Michigan Choice
Market Settlement
Policies & Procedures

Revised 11/2018

Contents

I&M Glossary of Settlement Acronyms

Source of acronyms are noted in parenthesis. Those not noted are considered standard industry terms.

AEPCH	AEP Clearing House (AEP)
AES	Alternative Electric Supplier (Michigan Choice Market)
CP	Coincident Peak
CSP	Curtailment Service Provider
DOPLSR	Daily Obligation Peak Load Scaling Factor (PJM)
DR	Demand Response
DZF	Daily Zonal Scaling Factor (PJM)
EDC	Electric Distribution Company
EDI	Electronic Data Interchange
EDU	Electric Distribution Utility
FSL	Firm Service Load
FPR	Forecast Pool Requirement (PJM)
FRR	Fixed Resource Requirement
FZSF	Final Zonal Scaling Factor (PJM)
LRA	Load Research and Analysis (AEP)
LMP	Locational Marginal Price (PJM)
LASOR	Load Accounting System of Record (AEP)
LDC	Local Distribution Company
LERS	Load Estimation and Reallocation System (AEP)
LSE	Load Serving Entity (PJM)
MACSS	Marketing Accounting and Customer Services System (AEP)
MV90	Multi-Vendor Version 90 (Interval meter interrogation software by Itron)
NITS	Network Integration Transmission Services (PJM)
NSPL	Network Service Peak Load (PJM)
PLC	Peak Load Contribution (PJM)

RPM	Reliability Pricing Model (PJM)
RTO	Regional Transmission Organization
SAS	Statistical Analysis System (business analytics software tool)
SDI	Service Delivery Identifier (I&M)
SOX	Sarbanes-Oxley
UFE	Unaccounted For Energy
WNF	Weather Normalization Factor (PJM)

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Overview of the AES market settlement process at I&M

Overview In the I&M Michigan Choice market Alternative Electric Suppliers (AES) are responsible for the purchase of energy, transmission and transmission ancillary charges related to serving their allotment of customers. Similarly, as the Electric Distribution Utility, I&M is responsible for billing of distribution wires charges to end-use customers, and as an FRR entity, within wires rates recovery of capacity costs to serve all customers, including shopping customers. As an Electric Distribution Company (EDC) operating within PJM, I&M provides daily allotment values to PJM for AES participating in the Choice market in Michigan for the purpose of settlement. Allotment values sent to PJM for market settlement are daily energy forecasts, daily transmission NSPL values, and final 60 day (Settlement B) true-up energy values after meter readings are received.

Though capacity is not a responsibility of the AES in the I&M Michigan market, and the shopping queue is based upon annual kWh usage (not capacity), capacity tag (Peak Load Contributions or PLC) values are calculated and made available to the AES. Processes used by I&M for the calculation of PLC values are shared within this document for transparency and clarity. In addition to PLC values, transmission peak values (Network Service Peak Load or NSPL) are calculated annually and made available to AES's, also documented within.

***Disclaimer**: Although I&M makes a good faith effort to document policy and procedures as comprehensively as possible within this document as a service to participating AES in the Michigan market, I&M adheres to policies, processes and* *rules established by PJM and the State of Michigan supporting the Michigan Choice Market. It is ultimately the responsibility of participating AES in the Michigan Choice market, and as a Load Serving Entity (LSE) in PJM to understand those rules as they apply, and as changes may occur that may not be reflected in this document.*

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I&M Capacity Tag Calculation Process

Overview

Individual Service Delivery Identifier (SDI) capacity tags (also referred to as PLC tags) are calculated annually for each SDI in the I&M territory based upon the five PJM Peak date/times (PLC hours) published by PJM. For SDIs which are interval metered, the actual hourly usage at those five hours is averaged to determine the at-the-meter PLC component. For non-interval metered customers, their at-the-meter PLC component is calculated using load profile customer class load shapes.

Load Profiling Cumulative Metered SDIs

For SDIs which are not interval metered only total usage and maximum demand over the billing cycle may be known, so the at-the-meter usage at the five PLC hours must be estimated. This estimation is accomplished by performing a load profiling process. In the load profiling process, each SDI is assigned a load_profile_id defining the load characteristic group to which it belongs. Each load_ profile_id has an associated hourly load profile, normally computed from actual interval metered usage of randomly selected sample customers within each profile_id group. The PLC tag calculation algorithm then utilizes the individual SDI monthly billing cycle usage spanning each PLC date/time to scale the hourly profile usage over that time to the appropriate level for the SDI, thus providing a reasonable representation of the hourly usage of each SDI. Once that is accomplished for all hours throughout the billing cycle periods spanning the five PLC date/times, the resulting hourly usage estimates at the five PLC hours are averaged to determine the at-the meter PLC component.

