Performance Impact of Multi-Schedule Model in Market Clearing Engine With Configuration-Based Models

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I. Executive Summary

Multi-configuration models will be an important feature under the PJM nGEM model. A multi-configuration model will be used for the Enhanced Combined Cycle model and the Energy Storage Resource and Hybrid Resource model. This modeling is needed in the market software to best capture the resource parameters and operational characteristics while allowing the PJM market clearing engine to best commit and dispatch these resources and maintain reliability reserve requirements. The multi-configuration model, in concert with the existing multi-schedule framework, introduces performance impacts on the clearing engine and solution time. Provided in more detail in this research paper, the performance impact is due to each schedule of each configuration in the model being represented as a logical resource. The cumulative schedules of configurations of all combined cycles, energy storage and hybrid resources in PJM would drastically increase the number of logical resources and exponentially increase the optimization solution time.

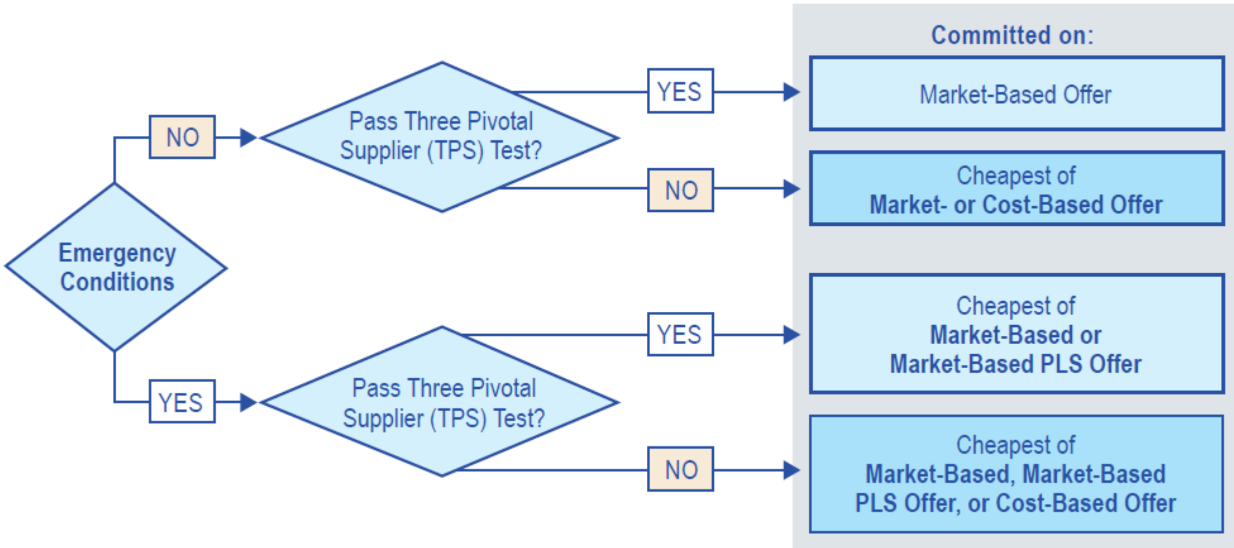
PJM believes the best approach to address the performance impacts will be to address the current multi-schedule model in the market clearing engine and ultimately pass only one schedule to the engine for commitment. There are a number of design solutions that can result in only one schedule being passed to the clearing engine. These options are numerated and detailed in the research paper. This paper further delineates which proposed solutions would be in scope or out of scope of PJM's proposed Issue Charge as of the January 2023 Market Implementation Committee meeting (https://www.pjm.com/-/media/committees-groups/committees/mic/2023/20230111/item-04a-2---performance-impact-of-multi-schedule-model-in-mce-for-ecc-model---issue-charge.ashx). PJM's rationale to narrow the solution scope is in an effort to minimize the impact to the current offer structure and market rules. The in-scope proposals will allow the issue to be addressed without changing current schedule and parameter market rules, current schedule-switching rules and current market-mitigation rules.

II. Existing Market Rules for Submission and Use of Schedules

Generation resources can submit three types of schedules in the Day-ahead and Real-time markets: a market-based schedule (non-parameter limited), and two types of schedules used for mitigation: a cost-based schedule (parameter-limited) and a market-based parameter-limited schedule. A market-based schedule (non-parameter limited) is referred to as a price schedule, and a market-based parameter-limited schedule is referred to as a price parameter-limited schedule (PLS).

