generation facilities covered by the power purchase agreement, the size of each facility, generator technology, expected nameplate capacity, availability, heat rates, expected life, fuel type, other significant operational characteristics and the location of the generation facilities, including identification of the municipalities in which the facilities are located;	Not Applicable				N

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	**Origin of Requirement**	**General Filing Requirements**	**Witness**	**Testimony Section (s)**	**Exhibit Reference**	**Work Paper Reference**	**Applicable (Y/N)**
41	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The name and address of the power provider supplying contract products and services under the power purchase agreement;	Not Applicable				N
42	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	For power purchase agreements that are the result of a competitive solicitation, the following shall be included in the certificate of necessity application: (a) A copy of the request for proposal for electric capacity and/or energy and a description of how the request was issued to potential respondents; (b) Copies of responses to the request for proposal. Responses submitted as part of a certificate of necessity application may be presented in such a way that the identities of the respondents and other commercially sensitive information is protected; and (c) A description of the proposal selection process.	Not Applicable				N
43	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The date the resources covered by the power purchase agreement will be available, the term of the power purchase agreement, and a description of significant contract provisions that could result in early termination of the contract;	Not Applicable				N
44	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The price to be paid for capacity and energy contract products and services delivered under the power purchase agreement;	Not Applicable				N
45	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If the contract includes provisions which may result in an increase in cost due to the price of fuel, the fuel type and sources, including the identification and justification of fuel price forecasts used over the study period;	Not Applicable				N
46	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The annual expected emissions of carbon dioxide and greenhouse gases, particulates, sulfur dioxides, volatile organic compounds, oxides of nitrogen, mercury, and other hazardous air pollutants over the life of the facility or contract and an assessment of whether some or all of the anticipated emissions and their anticipated health impacts could be eliminated or reduced through the use of feasible and prudent alternatives;	Not Applicable				N
47	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Descriptions of the alternatives that could defer, displace, or partially displace the proposed power purchase agreement that were considered, and the justification for the choice of the proposed power purchase agreement. Comparative costs of supply alternatives shall be included. The supply alternatives shall consider energy optimization, load management, demand response, energy storage and renewable energy;	Not Applicable				N
48	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Any workpapers used in developing the application, supporting testimony, and any accompanying integrated resource plan. Such workpapers shall, whenever possible, be provided in electronic format with formulas intact;	Not Applicable				N
49	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	Any modeling input or output files used in developing the application, supporting testimony, and any accompanying integrated resource plan. Such modeling input and output files shall, whenever possible, be provided in electronic format with formulas intact. The applicant shall also identify each modeling program used, and provide information for how interested parties can obtain access to such modeling program;	Not Applicable				N
50	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	If a financial incentive is being requested, the requested amount and a certification that the applicant is not affiliated with the power provider.	Not Applicable				N
51	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A copy of the proposed power purchase agreement.	Not Applicable				N
		VIII. Certificate of Necessity That the Estimated Capital or Purchase Costs of the New or Existing Electric Generation Facility or the Investment in an Existing Electric Generation Facility Will Be Recoverable in Rates From the Electric Utility's Customers. A. Construction of New Facility or Investment in Existing Facility:					
52	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	An application seeking a certificate of necessity to construct a new electric generation facility, to make a significant investment in an existing electric generation facility, or to purchase an existing electric generation facility shall provide an estimate of the costs required for the specified purchase or construction, as well as projected facility operation costs. Cost estimates filed with the certificate of necessity application shall include:	Nathan J. Washburn	Part IV Thetford Generating Station Proposed Projects Costs		WP-NJW-1	Y
53	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	To the extent applicable and available, engineering, procurement and construction costs, transmission interconnection costs, owner's costs, and project financing costs shall be included. Estimates filed with the application that are the result of competitively-bid engineering and procurement and construction contracts shall be separately identified. If the scope, scale, timing, or other aspects of the project, including legislative or regulatory uncertainty, make competitively-bid solicitations unlikely to produce reliable or timely project cost estimates, the application shall include cost estimates developed in an alternative manner, along with a proposed contract strategy for project development and implementation.	Nathan J. Washburn	Part I – Methodology for Cost Estimates, Contracting Strategy, and Major Procurement;Part II – Status of Procurement;Part IV Thetford Generating Station Proposed Projects Costs		WP-NJW-1	Y
54	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	For new construction, the certificate of necessity application shall include the expected typical annual costs associated with operating the facility including fuel, operations and maintenance, and environmental compliance.	Nathan J. Washburn; Angie K. Rissman	**Washburn:** Part IV Thetford Generating Station Proposed Projects Costs **Rissman:** Section VI-Expected Fuel Type, Supply,Costs, and Contractural Arrangements Associated with the PCA.	Rissman: Exhibit A-87(AKR-10)	WP-NJW-1	Y
55	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	For investment and upgrades at an existing facility, the certificate of necessity application shall include an estimate of the incremental operating costs for the facility after upgrades are complete including fuel, operations and maintenance, and environmental compliance.	Not Applicable				N
56	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	To the extent applicable, the certificate of necessity application shall describe any definitive joint ownership plans for the proposed generation facility assets and the impact such plans will have on the costs for which a certificate of necessity is requested. For the purposes of a certificate of necessity application, changes in allocated costs among joint owners shall be considered an aspect of the estimated cost included in the filing.	Not Applicable				N
57	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A disclosure indicating the portion of investment included in the applicant's request for a certificate of necessity which was previously included in the applicant's rate base.	Steven Q. McLean	Section VII – Description of Significant Proposals and Summary of Requested Relief			Y
		VIII.B. Purchase of Existing Facility					
58	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	As applicable, the estimated costs associated with purchasing the existing facility assets including the price to be paid for the assets, acquisition and transition costs, financing costs, and any significant financial liabilities that will accompany the asset transfer; and	Not Applicable				N
59	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	The expected typical annual costs associated with operating the generation facility including fuel, operations and maintenance, and environmental compliance.	Not Applicable				N
		IX. Power Purchase Agreement Cost Recovery					
60	MPSC 2016 PA 341 CON Filing Requirements / MCL 460.6s	A utility seeking rate recovery for future payments made pursuant to a power purchase agreement shall file a certificate of necessity application providing an estimate of the capacity and energy payments to be made for contract products and services pursuant to the agreement. The estimated payments shall be presented on a yearly basis in nominal dollars over the primary term of the contract.	Not Applicable				N

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan and Certificates of Necessity under MCL 460.6s and 460.6t, certain accounting approvals, and for other relief.	)))))))	Case No. U-22127

REDACTED

DIRECT TESTIMONY

OF

ADAM J. MORITZ

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2026

Section I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Adam J. Moritz, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. In what capacity are you employed?

A. I am the Director of Electric Supply Planning.

Q. Please describe your educational background and business experience.

A. I received a Bachelor of Science Degree in Chemical Engineering with a minor in Mineral Processing from Michigan Technological University in 2014. I joined the Company's Resource Planning department in July 2015. I was responsible for maintaining the Strategist models used in production cost forecasts, strategic studies, and Integrated Resource Plans ("IRPs"). In August 2017, I assumed primary responsibility for forecasting the Company's Planning Reserve Margin Requirement ("PRMR") capacity until February 2021. I supported model development in both the Company's 2018 IRP (Case No. U-20165) and 2021 IRP (Case No. U-21090) as well as provided support for development of testimony and exhibits filed with the Michigan Public Service Commission ("MPSC" or the "Commission"). After the 2021 IRP Settlement, I worked on enhancements to the Aurora model that would allow for capacity planning changes from MISO's seasonal construct and modeling the new renewable and clean targets from the 2023 energy law. As of July 2024, I have led the modeling team now referred to as "Electric Supply Planning."

Q. What are your present responsibilities as Director of Electric Supply Planning?

A. Presently I, or those under my supervision, am responsible for all long-term capacity expansion and production cost modeling used to inform the Company's long-term electric supply strategy decisions. In particular, my team supports all economic, risk, and reliability modeling in support of supply strategy related matters. My team utilizes Energy Exemplar's ("EE") Aurora software platform ("Aurora") to perform all aforementioned modeling.

Q. Have you previously provided testimony before the Commission?

A. Yes. I provided testimony in the following MPSC cases:

Case No. U-20219	2019 Power Supply Cost Recovery ("PSCR") Plan case; and
Case No. U-20525	2020 PSCR Plan case.

Section II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to:

- Identify and describe the scenarios, sensitivities, and portfolios evaluated and presented in the IRP;
- Describe the planning and modeling processes performed in support of the IRP;
- Identify the Company's near- and long-term capacity position and need;
- Describe the supply- and demand-side resource options considered in the IRP analysis;
- Present the results of the IRP modeling and provide interpretation of the economic and statistical results that informed development of the Company's Proposed Course of Action ("PCA"); and
- Provide the economic alternatives analysis in support of the Company's request for approval of the certificates of necessity for a natural gas combined cycle ("CC") Power Purchase Agreement ("PPA"), [CONFIDENTIAL] [redacted]

[redacted] [END CONFIDENTIAL], the Thetford natural gas combustion turbine plant, and the D.E. Karn ("Karn") natural gas combustion turbine plant.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits, all of which were prepared by me or under my supervision:

Exhibit A-15 (AJM-1)	2026 IRP CE and MPSC Required Scenarios and Sensitivities;
Exhibit A-16 (AJM-2)	2026 IRP Commodity Price Outlook – Energy Price and Capacity Price;
Exhibit A-17 (AJM-3)	Confidential 2026 IRP Existing Assets Zonal Resource Credits and Projected Generation;
Exhibit A-18 (AJM-4)	Confidential 2026 IRP Resource Screening – Levelized Cost of Energy, Levelized Cost of Availability, and Levelized Net Cost of Capacity;
Exhibit A-19 (AJM-5)	2026 IRP MISO Market Topology;
Exhibit A-20 (AJM-6)	2026 IRP EWR Resource Blocks, by Scenario, for Aurora;
Exhibit A-21 (AJM-7)	2026 IRP Demand Response Resource Blocks, by Scenario, for Aurora;
Exhibit A-22 (AJM-8)	2026 IRP Portfolio Design;
Exhibit A-23 (AJM-9)	2026 IRP Aurora NPV Results;
Exhibit A-24 (AJM-10)	2026 IRP Aurora Resource Selections, by New Technology Resource;
Exhibit A-25 (AJM-11)	Confidential 2026 IRP Installed Capacity – PCA, Alternate Plans, and Support Plans;
Exhibit A-26 (AJM-12)	Confidential 2026 IRP Stacked Bar Graph of Capacity Credit – Summer, Fall, Winter, and Spring;
Exhibit A-27 (AJM-13)	Confidential 2026 IRP Stacked Bar Graph of Annual Energy PCA, Alternate Plan, and Required Scenarios/Sensitivities;

Exhibit A-28 (AJM-14)	Confidential 2026 IRP General Information and Operations for Resourced Requested under Certificates of Necessity;
Exhibit A-29 (AJM-15)	Confidential 2026 IRP Modeling Data Provided to Rates Team;
Exhibit A-30 (AJM-16)	2026 IRP Total Fuel Cost of Existing Owned Units – PCA, Alternate Plan, and Aurora Optimal Plans, by Scenario;
Exhibit A-31 (AJM-17)	2026 IRP Direct Loss of Load Capacity Accreditation – Base Case and PCA;
Exhibit A-32 (AJM-18)	2026 IRP Short-term Fuel and Capacity Price Outlook Versus PSCR; and
Exhibit A-33 (AJM-19)	Confidential 2026 IRP - CON Analysis.

Q. How is the remainder of your direct testimony organized?

A. The remainder of my direct testimony is organized in sections as follows:

Section I.	INTRODUCTION AND QUALIFICATIONS	1
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Section III. SUMMARY

Q. Please summarize your direct testimony.

A. My direct testimony provides quantitative support for the resources included in the Company's PCA, discussed in the direct testimony of Company witness Steve Q. McLean. The Company's modeling proceeded in two analytically distinct phases. In Phase 1, the Company developed a set of scenarios and sensitivities to conduct a planning-level portfolio analysis to evaluate a broad range of plausible future conditions and identify recurring patterns in the types, timing, and approximate amounts of generic candidate resource options required to meet future needs.

In Phase 2, the Company used those planning insights, together with updated project-specific, commercial, execution, reliability, and risk information, to develop and evaluate **executable portfolio options**, which include the PCA and Alternatives.

I will show that the initial scenario and sensitivity optimization (Phase 1) results provided directional guidance regarding the generic candidate resource options likely to be needed across a range of futures, though those optimized portfolios were not intended to constitute an executable acquisition and construction plan. The Company developed specific portfolio alternatives (Phase 2) using updated information, including storage pricing and availability from the all-source Request for Proposal ("RFP"), vendor- and site-specific information for the Karn and Thetford combustion turbines, the availability and terms of the two PPAs, and updates to other material assumptions. The later portfolio modeling was informed by the initial resource insights, but it was not intended to be a direct continuation of, or numerically comparable to, the earlier optimization runs because the candidate resources and material assumptions had changed.

Section IV. PROCESS USED IN MODELING

Q. Please provide a general description of the process used in modeling for the Company's IRP.

A. The process used for IRP modeling is based on the requirements contained in MCL 460.6t and in the Michigan Integrated Resource Planning Parameters ("MIRPP"). Consumers Energy utilized its existing robust resource planning process, comprised of multiple inputs, calculations, and models, to meet these requirements. The planning process begins by developing base forecasts of key planning parameters. These key planning parameters include consideration of electric demand forecasts; existing supply-side resources; existing demand-side resources such as Energy Waste Reduction ("EWR"), Conservation Voltage Reduction ("CVR"), and Demand Response ("DR"); renewable and clean portfolio requirements; applicable commodity pricing for carbon, natural gas, coal, and oil; environmental compliance requirements; and system constraints such as reserve margin, energy import capability, and capacity import capability.

The IRP modeling process includes multiple interrelated steps to develop and evaluate potential resource portfolios. These steps are iterative in nature because information is passed back and forth among the steps, and implications of some of the analytical steps could result in returning to previous steps for further analysis. A summary of each of the major steps is provided below:

1. Develop production cost models including appropriate inputs and assumptions;
2. Determine capacity position and first year of need;
3. Identify viable resource options;
4. Develop portfolio designs for evaluation;
5. Perform portfolio capacity expansion and production cost simulation analysis;

6. Evaluate portfolios using quantitative and qualitative measures;

7. Evaluate portfolios through scenario and sensitivity analysis;

8. Complete a risk analysis; and

9. Determine the most reasonable and prudent plan that meets the MPSC and Company planning objectives, considering stakeholder feedback.

Step 1: Development of Production Cost Models

Q. How were the production cost models and inputs for various assumptions developed in Step 1 of the modeling process?

A. The input data required to develop the models is extensive due to the volume and complexity necessary to perform long-term capacity expansion ("LTCE") and production cost modeling. Many major input assumptions to the base models used were explicitly defined in the MIRPP. The Company relied upon internal and external subject matter experts to develop many of the major assumptions and forecasts modeled in the IRP. Subject matter experts are included as witnesses in this proceeding. Below is a discussion of each of the major input assumptions:

- The first major assumption collected was a series of load forecasts. Multiple load forecasts were developed in support of this IRP, with a range of outcomes considered. Each load forecast represents variations on different input assumptions that may include: levels of EWR and DR, electric vehicle ("EV") load consumption, distributed generation ("DG") levels, economic development load growth, and the assumptions around customers taking service on Choice. For further information regarding load forecast development, please see Section VI of my testimony and the direct testimony of Company witness Eugène M. Breuring.

- An accounting of all existing supply was undertaken. An overview of the Company's existing supply-side resource portfolio can be found in Confidential Exhibit A-17 (AJM-3). For information on existing owned units and their projected retirement dates, please see the direct testimony of Company witness Marianne M. Walter.

- The next major assumption included existing renewable energy inputs, including output, capacity factor, and tax credits. This information was used as

an input in all base case scenarios and sensitivities. For further information regarding renewable energy assumptions and inputs, please see the direct testimony of Company witness Kenneth D. Johnston.

- The next major assumption included existing and capacity expansion options for EWR programs, including incremental decreases in retail sales and forecasted peak demand and impact. This information was used as an input in all base case scenarios and sensitivities. For further information regarding EWR programs and assumptions, please see the direct testimony of Company witness Alex M. Gast, and Section VIII of my direct testimony.

- The next major assumption was regarding demand-side management programs, including direct load control, dynamic peak pricing, CVR, and incremental DR. This information was used as an input in all base case scenarios, with varying levels of growth and expansion between Business As Usual ("BAU"), Physical Climate Change ("PCC"), and Aggressive Load Growth ("ALG"). For more information regarding demand-side management programs, please see the direct testimony of Company witnesses Daniel A. Schmoekel for CVR, and Gast for DR, as well as Section VIII of my direct testimony.

- The next major assumption was regarding operating parameters and capital and operating costs for new supply-side resources. New resources offered for model selection include natural gas CC, natural gas CC with carbon capture and sequestration ("CCS"), natural gas combustion turbine ("CT"), new-build nuclear, wind, solar, and battery storage. For more information on the new supply-side technology resources, please see the direct testimony of Company witness Thomas P. Clark.

- The next major assumption was regarding transmission network upgrade costs for all new generation resources. The information was used in all base case scenarios and sensitivities. For more information on network upgrade costs, please see the direct testimony of Company witness James R. McCormick III.

- The next major assumption was the amount of import and export capabilities into and out of Zone 7. Please see the direct testimony of Company witness McCormick for additional information.

- The next major assumption was in regard to the assumptions for capacity accreditation under the direct loss of load ("DLOL") methodology for *all* technology resources. As will be discussed in further detail later in my testimony, the DLOL accreditation value determines how much of a resource's installed capacity can be counted to meet the PRMR. This information is published by the Midcontinent Independent System Operator, Inc. ("MISO") and the inputs to this case are largely taken from various MISO publications.

- The next major assumption was forecasted fuel prices throughout the planning period. Fuel price forecasts include pricing for natural gas, and oil. This

information was used in the base case for all identified scenarios and sensitivities and is discussed in the direct testimony of Company witness Angela K. Rissman[1].

- Many existing PPAs with Non-Utility Generators were assumed to terminate at existing contract expiration dates. However, wind PPAs were assumed to continue to be renewed as described in the Company's renewable energy plan and are included in the base case scenarios and sensitivities. In the base case, the contract with Midland Cogeneration Venture Limited Partnership ("MCV") is assumed to terminate in May 2030, as approved by the Commission in Case No. U-20896. For more information on these and other wholesale energy and/or capacity contracts, please see the direct testimony of Company witness Beth A. Skowronski.

- The final major assumption made was regarding economic parameters such as an assumed discount rate and fixed charge rate ("FCR"). All base scenarios, and all MPSC required sensitivities, were modeled using an assumed rate of return as approved in Case No. U-21585. Those parameters are reflected in Section X of my testimony.

Q. Please describe the sensitivity of forecasts to variability in assumptions.

A. Because the forecasted assumptions used in the modeling of the Consumers Energy system are variable and statistical in nature, it is critical to ensure that the assumptions used in the various scenarios and sensitivities cover the range of reasonably possible values. Inherent uncertainty and risk associated with input assumptions were addressed in the initial phases of the IRP process through the stakeholder engagement process and thoughtful development of the scenarios and sensitivities to include specific parameters known to be key uncertainties. The development of production cost models for use in an IRP requires careful development of input assumptions from many subject matter experts. All inputs and modeling decisions were carefully reviewed by me or under my supervision. The direct

[1] Company witness Rissman presents fuel price forecasts for assets in Consumers Energy's portfolio. Fuel price forecasts for resources outside of Consumers Energy's portfolio are included in the database provided by Energy Exemplar.

testimony of Company witness Paul I. Soni addresses assessment of risk and evaluation of the range of input variable assumptions in this IRP.

Q. Are the natural gas prices used in the four scenarios based on reasonably current commodity price outlooks?

A. The gas prices used in the base case scenarios are from the Energy Information Administration's ("EIA") 2025 Annual Energy Outlook ("AEO") as discussed in the testimony of Company witness Rissman, published in April 2025. An updated 2026 AEO was published in April 2026; however, the Company did not utilize the April 2026 updates in this filing. Development of inputs used in modeling was initiated in January 2025 and required significant time to complete all required scenarios and sensitivities. The 2026 AEO reflects slightly higher projected natural gas prices than the 2025 AEO starting in year 2025 and continuing through the planning period.

Q. What are the likely impacts from the differences in gas prices identified?

A. Recent updates to the AEO gas price forecast reflect <u>increases</u> in forecasted natural gas prices compared to those used in IRP modeling. However, the gas price difference of approximately 17% for most of the study period are not expected to change the results of this IRP in any significant way. Exhibit A-32 (AJM-18) shows the short term (2026-2030) forecasted natural gas and capacity prices from the Company's most recent PSCR Plan case filing, As will be presented later in this testimony, natural gas-fired units included in the build plan are being chosen for both economic and reliability purposes. Furthermore, a risk analysis was performed on the PCA and alternate plans by Company witness Soni. This risk analysis includes price variations for natural gas prices which would capture the range of increase observed in the more-recent AEO forecast.