PJM Demand Response Add-Backs

If a customer has a PJM interruptible component to their load and was interrupted as a result of the program on one or more of the PLC hours, the best estimate of the amount of load interrupted is added back to the interval data to provide the best estimate of normal uninterrupted PLC values. Add backs are only calculated for customers that participate in a PJM program, and curtail during one of the five PLC hours. Customers that participate in other non-PJM Curtailment Service Provider demand response programs, I&M system emergency curtailments, or intentionally curtail on their own for operational reasons are not included in the add-back process.

For example, if ‘ABC’ customer has an estimated base-line load of 110 MW during the PJM peak hour, with a firm service level of 10 MW, and curtails pursuant to a PJM program event to 10 MW, I&M would report 110 MW if the hour were one of PJM’s 5CP hours. However, if under the same scenario, the company curtails on their own, curtails in response to an I&M system emergency, or curtails under a non-PJM program, I&M would report 10 MW if the hour were one of PJM’s 5CP hours.

Disclaimer*: Although I&M makes a good faith effort to document policy and procedures as comprehensively as possible within this document, there may be unforeseen SDI-level special circumstances that arise and are evaluated on a case-by-case basis that could result in the requirement of an add-back, including but not limited to power outages, metering errors or changes in PJM policy.*

Net Metered Customers Customers on a net-metered tariff receive benefit from their generation in the PLC tag calculation process. For net-metered customers with hourly interval metering, any generation they may have had at the time of the PLC peak hours offsets their load (up to zero) for those hours. For non-hourly metered cumulative usage customers, their generation for each month is deducted from their usage, which decreases their cumulative usage at-the-meter amounts for the month. The reduced cumulative usage then follows the Load Profile process above.

Loss Adjustment to At-The-Meter Values All at-the-meter values are then loss adjusted to the generation level based upon loss factors as filed in the Company tariffs. A check is performed to ensure that the sum of all loss adjusted SDI tags compares closely to the interruption adjusted I&M system load at the 5 CP hours providing evidence that the capacity tags in total reasonably represent the system total load.

Completion and Availability to Market Participants The individual SDI capacity tags are then made available to AES suppliers via the Business Partner Portal and customer enrollment list, and sent via EDI transactions to the customer's assigned AES. Capacity tags become effective June 1st of every year and the Business Partner Portal will show effective dates where multiple year tags are available. Tags remain unchanged until the next PJM year calculation is performed, even though some SDIs may experience significant load growth or load reduction in the period between the five hours on which the tag is based and the load days to which it is applied.

New Premise Installs During the Year

There are normally a limited number of new SDIs that were either not active during the five PJM PLC hours, or are installed during the year, and which therefore had no interval usage or monthly billing usage for that period. Those SDIs are assigned a default PLC tag, based upon the profile group average value. In the rare instance when new facilities are built for an existing premise resulting in an additional SDI, but with no expected net load change at the combined facilities, the new SDI will receive a tag equivalent to the estimated portion of load delivered through the new service point, rather than a class average. The tag for the original SDI will be accordingly adjusted downward so that the combined capacity tags will match the original load. New SDIs with behind-the-meter generation or on a net-metered tariff will be assigned a default PLC.

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<u>Example</u> of Calculation

		Capacity Calculation and Settlement Steps	Value
Calculate Variables	pjm	Each year PJM Identifies the Five Coincident (5CP) Summer Peaks	
		PJM Identifies the EDU Zone Weather Normalized Coincident Peak (e.g. 2016 Peak year)	21,940
	I&M	I&M periodically performs system loss studies, updating transmission and distribution losses for applicable tariffs	Secondary - 1.09529 Primary - 1.06496 Sub-Tran - 1.0341
Calculate Yearly Customer PLCs		I&M identifies and averages the 5CP at-the-meter hourly loads for 'XYZ' customer (customers without hourly metering are profiled using sample customer hourly data)	90 MW
		Where necessary, I&M calculates "add-backs" for customers that participated in a PJM demand response event during one or more of the 5CP hours.	100 MW
		I&M applies transmission and distribution losses to the metered 5CP values to arrive at 'XYZ' Customer' PLC. (e.g. a Sub-Tran customer value of 1.0341)	103.41 MW
		I&M publishes PLC values via EDI, the customer enrollment list, and the Business Partner Portal	103.41 MW