0 below illustrates when PJM considers market-based offers (non-parameter limited), market-based parameter-limited offers and cost-based offers in ultimately determining the appropriate schedule of a unit for commitment and dispatch.

Figure 1. Existing Schedule Selection Process



PJM's day-ahead commitment software is designed to commit resources based on the appropriate schedule offers that result in the lowest total system production cost. This approach is intentionally designed to maximize the social benefits of competitive markets by serving expected loads at least cost. The schedule that results in the lowest total system production cost depends on a combination of factors, such as the level of output needed from a unit's schedule, the incremental offer up to the needed output level, Start-Up Cost, No-load Cost and other operating parameters submitted in a schedule – all of which are considered when determining various offer schedules in committing units. The examples that demonstrate how some of the factors described above affect the cheapest schedule selection are in the Appendix. The schedule selection is performed by the optimization in the market clearing engine (MCE).

III. Schedule Selection Process in Current MCE

A. Day-Ahead Market

The MCE selects the cheapest schedule from the eligible schedules as described above by modeling each individual schedule as its own logical resource. Hence, a market resource has the same number of logical resources modeled as the number of eligible schedules. If each resource has two eligible schedules on which it can be committed, then there will be twice as many logical resources as market resources in the optimization formulation. Additionally, other associated constraints will be modeled to make sure only one eligible schedule is committed at a given time. This modeling of a market resource with as many logical resources as eligible schedules is what is referred to as a multi-schedule model in MCE optimization.

B. Real-Time Market

In the Real-time Energy Market, the cheapest schedule selection is determined from all eligible schedules using the dispatch cost formula below:

Dispatch cost for the applicable hour = [(Incremental Energy Offer@Economic Minimum for the hour [$/MWh]* Economic Minimum for the hour [MW]) + No-load Cost for the hour ($/H)]

For resources committed in the Real-time Energy Market, the resource is committed on the offer with the lowest Total Dispatch cost at the time of commitment.

Total Dispatch cost = sum of hourly dispatch cost over a resource's minimum run time ($) + Start-Up Costs ($)

IV. Performance Impact of Multi-Schedule Model in Current MCE

The multi-schedule model in the MCE has the effect of increasing the number of logical resources compared to a single-schedule model and, in turn, increases the optimization problem size. This increase in optimization problem size impacts the optimization solution time such that the commitment software requires more time to solve under the multi-schedule model. The increase in solution time is not linearly proportional to the problem size, but it is exponentially proportional. For example, in the current day-ahead production software, in the absence of any emergency conditions, a price-based resource will have one eligible schedule, a cost-based resource will have as many eligible cost-based offers as available schedules, and if a price-based resource fails the TPS test, then the resource will have one eligible price-based schedule and as many eligible cost-based schedules as available cost-based schedules. Currently, approximately 24% of market resources are cost-based resources with an average of two eligible cost-based schedules and with only a few market resources failing the TPS test on a daily basis. If this case is considered as the base case, then under emergency conditions, a price-based resource may have two eligible price-based schedules from which the commitment software would need to pick the cheapest one if it needed to commit the market resource. The optimization solution time increases approximately tenfold despite the increase in mixed-integer programming (MIP) convergence tolerance by 100 times. Ideally, if the optimization problem size is the same and the convergence tolerance is higher, the solution time should decrease. This exponential increase in solution time due to the multi-schedule model in the MCE is manageable in the current 2.5-hour day-ahead clearing window. This commitment problem with the multi-schedule model in the MCE is solved at least four times at various stages of Day-ahead Market clearing process.

V. Performance Impact of Multi-Schedule Model in MCE Under nGEM Configuration-Based Models

As described above, each eligible schedule for a market resource is modeled as a logical resource. In the configuration-based model, each configuration for a multi-configuration plant will be modeled as a logical resource. For example, a typical 2X1 combined-cycle plant would have at least six configurations and therefore have six logical resources modeled. If each of these six configurations has two eligible schedules, then the number of logical resources modeled for a single combined-cycle plant would be 12 (6 configurations * 2 eligible schedules = 12). This would drastically increase the number of logical resources for the approximately 100 combined-cycle plants modeled in PJM's markets and will exponentially increase the optimization solution time.