Q. What other commodity prices are included in modeling?

A. Additional inputs required both for Aurora modeling and post-process net present value ("NPV") calculations include capacity and market energy prices. Energy market prices are input to Aurora based on the amount of energy projected to be available for purchase from the MISO market and the corresponding price of those purchases. These inputs allow the model to evaluate market purchases alongside the Company's other supply options. Exhibit A-16 (AJM-2) provides the MISO prices on page 2 and the Zone 7 prices on page 3. Page 4 details the output energy prices from the final model run discussed later in this testimony.

Exhibit A-16 (AJM-2), page 1 includes the capacity prices used to reflect the value of any surplus capacity resulting from Aurora capacity expansion simulations. Page 1 is also used to support the capacity price forecasts that are used to calculate the NPVs presented on pages 5 through 8 of Exhibit A-23 (AJM-9). The values in Exhibit A-16 (AJM-2), page 1, column (b) are based on 75% of MISO's published cost of new entry ("CONE") for planning year ("PY") 2025/2026 and escalated at 2.2% every year thereafter.

Q. Why does the Company assign value to surplus capacity, and how does maintaining surplus capacity benefit customers?

A. Consistent with the Company's planning standards and regulatory filings, the Company recognizes that all capacity within the portfolio has value and credits that value as an offset to customer costs. It is prudent to maintain a reasonable amount of surplus capacity because the obligation to serve customers must be met under uncertain and changing conditions, not merely under a single forecast. Long-term demand, resource accreditation, unit availability, project execution schedules, retirement decisions, and contract expirations can all differ from current expectations. A measured surplus provides a reliability buffer that

can absorb those changes, help cover unexpected outages or delays, and reduce the risk that the Company will be forced to procure capacity on short notice when availability may be limited and prices may be high. In that respect, surplus capacity is not simply excess supply; it is a flexible portfolio resource that helps protect customers and supports the Company's fundamental obligation to maintain reliable service. The Company manages its overall capacity position to preserve and optimize this value. When surplus capacity is not needed within the portfolio, the Company may monetize it through MISO's annual Planning Resource Auction ("PRA") or other available opportunities, with the resulting value credited to customers.

Q. What is the basis of the capacity price forecast, presented on page 1 of Exhibit A-16 (AJM-2)?

A. The Company has historically[2] used 75% of CONE as the best proxy for the value of long-term capacity in MISO, and this remains a reasonable and prudent estimate based on recent market data and expected future trends.

It is important to again note that all capacity in MISO has value, and recent capacity market design changes, discussed in Section VI, have been implemented to ensure that MISO's annual PRA provides the right signals, especially as the regional supply-demand balance tightens. In fact, MISO's Reliability Imperative was created in part to ensure that markets "reflect evolving reliability risks, send accurate investment signals, and value resource performance in all seasons and conditions."[3] Most notably, in 2024 FERC-

[2] The 2018 IRP, the 2021 IRP, all PSCR Plan cases for many years, and the Company's filing of contracts to add new capacity resources have all consistently presented a capacity price forecast of 75% MISO CONE.
[3]See Executive Summary of MISO's 2026 Reliability Imperative Report, https://cdn.misoenergy.org/2026%20Reliability%20Imperative%20Report744320.pdf

approved MISO's Reliability-Based Demand Curve ("RBDC"),[4] which replaced the vertical demand curve construct with a sloped demand curve to better reflect the fact that capacity has significant value even when the system as a whole has surplus capacity above MISO minimum requirements. Additional discussion regarding capacity price forecast values expected under MISO's DLOL methodology is included in Section VI of this testimony.

Step 2: Capacity Position

Q. Please explain how the determination is made under Step 2 of the process used in modeling, which you described as determining capacity need.

A. Determination of capacity need is established by comparing projected peak demand levels as provided by Company witness Breuring and required reserve margins against existing and planned capacity resources as well as unregistered DR and EWR resources, as discussed by Company witness Gast. Section VI of my testimony identifies existing (or planned) resources included in the Company's base case, with details provided in Confidential Exhibit A-17 (AJM-3). Note that the approved Settlement Agreement from Case No. U-21090 provided approval for the recovery of costs for only the first three years of the study period. The approval included the Company's plans to purchase the Covert Plant; expand DR to 641 MW through year 2025; expand EWR at 2% of prior year sales through year 2025; retire Karn Units 3 and 4 on or before May 31, 2031; and the deployment of 75 MW of battery. All remaining resources included in the long-term plan presented in the 2021 IRP will be removed from the portfolio as part of this IRP and re-evaluated for economic consideration. The remaining portfolio of resources, along with the

[4] MISO's original filing, which lays out the rationale for the RBDC can be found here: https://cdn.misoenergy.org/2023-09-29%20Docket%20No.%20ER23-2977-000630405.pdf

corresponding date assumed as each resource's current end of life or end of PPA is compared to the Company's base case forecasted PRMR, which identifies years in which a shortfall of capacity occurs. One of the objectives of the IRP is to develop a plan to meet PRMR in each season of each planning year of the study horizon. The Company's baseline capacity position is presented in Section VI of my direct testimony.

Step 3: Viable New Resource Options

Q. Please explain Step 3 of the modeling process, which you describe as identifying viable resource options.

A. Potential new resource options include additional new generating unit technologies, which include solar, wind, battery storage, natural gas-fired CTs, natural gas-fired CCs with and without carbon capture, and nuclear. Other options include short-term or spot market purchases and expansion of virtual power plant ("VPP") options such as EWR, DG battery and solar, and DR resources. These options reflect the result of the resource screening process, which is further discussed in Section VII of my direct testimony.

Step 4: Optimization Portfolio Development

Q. Describe how portfolios were constructed for evaluation in Step 4 of the modeling process.

A. Section IX of my direct testimony details development of portfolios. Generally speaking, a portfolio used in the planning-information phase is a collection of generic candidate resource options, including supply-side and demand-side options, that can be used to fill a capacity need. Several different combinations of generic candidate resource options can be offered into the optimization and are selected by Aurora based on the lowest-cost outcome, from all possible options considered within the constraints and resource options established

for each portfolio. The outcome of Aurora—the selected mix, amounts, and timing of generic candidate resource options—is then evaluated for relative cost, feasibility, resource diversity, environmental impacts, and possibly more.

Q. Why did the Company construct different portfolios as part of the model-selection process?

A. Varying portfolios can provide valuable information when compared to each other. During development of this IRP, new information was made available at various times throughout the process; using different portfolios allowed the Company to maintain consistency across its economic analysis, while evaluating this new information. Section IX of this testimony provides significant additional detail on how portfolios and changing information were addressed in this IRP.

Steps 5 & 6: Capacity Expansion and Production Cost Simulations

Q. Please describe the software that was used in Steps 5 and 6 for portfolio optimization and production cost simulation analysis, and how the Company used that software.

A. The Company uses proprietary data and software programs in its integrated resource planning activities. The Company uses Aurora to optimize its resource plan and alternatives. Aurora, a computer software application developed by EE, supports electric utility decision analysis and corporate strategic planning. The Company also uses EE's database, which is used primarily for regional market modeling of energy resources and demand.

Q. Please identify the entity responsible for development of the models used in the IRP process.

A. The models were developed solely by the Company. Models of Consumers Energy's system were derived from input data provided by internal sources. Models of the regional market area outside of Consumers Energy's service area were derived from a mixture of sources including EE's database software, publicly filed documents, data available from MISO, and internal planning assumptions.

Q. Please provide a general description of the Aurora optimization process.

A. The Aurora model simulates the commitment and dispatch of the Company's generation resources and the resources of all generators in the MISO footprint for every hour of every year over the planning period. The planning period for the IRP covers the 24-year period beginning January 1, 2027 and ending December 31, 2050. Aurora is used in two modes for the IRP: production cost simulation ("zonal") mode and LTCE mode. In the zonal mode, the resource mix is held constant and the model simulates hourly commitment and dispatch to produce hourly market prices and unit level generation. In LTCE mode, the software selects incremental capacity additions from a menu of various generic candidate resource options according to technology, amount, and timing to arrive at a least-cost resource plan that is a co-optimization of meeting hourly energy requirements, ensuring that required capacity reserve margins are maintained, renewable and clean energy standards ("CES") are met, and market reliance limitations are respected. Aurora performs this selection through a long-term optimization that evaluates generic candidate resource additions across all years of the planning period together, rather than determining these decisions one year at a time. The optimization is solved iteratively, so in each pass an

updated set of generic candidate resource options is placed in the system, and a full hourly commitment and dispatch run is performed to evaluate the economic performance of each candidate. The set of resources is adjusted in each iteration until it identifies the optimal plan. Aurora will consider several alternative combinations of generic candidate resource options offered (a portfolio) within user-defined modeling constraints and then rank the multiple portfolios in economic order. To do so, the software calculates all costs associated with a resource, including capital and construction costs, financing costs, property taxes and insurance, transmission costs, fixed and variable operating and maintenance ("O&M") expense, off-setting tax credit revenues, fuel expense, and emission expense. Some fixed costs, for existing resources that are common to all scenarios and sensitivities and have no impact on generating unit dispatch and resource plan optimization results, are excluded from these simulations. With the nominal values developed for each year of the planning period, the NPV of the Revenue Requirement[5] is calculated and the alternative resource plans considered within the optimization are ranked in economic order from lowest to highest NPV. Post-optimization, any surplus capacity is credited at the forecasted value of capacity.[6] The surplus capacity revenue is not calculated within the model so as not to influence the optimization into building or adding new resources simply to sell off into the market. The result of this overall modeling process is the identification of the most cost-effective resource portfolio for each scenario and sensitivity.

[5] NPV of the revenue requirements represents the current value (2026 dollars) of a stream of annual revenue requirements the Company must receive from its customers in order to cover all costs, operating expenses, taxes, depreciation, and return on investment.

[6] The value of capacity in this IRP is 75% of CONE of a CT unit. The value of CONE was published by MISO, as submitted to the Federal Energy Regulatory Commission ("FERC") in September 2024 for PY 2025-2026.

Q. Are there any other differences in the model between an LTCE and a zonal run besides fixed resource plans?

A. Yes. During an LTCE model run, market purchases from outside the Consumers Energy zone are limited. This is referred to as an import limit. This is done to prevent the model from over relying on resources from outside the zone to supply energy. Without this restriction the resource plan created would have a higher market dependency. Once the resource plan is created in the LTCE model run it is then run through the zonal model with the import limit turned off. This then allows the model to freely commit and dispatch all available resources including energy purchases from outside the zone. This final step is done for the PCA, alternate, and support plans to calculate their final NPV.

Q. How does Aurora account for the surplus capacity value, discussed in Step 1?

A. Aurora does not include the value of surplus capacity within the capacity expansion optimization. Excluding that value prevents the model from selecting resources beyond those needed to satisfy the modeled energy, capacity, renewable, clean energy, and other requirements merely to create surplus capacity that could be sold into the market. Instead, Aurora identifies the least-cost portfolio necessary to meet the modeled requirements, and the value of any surplus capacity that results from that portfolio is recognized separately in the post-processing calculation of portfolio NPV. This approach credits customers for the value of surplus capacity without creating an incentive for Aurora to add unnecessary capacity.

Q. In selecting new resources, how does Aurora account for the seasonal and operational characteristics of different resource types?

A. Aurora represents resources based on the characteristics that determine their availability, energy production, operating costs, and contribution toward the Company's resource needs. These characteristics include hourly generation profiles for variable resources, forced-outage assumptions, seasonal facility ratings and derates, operating limitations, energy or duration limitations, and seasonal capacity accreditation. As a result, Aurora sees that each megawatt of installed capacity is not equally available in every hour or season.

Q. How are thermal resources represented in the model?

A. Existing and candidate thermal resources are represented using assumptions concerning seasonal generating capability, fuel and variable operating costs, heat rates, forced and planned outages, and other operating limitations. Where applicable, Aurora also reflects unit commitment or dispatch characteristics that may affect the resource's operation.

Q. How are variable, energy-limited, and customer resources represented?

A. Solar and wind resources are represented using hourly generation profiles that vary by time of day and season. Storage resources are subject to their power rating, energy duration, charging requirements, efficiency, and state-of-charge limitations. DR, EWR, distributed resources, and VPP resources are represented using applicable hourly load impacts, seasonal availability, program limitations, and capacity accreditation assumptions. These characteristics permit Aurora to recognize that each resource contributes differently to energy and capacity needs.

Q. How does Aurora reflect thermal unit forced and planned outages and facility derates?

A. Aurora reflects thermal unit forced and planned outages and other availability limitations. Seasonal ratings and applicable derates are used to reflect impacts to weather, outage planning, fuel availability, or operational limitations. These assumptions affect dispatch, available energy, and capacity contribution. Additional evaluation of thermal unit availability are included in the reliability analysis sponsored by Company witness Soni, under a broader range of outage, weather, and resource-availability conditions.

Q. Does Aurora's capacity expansion optimization ensure that a portfolio will satisfy the Company's reliability criteria?

A. No. Aurora identifies economical resource portfolios subject to the modeled energy, seasonal resource adequacy ("RA") requirements, policy, and operating constraints. Company witness Soni evaluates portfolio reliability under variations in demand, weather, outages, resource availability, transmission constraints, market conditions, and other uncertainties. The Company relies upon results of that analysis, together with Aurora's economic results, in developing the PCA.

Step 7: Review of Modeling Results

Q. How does the Company use the scenario and sensitivity analysis to develop its PCA?

A. As previously mentioned, the Company used the BAU, ALG, PCC, MIRPP Scenario One ("MSO") scenario, and sensitivity modeling primarily as a planning-information exercise. Those analyses evaluated a broad range of plausible future conditions and allowed the Company to identify recurring patterns in the types, timing, and approximate amounts of generic candidate resource options selected by Aurora. The results provided guidance

regarding the resource characteristics likely to be needed across a range of futures, but the optimized portfolios from those runs do not necessarily constitute an executable acquisition and construction plan. Review of the trends and themes provided guidance to the Company on durable planning insights, including the expected need for renewable and clean resources, firm accredited capacity, and a balanced mix of storage, dispatchable resources, and demand-side options. Section X of my direct testimony provides the details of those evaluations, comparisons, and key conclusions.

Q. How did the Company use the planning insights to develop executable portfolio alternatives?

A. After reviewing the initial modeling results, the Company developed more actionable portfolio alternatives using updated and project-specific information that became available during the planning process. This included storage information obtained through the all-source RFP, vendor- and site-specific information for the Karn and Thetford CTs, the availability and terms of the two PPAs, and updates to other material assumptions. The Company also considered execution timing, procurement feasibility, siting, reliability, resource diversity, customer impacts, environmental impacts, and regulatory requirements. That process converted the directional guidance from the initial modeling into specific portfolio alternatives capable of execution. Section IX of this testimony provides more in-depth discussion of this process.

Step 8: Risk Analysis

Q. Please discuss Step 8, completion of a risk analysis.

A. The Company completed multiple levels of risk assessment within this IRP, including Stochastic risk analysis, portfolio risk assessment, scenario and sensitivity modeling, and

electric reliability analysis. The testimony of Company witness Soni discusses the electric reliability and risk analysis, while Section IX discusses the assessment of risk through portfolio, scenario, and sensitivity analyses.

Q. How did the Company rely on third-party industry expert consultation for this IRP?

A. The Company contracted a third-party review of its modeling and support of reliability analyses through Charles River Associates ("CRA") Consulting. The Aurora models used in support of the IRP were provided to CRA in order for them to review input assumptions, modeling methodologies, and model selections. The Company also contracted with PowerGEM early in IRP development. PowerGEM was consulted regarding DLOL accreditation for new and existing generation units.

Step 9: Determination of the Proposed Course of Action

Q. Please discuss Step 9, the determination of the most reasonable and prudent plan.

A. The initial modeling planning phase provided the foundation for observing the types, amounts, and timing of generic candidate resource options that perform well across a range of uncertain futures. It did not, by itself, determine the PCA. The Company used those planning insights as a starting point to develop executable portfolio alternatives using updated project-specific costs and operating information, commercially available resource opportunities, execution and procurement considerations, reliability and risk analysis, regulatory requirements, stakeholder feedback, and customer impacts. The executable portfolio alternatives are represented as the PCA, Alternate Plans, and Support Plans, in this case. Final development and selection of the PCA is discussed in Section XI of my testimony, as well as in the testimony of many witnesses in this case.

Q. Please summarize the nine-step quantitative economic modeling process completed in support of this IRP.

A. As described above, the Company's approach to fulfilling the requirements of IRP economic analyses is a multi-step process that has been designed to evaluate a broad range of potential resource portfolios across identified scenarios and sensitivities. This allows the Company to determine the amounts, timing, and types of resources that best meet the long-term needs of Michigan from a variety of perspectives and uncertain futures.

Section V. SCENARIO AND SENSITIVITY DEVELOPMENT

Q. What scenarios and sensitivities were included in the IRP modeling?

A. The Company evaluated four scenarios. Two were developed to satisfy the MIRPP, adopted by the Commission in Case No. U-21867 pursuant to MCL 460.6t: BAU and MSO. BAU is based on MISO Series 1A Future 2a and reflects the Company's most-probable assumptions for customer demand, EWR, DR, the cost of capital for new resource technologies, environmental regulations, and other planning inputs. MSO is consistent with MISO Series 1A Future 3a and assumes high levels of electrification and decarbonization, with all new generation either carbon-free or using carbon capture technology. The major input assumptions for these scenarios are summarized in Exhibit A-15 (AJM-1).

The Company also developed two additional scenarios. The ALG scenario uses MISO Future 1a retirements and decarbonization in the MISO outside-world modeling, but includes substantially greater demand growth, and EWR and DR assumptions that differ from BAU. The PCC scenario is generally consistent with MSO but uses the Company's assumptions for EWR costs and ramping rather than the assumptions prescribed for MSO.

Across these four scenarios, where applicable, the Company evaluated 30 unique sensitivities identified in the MIRPP or developed by the Company. The sensitivities tested changes in demand growth and reduction; EWR; natural gas prices; renewable-resource availability and land-based renewable build limits; DG levels and cost methodology; atypical weather; resource retirements; natural gas generation with carbon capture; renewable, storage, and natural gas-fired resource costs; projected transmission network-upgrade costs; and transmission import and export limits.

Q. How did the Company's MSO and BAU scenarios correspond to the MIRPP-required scenarios?

A. The Company's MSO Scenario was developed to satisfy the first required MIRPP scenario, while the Company's BAU Scenario was developed to satisfy the second required MIRPP scenario. The Company mapped the assumptions in each scenario to the corresponding MIRPP requirements and evaluated the required sensitivities associated with each scenario.

Q. Does the second, optional MIRPP scenario, specified as BAU, use MISO Futures 1a, as suggested in the description of MIRPP Scenario #2?

A. No. The BAU scenario was designed to be the Company's most-probable forecast of assumptions, both for the utility and for the MISO footprint. Based on its review of existing and incremental capacity projected, the Company determined Future 2a more-closely captures BAU conditions. The Company did, however, include the recommended Future 1a assumptions in one of the IRP scenarios, to allow for consideration of those assumptions in modeling, through the ALG scenario.

Q. Why was the PCC scenario developed?

A. The PCC scenario was developed based on stakeholder feedback as well as an opportunity to include MISO Future 3a and evaluate a future in which a large amount of EV and heating electrification is adopted and all new generation offered is either carbon-free or utilizes carbon capture technology. This scenario was primarily based upon MSO, however, the PCC aligns with the Company's potential study for demand-side resources, as opposed to those required in the MIRPP.

Q. Why was the ALG scenario developed?

A. The ALG scenario was developed to consider a future that represents a large amount of economic development load growth occurring in Michigan and elsewhere within MISO, aligning with the upper bound of load growth identified in sensitivities. Consistent with the MISO Future 1a, this scenario contemplates slower and less-aggressive decarbonization.

Q. Why did the Company not utilize the final MISO Series 2 Futures in its modeling?

A. The final MISO Series 2 Futures were not available when the Company initiated its planning analysis and established the core assumptions used in the IRP. In fact, as will be discussed later in this testimony, while MISO has published a report of its progress on Series 2, portions of the analysis are identified as still under development. Nevertheless, the Company actively monitored the development of the Series 2 Futures throughout the planning process and assessed emerging changes relative to the prior MISO Futures framework.

The Company's review indicated that two of the most significant developments within the Series 2 process were (1) increased expectations for future load growth and (2) delayed retirement assumptions for existing generating resources across the region.

Consistent with those developments, the Company incorporated a range of load growth and regional supply assumptions within its planning scenarios that reflected both its internal forecasting analysis and the evolving discussion occurring through the MISO Futures process.