**** Values are for demonstration purposes only***

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I&M AES Transmission Obligation Calculation Process

Overview

Individual Service Delivery Identifier (SDI) transmission tags (also referred to as NSPL tags) are calculated annually for each SDI in the I&M territory based upon the PJM published date and time of the PJM AEP Zonal maximum demand from the previous November 1 to October 31 year. For SDIs which are interval metered, the actual hourly usage at that hour provides the at-the-meter NSPL tag component. For non-interval metered customers, their at-the-meter NSPL component is calculated using load profile customer class load shapes.

Load Profiling Cumulative Metered SDIs

For SDIs which are not interval metered only total usage and maximum demand over the billing cycle may be known, so the at-the-meter usage at the NSPL hour must be estimated. This estimation is accomplished by performing a load profiling process. In the load profiling process, each SDI is assigned a load_profile_id defining the load characteristic group to which it belongs. Each load_ profile_id has an associated hourly load profile, computed from actual interval metered usage of randomly selected sample customers within each profile_id group. The NSPL tag calculation algorithm then utilizes the individual SDI monthly billing cycle usage spanning the NSPL date/time to scale the hourly profile usage over that time to the appropriate level for the SDI, thus providing a reasonable representation of the hourly usage of each SDI. Once that is accomplished for all hours throughout the billing cycle periods spanning the NSPL date/time, the resulting hourly usage estimates at the NSPL time determines the at-the-meter NSPL component.

Net Metered Customers

Customers on a net-metered tariff receive benefit from their generation in the NSPL tag calculation process. For net-metered customers with hourly interval metering, any generation they may have had at the time of the peak hour offsets their load (up to zero) for the hour. For non-hourly metered cumulative usage customers, their generation for each month is deducted from their usage, which decreases their cumulative usage at-the-meter amounts for the month. The reduced cumulative usage then follows the Load Profile process above.

Loss Adjustment to At-The-Meter Values

All at-the-meter values are then loss adjusted to the generation level based upon loss factors listed in the Company Tariffs. A check is performed to ensure that the sum of all loss adjusted SDI tags compares closely to the I&M system load at the NSPL peak hour providing evidence that the tags in total reasonably represent the system total load.

Completion and Availability to Market Participants

The individual SDI tags are then stored for use in the daily AES NSPL obligation calculations, made available to AES Providers via the Business Partner Portal and customer enrollment list, and sent via EDI transactions to the customer's assigned AES. NSPL tags become effective January 1st of every year and the Business Partner Portal will show effective dates where multiple year tags are available. Tags remain unchanged until the next calendar year calculation is performed, even though some SDIs may experience significant load growth or load reduction in the period between the period upon which the tag is based and the days to which it is applied.

New Premise Installs During the Year

There are normally a limited number of new SDIs that were either not active during the NSPL peak hour, or are installed during the year, and which therefore had no interval usage or monthly billing usage for that period. Those SDIs are assigned a default tag, based upon the profile group average value. In the rare instance when new facilities are built for an existing premise resulting in an additional SDI, but with no expected net load change at the combined facilities, the new SDI will receive a tag equivalent to the estimated portion of load delivered through the new service point, rather than a class average. The tag for the original SDI will be accordingly adjusted downward so that the combined transmission tags will match the original load. New SDIs with behind-the-meter generation or on a net- metered tariff will be assigned a default NSPL value.

AES NSPL Aggregation

AES daily NSPL obligations are then calculated from the summation of the tags for each of the SDIs for which the AES has responsibility on the day, with a calibration factor applied by PJM to ensure that the total I&M load is fully allocated among the I&M SDIs.