Based on the last several years of experience with a multi-schedule model in the current MCE and discussions with GE, it is apparent that the multi-schedule model in the MCE with the configuration-based model will have a significant performance impact that will jeopardize the clearing of the Day-ahead and Real-time energy markets in the approved time frame with sufficient accuracy.

The performance impact of the multi-schedule model in the MCE will affect nGEM configuration-based models such as Enhanced Combined Cycle (ECC), Energy Storage Resource (ESR) and Hybrid Resource models. It will also impact the future nGEM multi-configuration-based ESR model and Hybrid Resource model. The current ESR model does not have a concept of different operating models. Therefore, the MCE solution time is not affected by the current self-scheduled ESR model. However, the nGEM ESR model will be a configuration-based model, similar to the ECC model, to accommodate the characteristics of energy storage resources that the current production model does not have. The nGEM ESR model will also be extended to model the characteristics of future hybrid resources. The performance impact of the nGEM ESR and Hybrid Resource models may cause further deterioration of the MCE solution time due to the multi-schedule model in the MCE optimization depending upon how many resources participate in these nGEM models.

VI. Defining Solution Options

In defining the options to address the market clearing engine performance impacts, PJM looked for solutions that enabled only one schedule and set of parameters to be considered in the market clearing engine. PJM scoped the solutions options in this manner to minimize the optimization problem and address solution times. There are a number of solution options that could be implemented to achieve this goal, which are detailed in this paper. Further, PJM defined these options as "in scope" and "out of scope" with respect to the current PJM Issue Charge at the Jan. 11, 2023, Markets Implementation Committee meeting. The goal of this in- or out-of-scope delineation was to recommend solutions that met the nGEM development timeline and minimized impacts to the current market rules. The "in scope" solutions will allow the market clearing engine performance issues to be addressed without changing current schedule and parameter market rules, current schedule-switching rules and current market mitigation rules.

The suite of options that will be detailed in the following sections VII and VIII are:

A. Remove Multi-Schedule Model From MCE Optimization
   a. Base preferred schedule selection on predefined formula with parameters and offer structures as status quo.
   b. Consider only parameter-limited schedules during emergency conditions such as Hot Weather Alert (HWA)/Cold Weather Alert (CWA)/Maximum Generation Alert conditions.
   c. Allow one set of operating parameters, incremental energy offers, Start-Up and No-load Costs.
   d. Allow only cost-based schedules with one set of parameters.
   e. Allow only parameter-limited schedules with one set of parameters.
   f. Create a "new preferred schedule" from all available schedules.

B. Remove Multi-Schedule Model From PJM Markets

The impact to other market areas for these solutions will vary. At the end of each solution option discussion there is a table summarizing additional market rule changes that will need to be discussed if that given solution option is selected. **It is important to note that all solution options are intended to apply to all market participants, not just market participants with resources utilizing a configuration-based model.**

VII. In-Scope Options To Reduce Performance Impact of Multi-Schedules Based on PJM's Issue Charge Presented in Jan. 11, 2023, Markets Implementation Committee (MIC)

The below options minimize the performance impacts related to the multi-schedule model in the MCE and are in-scope based on PJM's current Issue Charge.

A. Remove Multi-Schedule Model From MCE Optimization

This option is to remove the multi-schedule model from the MCE optimization. Under this option, the current offer structure of market-based offers and cost-based offers will be preserved. However, only one set of operating parameters and one set of incremental energy offers, including Start-Up and No-load Costs per market resource, will be provided to the MCE for commitment and dispatch purposes. This ensures that the optimization problem size does not increase and hence addresses the performance impact due to the multi-schedule model in the MCE. This option requires creating a predefined set of rules and a formula to determine the preferred schedule among all eligible schedules that can be used in the MCE for commitment and dispatch purposes.

There may be several ways to set up rules and create a predefined formula based on resource operating parameters and offers to determine the schedule used by the MCE for commitment dispatch purposes. At this time, the following options have been identified to determine the selected schedule outside of MCE optimization.

1. Schedule selection based on a predefined formula with parameters and offer structures as status quo.

In this option, there is no change in how market participants submit schedules and offer parameters. As parameters are different on each schedule, the schedule selection will need to be based on a predefined formula. The objective of this predefined formula is to determine the schedule outside of the MCE such that the MCE will have only one schedule for commitment and dispatch purposes. Once the schedule has been determined, that schedule will be used for commitment and dispatch purposes for the duration of the market software study period.