Specifically, the Company used the ALG and PCC frameworks to bound the range of potential outcomes associated with future load growth and regional resource availability. The ALG framework reflects the upper-end assumption for non-electrification-driven load growth and incorporates delayed generation retirements. The PCC framework reflects the upper-end assumption for electrification-driven load growth and more-aggressive generation retirements.

As a result, although the final Series 2 Futures were not available or complete for use in the Company's modeling, the scenarios incorporated the directional changes being developed through the Series 2 process, including higher projected load growth and delayed regional resource retirements. This approach allowed the Company to evaluate resource needs across a broad range of plausible future conditions while relying on the information available at the time the analysis was performed.

Q. How was the MISO footprint incorporated into the modeling?

A. The entire MISO market area is represented in the Aurora IRP model. For each scenario, capacity expansion optimizations were performed for the entire regional market area. The results of these optimizations were then translated into a market price and availability curve. Based on the optimized regional market area, the model then was able to optimize the Consumers Energy system. This methodology provides a balanced view of long-term reliability requirements in the study for the Consumers Energy system, the Lower

Peninsula of Michigan, as well as the entire MISO market footprint. The result of this multi-step modeling process is a comprehensive plan that considers the interchange of power between the Consumers Energy system and the rest of the MISO market.

Q. Does the Company's reliance on the MISO Futures mean that it adopted MISO's assumptions without independently evaluating them?

A. No. The Company uses the MISO Futures as a regional planning reference, not as a substitute for Company-specific analysis. MISO develops the Futures based on its assessment of significant industry trends and uncertainties, such as decarbonization, resource retirements, load growth, electrification, and technological change. Because the Futures span different potential trajectories for these drivers, they provide a useful foundation for evaluating a reasonable range of future conditions.

The Company evaluates MISO's assumptions, develops ones appropriate for its own system and customers, and calibrates its modeling against the range represented by the MISO Futures. Where the Company's assumptions differ from MISO's, those differences can be assessed in light of the information available and the purpose of the analysis.

This approach is consistent with the MIRPP, which contemplates the use of MISO planning scenarios, and supports coordination with the Michigan Electric Transmission Company ("METC"). METC uses the MISO Futures, including through MISO's Long Range Transmission Planning ("LRTP") process, to evaluate future transmission needs. Considering the same regional scenarios allows the Company's resource planning and METC's transmission planning to proceed from a reasonably consistent view of potential future conditions, while abiding by its own and MIRPP planning processes.

Q. Please describe the sensitivities included in this IRP.

A. A total of 28 sensitivities were applied to the four IRP scenarios, where applicable. As well as three additional sensitivities used for the PCA, alternate, and support plans.

Table 1 provides a summary of all the sensitivities evaluated in this IRP and the scenario in which they were run.

Table 1: Summary of Sensitivities Evaluated Across Scenarios

#	Sensitivity Description	MSO	BAU	ALG	PCC
01	**MIRPP Scenario 1 Sensitivity 4-1 – Low Large Load Forecast: 500 MW Economic Development.** Adds a ramping curve of large customer demand beyond what is included in the base demand forecast of each scenario. In ALG this was evaluated as a load reduction because the base load is higher than BAU and PCC.	✓	✓	✓	✓
02	**1,000 MW Economic Development.** Adds a ramping curve of large customer demand beyond the base demand forecast. In ALG this was evaluated as a load reduction because the base load is higher than BAU and PCC.	-	✓	✓	✓
03	**1,500 MW Economic Development.** Adds a ramping curve of large customer demand beyond the base demand forecast. In ALG this was evaluated as a load reduction because the base load is higher than BAU and PCC.	-	✓	✓	✓
04	**MIRPP Scenario 1 Sensitivity 4-2 – Medium Large Load Forecast:** 2,000 MW Economic Development. Adds a ramping curve of large customer demand beyond the base demand forecast. In ALG this was evaluated as a load reduction because the base load is higher than BAU and PCC.	✓	✓	✓	✓
05	**2,500 MW Economic Development.** Adds a ramping curve of large customer demand beyond the base demand forecast. In ALG this was evaluated as a load reduction because the base load is higher than BAU and PCC.	-	✓	✓	✓
06	**3,000 MW Economic Development.** Adds a ramping curve of large customer demand beyond the base demand forecast. In ALG this was evaluated as a load reduction because the base load is higher than BAU and PCC.	-	✓	✓	✓

#	Sensitivity Description	MSO	BAU	ALG	PCC
07	**MIRPP Scenario 1 Sensitivity 4-3 – High Large Load Forecast: 3,500 MW Economic Development.** Adds a ramping curve of large customer demand beyond the base demand forecast. In ALG this was evaluated as a load reduction because the base load is higher than BAU and PCC.	✓	✓	✓	✓
08	**CIL CEL Low Sensitivity**. Assumes a low Capacity Import Limit ("CIL") and Capacity Export Limit ("CEL"), affecting reliance on transfers between market zones.	-	✓	✓	✓
09	**CIL CEL High Sensitivity.** Assumes a high CIL and CEL, affecting reliance on transfers between market zones.	-	✓	✓	✓
10	**Transmission Network Upgrade Costs.** Assumes increased network upgrade costs for new resources built in Aurora.	-	✓	✓	✓
11	**Zeeland Retirement 2040.** Retires Zeeland generating units on 5/31/2040.	-	✓	✓	✓
12	**Covert Retirement 2040.** Retires Covert generating units on 5/31/2040.	-	✓	✓	✓
13	**Zeeland CCS Retrofit.** Retrofits the Zeeland CC unit with CCS.	-	✓	✓	✓
14	Intentionally unused sensitivity number.	-	-	-	-
15	**Increased renewable, storage, and natural gas resource costs.** Increases renewable and storage costs by 140% and natural-gas resource costs by 20% to 40%.	-	✓	✓	✓
16	**Increased natural gas-fueled capital cost**. Increases capital costs of new natural-gas resources by 20% to 40%.	-	✓	✓	✓
17	**MIRPP Scenario 1 Sensitivity 1 and MIRPP Scenario 2 Sensitivity 1 – AEO High Gas Price.** Uses the EIA 2025 AEO high-gas-price forecast.	✓	✓	-	-
18	**MIRPP Scenario 1 Sensitivity 2 – Renewable Build Constraint Reduced by 20%.** Assumes a 20% reduction in available renewable build potential.	✓	-	-	-
19	**EWR 2%.** Increases EWR to 2.0% annual growth.	-	✓	-	-
20	**MIRPP Scenario 1 Sensitivity 3-2 and MIRPP Scenario 2 Sensitivity 3 – EWR 2.5%.** Increases EWR to 2.5% annual growth.	✓	✓	-	-
21	**MIRPP Scenario 1 Sensitivity 5 – Land-Based Renewable Cap.** Caps land-based renewable builds to 60% of the clean energy standard portfolio and assumes no new solar builds after 2040.	✓	-	-	-

#	Sensitivity Description	MSO	BAU	ALG	PCC
22	**MIRPP Scenario 1 Sensitivity 6-1 – Distributed Generation 10%.** Increases embedded DG to 10%.	✓	-	-	-
23	**MIRPP Scenario 1 Sensitivity 6-2 – Distributed Generation 15%.** Increases embedded DG to 15%.	✓	-	-	-
24	**MIRPP Scenario 1 Sensitivity 6-3 – Distributed Generation 20%.** Increases embedded DG to 20%.	✓	-	-	-
25	**Distributed Generation Solar Outflow Cost.** Changes DG costing from NREL-based assumptions to outflow cost assumptions.	-	✓	✓	✓
26	**MIRPP Scenario 1 Sensitivity 7 and MIRPP Scenario 2 Sensitivity 5 – Atypical Weather Events**. Simulates increased atypical weather events.	✓	✓	-	-
27	**MIRPP Scenario 2 Sensitivity 2a – High Load.** Increases demand above the base case by 0.5%.	-	✓	-	-
28	**MIRPP Scenario 2 Sensitivity 2b – Low EV Adoption**. Assumes EV adoption and electrification occur more slowly than expected.	-	✓	-	-
29	**CIL High Sensitivity with METC Update.** Assumes import capacity limit increases to 7,775 MW.	-	✓	✓	✓
53	**Support Plan Updates.** Incorporates updates for Karn and Thetford CTs, PPAs, batteries, EWR, DR, CIL/CEL, network upgrade costs, storage, load, and tax credits.	✓	✓	-	-
54	**Alternate Plan Updates.** Applies the Sensitivity 53 updates to Alternate Plan portfolios.	✓	✓	-	-
55	**Proposed Course of Action Updates**. Applies Sensitivity 53 updates to PCA portfolios with an additional load modification.	✓	✓	-	-

Q. Please define the difference between a scenario and sensitivity.

A. The Company's IRP uses a structured set of scenarios and sensitivities to evaluate how the electric system may evolve under a range of potential future conditions. These analyses are developed consistent with the requirements of MCL 460.6t and the MIRPP, which establish the analytical framework for long-term planning.

Scenarios represent distinct, internally consistent future outlooks that reflect different combinations of key drivers such as customer demand, electrification, resource

availability, policy, and decarbonization trajectories. Each scenario describes a plausible "future state" of the system, allowing the Company to evaluate how resource strategies perform under materially different conditions.

Sensitivities are then applied to these scenarios to isolate the impact of uncertainty in key assumptions. These sensitivities vary individual inputs, one at a time—such as demand growth, fuel prices, technology costs, and system constraints—to evaluate how each change influences planning outcomes.

Section VI. SUPPLY AND DEMAND ASSESSMENT

Baseline Capacity Position

Q. In Section IV of this direct testimony, you described how the Company's baseline capacity position is identified. Can you further explain how a capacity position and need was identified for each scenario and sensitivity included in this IRP?

A. Yes, as I described in Step 2 of Section IV – at the highest level, the capacity position is determined by comparing existing and planned supply- and demand-side resources to projected peak demand plus reserves.

Q. What is the projected capacity position and need in the BAU base case outlook?

A. As will be discussed within this section of my testimony, the resulting BAU baseline capacity position and need is presented in Figures 1 through 4, below. These figures indicate that under current assumed retirement schedules and BAU base case demand, the Company has a capacity need beginning in 2028.

Figure **1**: Base Case Summer Capacity Need

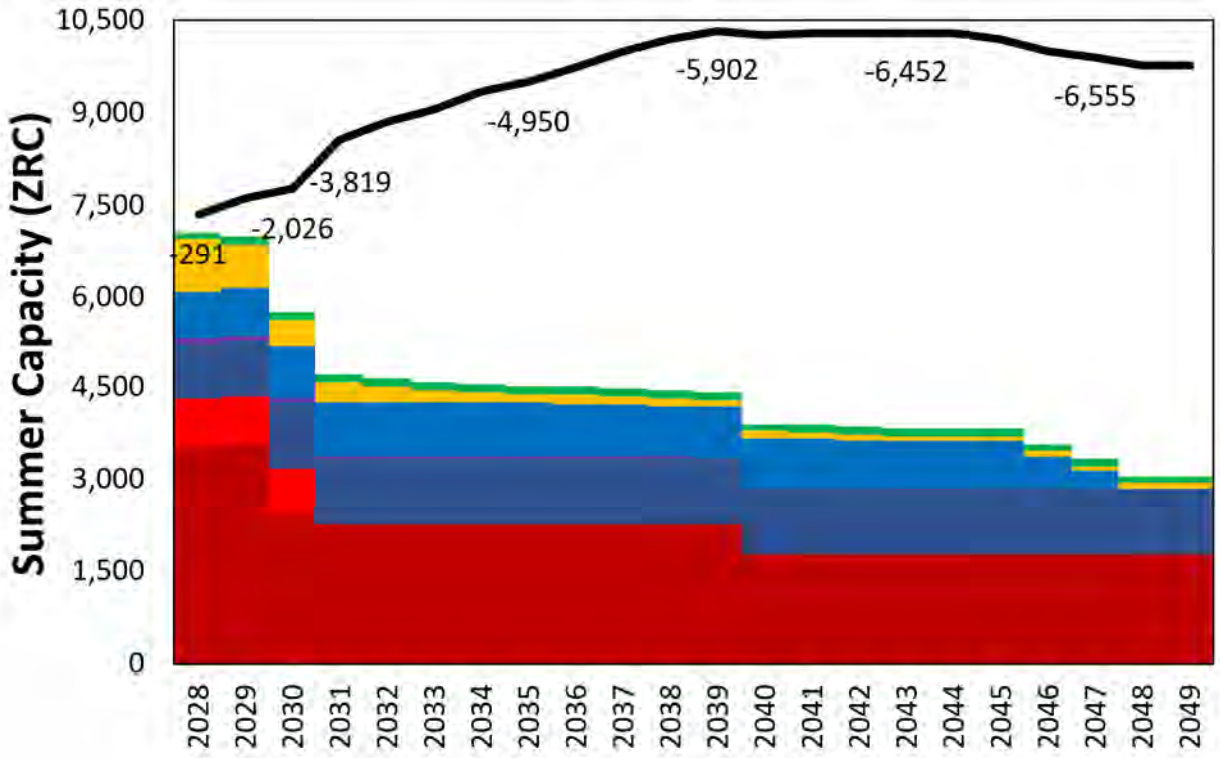


Figure 2: Base Case Fall Capacity Need

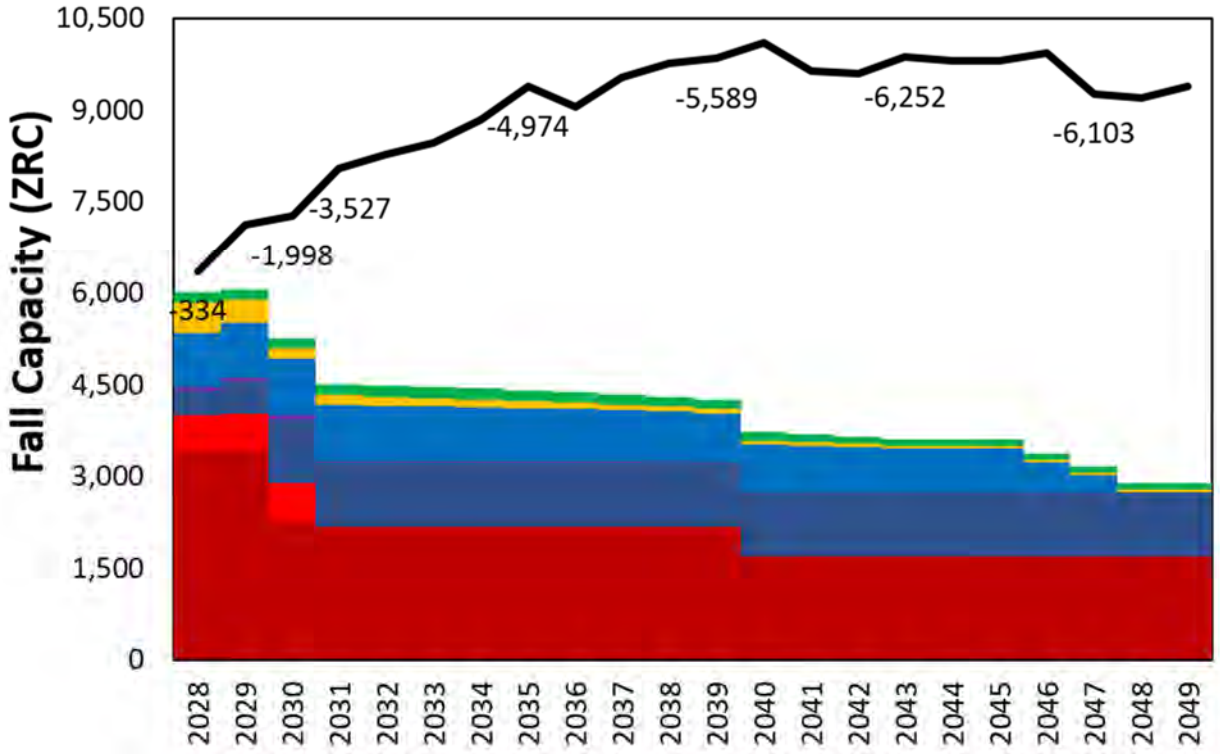


Figure 3: Base Case Winter Capacity Need

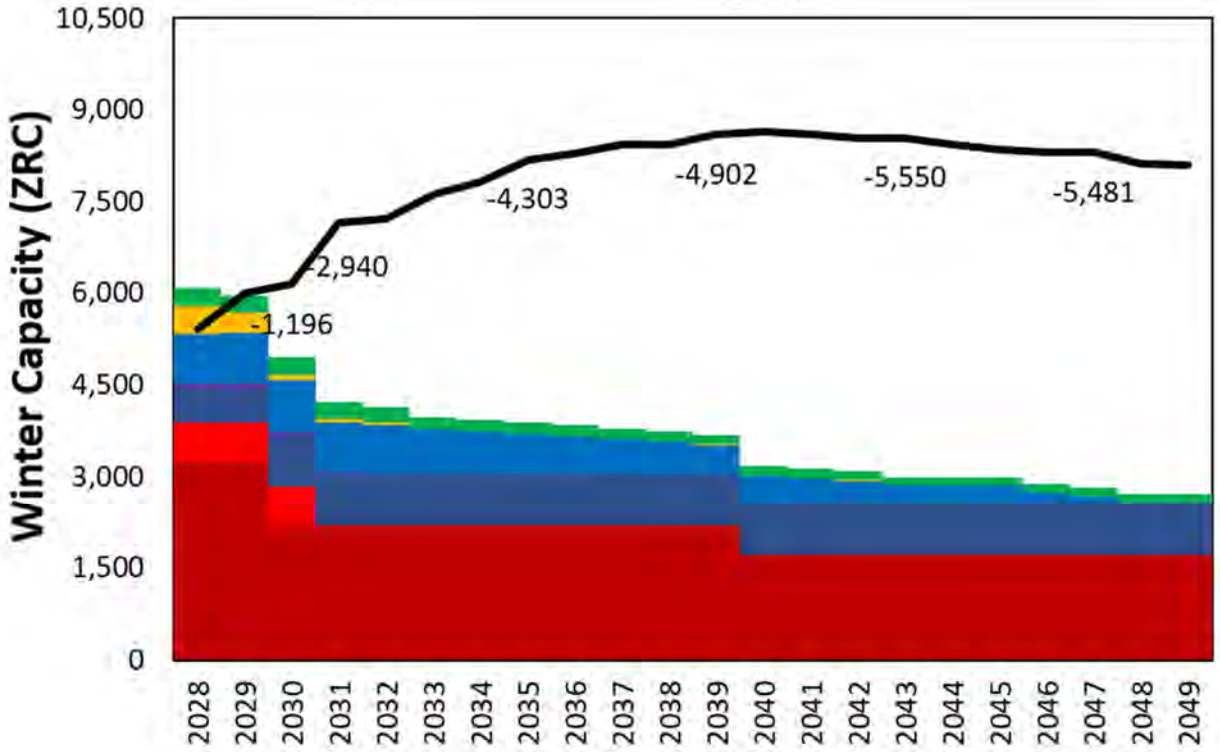
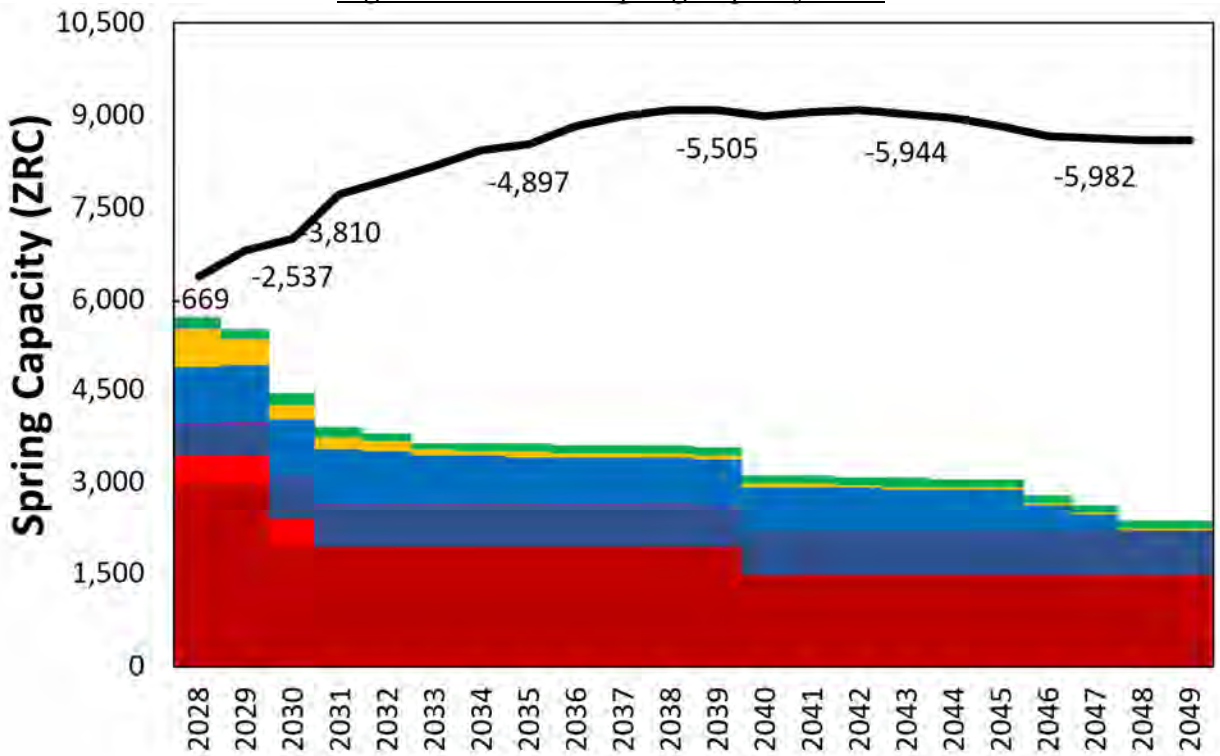


Figure 4: Base Case Spring Capacity Need



Q. What assumptions regarding existing and planned supply-side resources are included in the projected capacity position?