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Example of Calculation and Aggregation

		NSPL Calculation and Settlement Steps	Value
Calculate Variables	pjm	I&M periodically performs system loss studies, updating transmission and distribution losses for applicable tariffs	Secondary - 1.09529 Primary - 1.06496 Sub-Tran - 1.0341
Calculate Variables	I&M	Each year PJM Identifies the Coincident (1CP) Peak	
Calculate Yearly Customer Tags	I&M	I&M identifies the 1CP at-the-meter hour load for 'XYZ' customer (customers with-out hourly metering are profiled using sample customer hourly data)	100 MW
Calculate Yearly Customer Tags	I&M	I&M applies transmission and distribution losses to the metered 1CP value to arrive at 'XYZ' Customer's NSPL tag. (e.g. a Sub-Tran customer value of 1.0341)	103.41 MW
Calculate Yearly Customer Tags	I&M	I&M publishes NSPL values via EDI, the customer enrollment list, and the Business Partner Portal	103.41 MW
Daily Settlement	I&M	"ABC" AES' daily customer NSPL tags are aggregated	500 MW
Daily Settlement	I&M	"ABC" AES' daily NSPL obligation is submitted to PJM	500 MW
Daily Settlement	pjm	PJM applies Daily Zonal Scaling Factor	500.1 MW*
Daily Settlement	pjm	PJM uses the aggregated NSPL values to calculate appropriate Transmission Charges and Credits for the AES	$750k*
Daily Settlement	pjm	PJM posts the AES Charges and Credits to the AES' PJM sub-account.	$750k*

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I&M AES Hourly Energy Calculation Process

Overview Michigan rules place the responsibility for calculation of AES Provider load obligations for settlement on the local distribution company. Also, as I&M is in the PJM control area, compliance with PJM procedures is necessary. The PJM energy market is an hourly market with associated bids and hourly spot market prices. Each AES Provider is a Load Serving Entity (LSE) in the market for which the hourly energy obligation must be calculated, as it is not separately metered on the PJM power grid. This calculation is performed by I&M using automated systems which develop an hourly load estimate for each Service Delivery Identifier (SDI) and aggregates the hourly SDI usage to each AES for the SDIs served by the AES during each load day.

I&M's role in settlement is to provide PJM with the hourly energy supply obligation for the sum of all SDIs served for each AES. On a daily basis, I&M submits to PJM an initial settlement of each LSE’s hourly energy supply obligation from the previous day (known as the "day-after settlement" or “Settlement A”) in the I&M zone. These initial values are largely comprised of estimates based upon historical SDI usage, historical load profiles, historical weather, and forecasted weather on the load day.

After all meter reading schedules are completed for the month, I&M re-calculates each LSE's hourly energy usage for each day in the month using actual period meter readings, actual period interval data, actual period load profiles from load research samples, and net metered customer generation values. I&M then submits hourly energy differences between the initial and revised loads for each LSE to PJM through the InSchedule (formerly eSchedule) system. This true-up is known as the "60-day settlement" or "Settlement B". Data submitted to PJM is available to electricity suppliers through PJM's systems.

AES Hourly Energy Obligation Calculation

Most retail SDIs do not have meters capable of registering energy usage on an hourly basis. To enable these SDIs to participate in electric customer choice, a process known as "load profiling" is used to estimate the SDI hourly energy. At the time each bill is processed, the usage for each SDI is transferred from I&M's Customer Information System to the load estimation and reallocation system, which then disaggregates this total usage through the load profiling process. For SDIs which do have meters which register usage on an hourly basis, the actual interval usage is transferred to the market settlement system and load profiling is not necessary. The market settlement process runs for every SDI in I&M whether or not the SDI is a shopping customer.

PJM Settlement "A"

For the initial day-after settlement process, the load estimate process is performed during the load day itself, or on the last business day prior to weekends and holidays. Forecasted hourly temperatures for the days to be estimated are compared to the hourly temperatures from similar day-type days in a specified historical time period (the latest 15 months) and the load profiles from the most similar historical day are used as a proxy for the load day and applied to the current load day. For each SDI in I&M, a usage scale factor is developed which relates the load level of that SDI to the load profile load level. The estimate of that SDI's load on each hour of a load day is then computed by multiplying the load profile hourly load by the

SDI usage scale factor. For SDIs which do have an interval meter, the estimate of the hourly load is derived straight from the SDI's hourly load on the selected historical proxy load day. Resulting hourly load estimates are then loss adjusted to represent generation level rather than meter level loads, and are aggregated by AES.