As offer parameters and offer costs, such as Minimum Run Time, Maximum Run Time, start-up plus notification time, hourly No-load Cost, hourly Start-Up Cost, etc., are different on different schedules for this option, there may be a number of ways to come up with a formula to determine the schedule for commitment and dispatch purposes for the MCE. Below is the list of options to determine the schedule's hourly cost and total cost for all available schedules that can be utilized to determine the schedule to be used in the MCE.

- **Schedule hourly cost (for each available schedule)**

  Options to determine schedule's hourly cost based on submitted offer parameters for each hour of the day:

  - Schedule hourly cost = Area under the bid-in offer curve@EcoMin + No-load Cost
  - Schedule hourly cost = Area under the bid-in offer curve up to EcoMax + No-load Cost
  - Schedule hourly cost = Area under the bid-in offer curve up to maximum of (EcoMax, last megawatt break point on bid in offer curve) + No-load Cost.

  As hourly cost can be different for all 24 hours on each of the available schedules, there may be a number of ways to come up with one hourly cost that can be used in Total Cost determination for each schedule; for example, the highest hourly cost among 24 hours, the lowest hourly cost among 24 hours, the average hourly cost for 24 hours, and the average hourly cost for Minimum Run Time, etc.

- **Total Cost (for each available schedule)**

  Options to determine Total Cost based on schedule hourly cost described above:

  - Total Cost = sum of schedule hourly cost over a resource's Minimum Run Time + Start-Up Cost
  - Total Cost = sum of schedule hourly cost over a resource's Maximum Run Time + Start-Up Cost
  - Total Cost = sum of schedule hourly cost over a resource's Minimum Run Time + Start-Up Cost

  - The Minimum Run Time for the purpose of this formula is the Maximum of Minimum Run Time of all available and eligible schedules.

- Total Cost = sum of schedule hourly cost over resource's Maximum Run Time + Start-Up Cost
  - The Maximum Run Time for the purpose of this formula is the minimum of Maximum Run Time of all available and eligible schedules.
- Total Cost = average of Total Cost of first two formula mentioned in this list.

As resource's actual run time is unknown at the time of determining the schedule, all of the above Total Cost formulas are based on resource's Minimum Run Time and/or Maximum Run Time parameters and not based on actual run time for a resource. In addition, these formulas do not take into account start-up and notification time for resource's schedule that might influence the commitment decision of a schedule.

This approach may provide a less optimal solution than status quo; however, this approach will allow the schedule selection outside of the MCE, eliminating the performance impact due to the current multi-schedule model in the MCE. This will enable the implementation of better models for generation resources to accommodate various operating characteristics that are not being considered in current the implemented model. Currently, this approach of determining schedule selection based on a predefined formula has been implemented in Real-time Market for existing resources and models.

Below is an example to better understand how the above formulas can be used to determine the preferred schedule.

Assume the market resource has three schedules available – *price, price PLS and cost schedule. Based on any of the Total Cost options described above, the Total Costs for each of these available schedules are obtained as follows:*

Total Cost on price schedule = $100

Total Cost on price PLS = $90

Total Cost on cost schedule = $50

The following schedule will be passed to the MCE for commitment and dispatch purpose.

- **If a resource owner does not fail TPS test:**
  - Price PLS for the resource will be passed to the MCE, as that schedule has the minimum Total Cost among price and price PLS.
- **If a resource owner fails TPS test:**
  - Cost schedule will be passed to the MCE, as that schedule has the minimum Total Cost among price, price PLS and cost schedule.

For configuration-based, the scheduled hourly cost and Total Cost are applied at the configuration level. This means we may have a different schedule with the lowest dispatch cost for each configuration. There may *be a need to select only one particular schedule for all available configurations for that day. For example, as most new combined cycle plants cannot operate in simple cycle mode, the available schedules from either one CT plus steam or two CTs plus steam configurations can be used to determine the preferred/cheapest schedule for combined cycle plants based on a predefined formula used for other resource types. If a price schedule among all available schedules is cheaper on this predefined configuration, then price schedule will be used for all configurations for that combined cycle plant. Similar methodology needs to be developed for other configuration-based models, such as ESR and hybrid plants.*

Summary of Impacted Items for Solution Option VII(A)(1)

Energy Market Offer Structure	Definition of a Single Set of Operating Parameters	Possible Schedule-Switching Market
No	No	N/A

2. **Consider only parameter-limited schedules during emergency conditions such as Hot Weather Alert (HWA)/Cold Weather Alert (CWA)/Maximum Generation Alert conditions.**

   This option is similar to the option described in section VII(A)(1) above, except the price schedule, which is a non-parameter-limited schedule, will not be considered during emergency conditions such as Hot Weather Alert, Cold Weather Alert or Maximum Generation Emergency alert conditions as available, eligible schedule.