A. The Company's diverse portfolio of existing generating resources includes a mix of owned resources, PPAs, and VPPs. Company witnesses Walter, Skowronski, Johnston, Schmoekel, and Gast describe the IRP assumptions related to these existing supply- and demand-side resources, as well as currently planned additions, such as future projects included in the Company's Renewable Energy Plan. The assumptions regarding these existing and planned resources are common to all scenarios and sensitivities within the IRP. In addition to resources included in Confidential Exhibit A-17 (AJM-3), the base case scenarios include the following major planned capacity resources:

- Addition of 861 MW of voluntary green pricing ("VGP") capacity by 2035;
- Addition of 828 MW of storage capacity by 2028 as filed and approved by the Commission via PPAs;
- Addition of 1,600 MW of 2024 Renewable Energy Plan approved solar capacity by 2030;
- DR, averaging 643 MW as presented on Exhibit A-93 (AGM-2), line 7;
- The terms of the current MCV PPA approved in Case No. U-20896 and terminating in May 2030;
- The retirement of Karn Units 3 and 4 in 2031 consistent with the Settlement Agreement approved in Case No. U-21090;
- The operation of the Zeeland, Covert, and Ludington resources throughout the duration of the study period, while Jackson is assumed to retire May 31, 2040 for modeling purposes; and
- The sale of all Company-owned hydro facilities in 2027 consistent with the Company's request under Case No. U-21985.

Confidential Exhibit A-17 (AJM-3) provides a detailed summary of the total amount of capacity from existing and planned assets, and the associated year through which those resources are available.

Q. What assumptions regarding existing and currently planned demand-side VPP resources are included in the projected capacity position?

A. Existing and planned demand-side VPP management programs generally fall into two categories:

1. Peak, or demand, load management programs that are designed to reduce demand during system peak hours, thereby avoiding or deferring new capital investment for generation and transmission; and

2. EWR programs that are designed to reduce long-term energy use through increased efficiency of energy consuming equipment, conservation programs that promote the use of more energy efficient building materials, and educational programs that promote the merits of lower overall use of energy and attempt to motivate a change in customer behavior.

Demand-side controls and EWR programs have and will continue to be an effective resource option for the Company. Accordingly, the IRP includes forecasts of expanded EWR and demand reduction programs, as discussed in the direct testimonies of Company witnesses Gast and Dimitry J. Burdjalov.

Q. What assumptions regarding peak demand and energy requirements are included in the IRP?

A. The system load and system generation requirements data was provided by Company witness Breuring. His direct testimony and exhibits set forth and explain relevant assumptions and calculations supporting the forecast.

The forecast is made up of components that consider residential, commercial, and industrial customer consumption; EWR; DG; CVR; large load consumption; EVs; unregistered DR; and customers taking service under retail open access. Each of these

components has a unique profile of when the demand load or reduction is occurring for every hour of every year for the study period. The Aurora model uses the summation of each of those hourly load shapes as input to determine annual generation requirements and seasonal peak demands. Every hour of demand is solved by Aurora through a combination of existing resources, market interchange, and/or building new resources though its LTCE.

Q. How has the data provided by Company witness Breuring been used to determine projected peak demand plus reserves used to determine the projected capacity position?

A. With monthly peak demand levels identified, a *seasonal peak* is identified, based on the following definitions

- Summer includes June, July, and August;
- Fall includes September, October, and November;
- Winter includes December, January, and February; and
- Spring includes March, April, and May.

Within each season, the highest monthly peak demand is identified. To each of the four seasonal peak demand levels for a given PY, a seasonal reserve margin requirement percentage is applied to Consumers Energy's seasonal bundled peak demand amounts at the time of MISO's seasonal peak demands.

Q. Can you define what you mean by a PY?

A. Yes. As opposed to a calendar year that runs January through December of any given year, MISO does its planning based on a PY, defined as June through December of one calendar year, plus January through May of the next calendar year. Thus, PYs are generally noted as "PY2026-2027," which would cover the period of June 2026 through May 2027.

The remainder of this section will provide a more detailed discussion on the specific calculations necessary to generate the resulting capacity position and need presented in Figure 1 through Figure 4.

Q. How is the remainder of this section organized to explain the calculation of the Company's capacity position and need?

A. Each subsequent section of this testimony will provide details regarding (i) an overview of the changes to MISO's RA rules, (ii) how accredited capacity for existing, planned, and new supply- and demand-side resources was determined, and (iii) how the PRMR that must be met under the new MISO RA rules was determined.

Changes to MISO RA Rules

Q. Have there been any significant changes to supply and demand planning since the last IRP, filed by the Company in 2021?

A. Yes. Since 2021, MISO has been making a number of significant changes to its RA construct under its Reliability Imperative. Within the context of this IRP, these changes impact how capacity position (or the balance between supply and demand) is determined. Those changes include

- Implementation of a **seasonal capacity market** construct;
- Implementation of an RBDC, to better reflect the valuation of incremental capacity and address price volatility and stabilize price signals;
- Adoption of a **DLOL** resource accreditation methodology, beginning in 2028, which shifts from an annual or seasonal peak hour determination of resource accreditation, to an "all-hours" approach that reflects resource availability during high-risk hours; and
- Additional changes to RA rules which include **reforms to load modifying resource** ("LMR") testing, accreditation, performance, penalties, and other changes.

Q. How has modeling been updated to reflect the changes to reflect MISO's planning based on a seasonal capacity market?

A. All resources now include an amount of accredited capacity for each of the four planning seasons. This amount reflects seasonal considerations such as operational characteristics, seasonal capacity derates, seasonal profiles, outage rates and availability, and more. In Aurora modeling, all existing and new resource alternatives are represented with the amount of capacity by season that contributes toward the seasonal PRMR. Accredited capacity is defined and discussed in the next topic of this section.

As previously noted, peak demand forecasting also reflects seasonal planning by forecasting a peak for each season.

Q. How has modeling been updated to reflect the RBDC change in MISO's RA rules?

A. No modeling changes are required. For many years, the Company has supported that the long-term value of capacity is approximately 75% of CONE. For some time, MISO's annual capacity auction, the PRA, has cleared at values materially lower than 75% of CONE. As discussed in Section IV of this testimony, the PRA is not indicative of the *long-term* value of capacity; rather, the PRA is a residuals market, clearing only small amounts of capacity needs for load-serving entities, on a single-year basis.

MISO's adoption of the RBDC is expected to put upward pressure on capacity prices that clear in the seasonal PRA and better reflect the value of incremental capacity. In PY 2025-2026, the average annual clearing price was approximately 60% of CONE, with the highest season clearing at 185% of CONE. In PY 2026-2027, the average annual clearing price was 33%, with the highest season clearing at 113% of CONE. As reserve margins potentially decline in the future, the clearing price for capacity could go even

higher, particularly in seasons and years where shortages might occur. It is important to note that MISO has no annual price cap, although each season is capped at what is called the annual Gross CONE amount, meaning that prices on an annual level could go as high as four times CONE.

Q. Please explain the fundamental drivers that may result in tightening regional reserve margins and additional potential upward pressure on capacity clearing prices.

A. Load across the MISO footprint is expected to grow at levels not seen in decades, with MISO's recent 2026 long-term load forecast report producing a benchmark forecast with over 40 GW of peak load growth over the next decade and a 20-year compound annual growth rate of 2.0%.[7] Meanwhile, coal retirements are expected across the region over the next several years, and the recent OMS-MISO survey notes several risks associated with bringing new supply online, including persistent supply-chain disruptions, labor constraints, permitting challenges, and interconnection backlog.[8] On top of that, the new DLOL market design, discussed next in this testimony, will result in lower resource accreditation values for many technology types, which will reduce overall accredited supply in the market and introduce new uncertainties associated with future PRA pricing.

Q. What is DLOL?

A. DLOL is MISO's RA framework that evaluates reliability risk during the hours identified as contributing to loss-of-load events in MISO's probabilistic reliability analysis. The methodology evaluates resource availability and peak demand reserve margin

[7] See: https://cdn.misoenergy.org/20260413%20LTLF%20Workshop%202026%20Long%20Term%20Load%20Forecast%20Summary_UPDATED750524.pdf
[8] See: https://cdn.misoenergy.org/20260604%20OMS-MISO%20Survey%20Results%20Workshop%20Presentation761711.pdf

requirements during reliability-risk periods and uses a two-step process that establishes resource-class accreditation values and then adjusts those values based on each resource's performance.

DLOL recognizes that RA risk is not necessarily limited to the hours of highest forecasted demand. As MISO's resource mix changes to include weather-dependent, energy-limited, and other intermittent resources, loss-of-load risk may arise in other hours because of the combined effects of load, weather, outages, resource availability, energy limitations, and the output of variable resources. Accordingly, the methodology evaluates reliability risk across all hours of the year rather than assuming risk occurs only during traditional peak-demand periods.

MISO's tariff provides for implementation of the DLOL methodology beginning with the 2028–2029 PY. Until implementation, MISO is publishing indicative DLOL-based accreditation results before the applicable PRAs.

Q. How does the transition to DLOL change the load and capacity requirement for which the Company plans?

A. The transition to DLOL does not, in itself, change the Company's forecast of customer demand or eliminate the use of a seasonal coincident-peak demand forecast. MISO's PRMR continues to begin with the applicable forecasted seasonal coincident peak demand, adjusted for items such as transmission losses and full-responsibility purchases and sales. MISO then applies a Planning Reserve Margin developed through its Loss of Load Expectation ("LOLE") study to determine the quantity of accredited capacity that a load-serving entity must obtain.

What changes under DLOL is the framework used to determine both the amount of

accredited capacity required and the capacity contribution of the resources used to satisfy that requirement. Before DLOL, MISO used different accreditation methodologies for different resource types, including effective load carrying capability ("ELCC") for wind, seasonal default values for solar, and separate capability-, availability-, or performance-based methodologies for thermal generation, storage, DR, and other resource categories. Planning Reserve Margins were determined consistent with that prior accreditation framework.

Under DLOL, MISO's probabilistic model identifies the hours in which the system is most at risk of experiencing a loss of load or operating with a low planning margin. Those critical hours are not necessarily the single hour in which forecasted demand reaches its seasonal maximum. For example, reliability risk may occur during an hour with lower demand if renewable output is low, thermal-resource availability is reduced, storage is energy limited, imports are constrained, or several of those conditions, or others, occur together. DLOL measures the expected contribution of each resource class during that broader set of high-risk hours.

MISO also develops a DLOL-consistent Planning Reserve Margin through the same underlying probabilistic reliability framework. The resulting reserve margin is applied to the seasonal coincident-peak demand forecast to establish a PRMR stated in DLOL-accredited or unforced-capacity terms. MISO's indicative DLOL publications therefore provide both resource-class accreditation values and corresponding seasonal PRMR values. The two must be used together because the accredited capacity on the supply side and the reserve requirement on the load side are derived from the same reliability framework.

Accordingly, the Company continues to forecast seasonal peak demand, but assesses RA under the DLOL framework rather than by comparing that peak, plus the former reserve margin, with nominal or previously accredited capacity. Instead, the Company compares the seasonal PRMR, calculated using the DLOL-consistent reserve margin, with the portfolio's expected DLOL-accredited capacity. This approach accounts for the fact that the hours of greatest reliability risk may not coincide with the hour of maximum customer demand.

Q. Were there modeling updates to reflect reforms to load modifying resources under MISO's DLOL methodology?

A. No. There were no modeling-specific changes to the demand resource described by Company witness Gast.

Supply Resource Accreditation under DLOL

Q. What is resource accreditation?

A. This refers to the amount of capacity a technology class provides toward meeting PRMR as a percentage of its installed capacity. Resource accreditation is determined by MISO based on historical performance of a resource, during what is referred to as "tight hours," and the amount of maximum capacity a resource can prove it is capable of, during testing.

MISO's DLOL accreditation framework is designed to be responsive to changes in system conditions. Accreditation values are derived from probabilistic reliability studies that reflect the forecasted generation fleet, load forecasts, outage assumptions, weather patterns, and resource performance characteristics. As these inputs evolve, MISO recalculates reliability risk and resource contributions during periods of highest system

stress. Consequently, resource accreditation values are expected to change over time as the MISO system transitions and reliability risks migrate across seasons and hours of the day.

Q. Does this resource accreditation apply to both existing and new resources?

A. Yes.

Q. How has modeling been updated to reflect resource accreditation determined under MISO's DLOL accreditation methodology?

A. The base case reflects model updates for DLOL from MISO documentation available at the time of model development. Specifically used were the *LOLE Modeling Enhancements Storage Modeling*[9] presentation for PYs 2025 and 2030 and the *Technical Appendix: 2024 Regional Resource Assessment Assumptions and Methodology*[10] for PYs 2033 and 2043. Values in between the specific years provided from those documents were linearly interpolated and values beyond the latest published year were held constant. Values for resource type accreditation, by year and season, can be found in Exhibit A-31 (AJM-17). This exhibit includes one page for each of MISO's PY seasons on pages 2 through 5, and an annual average presented on page 1.

Q. Have there been any changes to base case assumptions for resource accreditation?

A. Yes. The referenced values used for base case development were published in August 2024 and January 2025, respectively, for the referenced reports. However, as clarified in both reports, these initial values were preliminary. Subsequently, MISO has published its Series 2 Futures Report,[11] which represents the most-up-to-date long-term scenario

[9] https://cdn.misoenergy.org/20240821%20RASC%20Item%2006b%20LOLE%20Modeling%20Enhancements%20Storage%20Modeling643281.pdf
[10] https://cdn.misoenergy.org/2024%20RRA_Technical%20Appendix676208.pdf
[11] MISO Futures Report Series 2 766529.pdf

modeling under DLOL, at time of this filing. While MISO initially planned to publish long-term battery storage estimates by Q1 2026, as of this June 2026 publication, MISO has yet to determine projections for battery storage accreditation. MISO notes in this report "Please note that these tables are placeholder tables only and will be updated when storage accreditation is complete."

Q. How has the Company modeled battery storage accreditation under DLOL, given limited or incomplete information from MISO on the topic?

A. Battery storage accreditation under DLOL remains uncertain because MISO has not provided long-term projections on which the Company can rely. MISO's DLOL framework is designed to respond to changing system conditions, including the forecasted generation fleet, load, outages, weather, and resource performance. As those conditions evolve and reliability risk shifts across seasons and hours, the accredited contribution of storage may also change.

Early iterations of the Company's loss of load analysis showed that storage reliability was under-performing relative to the DLOL accreditation assumptions provided in preliminary (2024-2025) estimates provided by MISO and used in Phase 1 of modeling.

As previously mentioned, the Company anticipated that MISO would provide updated projections as part of their Futures Series 2; however, despite stating that these would be made available Q1 2026, they are still not available at the time of this filing. Because of this, an analysis was conducted within the Company's loss of load analysis, and reviewed with the Company's consultants, to determine battery storage DLOL accreditation consistent with the system conditions present in its model. By 2029, the difference in annual DLOL accreditation (compared to MISO's 2024 estimates) drops from

92% in the base case to 56%. The long-term projection drops from ~60% to ~40%. Exhibit A-31 (AJM-17) provides the annual average and seasonal accreditation levels. The upper range of storage accreditation is presented in column (d) of each page, and the lower range is presented in column (p).

Rather than relying on a single forecast in light of the available information, the Company modeled a *range* of potential battery accreditation levels through its portfolio analyses to understand the effect on portfolio cost and reliability. The absence of a long-term MISO forecast indicates that uncertainty regarding battery performance during DLOL risk events is greater than for resources with more-established accreditation projections. The Company therefore treated battery accreditation as a material planning risk, particularly with respect to the extent to which battery storage can provide reliability during stressed conditions and contribute toward satisfaction of the PRMR.

Q. Why is resource accreditation important in the capacity expansion modeling presented in this testimony?

A. Resource accreditation determines how much of a resource's installed capacity Aurora may count toward satisfying the Company's PRMR. As discussed in Section IV of my testimony, Aurora must select enough accredited capacity to meet the PRMR in every season of every year in the planning period.

As an illustrative example, if a battery storage resource receives 50% accreditation, Aurora must add 200 MW of installed battery capacity for that resource to contribute 100 MW of *accredited* capacity toward the PRMR. Accordingly, accreditation assumptions directly affect the amount and mix of resources selected by the model and the resulting portfolio cost.

Demand Forecast Under DLOL Methodology

Q. How has modeling been updated to reflect the changes to PRMR to reflect MISO's planning based DLOL?

A. In addition to the Company now forecasting seasonal peak demand, reserve margin targets are now based on the indicative values provided by MISO, using the DLOL methodology instead of the previous ELCC targets beginning in 2028. Those values were included in MISO's *Planning Year 2025-2026 Indicative Direct Loss of Load Results*.[12] Indicative reserve margins for PY 2025-2026 of 2.3%, 6.0%, 5.6%, and 1.0% were estimated for each of the summer, fall, winter, and spring seasons, respectively. No values were provided for years beyond PY 2025 so all forecasted years use the same reserve margin.

Q. What are DLOL reserve margins?

A. The DLOL reserve margin represents the percentage above forecasted peak coincident demand that is required to maintain reliability in the DLOL methodology. DLOL reserve margins are significantly lower than current market rules under ELCC because times of market stress may not necessarily align with system gross peak load, even though the gross peak load is still reported by load serving entities, per current RA rules.

Q. Please summarize the impact of changes in RA rules and any significant observations of the supply and demand assessment.

A. Previous IRPs only planned for a single annual peak (the summer season), while we now plan for four seasonal peak periods. Changing to the DLOL methodology provides even deeper granularity – shifting the focus from planning for four peak demand hours to requiring planning for any hour of the year in which a "tight hour" can occur. The tight-

[12] MISO Indicative DLOL Results PY 2025-2026_Update_Apr2025

hour methodology considers a net peak that accounts for both load on the system as well as availability of supply. As discussed and presented in Figure 1, Aurora's objective to meet PRMR has become more complex than prior IRPs.

Section VII. SUPPLY-SIDE RESOURCE OPTIONS CONSIDERED IN THE IRP

Supply-Side Resource Options

Q. What resources, other than the existing and planned resources previously described in Section VI, were considered as potential supply options to serve demand in the future?

A. As part of its planning process, the Company considered a wide range of supply and demand-side resources to serve future electric demand. Due to the volume of calculations made by the Aurora model as it solves for all potential solutions to satisfy the model's constraints, it would not be practical to offer all possible resources for selection. Therefore, some resource technologies were "screened out" before the scenarios and sensitivities were modeled. The technologies were screened on criteria such as commercial availability, cost, scale, resource type (e.g., peaking, intermediate, and baseload), technical viability, and other considerations. Technologies that were screened out include the following:

- Thermal Storage - An initial technical screening indicated thermal storage was a higher cost application than other options associated with energy storage as well as having a lower technological maturity;
- Compressed Air - An initial technical screening indicated compressed air technology did not demonstrate enough technological advancement to be applied at a utility scale level;
- Flywheel - An initial technical screening indicated flywheel technologies were a higher cost application than other options associated with energy storage as well as a lack of widespread adoption making them non-viable for widespread utility scale adoption;
- Combined Heat and Power - Based upon Company subject matter expert feedback and a survey completed as part of the 2021 IRP settlement agreement,

the current and future economics and growth of Combined Heat and Power does not reflect a feasible alternative to consider as an alternate resource. The need for a steady steam supply tied to site-specific requirements makes this type of facility less viable than other resources;

- Fuel Cells - Initial technical screening indicated fuel cells were a higher cost application than other options associated with energy storage;

- Hydrogen – Initial technical screening indicated hydrogen is not yet commercially viable for utility scale electric production. This technology will continue to be monitored for future IRP filings.

- Geothermal - An initial technical screening indicated geothermal storage did not demonstrate enough technological advancement to be applied at a utility scale level; and

- Coal - New construction of coal was not included in the portfolio optimizations. Coal is not an attractive resource option because of intensive capital costs and long time periods required for construction and does not align with the state's clean energy requirements.