PJM Settlement "B"

Approximately 45 days after the end of a calendar month, the 60-day settlement calculation process begins. The electricity supplier hourly load obligations are re-calculated using the same processing steps used to derive the original AES values, but now all actual metered load data subsequently collected is utilized. As a result of the data collection and subsequent reprocessing:

- The hourly profiles for non-interval metered SDIs are now based on dynamic load profiles for the actual days of the settlement period, instead of on weather proxy day static load profiles.
- The actual load data for interval metered SDIs is now available to replace the estimated data used in the day-after settlement.
- The meter reading cycle is completed for the month to be settled, so the hourly load profiles of all SDIs can be scaled to match known metered usage spanning each day of the month.

Net Metered Customer Generation

Customers on a net-metered tariff are metered through the month using either hourly interval metering or cumulative monthly metering, depending upon the size of the customer load. After cycle bill usage calculations are performed through the month, the net-negative generation by customer is calculated, and then used to offset the aggregated load obligations for their assigned AES in two different ways based upon the two types of metering.

- For net-metered customers with hourly interval metering, any hourly net-negative generation amount is applied as a credit for the assigned AES aggregated settlement amount.
- For net-metered customers with non-hourly interval metering (monthly cumulative), the customer's generation offsets the load requirement for the assigned AES up to zero. The resulting load obligation then follows the standard load profile process to establish hourly settlement values up to zero.

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Example Settlement "A"

		PJM Settlement "A" - Initial Settlement	Value
Calculate Variables	I&M	I&M periodically performs system loss studies, updating transmission and distribution losses for applicable tariffs	Secondary - 1.09529 Primary - 1.06496 Sub-Tran - 1.0341
Calculate Variables	I&M	Customer load profiles are derived for different customer usage classes, calculated from sample customer data with hourly metering, and assigned to each SDI.	
Usage Forecast and Aggregation	I&M	Customer historical usage is stored. For customers without hourly metering, profiled hourly usage is created from customer class profile IDs.	
Usage Forecast and Aggregation	I&M	Weather forecast data and historical usage are used to select a proxy day hourly usage for the daily load estimate.	
Usage Forecast and Aggregation	I&M	Example: 'XYZ' customer's estimated hourly load for the initial settlement day.	100 kwh/day
Usage Forecast and Aggregation	I&M	I&M applies system losses to the energy forecast based upon premise voltage delivery level. (e.g. a Sub-Tran customer value of 1.0341)	103 kwh/day
Usage Forecast and Aggregation	I&M	Sum of "ABC" AES' assigned customer's forecasted usage is aggregated by hour.	200,000 kwh/day*
Usage Forecast and Aggregation	I&M	I&M submits "ABC" AES' forecasted settlement A to PJM via InSchedule.	202,000 kwh/day*
Settlement "A"	pjm	PJM applies a deration factor to calculate energy and transmission costs separately	195,900 kwh/day*
Settlement "A"	pjm	PJM applies initial hourly LMP values to energy = Settlement A	$1M*

**** Values are for demonstration purposes***

<u>Example</u> Settlement "B"

		PJM Settlement "B" - Final 60 Day Settlement	Value
Calculate Usage	I&M	I&M reads meters for all customers during the revenue month, and calculates final metered usage.	
Calculate Usage	I&M	For customers without hourly metering, profiled hourly usage is created from customer class profile id.	
Usage True-up and Aggregation	I&M	I&M aggregates by hour the sum of the usage, with losses, for "ABC" AES' assigned customers for the settlement month, to arrive at their actual final usage.	6,067 MWH/month
Usage True-up and Aggregation	I&M	I&M calculates all distributed generation (net metering) customer values for the customers net-negative values (excess generation on to the grid). A credit is calculated by hour for the assigned AES for all of their assigned customers. (e.g. 100,000 kwh credit)	5,967 MWH/month
Usage True-up and Aggregation	I&M	I&M calculates (by hour) the hourly variance between the initial settlement submitted to PJM, and final values, arriving at the final 60 day settlement true-up values for each AES.	10.5 MWH/month*
Usage True-up and Aggregation	I&M	I&M submits "ABC" AES' final settlement B true-up to PJM.	10.5 MWH/month*
Settlement "B"	pjm	PJM applies a deration factor to calculate energy and transmission costs separately	10.17 MWH/month*
Settlement "B"	pjm	PJM applies final hourly LMP values to energy = Settlement B	$305.10*

**** Values are for demonstration purposes***

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