   The same formulas for the schedule's hourly cost and Total Cost as described in section VII(A)(1) can be used to determine the schedule for commitment and dispatch purposes.

Summary of Impacted Items for Solution Option VII(A)(2)

Energy Market Offer Structure	Definition of a Single Set of Operating Parameters	Possible Schedule-Switching Market Rules
No	No	N/A

VIII. Out-of-Scope Options To Reduce Performance Impact of Multi-Schedules Based on PJM's Issue Charge Presented on Jan. 11, 2023, Markets Implementation Committee (MIC).

Additional options have been identified that minimize the performance impacts related to the multi-schedule model in the MCE; these options are considered "out of scope," based on PJM's current Issue Charge.

A. Remove Multi-Schedule Model From MCE Optimization

This approach is described in section V(A). The options below are additional options from section V(A) to minimize the performance impact related to the multi-schedule model in the MCE but identified as out of scope based on PJM's Issue Charge.

1. Allow one set of operating parameters, incremental energy offers, Start-Up and No-load Costs.

In this option, only one set of operating parameters will be allowed on all schedules for a market resource. This will eliminate any difference among schedules caused by operating parameters. There will not be any crossing curves allowed for incremental energy offers on various schedules. The megawatt break points on incremental energy offers will also need to be the same on all available schedules such that the cheapest incremental energy offers can be easily determined. Start-Up and No-load Costs will have to be the same on all schedules for a market resource. These changes would impact the current energy market offer structure.

The above set of rules will allow the software to predetermine the schedule on an hourly basis, and the least-cost schedule will be the one with the lowest incremental energy offer on a particular megawatt break point. Under this option, there is the potential for one offer schedule to be the lowest cost in a particular hour and a different schedule to be the lowest cost in other hours, despite not having crossing incremental energy offers among schedules. Business rules will need to be established to determine how to select the schedule to pass to the MCE. This may require changes to schedule-switching rules. For example, in current production, the Minimum Down Time of a schedule that is being committed is honored before committing that schedule for a market resource.

Summary of Impacted Items for Solution Option VIII(A)(1)

Energy Market Offer Structure	Definition of a Single Set of Operating Parameters	Possible Schedule-Switching Market Rules
Yes	Yes	Yes

2. Allow only cost-based schedules with one set of parameters.

In this option, only cost-based offers will be allowed for market resources with one set of parameters applied to all cost-based schedules. Crossing curves for incremental energy offers among various cost-based schedules will not be allowed. This requires having the same megawatt break points on incremental energy offer curves for all schedules.

The above set of rules will allow the software to predetermine the preferred schedule on an hourly basis, and the cheapest schedule will be the one with the lowest incremental energy offer on a particular megawatt break point among all available cost-based schedules.

This option can easily identify the cheapest schedule on an hourly basis, but if one schedule is cheaper in a particular hour and a different schedule is cheaper in other hours despite the schedules not having crossing incremental energy offers, then which schedule should be selected as the preferred schedule and used by the MCE? This may require changes to schedule-switching rules if current schedule-switching rules need to be preserved. For example, in current production, the Minimum Down Time of a schedule that is being committed is honored before committing that schedule for a market resource.

Summary of Impacted Items for Solution Option VIII(A)(2)

Energy Market Offer Structure	Definition of a Single Set of Operating Parameters	Possible Schedule-Switching Market Rules
Yes	Yes	Yes

3. Allow only parameter-limited schedules with one set of parameters.

This option requires a change in the current energy markets offer structure. In this option, only PLSs (price PLS and cost-based schedules) will be allowed for market resources with one set of parameters among all schedules. Crossing curves for incremental energy offers among various PLS schedules will not be allowed. This will also require having the same megawatt break points on incremental energy offer curves for all schedules.