Q. Did you evaluate combinations of resources co-located, or sited as a single facility?

A. Yes. The Company evaluated the potential cost savings associated with co-locating multiple resources at a single facility. Depending on the project configuration and site, co-location may reduce or avoid duplicative costs by allowing resources to share land, interconnection facilities, transmission network upgrades, switchyards, substations, protection and control systems, site access, operations and maintenance activities, and staffing. These savings are project-specific and depend on the resources, site conditions, and interconnection requirements. The Company anticipates that many renewable and storage projects acquired through competitive solicitations may be co-located where doing so is feasible and cost-effective, thereby lowering overall project costs and improving use of shared infrastructure.

Q. How have you summarized the costs of resources included for final selection in modeling?

A. A preliminary economic analysis of the remaining technologies not screened out was performed using a Levelized Cost of Energy ("LCOE") comparison between similar technologies.

Confidential Exhibit A-18 (AJM-4), page 1, columns (b) through (o) present the LCOE of the various resources included for final selection to be offered into Phase 1 of the optimization modeling. An LCOE comparison allows a comparison of resources based on the amount of energy delivered by that resource, relative to the costs of construction, financing, O&M, fuel, applicable network upgrade costs, as well as any offsetting revenues provided via tax credits. The levelizing function allows the Company to take a varying stream of numbers and reduce them to one value, representing the entire period. Costs often increase over time due to inflationary factors; levelization takes these increasing values, discounts them to today's dollars, and expresses the result as one number, usually in the current year dollars. However, it is very important to note that while LCOE is widely used across this industry and can be a useful tool for comparison across multiple technologies, it has pitfalls as well. Specifically, for resources that are designed primarily to provide capacity, with potentially very little energy production, the LCOE can look poor relative to other resources. Confidential Exhibit A-18 (AJM-4) compares most resources according to the magnitude of their LCOE excluding Allowance for Funds Used During Construction ("AFUDC").

Q. Given the limitations you identified with the LCOE metric, did the Company evaluate any other comparative metrics for resources considered for final selection to be offered into the optimization?

A. Yes. As previously mentioned, the LCOE is a reasonable metric if one is "shopping for" energy since it compares the costs to construct and operate a resource relative to the energy it *delivers*. However, of increasingly equal importance as the delivery of energy, is the *availability* of energy from a resource. As the Company and the region add intermittent resources like renewables and storage, there is an increasing need for reliability assets that "backstop" the intermittent resources. This trend is nowhere more evident than in the MISO Reliability Imperative, initiated in 2020 and on-going through the next several years. Efforts and market changes resulting from MISO's Reliability Imperative are discussed in Section VI of my testimony.

Q. How did you calculate and compare resources offered into the optimization from an energy *availability* perspective?

A. I calculated a levelized cost of available energy ("LCOA") for all resources offered into the optimization, to determine which resources are likely to be chosen by the model due to their ability to provide reliability and support the expansion of renewable and storage resources. This method was used as an additional screening tool to expand the pool of available resources included in the model optimizations. LCOA is not a reliability metric, capacity accreditation metric, or substitute for Aurora or reliability analysis. It is a supplemental screening indicator designed to prevent low-capacity-factor but high-availability resources from being excluded solely because their LCOE appears high. Using LCOA allows for consideration of resources that would have been passed over by only

using the LCOE method. Page 2 of Confidential Exhibit A-18 (AJM-4) compares resources evaluated in Phase 1 of modeling according to the magnitude of their LCOA, excluding AFUDC.

Q. Please describe how the calculation of LCOA compares to the calculation of LCOE.

A. LCOA and LCOE are both levelized, life-of-asset cost metrics, and both include construction and financing costs, fixed O&M ("FOM") expenses, applicable network upgrade costs, and offsets from tax-credit revenues. They differ in two principal respects. First, LCOE includes variable operating costs, such as fuel, whereas LCOA excludes those costs. Second, LCOE divides the applicable costs by the energy the resource is expected to generate or deliver, whereas LCOA divides its applicable costs by the total energy the resource could make available. As a result, LCOE measures the cost of energy actually produced, while LCOA measures the cost to have the resource added to the system and available, including during hours when it is available but not economically dispatched.

Q. Why is it appropriate to use energy available in the denominator of the LCOA calculation instead of the zonal resource credit ("ZRC") measure of capacity?

A. It is appropriate to use energy available in the denominator of the calculation for LCOA instead of capacity or ZRCs because the ZRC value of a unit is fully dependent on MISO and uncertain through the study period considered. The values could change in the future based on how MISO determines accreditation. The available energy that a unit can produce is more stable and provides a better comparison over the life of a unit.

Q. Can you give an example of when it is appropriate to use LCOE and when it is more appropriate to use LCOA?

A. Yes. LCOE and LCOA are comparative screening metrics used to evaluate generating technologies; neither is an input to Aurora nor affects the model's resource selections. An illustrative example is the comparison of a solar resource to a natural gas combustion turbine. At a 20-25% capacity factor, a solar resource might have an LCOE of $75/MWh. A CT plant generally does not run very often, as it is designed to operate when demand is high, energy market prices are high, or other lower-cost supply options are not available. At a 5-10% capacity factor, a CT might have an LCOE of $200-300/MWh. If the comparison ends there, it would appear that a CT is a less valuable or less desirable resource than solar in its ability to deliver electricity.

However, if these resources are examined under the LCOA metric, additional insight can be gained. In the case of solar, the energy available *is* the energy delivered. Solar only produces when it is available (when sufficient sunlight is available). Therefore, the LCOE of solar is exactly equal to the LCOA. In the case of the CT, while it may only dispatch economically or for reliability purposes at a 5-10% capacity factor, the plant is likely available nearly 90% of all hours, or more, and is a valuable *option* should prices spike, renewables or storage fall offline, or other circumstances occur requiring the CT's availability. When we recognize all those hours of availability in the denominator of the LCOA, the result is a $35/MWh LCOA of CT, compared to a $75/MWh LCOA for solar.

Q. What do you conclude in your example, regarding the economics of the supply resources, using LCOE and LCOA?

A. I conclude that both options are critical for success in delivering a diverse and balanced resource portfolio. When there is a need and one must "shop" for resources that deliver energy, the solar asset is the economical choice between the two options. When there is a need and one must "shop" for resources to provide reliability, the CT is the lower-cost choice between the two options. Using both metrics allows one to understand how a balanced portfolio works together, to deliver reliability, energy, and renewable and clean attributes.

Q. Are there any other screening metrics used?

A. Yes. Levelized Cost of Capacity ("LCOC") is also used to compare resources. The numerator includes construction and financing costs and FOM expenses and the denominator includes the capacity in ZRC expected to be delivered over the life of the asset. The LCOC metric is similar to the CONE value provided by MISO with the difference being that LCOC, as calculated by the Company, divides the applicable costs by ZRCs, while the MISO calculation reflects the installed capacity in its denominator. Confidential Exhibit A-18 (AJM-4), page 3 compares most resources according to the magnitude of their LCOC, without AFUDC.

Levelized Net Cost of Capacity ("LNCC") is also used to compare resources. The numerator includes construction and financing costs, FOM expenses, applicable network upgrade costs, offsets from tax-credit revenues, fuel, and variable operating & maintenance ("VOM") expenses, less energy revenue, and the denominator includes the capacity in ZRCs expected to be delivered over the life of the asset. The LNCC metric is

similar to the "Net CONE" value provided by MISO with the differences being that LNCC, as calculated by the Company, includes network upgrade costs, while MISO's net CONE does not. And the Company's LNCC divides the applicable costs by ZRCs, while the MISO calculation reflects the installed capacity in its denominator. Confidential Exhibit A-18 (AJM-4), page 4 compares most resources according to the magnitude of their LNCC, without AFUDC.

Q. Please reconcile the cost differences between MISO's 2025 PY CONE and the LCOC of a CT F-Class ("CTF"), column (m) and line 1, in Exhibit A-18 (AJM-4), page 7?

A. LCOC for a CTF in 2029 (Phase 2 modeling) shows $281,438/ZRC-yr on page 7, while the publicly-available CONE value for PY 2025 was $130,930/MW-yr for Local Resource Zone 7 as shown below:

Reconciliation Item	Unit	MISO CONE	CTF LCOC
CONE / LCOC	$/MW-yr / $/ZRC-yr	130,930	281,438
Capital	$/kW	1,018	1,766
Capacity Credit	%	100%	85%
Network Upgrade Cost	$/kW-yr	0	18

The MISO CONE value assumes lower capital cost, higher capacity credit, and excludes network upgrade cost, which are the primary drivers of the lower value.[13]

Q. How are the levelized cost metrics used within the modeling process you described in Section IV of your testimony?

A. The levelized cost metrics are not utilized within the process described in Section IV of my testimony. Section IV describes the process by which candidate resources are selected within the Aurora modeling process. These two metrics are simply used as a screening tool and as an aid in understanding *why* the model picks what it picks. It highlights what is

[13] Lifespan assumed by MISO is 20 years versus a CTF LCOC assumption of 50 years and therefore the fixed charge rate would also change, but this has a relatively smaller impact.

"needed" to deliver an all-of-the-above set of resources to meet capacity, energy, and renewable and clean requirements.

None of the levelized cost metrics are input into Aurora at any point in time. Those metrics have no ability to impact modeling outcomes.

Q. What are your conclusions from the levelized cost metric screening of resources considered for final selection to be offered into the optimization?

A. As a result of the supply option review, the Company has focused its modeling on the following specific technologies: natural gas-fueled CTs, natural gas-fueled CC, natural gas-fueled CC with CCS, natural-gas fueled reciprocating internal combustion engine, nuclear, wind, solar, and battery storage.

For details regarding the operating parameters and costs for natural gas-fueled, renewable energy, and storage technologies, please see the direct testimony and exhibits of Company witness Clark.

Q. Please describe how curtailment was modeled for intermittent resources.

A. For purposes of calculating the levelized cost metrics, intermittent resources were assumed to have no curtailment; however, this was factored in for modeling within Aurora. While intermittent resources produce energy on a fixed profile, there are times when there is saturation and there is no need for further intermittent energy for demand, market sales, or energy storage. In these cases, the intermittent generation is curtailed such that it is producing less energy in that hour than its full capability.

Q. Were any other resources, beyond those discussed as part of the resource screening process, included in capacity expansion optimizations?

A. Yes. As discussed in Section IX, as part of Phase 1 planning-information analysis, early modeling and risk and reliability assessments indicated a need for natural gas CT resources to meet reliability and RA requirements. As such, in preparation for Phase 2, the executable portfolio development, two resource options were added for selection within the capacity expansion optimizations – a 456-MW natural gas CT at the Karn site, and a 919-MW natural gas CT at the Thetford site. Those resources are included in columns (s) and (t) on each page of Confidential Exhibit A-18 (AJM-4), beginning on page 5, with detailed input assumptions for these plants presented in the direct testimony of Company witness Clark.

Additionally, the PPA for 1,240 MW of capacity at the MCV plant that had been included in Phase 1 modeling continued to be offered into the model for selection beginning in 2030. See column (v) on each page of Confidential Exhibit A-18 (AJM-4), starting on page 5, with detailed input assumptions for this PPA provided in Confidential Exhibit A-28 (AJM-14) and discussed in the direct testimony of Company witness Troyer.

And finally, a [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] See column (u) on each page of Confidential Exhibit A-18 (AJM-4), starting on page 5, with detailed input assumptions for this PPA provided in Confidential Exhibit A-28 (AJM-14) and discussed by Company witness Troyer.

Because these four supply-side resources became available only after Phase 1 was completed, they were not evaluated in every IRP scenario and sensitivity. Instead, they were evaluated in Phase 2 through the PCA, Alternate Plans, and Support Plans.

Transmission Options

Q. What assumptions regarding the existing transmission topology are included in the IRP?

A. A fundamental assumption in the Company's resource need assessment and planning process is the transmission topology and the extent to which power can be imported or exported throughout the existing transmission system. The transmission topology can best be represented by a series of areas representing "transmission areas" or "zones," which are interconnected by transmission "paths." Within each of the zones are the hourly customer loads and electric generating resources. The paths reflect the aggregate import and export limitations of all transmission lines between the zones. Exhibit A-19 (AJM-5) provides the Company's representation of the basic transmission topology for the MISO market footprint within the Aurora IRP model. Further discussion of the import and export capabilities is also provided in the direct testimony of Company witness McCormick.

Q. What is the relevance of transmission import and export capabilities, within modeling?

A. Transmission import and export capabilities affect both resource-adequacy planning and hourly system operations. For RA, the applicable capacity import and export limits define the amount of capacity that may be transferred into or out of the relevant MISO zone and therefore affect the amount of capacity the Company must obtain to satisfy MISO requirements. Those requirements are translated to Aurora constraints and affect the extent

to which imported capacity may be counted toward meeting the Company's seasonal capacity needs.

Transmission capability also determines how much energy can be imported or exported on any hourly basis. Imports may be used to serve customer demand when they are needed for reliability or when market energy is less expensive than dispatching available Company resources. Exports allow excess generation to serve demand elsewhere in MISO when transmission capability is available. Appropriate dispatch of these transfers recognizes the operational and economic benefits customers receive from participation in the MISO market. Company witness Soni discusses the topic of market reliance; the objective in modeling is not to eliminate all market use, which could require unnecessary investment in Company-owned or contracted resources, but to develop a portfolio that limits excessive *dependence* on imports while preserving the ability to use the regional market when doing so supports reliability or lowers customer costs. Please see the direct testimony of Company witness Soni for a more in-depth discussion on market reliance.

Q. Did the IRP consider transmission expansion as an additional supply option beyond the existing transmission capabilities described above?

A. Yes. The IRP evaluated transmission expansion through sensitivities that increased import and export limits, allowing the Company to assess how additional transfer capability could help meet future demand requirements. Company witness McCormick discusses the transmission expansions evaluated in the IRP, and Exhibits A-23 (AJM-9) and A-24 (AJM-10) present the corresponding modeling results.

Resource Option Constraints

Q. What constraints were applied to the Aurora resource optimizations?

A. Certain constraints are applied to the optimization runs in Aurora for a number of reasons. Some of those constraints include:

- Minimum amounts of storage capacity required;
- Minimum amounts of energy from renewable and clean sources;
- Build limits on new resource types;
- Timing of resource availability;
- Maximum amount of energy able to be imported from outside of Consumers Energy's portfolio; and
- Minimum reserve margin requirements.

Q. Explain how constraints are generally applied in Aurora.

A. Constraints in Aurora can be applied in various ways. For the specific constraints discussed, Aurora has the capability to solve within the specified requirements as part of the optimization, while others are recognized outside of the optimization. Some constraints are required inputs for an Aurora LTCE while others are optionally defined.

Q. Explain how constraints are applied in Aurora for minimum amounts of storage capacity required.

A. This constraint was utilized to comply with Public Act 235 of 2023 ("Act 235") that established a statewide energy storage target of at least 2,500 MW. On April 29, 2025 the MPSC Staff filed specific amounts required in Case No. U-21775. For Consumers Energy this amount was 817.3 MW. The Aurora model is constrained to have a minimum amount of capacity from storage resources equal to or greater than that mandated amount. This

includes all storage resources included in the base case modeling as well as model built new storage, but does not include Ludington Pumped Storage.

Q. Explain how constraints are applied in Aurora for minimum amounts of energy from renewable and clean sources.

A. As Company witness Johnston explains, Act 235 requires the Company to achieve specified levels of renewable and clean energy. Aurora models these requirements as annual minimum-energy constraints, measured in MWh, for resources that qualify for renewable energy credits or clean energy credits.

Renewable Portfolio Standard ("RPS"): Aurora requires eligible renewable resources to produce enough energy to satisfy RPS targets of 15% through 2029, 50% from 2030 through 2034, and 60% from 2035 through the end of the study period. Company witness Johnston presents the required renewable energy credit quantities. The model may satisfy these requirements through existing and planned renewable resources included in the base case and new solar and wind resources selected by Aurora. EWR reduces forecasted retail sales and may therefore reduce the MWh needed to satisfy percentage-based requirements, but it is not treated as renewable generation unless authorized by applicable law.

Clean Energy Standard ("CES"): Aurora also requires eligible resources to produce enough energy to satisfy CES targets of 80% by 2035 and 100% by 2040. Company witness Johnston presents the required clean energy quantities. The model may satisfy these requirements through existing renewable and clean resources included in the base case and new solar, wind, nuclear, and natural gas CC resources with CCS selected by Aurora.

Note that although a storage resource may be charged from renewable or clean

generation, energy discharged from storage does not count toward either the renewable or clean energy constraint.

Q. Explain how constraints are applied in Aurora for build limitations on new resource types.

A. This constraint is applied in the Aurora model by setting a new resource's annual capacity, annual maximum amount, and overall maximum amounts. The intent of this constraint is to ensure the model only selects achievable amounts of new capacity. These annual build limits were provided by Company witness Clark.

Q. Explain how constraints are applied in Aurora based on when new resources become available.

A. Some resources require significant construction lead time prior to the commercial operation date (for supply-side resources) or significant lead time to ramp up (for demand-side management programs). Therefore, constraints were applied in the optimization to indicate a "first-year available" and applicable resource amount limitations of each individual resource option.

- Natural gas: Economic selection of a CT unit can be made as early as 2031, with an overall limitation of 1,500 MW available throughout the 2030s. A CC, with or without CCS would not be available for economic selection until 2033, due to the increased construction and lead time for CC and CCS units. The Company contemplated up to two sites, each approximately 1,200 MW, available throughout the study period.

- Solar: Economic selection of solar resources can be made as early as 2029, since base case inputs already include several planned solar resources filed with the Commission for years 2028 and prior.

- Wind: Economic selection of wind resources can be made as early as 2029, assuming that the Company could potentially enter into a PPA or a build-transfer agreement by that time.

- Storage: Economic selection of battery storage resources can be made as early as 2029, since base case inputs already include several planned battery storage resources filed with the Commission for years 2028 and prior.

- EWR: The Company's EWR is based on what is included in the current load forecasts created by Company witness Breuring and supported by Company witness Gast, as well as the additional amounts identified in the potential study through 2025. Therefore, any expansion of EWR can be added starting in year 2026.

- DR: Like solar capacity, the 2021 IRP PCA provided for pre-approved levels of DR. In the 2021 IRP, the Company committed to achieving 641 MW of DR by 2025; therefore, expansion of DR can be selected starting in year 2026 based on what was indicated by the potential study as discussed by Company witness Gast.

Q. How does Aurora limit energy imports during long-term capacity expansion modeling?

A. During long-term capacity expansion modeling, Aurora limits gross energy purchases from zones interconnected with the Consumers Energy zone to 20% of monthly energy requirements. This monthly energy constraint is distinct from the CIL, which limits the capacity that may be imported during a particular hour. The 20% constraint is consistent with the Company's historical level of market purchases and encourages Aurora to select a portfolio that is less dependent on imports to serve customer demand.

Q. Why did the Company apply this constraint?

A. Aurora's long-term capacity expansion model selects resources to satisfy hourly energy needs and seasonal capacity requirements, but it does not and cannot simultaneously perform the Company's probabilistic reliability analysis. The energy-import constraint therefore serves as a screening mechanism during portfolio development: it discourages Aurora from selecting a resource plan that appears economic primarily because it assumes substantial market purchases will remain available when needed. The constraint does not necessarily establish that a portfolio is reliable and certainly does not replace the separate

reliability analysis sponsored by Company witness Soni. That analysis evaluates portfolio performance under variations in load, weather, outages, renewable production, market availability, and other uncertainties using LOLE and complementary reliability metrics.

Q. What is the distinction among market reliance, market dependence, market exposure, and market utilization?

A. **Market reliance** is the broad term for the Company's use of the market for either reliability or economic purposes. **Market dependence** is the extent to which market purchases are necessary to serve customer demand because the Company's portfolio is otherwise insufficient. **Market exposure** is the economic risk associated with market dependence, reflecting both the quantity of required market purchases and the prices at which those purchases occur.

Market utilization, by contrast, occurs when market energy is purchased because it is less expensive than dispatching an available portfolio resource. Economic market utilization can benefit customers and does not, by itself, indicate that the portfolio depends on the market for reliability.

Q. How does the Company preserve the benefits of economic market utilization after applying the energy-import constraint?

A. In long-term capacity expansion mode, Aurora selects the least-cost mix of resources subject to the applicable modeling constraints, including the 20% monthly energy-import constraint. After the resource portfolio is established, the Company performs an additional zonal production-cost simulation without that constraint applied. This second simulation allows Aurora to identify economical market purchases based on available resources and market prices. Accordingly, the Company uses the constrained capacity expansion run to

develop a portfolio that limits market dependence, while using the subsequent unconstrained production-cost simulation to recognize the customer benefits of economical market utilization.

Q. Did the Company evaluate whether the market-dependence constraint unreasonably affected portfolio cost or resource selections?

A. Yes. Before applying the constraint in the IRP modeling, the Company tested its effect on portfolio costs and resource selections. The testing indicated that the constraint could discourage excessive market dependence without unreasonably distorting the optimization results.

Following the capacity expansion and production cost simulations, the Company then subjected the resulting portfolios to the separate probabilistic reliability analysis sponsored by Company witness Soni. The Company considered those reliability results together with Aurora's economic results and the IRP's statutory and policy requirements in developing the PCA.

Q. Explain how constraints are imposed in Aurora for minimum reserve margins.

A. To conduct a capacity expansion optimization, the Company establishes a minimum reserve-margin constraint based on the seasonal PRMR applicable under State and MISO RA requirements. The MISO reserve-margin percentages and the calculation of the seasonal PRMR are discussed in Section VI of my testimony.

For each season of each year in the study period, Aurora compares the portfolio's accredited capacity with the applicable PRMR. If accredited capacity is insufficient, Aurora must select additional eligible resources, subject to the other modeling constraints, until the requirement is satisfied. Because each resource's contribution is based on its

seasonal accreditation rather than its installed capacity alone, this constraint affects both the amount and mix of resources selected by the model.

Section VIII. VIRTUAL POWER PLANT OPTIONS CONSIDERED IN THE IRP

Q. What VPP resources were considered for optimization within Aurora?

A. In addition to the supply-side resources previously mentioned, the Company developed a VPP framework to evaluate distributed energy resources and load modifying resources as selectable options within the IRP. The framework is evaluated collectively as a portfolio of distributed and demand-side resources, described in detail below, and consists of:

1. Increasing levels of DR: Multiple different types of DR programs such as smart thermostat programs, device cycling, dynamic peak pricing, and contractual and interruptible load were offered in this IRP. These programs are further described and supported in the direct testimony of Company witness Gast.

2. EWR: The Company's base case assumes 1.3% EWR savings growth 2027-2028 and 0.8% for years 2039-2050. Expansion of EWR savings were offered into the optimization beyond the base case assumption and supported in the direct testimony of Company witnesses Gast and Burdjalov.

3. DG Solar: A portfolio was evaluated with an aggregate of DG Solar resources that are offered beginning in 2029 through the end of the study with an annual maximum of 25 MW per year.

4. DG Battery Storage: A portfolio was evaluated with an aggregate of DG battery storage resources that are offered beginning in 2029 through the end of the study with an annual maximum of 25 MW per year.

The VPP designation is an organizational construct and does not represent a separate generating resource within the model.

Q. Why did the Company develop a VPP framework?

A. The VPP framework was partly developed to satisfy the requirements of the 2021 IRP Settlement Agreement, which directed the Company to model DG as a selectable resource and evaluate its economic costs relative to other supply-side alternatives. The framework

also aligns with Commission guidance encouraging the consideration of aggregated distributed energy resources within resource planning.

Q. How were VPP resources represented in the IRP modeling?

A. Each VPP component was modeled individually using resource-specific performance characteristics, including load shapes, capacity contributions, and operational attributes. However, the resources were evaluated collectively as a portfolio of distributed and demand-side solutions that competed directly with traditional supply-side resources in the optimization process. Consistent with the methodology used for EWR, the resources were represented as scalable system resources rather than discrete customer installations.

Q. Did the Company model avoided transmission and distribution benefits associated with VPP resources?

A. While the inputs provided by Company witness Gast reflect the aggregate system impacts and operational characteristics of the VPP resources such as avoided line and marginal line losses, where applicable, avoided transmission and distribution benefits were not explicitly modeled due to data and methodological limitations. Nevertheless, the framework allowed the Company to evaluate the contribution of distributed resources toward meeting future system needs.

<u>Demand Response</u>

Q. Please describe the source of DR programs offered into Aurora.

A. The DR programs offered into Aurora data was provided by Company witness Gast. His direct testimony and exhibits set forth and explain the relevant assumptions and calculations.

Q. Please describe the DR program offered into Aurora.

A. The DR resources offered into Aurora in this IRP comprise both residential and business DR programs. The portfolio consists of three residential programs: Device Cycling and Residential Smart Thermostat Program ("STP"); and two business programs: Commercial and Industrial ("C&I") Contractual DR, and C&I Rate options. The size of each of these programs by year and for each scenario is included in Exhibit A-21 (AJM-7).

For modeling purposes, the costs of the DR programs are broken into three components: capital, O&M, and incentive costs. The cost of each of the programs offered into Aurora was the summation of these three components. The costs of each of these programs by year and for each scenario are included in Exhibit A-21 (AJM-7).

Q. Were there any other DR programs modeled in Aurora?

A. Yes. As previously discussed in the load forecast, unregistered DR was included. Programs included in this category were Dynamic Peak Pricing, Summer Time of Use, CVR, and an assumption for a new electric vehicle shaping program. In 2025 these programs are approximately 200 MW and increase to a maximum of approximately 1,400 MW in the study period.

Energy Waste Reduction

Q. Please describe the source of EWR programs offered into Aurora.

A. The EWR programs offered into Aurora data was provided by Company witnesses Gast and Burdjalov. Their direct testimonies and exhibits set forth and explain the relevant assumptions and calculations.

Q. Please describe the EWR programs offered into Aurora.

A. The EWR programs offered into Aurora were based on the 2025 EWR Potential Study supported by Company witness Burdjalov. In that study, EWR amounts, costs, and energy savings were determined for "Achievable," "Technical," and up to a maximum "Aspirational" level that coincided with 2.50% savings. The EWR then offered to the Aurora model was the difference between what EWR was already included in the previously discussed load forecast, anywhere from 0.80% to 1.50% depending on the year, and the maximum amount of EWR from the potential study. Six blocks were developed in increments of approximately 0.25% such that the model could select additional EWR up to the maximum determined in the potential study. The cost of these blocks can be found on Exhibit A-20 (AJM-6).

Q. Were any modifications made to the EWR program offered into Aurora?

A. Yes. The transition to the DLOL methodology can create small capacity shortfalls in one season during the early years of the planning period, even when the portfolio is capacity sufficient in the other seasons. When that occurs, Aurora is forced (via model constraints) to select any available resource that provides capacity credit to eliminate the shortfall, regardless of whether that resource represents a reasonable or economical solution.

Incremental EWR blocks available during this transition period are substantially more expensive than the other resource options, with levelized costs exceeding $1,000/MWh. Those costs also substantially exceed the modeled cost of addressing a limited seasonal shortfall through a short-term capacity purchase in the MISO PRA. Allowing Aurora to select those EWR blocks solely to resolve a small seasonal shortfall

would produce an unrealistic and unnecessarily costly resource plan. The specific cost impact is provided in Exhibit A-23 (AJM-9) and discussed in Section X of my testimony.

To avoid significant and unnecessary costs, the uneconomical EWR prototypes were not assigned peak capacity credit during the initial DLOL transition period. Peak capacity credit was assigned once additional resource options became available to address seasonal capacity needs more economically. This modification affects the timing of the EWR prototypes' modeled capacity contribution; it does not prevent Aurora from recognizing their energy savings or evaluating EWR as a resource option.

Q. Did the EWR programs offered into Aurora have any impact on the constraints described in Section VII?

A. Yes. EWR programs reduce load in the model, and therefore reduce sales, which means they reduce the renewable and clean energy requirements.

Distributed Generation Solar and Battery

Q. Please describe the DG programs offered into Aurora.

A. Distributed solar and battery resource costs were evaluated from two perspectives. First, a societal cost perspective based on National Renewable Energy Laboratory ("NREL") projections was used to assess the broader economics of the technologies. Second, based on stakeholder feedback, a utility cost perspective was used to reflect utility outflows, program costs, and customer impacts. This dual-cost framework allowed the Company to evaluate these resources from both an economic and revenue requirement perspective.

Q. How did the Company account for DG already included in the load forecast?

A. DG embedded within the load forecast was reflected as a reduction to baseline system load. The selectable DG resources evaluated through the VPP framework represented

incremental deployment beyond the levels already reflected in the forecast. This distinction avoided double-counting the impacts of distributed resources.

Q. What resource availability assumptions were applied to the VPP options?

A. The Company limited selectable DG solar and DG battery resources to incremental deployment above forecasted levels, with a cap of approximately 550 MW, or 10% of peak demand. The 550 MW cap also equates to 25 MW a year over the study period. In addition, total incremental VPP resources were capped at approximately 6,000 MW above the roughly 3,000 MW of distributed resources already reflected in the base case. These bounds were intended to reflect reasonable adoption potential and maintain consistency between forecast assumptions and resource modeling.

Q. How were the DG programs modeled?

A. Both resources were built based on the utility-scale version. For DG solar, the costs, capacity factor, and capacity credit were modified. For DG battery the costs and capacity credit were modified. Other model inputs like shaping or dispatchability remained the same. While a DG resource can either be reducing demand or adding energy to the system, the model represents the resource as adding energy to the system.

Q. Please summarize the Company's VPP modeling approach?

A. The Company's VPP framework satisfies the requirements of the 2021 IRP Settlement Agreement by aggregating distributed resources into a system-level construct, applying a methodology consistent with EWR modeling, incorporating utility cost impacts, and allowing distributed resources to compete directly with conventional resource alternatives in the IRP optimization process.

Section IX. OPTIMIZATION PORTFOLIOS

Q. How were the portfolio designs discussed in Section IV of your testimony developed?

A. Portfolio designs were developed by defining the candidate resources and modeling constraints applicable to each optimization. The designs generally varied the new resources available for Aurora to select, particularly where the Company sought to evaluate how resource availability affected portfolio composition and cost. Unless otherwise specified for a particular design, Aurora selected the least-cost mix, amount, and timing of eligible resources within the established constraints. The resulting portfolios were then evaluated for economic, reliability, risk, environmental, and other planning impacts. Section IX of my testimony provides additional detail regarding the portfolio designs evaluated in this IRP.

Q. Were all portfolio designs evaluated for every model run included in the IRP?

A. No. As introduced briefly in Section IV of this testimony, Portfolio Designs 1, 3, and 4 were used in Phase 1, the initial planning-information phase, and were run, as applicable, within the BAU, PCC, ALG, and MSO scenario and sensitivity analyses. Those portfolio designs allowed Aurora to optimize among eligible generic candidate resource options and provided guidance regarding recurring resource-selection patterns, including the types, timing, and approximate amounts of resources favored under different future conditions.

In Phase 2, Portfolio Designs 96 through 99 were used in the later executable-portfolio phase to evaluate the PCA, Alternate Plans, and Support Plans. Those portfolios reflected specified resource plans and materially updated assumptions and resource opportunities; accordingly, they were not designed as direct continuations of, or direct numerical comparisons to, the earlier Portfolio Design 1, 3, and 4 optimization runs.

Q. How were each of these portfolios constructed?

A. A total of eight portfolio designs were included in the Aurora optimizations and are presented in Exhibit A-22 (AJM-8).

Phase 1: Planning-information phase

- Portfolio design 1, "Base," allows Aurora to select from eligible supply-side and demand-side resources to meet the Company's demand and reserve margin requirements. Within the constraints described in Section VII, Aurora determines the least-cost mix, amount, and timing of new resources. Because the model evaluates a range of technologies over the full study period, it may develop multiple resource plans, which are ranked based on their respective NPVs. Sensitivities evaluated under Portfolio design 1 are indicated as such in column (c) on each page of Exhibit A-22 (AJM-8). If entries do not show a "checkmark," that indicates Portfolio design 1 was not evaluated for that sensitivity.

- Portfolio design 3, "Midland Cogeneration Venture New Contract," represents a portfolio in which the Company includes a 10-year PPA at the MCV plant and meets the remaining capacity needs in the same manner as the Base portfolio. This design was evaluated, as applicable, within the BAU, PCC, ALG, and MSO scenario and sensitivity analyses. The 2030 MCV contract was held constant in each model run, while Aurora optimally selected all other new resources within the bounds described in Section VII, enabling a consistent comparison with the Base portfolio to determine whether the contract provides an economic benefit. Sensitivities evaluated under Portfolio design 3 are indicated as such in column (d) on each page of Exhibit A-22 (AJM-8).

- Portfolio design 4, "Special Prototype Offerings", represents a scenario in which the Company offers all the technologies from the Base portfolio as well as adding in special prototype generation resources. The special prototypes offered are non-standard natural gas fueled reciprocating internal combustion engines, off-shore wind prototypes, and increased amounts of VPP-style resources including DG solar and storage energy resources. The new prototypes are offered as selectable resources with annual limits. Within the bounds described in Section VII, all new resources in the model are optimally selected by Aurora. Sensitivities evaluated under Portfolio design 4 are indicated as such in column (e) on each page of Exhibit A-22 (AJM-8).

Phase 2: Executable portfolio phase

A list of model input assumption updates included Portfolios 96-99 is provided below.

- Portfolio design 99, This is the PCA. This portfolio design includes increased economic development load ramping to 1,500 MW above the base BAU load

forecast, the new PPA with MCV in 2030, the [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], the construction of the natural gas fired CTs at the Karn and Thetford sites, and the rest of the energy and capacity needs filled to meet remaining compliance requirements. Sensitivities evaluated under Portfolio design 99 are indicated as such in column (f) on each page of Exhibit A-22 (AJM-8).

- Portfolio design 98, This portfolio represents Alternate Plan Current. This portfolio design assumes 91 MW additional load growth above the "BAU" scenario (which from this point forward will be referred to as "Current" load), the new PPA with MCV in 2031, the [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], the construction of the natural gas-fired CTs at the Karn and Thetford sites in 2031, with additional new build optimally selected by Aurora for the remainder of the study period. Sensitivities evaluated under Portfolio design 98 are indicated as such in column (g) on each page of Exhibit A-22 (AJM-8).

- Portfolio design 97, This portfolio represents Support Plan 1c. This portfolio design assumes 91 MW of additional load growth above the "BAU" scenario (Current load). The full balance of the capacity need is filled with an open optimization, which offers in the new MCV PPA, the natural gas fired CTs at the Karn and Thetford sites, the [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], and all resources offered in portfolio design 1, subject to model input assumption updates described below. Sensitivities evaluated under Portfolio design 97 are indicated as such in column (i) on each page of Exhibit A-22 (AJM-8). Additional discussion on Support 1 Plans is included in Section X of this testimony.

- Portfolio design 96, This portfolio represents Alternate Plan Growth. This portfolio design includes increased economic development load ramping to 2,200 MW above the BAU Current load, the new PPA with MCV in 2031, the construction of the natural gas-fired CTs at the Karn and Thetford sites in 2031, the [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], with additional new build optimally selected by Aurora for the remainder of the study period. Sensitivities evaluated under Portfolio design 96 are indicated as such in column (h) on each page of Exhibit A-22 (AJM-8).

Q. What were the model input assumptions that were updated between Phase 1 and Phase 2 of the modeling process?

A. The following model changes were made prior to Phase 2 modeling:

- Karn and Thetford costs and operating parameters: Initial modeling was based on generic pricing information for CTs. When those generic CTs were identified as being optimally selected, teams refined the input assumptions to

reflect the specifics that eventually became the Thetford and Karn CTs; those specifics are presented in the testimony of Company witness Clark;

- PPA costs and resource parameters for MCV and [CONFIDENTIAL] [redacted] [END CONFIDENTIAL]: Once the terms for the PPAs were finalized, the costs and operating parameters modeling were updated to reflect the actual contract terms;

- EWR: 2026-2029 were updated with the EWR Plan as discussed by Company witness Gast. This changed the incremental amount of EWR that was available to model for selection;

- DR: line losses were updated which changed the capacity of each program;

- CIL and CEL: As discussed by Company witness McCormick, collaboration was completed with METC that resulted in an updated CIL and CEL forecast;

- Network upgrade cost: as discussed by Company witness McCormick, collaboration was completed with METC that resulted in updated network upgrade cost;

- Storage: Phase 1 modeling used preliminary capacity accreditations provided in column (d) on each page of Exhibit A-31 (AJM-17), as discussed in Section VI of this testimony. Phase 2 reflected storage accreditation assumptions developed and discussed in Section VI as well as the testimony of Company witness Soni. Those values appear in column (p) on each page of Exhibit A-31 (AJM-17);

- Demand forecast: Two updates were incorporated before Phase 2. First, customer migration assumptions were updated to reflect current planning expectations. Second, the load forecast was updated to reflect contracts executed during development of the IRP. The BAU Current forecast includes approximately 100 MW of additional contracted manufacturing load relative to the BAU base case. The PCA uses the Probable Load Growth forecast, which builds on BAU Current by adding approximately 1.5 GW of signed large-load commitments and a probability-adjusted assessment of the broader development pipeline;

- Tax credits: During Phase 1, the Company assumed that a CC resource with CCS placed in service between 2033 and 2035 would qualify for Section 45Q tax credits. After Aurora frequently selected this resource, the Company completed early stages of due diligence with its consultants regarding the detailed development schedule and determined that the CCS equipment could not be commercialized by 2035. Accordingly, the resource was not expected to qualify for the tax credit. Because of the complexity of modeling the CES constraint, the resource remained available for selection beginning in 2035, but

without the assumed tax-credit benefit. Company witness Clark discusses development matters further; and

- Near-term resource additions: As part of the Company's RFP process, several resources were added with commercial operation dates planned for 2027 and 2028. This change was accounted for in determining the amount of new capacity that could be selected by the model.

Q. Do all portfolio designs add enough renewable and clean resources to meet the requirements set forth in 2008 PA 295, as amended?

A. Yes. For more details on the specific compliance, see the testimony of Company witness Johnston.

Section X. SUMMARY OF PHASE 1 MODELING RESULTS

Q. Please explain how the IRP results are summarized.

A. Results of the Aurora modeling are provided in

- Exhibit A-23 (AJM-9): Provides the NPV **economic results** of the multitude of scenarios, sensitivities, and portfolio designs; and
- Exhibit A-24 (AJM-10): Demonstrates the amounts and timing of each type of new **technology resources selected** amongst the multitude of scenarios, sensitivities, and portfolios.

Economic Results

Q. What are the NPV economic results of the IRP scenario modeling?

A. The results of the IRP scenario modeling are presented in Exhibit A-23 (AJM-9). This exhibit provides NPV costs for whichever of the eight portfolio options that were applicable to meet the Company's capacity, energy, renewable, and clean needs between 2025 and 2050.

Q. How are the NPV values in Exhibit A-23 (AJM-9) calculated?

A. The NPV results represent the present value of the modeled utility costs associated with each portfolio over the study period. Aurora calculates the applicable costs for each year,

and those annual costs are discounted to today's dollars using the assumed discount rate. The calculation also includes post-processing adjustments for the value of surplus capacity because that value is intentionally excluded from the capacity expansion optimization. This is discussed further in Section IV of this testimony.

A lower NPV represents a lower-cost portfolio for customers.

Q. How are the NPV economic results organized and summarized?

A. The NPV results summarize the economics of the scenarios, sensitivities, and portfolios described in Sections V and IX of my direct testimony. Because the IRP modeling was completed in two phases, the results are organized accordingly. The ability to compare NPVs in the exhibit is extremely limited since this IRP contemplates such significant variances in many inputs, especially load. Further, as previously discussed in this testimony, Phase 1 and Phase 2 results are not directly comparable due to the updates made prior to Phase 2 modeling.

This section of my testimony will discuss results of Phase 1**,** the Planning-Information Analysis. In Section XI, I discuss development of Phase 2 portfolios and will provide the economic NPV results in that section. Phase 1 evaluated four future scenarios and applicable sensitivities, totaling 175 scenario-and-sensitivity combinations. Most were evaluated using Portfolios 1, 3, and 4 described in Section IX. The portfolio designs allow comparison of the relative economics and risks associated with different resource types, amounts, and timing.

Q. Please further describe how Exhibit A-23 (AJM-9) is organized for Phase 1 modeling results.

A. Exhibit A-23 (AJM-9) is presented as follows:

Phase 1

- Page 1 provides the NPV cost results for all sensitivities evaluated within the BAU scenario, which is consistent with MIRRP Scenario 2. Column (d) shows the NPVs associated with portfolio design 1, Column (e) shows the NPVs associated with portfolio design 3, and Column (f) shows the NPVs associated with portfolio design 4.

- Page 2 provides the NPV cost results of all sensitivities evaluated within the ALG scenario. Column (d) shows the NPVs associated with portfolio design 1, Column (e) shows the NPVs associated with portfolio design 3, and Column (f) shows the NPVs associated with portfolio design 4.

- Page 3 provides the NPV cost results of all sensitivities evaluated within the PCC scenario. Column (d) shows the NPVs associated with portfolio design 1, Column (e) shows the NPVs associated with portfolio design 3, and Column (f) shows the NPVs associated with portfolio design 4.

- Page 4 provides the results of all sensitivities evaluated within the MSO scenario, MIRRP Scenario 1. Column (d) shows the NPVs associated with portfolio design 1, Column (e) shows the NPVs associated with portfolio design 3, and Column (f) shows the NPVs associated with portfolio design 4.

Pages 5 through 8 of this exhibit are discussed in Section XI.

As shown in Exhibit A-23 (AJM-9), not every portfolio was evaluated under every scenario and sensitivity. Portfolios were modeled only where the analysis was applicable or required. For example, the Company did not apply the load sensitivities to the PCA or Alternate Plans because those portfolios were designed for specific load forecasts; applying different load levels would cause the fixed build plans to be either overbuilt or underbuilt relative to customer needs. Price risks, including higher natural gas prices, were evaluated through the risk analysis sponsored by Company witness Soni rather than through separate PCA and Alternate Plan sensitivity runs. Exhibit A-23 (AJM-9) identifies portfolio and case combinations that were not modeled as "N/A."

Q. What conclusions do you find in the NPV cost results of Phase 1 sensitivities and portfolios presented in Exhibit A-23 (AJM-9)?

A. Observations of sensitivities and portfolios evaluated as part of the planning-information phase are as follows:

- In the PCC scenario, MSO scenario, and in lower load levels of BAU and ALG, Portfolio Design 4, column (f), resulted in cost decreases when compared to the Base case, column (d), as the incremental resources are replacing more expensive resources. In BAU and ALG at greater load levels, Portfolio Design 4 increases the cost relative to the base portfolio. This is due to constraints not being satisfied in Portfolio Design 1 and the incremental resources made available to the model that are optimally selected fill in the small gaps of those constraints. In other words, the load growth exceeds the model's ability to meet all renewable, clean, or capacity constraints. Typically, this is within the first few years that the model can add new capacity and is to relatively small amounts. Examples of this are if the renewable, clean, or capacity constraint was met to 99% of the specified amount in the inputs in the base case and then in Portfolio Design 4 additional resources are made available such that the model can solve the final 1%;

- On pages 1, 3, and 4, sensitivities 01 through 07 add blocks of economic development load and therefore result in higher NPVs. Compare the NPVs of each sensitivity (lines 2 through 8 on pages 1 and 3; lines 2 through 4 on page 4) back to the Base sensitivity 00 (line 1). However, the higher costs do not necessarily indicate that these sensitivities are less economic, since the NPV results do not reflect the benefits of additional sales. Accordingly, the NPVs of these sensitivities cannot be compared (on an apples-to-apples) basis with sensitivities with different load assumed. The benefits of additional sales is discussed in the direct testimonies of Company witnesses McLean and Heidi J. Myers. Recall that on page 2, sensitivities 01 through 07 contemplate lower economic development load sensitivities and therefore do not follow this trend;

- As expected, decreasing the CIL causes costs to increase when compared to the Base sensitivity 00 as shown on pages 1 through 3 in sensitivity 08, and conversely increasing the CIL in sensitivity 09 causes costs to decrease. Sensitivity 29 on line 18, also increases the CIL, but less so than in sensitivity 09;

- On pages 1 through 3 in sensitivities 11 to 13, the early retirements of Zeeland and Covert as well as the option of retrofitting Zeeland with carbon capture show that these are not economically beneficial when compared back to the Base sensitivity 00. The economics support operation of Zeeland and Covert through the study period;

- As expected, on pages 1 through 3 in sensitivities 15 and 16, increasing the cost of new-build resources increases overall costs when compared back to the Base sensitivity 00;

- As expected, on pages 1 and 4, sensitivity 17 increases overall costs because higher natural gas prices raise the operating costs of both existing and new-build gas-fired resources when compared back to the Base sensitivity 00;

- Sensitivity 18 on page 4 shows that when fewer renewable resources are available, overall portfolio costs increase, in order to comply with RPS and CES, compared with the Base sensitivity 00;

- Increased amounts of EWR as shown in sensitives 19 and 20 on page 1, and sensitivity 20 on page 4, show much higher costs across both scenarios when compared back to the Base sensitivity 00. This is due to the high cost of incremental EWR options, relative to other options, as determined by the potential study discussed by Company witness Burdjalov;

- Sensitivity 21 on page 4 shows cost increases compared to the Base sensitivity 00, similar to sensitivity 18, where certain new resources are limited;

- On page 4 (the MSO scenario results) in sensitivities 22 through 24, when DG is forced at specific levels, there are cost decreases relative to the Base sensitivity 00. As the amount of forced DG increases, the relative savings begin to diminish;

- On pages 1 through 3 in sensitivity 25, when DG solar is offered as a selectable resource priced at the outflow cost, costs are reduced relative to the Base case sensitivity 00 on line 1 because it is more economic than the other available resources. Section VIII explains why this cost assumption was used only for this sensitivity;

- On pages 1 and 4 in sensitivity 26, when atypical weather conditions are applied to load and generator availability, costs increase when compared back to the Base sensitivity 00 since load levels are increasing and resources are less available; and

- On page 1 in sensitivity 27, similar to other sensitivities that increase load levels, costs increase when compared back to the Base sensitivity 00. Conversely, in sensitivity 28, a reduction in load levels result in a reduction in costs.

Q. Please discuss the purpose of the sensitivities that evaluated operating the Zeeland and Covert generating facilities through the end of the study period versus 2040.

A. The sensitivities evaluated alternative operating periods for the Zeeland and Covert facilities under the BAU, ALG, and PCC scenarios. The base cases assumed that both facilities would remain available through the end of the study period. The sensitivities compared those cases with an alternative assumption under which each facility would cease operation on May 31, 2040. The purpose of this sensitivity was to evaluate whether the existing natural gas-fired resources would still be economic with the 100% clean standard starting in 2040. As indicated above, it was uneconomic to remove these units from service in 2040.

Q. Please discuss sensitivities 15 and 16 that evaluated increases to new build costs.

A. Sensitivities 15 and 16 both include increased new build natural gas capital costs. These costs were provided by Company witness Clark. All costs other than capital associated with new build gas units were unchanged in these sensitivities. The base and sensitivity capital costs can be found on Exhibit A-6 (TPC-1). Sensitivity 15 also includes a 140% increase in wind and solar costs. The basis for the 140% increase is discussed in the testimony of Company witness Johnston.

<u>New Technology Resource Selection Trends and Observations</u>

Q. Please explain how the new technology resource alternative selections are summarized.

A. Exhibit A-24 (AJM-10) presents graphical results of Aurora's selection of resources across 175 sensitivities. Each page of the exhibit represents the selection range of a single new technology resource alternative (in MW) chosen in a given year, across all scenarios and

sensitivities included in this IRP. Page 1 presents the amount of solar capacity selected in a given year in all sensitivities; page 2 presents the amount of wind; page 3 presents the amount of natural gas-fired CT; page 4 presents the selection of a new PPA with MCV; page 5 presents the amount of battery storage; page 6 presents the amount of long-duration energy storage; page 7 presents the amount of new natural gas-fired CC; page 8 presents the amount of new natural gas-fired CC with CCS; page 9 presents the amount of new nuclear; page 10 presents the amount of demand response; page 11 presents the amount of new EWR; page 12 presents the amount of new offshore wind; page 13 presents the amount of new distributed generation; and page 14 presents the amount of new natural gas-fired RICE. The graph includes a box and whisker format, which outlines the first and third quartiles within a shaded box, with the second quartile indicated with a horizontal line within the shaded box region; the maximum and minimum values with capped lines above and below the box ("whiskers"), and with outliers presented as single data points beyond the box and whisker collection of data points. The mean is indicated with an "x" data marker, also inside the shaded box region. Note that on some pages, no shaded box region appears; this is because there were such few selections of the specified resources across the 175 sensitivities.

Q. What is the purpose of summarizing the Aurora resource selections in graphical format, as presented in Exhibit A-24 (AJM-10)?

A. By presenting the amounts of each new technology resource as a collection of data points, it allows one to observe Aurora's affinity for one type of resource or another, by year. Given the significant number of sensitivities evaluated in this IRP the graphical

representations included in Exhibit A-24 (AJM-10) allows one to easily identify trends in resource selections.

Q. What principal factors drive Aurora's selection of new resources across the scenarios, sensitivities, and portfolios presented in Exhibit A-24 (AJM-10)?

A. Aurora's resource selections are driven primarily by renewable energy, clean energy, and RA requirements, together with the relative economics, availability, and operating characteristics of the eligible resources.

- Renewable energy requirements – All model runs must satisfy the applicable RPS requirements (50% by 2030 and 60% by 2035 and thereafter). Because solar and wind are the eligible new-build generating resources, the RPS model constraint drives substantial additions of both technologies, regardless of economics. Aurora generally selects more solar than wind based on the relative economics and applicable build limits.

- Clean energy requirements – All model runs must satisfy the CES requirements of 80% by 2035 and 100% by 2040. Solar, wind, nuclear, and CC+CCS are the eligible new-build generating resources that contribute toward this requirement. CC+CCS is selected broadly due to the potential for 45Q tax credit eligibility and because it contributes to both clean energy compliance and RA.

- RA requirements – The transition from ELCC to DLOL creates near-term accredited-capacity needs because the existing and planned resource portfolio was not designed to meet DLOL requirements. Beginning in 2029, Aurora generally adds the maximum available ZRCs available during the first two years to satisfy seasonal capacity requirements. Solar and wind additions contribute relatively little accredited capacity, so Aurora often selects storage at its maximum available level until CTs become available in 2031. Across much of the modeling, storage and CTs have similar economics, resulting in a mix of both resources.

- Energy and capacity needs – Large additions of renewable and clean resources provide substantial energy, reducing the need for new high-capacity-factor conventional CCs at moderate load levels. However, those additions do not eliminate the need for firm accredited capacity. Accordingly, CTs are commonly selected for capacity, while conventional CCs are generally selected only under higher load conditions or when larger replacement needs arise.

- Technology-specific results – Nuclear is selected only in limited circumstances, principally in the PCC and MSO scenarios, where new unabated gas generation is unavailable, or under exceptionally high load growth. DR is selected in all

scenarios while other VPP resources supplement the supply-side portfolio but are generally selected in limited quantities. EWR is selected until incremental blocks become uneconomic, as discussed in Section VIII, while selectable DG solar and storage remain small relative to utility-scale resource additions and are generally selected only under favorable cost assumptions or limited circumstances.

Q. What are the primary conclusions from the Phase 1 scenario, sensitivity, and portfolio modeling results regarding resource selections shown in Exhibit A-24 (AJM-10)?

A. The modeling results show distinct resource selection patterns over the study period as planning objectives shift from meeting RPS requirements, to maintaining RA, and ultimately achieving the CES.

2029-2030:

Resource selections are largely driven by model constraints. To satisfy the 2030 RPS requirement, Aurora consistently selects the maximum allowable additions of solar and wind. Battery storage and DR are also selected at or near maximum levels to meet RA requirements. In portfolio designs that include the MCV resource, Aurora indicates it is economically preferred and would be selected if available for consideration. VPP resources provide only limited support, with demand response and EWR selected up to cost-effective levels and DG selected only in niche circumstances.

2031-2032:

These years represent an inflection point as capacity needs increase due to load growth and the retirement of Karn Units 3 and 4. Aurora continues to add renewable and clean resources to satisfy RPS and CES requirements while selecting a combination of CTs and storage to meet RA needs. On average, CTs are selected more frequently than storage, indicating a slight economic preference for CTs. CC, CC+CCS, and nuclear resources are not yet available for selection. VPP resources continue to play only a limited role.

2033-2035:

The CES becomes a significant driver as the 80% clean energy requirement approaches in 2035. Because CC+CCS becomes available in 2033 and qualifies as a clean resource, Aurora generally selects two units across portfolios and scenarios, reflecting both CES compliance needs and available tax incentives. Wind and solar additions continue to be driven by the 60% RPS requirement in 2035. Remaining capacity needs are generally met with incremental storage. Conventional CC resources are selected only under higher-load conditions, and VPP selections remain limited.

2036-2040:

Resource selections are primarily driven by achieving the 100% CES requirement in 2040. When available CC+CCS opportunities have already been utilized, Aurora relies increasingly on wind, solar, and, in certain circumstances, nuclear resources to satisfy clean energy requirements. Solar additions generally exceed wind due to more favorable economics. Storage is added to address remaining capacity needs. CTs and conventional CCs are generally not selected until larger capacity requirements emerge near 2040 following resource retirements and contract expirations.

2041-2046:

This period is generally characterized by resource stability, with no major changes in clean energy, renewable, or capacity requirements. As a result, resource selections remain relatively consistent with prior years.

2047-2050:

Capacity needs become the primary driver as tax credits expire, contracts terminate, and some earlier renewable resources reach retirement. Aurora responds by selecting a

combination of storage, CTs, and, for the first time, meaningful quantities of conventional CC resources. CC+CCS and nuclear resources are generally not selected during this period. VPP resources continue to provide only limited contributions due to economics.

Overall, the results demonstrate that resource selections are driven primarily by compliance with RPS, CES, and RA requirements, with Aurora consistently selecting the lowest-cost resources available to satisfy those constraints under each scenario, sensitivity, and portfolio design.

Section XI. PROPOSED COURSE OF ACTION

Q. How did the Company use the Phase 1 modeling results to develop the Phase 2 portfolios, ultimately finalizing its plan as the PCA?

A. As discussed previously throughout my testimony, the PCA was developed through a two-phase process. In the previous section, I discussed the results of the Phase 1 modeling effort and the conclusions the Company drew from those results. Next, the Company translated those directional insights into executable portfolios, which is discussed in detail in the testimony of Company witness McLean. In this section, I will discuss how the PCA, Alternate Plans, and Support Plans were evaluated.

Q. Can you please summarize the Phase 1 model learnings that impacted the PCA development?

A. The Phase 1 model learnings that impacted the PCA development were:

- Renewable build out is primarily driven by the RPS and CES requirements;
- Compliance with the CES will require large amounts of renewables and/or development and construction of CCS technology;
- [CONFIDENTIAL] [redacted] [END CONFIDENTIAL];

- Near-term resource adequacy needs driven by MISO's DLOL methodology and retirement of Karn Units 3 and 4 result in economic selection of the MCV PPA in 2030, battery storage (1,000 MW in each of 2029 and 2030), and natural gas CTs in 2031;
- Incremental load from the base case levels can be reliably supplied; and
- DR is selected and will remain an important portfolio resource; incremental VPPs can play a complimentary role in the PCA, but at relatively minimal amounts.

Taken together, these model learnings provided the planning foundation for Phase 2. The Company used the recurring resource needs and timing identified through the Phase 1 scenario and sensitivity analyses as directional guidance, then incorporated updated project-specific costs, commercially available resource opportunities, execution considerations, reliability and risk information, and other material assumption updates to develop the executable portfolios evaluated in Phase 2. Those portfolios, which are discussed next, translate the broader planning insights from the initial modeling into specific combinations of resources capable of implementation.

Q. What is the purpose of evaluation of the PCA portfolio in modeling?

A. The purpose of the PCA is to provide detailed model outcomes of the Company's updated and executable portfolios described previously in my testimony. The key components of the PCA are as follows:

1. Approximately 1.5 GW of load growth;[14]
2. Approximately 1,400 MW of natural gas CT capacity;
3. [CONFIDENTIAL] [redacted] [END CONFIDENTIAL];
4. Approximately 1,240 MW of natural gas CC capacity via a PPA with MCV;

[14] The PCA's load growth represents 1.5 GW higher load than current load levels that are planned and operational today, which include increased load due to manufacturing growth and EV consumption.

5. Nearly 700 MW of VPP, growing to over 1,400 MW within the study period;
6. Continued renewable expansion, achieving over 17,000 MW of total solar and wind capacity by 2040;
7. Over 5,000 MW of total storage capacity by 2040; and
8. [CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

The PCA was designated as portfolio design 99 in my exhibits. The full portfolio buildout is presented in Confidential Exhibit A-25 (AJM-11), page 1. This exhibit presents the installed capacity amounts, by year.

Q. What is the purpose of evaluation of the Alternate Plan Current portfolio in modeling?

A. The purpose of the Alternate Plan Current was two-fold: (i) it identifies the build plan the Company would pursue to serve only existing and contracted load (excluding large loads), and (ii) in comparison to Support Plan 1, described next, the Alternate Plan Current portfolio demonstrates changes to the portfolio once a [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] to serve existing and contracted load (excluding large loads) was added. The key components of the Alternate Plan Current are as follows:

1. BAU Current load;
2. Approximately 1,400 MW of natural gas CT capacity;
3. [CONFIDENTIAL] [redacted] [END CONFIDENTIAL];
4. Approximately 1,240 MW of natural gas CC capacity via a PPA with MCV;
5. Nearly 700 MW of VPP, growing to over 1,400 MW within the study period;
6. Continued renewable expansion, achieving over 13,000 MW of total solar and wind capacity by 2040;
7. Over 3,400 MW of total storage capacity by 2040; and

8. [CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Alternate Plan Current was designated as portfolio design 98 in my exhibits. The full portfolio buildout is presented in Confidential Exhibit A-25 (AJM-11), page 3. This exhibit presents the installed capacity amounts, by year.

Q. What is the purpose of evaluation of the Support Plan 1c portfolio in modeling?

A. The purpose of Support Plan 1c is to evaluate the portfolio cost impact of updated information regarding the Karn and Thetford CTs that became available shortly before the filing of this case. In particular, the updated CT cost information reflected increases relative to the lower range of costs previously evaluated. Support Plans 1, included on page 8 of Exhibit A-23 (AJM-9), includes three related portfolio evaluations (1a, 1b, and 1c) designed to isolate the effect of the updated CT costs and the economic value of including both CTs. The conclusion of these Support plans was addressed in Section X of my testimony, under the "Economic Results" discussion.

Key components of Support Plan 1c are as follows:

1. BAU Current load;
2. Approximately 1,400 MW of natural gas CT capacity;
3. Approximately 1,240 MW of natural gas CC capacity via a PPA with MCV;
4. Nearly 700 MW of VPP, growing to over 1,400 MW within the study period;
5. Continued renewable expansion, achieving over 11,500 MW of total solar and wind capacity by 2040;
6. Over 3,300 MW of total storage capacity by 2040; and
7. Approximately 1,200 MW of CC with CCS by 2035 and another 1,200 MW in 2040.

Support Plan 1c has an additional purpose within this IRP as it represents what the 2021 IRP would look like, re-optimized under current conditions and state, federal, and regional

policies. This portfolio represents existing load (prior to large load additions) but now solves to resource adequacy and renewable and clean energy requirements applicable today.

Support Plan 1c was designated as portfolio design 97 in my exhibits. The full portfolio buildout is presented in Confidential Exhibit A-25 (AJM-11), page 4. This exhibit presents the installed capacity amounts, by year.

Q. What is the purpose of Alternate Plan Growth?

A. The purpose of Alternate Plan Growth is to determine the optimized build plan for a future with higher amounts of large load growth beyond PCA load levels. This plan assumes an incremental economic development load of 700 MW above what is assumed in the PCA (portfolio design 99) or 2.2 GW above Current load levels.

The key components of Alternate Plan Growth include:

1. Approximately 2.2 GW of load growth;[15]
2. Approximately 1,400 MW of natural gas CT capacity;
3. [CONFIDENTIAL] [redacted] [END CONFIDENTIAL];
4. Approximately 1,240 MW of natural gas CC capacity via a PPA with MCV;
5. Nearly 700 MW of VPP, growing to over 1,400 MW within the study period;
6. Continued renewable expansion, achieving over 16,000 MW of total solar and wind capacity by 2040;
7. 6,000 MW of total storage capacity by 2040; and
8. Approximately 1,200 MW of CC with CCS by 2035 and another 1,200 MW in 2040.

[15] The Alternate Plan Growth load growth represents 2.2 GW higher load than current load levels that are planned and operational today, which include increased load due to manufacturing growth and EV consumption.

Alternate Plan Growth was designated as portfolio design 96 in my exhibits. The full portfolio buildout is presented in Confidential Exhibit A-25 (AJM-11), page 2. This exhibit presents the installed capacity amounts, by year.

Q. What are the NPV economic results of the Phase 2 portfolios?

A. The NPV results are presented in Exhibit A-23 (AJM-9) on pages 5-8:

Phase 2

- Page 5 of Exhibit A-23 (AJM-9) provides NPV cost results of the PCA.
- Page 6 of Exhibit A-23 (AJM-9) provides NPV cost results of the Alternate Plan Current.
- Page 7 of Exhibit A-23 (AJM-9) provides NPV cost results of the Alternate Plan Growth.
- Page 8 of Exhibit A-23 (AJM-9) provides NPV cost results of the Support Plans.

Q. Please discuss conclusions of the NPV cost results for Phase 2 and the extent to which they inform the projects for which the Company is seeking approval of a Certificate of Necessity ("CON").

A. Economic observations of resources requested through a CON, as well as Phase 2 modeling results in Exhibit A-23 (AJM-9), are as follows:

- Across nearly every scenario and sensitivity evaluated during Phase 1, portfolio design 3, which includes **the new PPA with MCV** beginning in 2030, is shown to be more beneficial compared to portfolio design 1 or 4, in which the new MCV PPA is not included. This is demonstrated by comparing column (e) to columns (d) and (f) on pages 1 through 4. A lower NPV is a lower-cost portfolio for customers.
- The economic benefits of the **natural gas CTs to serve Current load levels** are supported through Support Plans 1a, 1b, and 1c presented on page 8 of this exhibit.
    - Support Plan 1a is an open optimization using the lower range of CT costs discussed in the direct testimony of Company witness Clark. In that

evaluation, Aurora economically selects both the Karn and Thetford CTs, totaling approximately 1,400 MW.

- Support Plan 1b is an open optimization using an upper range of CT costs provided by Mr. Clark. In that evaluation, Aurora economically selects the Karn CT but does not select the Thetford CT.

- Support Plan 1c uses the same upper range of CT costs as Support Plan 1b but forces in both the Karn and Thetford CTs.

Comparing these three evaluations allows the Company to determine how the updated CT costs affect Aurora's resource selections and the overall economics of the portfolio. Comparing the portfolio NPV of Support Plans 1b and 1c isolates the incremental economic effect of including both CTs under the upper-cost assumption. Although Support Plan 1c includes more CT capacity than the open optimization in Support Plan 1b, Support Plan 1c is a lower-cost portfolio with the modeled value of surplus capacity revenues. This final calculation occurs outside of the Aurora model simulation (post-processing), so as not to unfairly bias the model to overbuild the portfolio, discussed in Section IV of my direct testimony. This tells us that although the model does not economically *select* both CTs, to meet Current load levels, including both results in lower costs for customers, as it provides increased flexibility within the portfolio.

- [CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Q. Are there any additional ways in which you have summarized results of the PCA?

A. Yes, the final results I will present highlight how the PCA will reliably serve customer demand and meet its seasonal RA obligations throughout the planning period.

Confidential Exhibit A-26 (AJM-12) is a graphical summary of how the PCA will comply with RA requirements. This exhibit presents 116 pages that includes the PCA, Alternate Plans, and the MSO and required BAU sensitivities' optimal portfolios. Each graph shows the total capacity by resource type compared to PRMR for a season. Each sensitivity or portfolio includes four capacity graphs, one for each season of the PY. This exhibit demonstrates that the PCA has successfully limited the overbuilds observed in many of the Aurora optimally-selected portfolios through its approach to a balanced and diverse portfolio.

Confidential Exhibit A-27 (AJM-13) is a graphical summary of how the PCA will serve customer demand in each year of the study period. This exhibit has 29 pages that include the PCA, Alternate Plans, as well the MSO and required BAU sensitivities' optimal portfolios. Each graph shows the total generation by fuel type compared to the demand total net of EWR.

Section XII. CAPITAL, O&M, AND FUEL COST SUMMARY

Q. What is the next topic you will discuss in your testimony?

A. The next set of data I will discuss and present is in support of the testimony sponsored by Company witness Myers for rate impact analysis.

Q. What are the capital and O&M costs associated with the PCA used in the rate impact analysis?

A. The capital and O&M costs associated with the PCA are summarized in Confidential Exhibit A-29 (AJM-15). This exhibit provides capital, O&M, and fuel and purchased power costs for the PCA and Alternate Plans.

Q. What are the fuel cost projections provided in support of this IRP?

A. Projected natural gas and oil fossil fuel costs for existing owned generating assets are provided in Exhibit A-30 (AJM-16). A summary of the fuel costs projected has been provided for each scenario, and for each of the following portfolios: (i) Aurora-selected optimal plans for all four scenarios; (ii) PCA; (iii) Alternate Plan Growth; (iv) Alternate Plan Current; and (v) high gas price, where applicable.

Projected fuel costs for the new-build natural gas units, as well as information related to the new PPAs with MCV and the [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] can be found in Confidential Exhibit A-28 (AJM-14), with the costs taken from the BAU PCA portfolio. Confidential Exhibit A-28 (AJM-14) consists of 5 pages. Pages 1 and 2 contain the new MCV PPA contract and pricing data, respectively. Similarly, pages 3 and 4 contain the [CONFIDENTIAL] [redacted] [END CONFIDENTIAL] contract and pricing data, respectively. Page 5 consists of the projected operations of the four units, including sections for the following;

- Projected generation on lines 1 through 4;
- Projected hours of operation on lines 5 through 8;
- Projected capacity factors on lines 9 through 12;
- Projected annual average net costs on lines 13 through 16;
- Projected delivered fuel costs on lines 17 through 20; and
- Projected startups per year on lines 21 through 24.

Section XIII. RESOURCE ALTERNATIVES ANALYSIS

Q. Regarding the Company's requested approval of four CONs in its filing, did the Company consider alternative technologies capable of meeting the needs addressed by the proposed resources?

A. Yes, the modeling presented in my direct testimony, as well as the supporting exhibits and testimony of other Company witnesses in this proceeding, reflect both quantitative and qualitative analyses demonstrating that the proposed resources represent the most reasonable and prudent options for meeting the Company's energy, capacity, renewable, and clean energy requirements and objectives.

Q. Please discuss the specific alternative technologies you evaluated, in modeling, for each of the resources included in the Company's CON filing.

A. The Company evaluated a range of alternative technologies as part of its planning process. Each alternative was assessed based on cost, reliability, timing, environmental performance, and operational characteristics. Other alternatives considered, but eventually eliminated from final selection are summarized below.

Natural Gas Combined Cycle (CC):

The Company evaluated unabated new natural gas CC generation; however, this option was not selected primarily due to timing constraints, as well as the desire to avoid high capacity factor generation that does not provide clean energy. The earliest feasible in-service date (2033) would not align with the Company's near-term capacity needs (2029-2031) largely caused by the planned retirements of Karn Units 3 and 4 and the expiration of the MCV contract.

Combined Cycle with Carbon Capture (CC + CCS):

The Company evaluated CC generation with CCS, since this option was widely selected during Phase 1 of modeling. However, this technology was not included in the PCA due to both timing and technological considerations discussed in the testimony of Company witness Clark. The earliest projected commercial availability would not address near-term capacity shortfalls; and given the relatively early stage of commercial deployment, [CONFIDENTIAL] [redacted] [END CONFIDENTIAL], the Company has determined it is prudent to allow further technological maturation before pursuing large-scale implementation. Furthermore, Mr. Clark discusses site-specific considerations that limit feasibility, as certain Company-owned locations are not well-suited for CCS infrastructure. That said, the Company continues to evaluate CCS as part of its longer-term resource planning strategy.

Battery Energy Storage Systems (BESS):

Battery storage plays an important role in the Company's portfolio, with over 5,000 MW of capacity by 2040. However, Battery Energy Store Systems ("BESS") alone cannot meet the identified reliability and energy needs, as demonstrated in the testimony and exhibits of Company witness Soni. BESS does not provide firm, dispatchable capacity independent of charging resources and therefore cannot fully address reliability requirements. A battery-storage-only portfolio presented by Company witness Soni fails reliability metrics. Further, accreditation risks associated with storage resources put RA compliance at risk. The Company's modeling, presented by Company witness Soni, indicates that the system faces potential *energy* shortfalls, not solely capacity shortfalls, further limiting the

effectiveness of BESS as a standalone solution. The Company is already projected to far exceed state-mandated storage targets, and incremental additions would not adequately address the identified needs.

Market Purchases and Zonal Resource Credits (ZRCs):

The Company evaluated reliance on market purchases, including ZRCs, to meet capacity needs. However, these options were determined to be insufficient and unreliable. Competitive solicitations have demonstrated limited market availability, often in relatively small volumes, coupled with high and volatile prices. Company witness Skowronski presents details regarding capacity solicitations. Additionally, increasing load growth and large-scale procurements by other entities are reducing surplus capacity availability. Given the magnitude of the Company's forecasted shortfall, reliance on market purchases would introduce significant risk to both reliability and affordability.

New Build Nuclear:

The Company considered new nuclear generation but determined it to be infeasible due to prohibitively long development timelines. New-nuclear resources were not economically selected in any BAU planning scenarios.

Additional Wind, Solar, and VPPs

Additional Wind, Solar, and VPPs were offered for selection into the model. In the case of VPPs, significant DR is included in the PCA; some options were cost-prohibited and not economically selected in modeling. Others, like distributed generation, have the potential to reduce customer costs. The Company is currently evaluating expansion of DG through its solicitation process, which would reduce utility-scale solar and storage builds; however, significant amounts of DG were not included in the PCA, as the Company has no control

over customer adoption. In the case of wind and solar, additional amounts were not available, since the PCA generally maximizes selection of these resources for RPS and CES compliance.

Q. How is the proposed MCV PPA supported by the Company's modeling?

A. The proposed MCV PPA is supported by the Company's modeling in several ways.

First, the Company's capacity-position analysis identifies a need for additional seasonal capacity beginning in planning year 2029 and persisting for several years. The proposed MCV agreement would provide approximately 1,059 ZRCs of seasonal accredited capacity, based on the assumptions summarized in Confidential Exhibit A-28 (AJM-14).

Second, the Company tested economics of the MCV PPA under the Phase 1 modeling in all BAU, ALG, and PCC scenarios and across 17 sensitivities as part of Portfolio Design 1 and 3. The agreement remains economically beneficial across all 51 comparisons, as is presented in Exhibit A-23 (AJM-9).

Third, the Company evaluated the MCV PPA, requiring it to compete for selection in Aurora. In open optimizations, Aurora economically selected the MCV PPA, relative to other alternative resources. Aurora selected the PPA in all open optimizations evaluated. This modeling demonstrates that MCV can economically supply energy and seasonal capacity better than any combination of market purchases, solar, wind, storage, CTs, VPPs, or other alternatives presented in Section VII and Section VIII.

Based on the combined capacity expansion, production cost, and alternative resources, the proposed MCV PPA is an optimal resource to include in the PCA as a means of meeting the Company's identified needs.

Q. How is the proposed [CONFIDENTIAL] [redacted]

[redacted] [END CONFIDENTIAL].

Q. How is the proposed Karn CT supported by the Company's modeling?

A. The proposed Karn CT is supported by the Company's modeling as a means of addressing an identified need for seasonal accredited capacity and dispatchable generation capability beginning in PY 2031.

The Company's seasonal capacity-position analysis identifies a shortfall of approximately 200 – 700 ZRCs in summer, fall, and spring by 2028 and increasing to 2,900 – 3,800 ZRCs in all four seasons by 2031, after accounting for existing resources, contracted resources, demand-side resources, retirements, and the applicable DLOL accreditation assumptions. That need is shown in Figure 1. Phase 1 of the modeling analysis presented in Section X of my testimony indicated the model's affinity for selection of CT resources.

The specifics of the Karn CT were represented in Phase 2 of Aurora modeling using assumptions of their capital cost, seasonal capability, DLOL accreditation, heat rate, fuel price, variable operating cost, forced outages, facility derates, expected commercial-operation date, and other applicable operating characteristics. The turbines were modeled as selectable candidate resources, as well as specified resources, in the PCA-support portfolios. Across all modeling in Phase 2, the Karn CT was selected by Aurora.

The Company also evaluated alternatives capable of addressing the same need by the required date, including storage, VPP resources, market capacity purchases, and renewable resources. This was done by examining portfolios that disallowed the selection of CTs and is discussed in the testimony of Company witness Soni. Some alternatives contributed toward the need but did not provide an equivalent quantity of seasonal accredited capacity because of declining accreditation combined with availability limitations. Other alternatives were more costly, unavailable in the required timeframe, or insufficient to resolve the full need.

The Karn turbines are expected to operate at a low annual capacity factor, as presented in Confidential Exhibit A-28 (AJM-14) and primarily provide capacity and energy during a combination high-load, low-renewable-output, market scarcity, or other stressed conditions. Their modeled value therefore does not depend on high annual energy production. Rather, their principal purpose is to provide seasonal accredited capacity, dispatchable energy, and electric reliability when economically or operationally needed.

Company witness Soni separately evaluated portfolios with and without the Karn turbines. That analysis demonstrates that the Karn turbines improve reliability during identified hours or event types. The reliability analysis also considers that the turbines remain subject to forced outages, derates, fuel availability, and other operating risks.

My testimony provides the results that demonstrate that capacity resources are needed, there is a balanced selection of storage and CTs, and Karn is an economically selected resource to meet the Company's needs. Based on the modeled need, comparison with alternatives, economic results, implementation timing, and reliability contribution, the proposed Karn CTs are an optimal resource for inclusion in the PCA.

Q. What impact do the Karn CTs have on the wholesale markets?

A. The Karn CTs will bring approximately 389 ZRCs into the MISO capacity market and will conceptually put slight downward pressure on capacity pricing. The impact on the energy market will be a slight lowering of market prices as the Karn CTs will be coming online as the Karn 3 and 4 oil and gas fired units retire. This replaces a high-cost peaking unit with a lower cost peaking unit, which brings more low cost energy into the market.

Q. How are the proposed Thetford CTs supported by the Company's modeling?

A. The proposed Thetford combustion turbines are supported by the Company's modeling as a means of addressing an identified need for seasonal accredited capacity and dispatchable generation capability beginning in PY 2031.

The Company's seasonal capacity-position analysis identifies a shortfall of approximately 200 – 700 ZRCs in summer, fall, and spring by 2028 and increasing to 2,900 – 3,800 ZRCs in all four seasons by 2031, after accounting for existing resources, contracted resources, demand-side resources, retirements, and the applicable DLOL accreditation assumptions. That need is shown in Figure 1. Phase 1 of the modeling analysis presented in Section X of my testimony indicated the model's affinity for selection of CT resources.

The specifics of the Thetford CTs were represented in Phase 2 of Aurora modeling using assumptions concerning their capital cost, seasonal capability, DLOL accreditation, heat rate, fuel price, variable operating cost, forced outages, facility derates, expected commercial-operation date, and other applicable operating characteristics. The turbines were modeled as selectable candidate resources, as well as specified resources, in the PCA-support portfolios. In Phase 2, the Thetford CTs were economically selected by Aurora at

the lower-range of cost estimates discussed in the direct testimony of Company witness Clark.

The Company also evaluated alternatives capable of addressing the same need by the required date, including storage, VPP resources, market capacity purchases, and renewable resources. This was done by examining portfolios that disallowed the selection of CTs and is discussed in the testimony of Company witness Soni. Some alternatives contributed toward the need but did not provide an equivalent quantity of seasonal accredited capacity because of declining accreditation combined with availability limitations. Other alternatives were more costly, unavailable in the required timeframe, or insufficient to resolve the full need.

The Thetford turbines are expected to operate at a low annual capacity factor, as presented in Confidential Exhibit A-28 (AJM-14), and primarily provide capacity and energy during a combination of high-load, low-renewable-output, market scarcity, or other stressed conditions. Their modeled value therefore does not depend on high annual energy production. Rather, their principal purpose is to provide seasonal accredited capacity, dispatchable energy, and electric reliability when economically or operationally needed.

Company witness Soni separately evaluated portfolios with and without the Thetford turbines. That analysis demonstrates that the Thetford turbines improve reliability during identified hours or event types. The reliability analysis also considers that the turbines remain subject to forced outages, derates, fuel availability, and other operating risks.

My testimony provides the results that demonstrate that capacity resources are needed, there is a balanced selection of storage and CTs, and Thetford is an economically

selected resource to meet the Company's needs. Based on the modeled need, comparison with alternatives, economic results, implementation timing, and reliability contribution, the proposed Thetford CTs are optimal resources for inclusion in the PCA.

Q. What impact do the Thetford CTs have on the wholesale markets?

A. The Thetford combustion turbines will bring approximately 783 ZRCs into the MISO capacity market and will conceptually put slight downward pressure on capacity pricing. The impact on the energy market will be a slight lowering of market prices as the Thetford combustion turbines will be coming online as Karn Units 3 and 4 retire. This replaces high-cost peaking resources with lower-cost peaking units, which brings more low-cost energy into the market.

Q. Was any modeling done to explicitly identify what the Aurora model would select in lieu of each of the four resources requested in the CON?

A. Yes. This is shown in Confidential Exhibit A-33 (AJM-19). For each resource, a separate portfolio design was created that disallowed selection of each resource in question, in turn. A summary of the NPV impact and replacement resources can be found in Confidential Exhibit A-33 (AJM-19). Page 1, column (e) details the NPV impact resulting from the removal of each resource, in turn, as well as the PCA (portfolio design 99). Column (f) provides the incremental cost delta back to the PCA. Positive values in column (f) indicate customer costs would increase if the resource was not included in the PCA. Page 2 of Confidential Exhibit A-33 (AJM-19) shows the impact to the PCA build plan by removing each of the above resources.

For these portfolio designs presented in this exhibit, it is important to note that these are not intended to be executable portfolio options or alternate plans. The reliability,

emissions, and rates analyses have not been evaluated. This analysis is simply intended to show the capacity expansion modeling alternative to the CON resource to demonstrate what the model would select and to quantify the NPV cost impact. If the reliability analyses were completed, it is possible additional resources would be necessary to meet reliability metrics, which would subsequently affect the emissions and rates analyses.

Q. What do you conclude from the evaluations presented in Confidential Exhibit A-33 (AJM-19)?

A. I conclude that the MCV PPA, the Karn CT, and the Thetford CT provide lower-cost options for customers than the available alternatives. As discussed previously in my testimony, [CONFIDENTIAL] [redacted] [END CONFIDENTIAL].

Q. Does this complete your direct testimony?

A. Yes.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 196

MISO ERAS Cycle 5 Release

MISO accelerates new generation and storage projects with fifth ERAS cycle

7.3 GW of proposed capacity will strengthen reliability and meet growing demand

For Immediate Release

September 8, 2026

Media Contact

McKenzie Barbknecht

CARMEL, Ind. — MISO is accelerating its efforts to help bring new generation online quickly with the fifth cycle of projects to be evaluated under the Expedited Resource Addition Study (ERAS) process. These projects will reinforce reliability and support economic growth across the region.

This cycle includes 15 proposed projects totaling approximately 7.3 gigawatts (GW) of new capacity. The portfolio spans MISO's North, Central and South regions and includes a mix of natural gas, solar, wind and battery storage resources that are expected to be in service by 2029.

"The MISO region is undergoing rapid change, with electricity demand rising at a historic rate," said Aubrey Johnson, MISO's Vice President of System Planning and Competitive Transmission. "Each ERAS cycle is helping us to bring reliability critical generation online faster while we work toward long-term improvements in the interconnection process."

The fifth study cycle will include the following ERAS projects:

- Bayou Point Combined Cycle (NextEra Energy Capital Holdings) – 750 megawatts (MW) of new gas generation in Louisiana

- Calcasieu Parish Combined Cycle (Entergy Louisiana) – 767.7 MW of new gas generation in Louisiana
- Crosley Energy Storage (NextEra Energy Capital Holdings) – 400 MW of new battery storage in Indiana
- DOUBLEC Energy Center (DOUBLEC Energy Center LLC) – 400 MW of new solar generation and 400 MW of new battery storage in Arkansas
- Little Rock Wind Project (Little Rock Wind Project LLC) – 300 MW of new wind generation in Minnesota
- Malden Battery Energy Storage System (NIPSCO) – 600 MW of new battery storage in Indiana
- Merom Energy Storage (NextEra Energy Capital Holdings) – 500 MW of new battery storage in Indiana
- Point Coupee Combined Cycle (Entergy Louisiana) – 377 MW of new gas generation in Louisiana
- Rapides Parish Combined Cycle (Cleco Power) – 756 MW of new gas generation in Louisiana
- Sandcut Energy Storage (NextEra Energy Capital Holdings) – 350 MW of new battery storage in Indiana
- Steamboat Energy Storage (NextEra Energy Capital Holdings) – 500 MW of new battery storage in Louisiana
- Sullivan County Combined Cycle (Maple Creek Energy) – 641.8 MW of new natural gas generation in Indiana
- Tradewater Energy Storage (NextEra Energy Capital Holdings) – 155 MW of new battery storage in Kentucky
- Trotman Energy Center (Trotman Energy Center LLC) – 400 MW of new gas generation in Indiana

Since the launch of the ERAS program, 58 projects representing nearly 29 GW of proposed capacity have been or will be studied. Of these, 38 projects representing approximately 18 GW of proposed capacity have advanced to completed generator interconnection agreements, with an additional 5 projects representing approximately 3 GW of proposed capacity nearing completion. The program is capped at 68 projects and will sunset in 2027.

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About MISO

Midcontinent Independent System Operator (MISO) is an independent, not-for-profit organization that delivers safe, cost-effective electric power across 15 U.S. states and the Canadian province of Manitoba. 45 million people depend on MISO to generate and transmit the right amount of electricity every minute of every day. MISO is committed to reliable, nondiscriminatory operation of the bulk power transmission system and collaborating with all stakeholders to create cost-effective and

innovative solutions for our changing industry. MISO operates one of the world's largest energy markets with more than $53 billion in annual gross market energy transactions.

News Release Link

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