The above set of rules will allow the software to predetermine the preferred schedule on an hourly basis, and the cheapest schedule will be the one with the lowest incremental energy offer on a particular megawatt break point among all available cost-based schedules.

Under this option, there is the potential for one offer schedule to be the lowest cost in a particular hour and a different schedule to be the lowest cost in other hours, despite not having crossing incremental energy offers among schedules. Business rules will need to be established to determine how to select the schedule to pass to the MCE. This may require changes to schedule-switching rules. For example, in current production, the Minimum Down Time of a schedule that is being committed is honored before committing that schedule for a market resource.

Summary of Impacted Items for Solution Option VIII(A)(3)

Energy Market Offer Structure	Definition of a Single Set of Operating Parameters	Possible Schedule-Switching Market Rules
Yes	Yes	Yes

4. Create a "new preferred schedule" from all available schedules.

This option requires a change in the current energy markets offer structure. In this option, the megawatt break points on the incremental energy offer curves must be the same on all available schedules. There will not be any other change as far as submission of operating parameters and offer prices from status quo.

The offer parameters and incremental energy offers, including Start-Up and No-load Costs, will be determined as below and assigned to a "new preferred schedule." This new preferred schedule will be used, if eligible, for commitment and dispatch purposes. This will not require a new schedule to be submitted by market participant, but rather a new schedule developed by the market software.

- The Minimum Run Time parameter for the new preferred schedule will be the lowest Minimum Run Time among all available schedules.
- The Maximum Run Time parameter for the new preferred schedule will be larger Maximum Run Time among all available schedules.
- The Minimum Down Time parameter for the new preferred schedule will be the lowest Minimum Down Time among all available schedules.
- The notification time for the new preferred schedule will be the lowest notification time among all available schedules.
- The start-up time for the new schedule will be lowest start-up time among all available schedules.
- The Maximum Daily Start for the new preferred schedule will be the highest Maximum Daily Start among all available schedules.
- Maximum Weekly Start for the new schedule will be the highest Maximum Weekly Start among all available schedules.
- Turn Down Ratio of the new schedule will be the highest Turn Down Ratio among all submitted schedules.
- Start-Up Cost for the new preferred schedule will be the minimum Start-Up Cost among all available schedules.
- No-load Cost for the new preferred schedule will be the minimum No-load Cost among all available schedules.

- Incremental energy offer curve for the new preferred schedule will be the lowest incremental energy offer price among all submitted parameters for that particular megawatt break point (prerequisite: megawatt break points of incremental energy offer curves for all available schedules must be the same among all schedules).

This new preferred schedule will be used in optimization for commitment and dispatch purpose when there is more than one eligible schedule to be committed.

Summary of Impacted Items for Solution Option VIII(A)(4)

Energy Market Offer Structure	Definition of a Single Set of Operating Parameters	Possible Schedule-Switching Market Rules
Yes	No	N/A

B. Remove Multi-Schedule Model From Market Rules

Under this option, the resource offer structure, including parameters, may be similar to other ISOs/RTOs. There will not be any distinction, such as price-based offers and cost-based offers, and the MCE will have only one set of parameters and incremental energy offers, eliminating the need of a multi-schedule model in the MCE. There are several advantages of this option:

- Simplified MCE optimization formulation design, as complex logic to handle the multi-schedule model, will no longer be needed.
- Single set of parameters and offers eliminate the need for complex schedule-switching logic in the MCE.
- The determination of offline reserve eligibility will be simpler with a single set of parameters.
- The MCE has better performance compared to the multi-schedule model in the MCE.

This option is a much more systemic change than the other options in this paper. This would require a much more complete redesign of the market offer structures, a redesign or modification of the market power mitigation test or TPS test, fuel cost policy business rules and offer verification process, among others.

Summary of Impacted Items for Solution Option VIII(B)

Energy Market Offer Structure	Definition of a Single Set of Operating Parameters	Possible Schedule-Switching Market Rules
Yes	Yes	N/A

IX. History of Stakeholder Work on Combined-Cycle Modeling

Prior to 2016, a couple of stakeholder groups were formed to review Combined-Cycle Model implementation in markets. However, no meaningful outcome that could be implemented came out of these groups. In 2016, several PJM stakeholders formed the combined-cycle owner user group to discuss the design and operation of combined-cycle units and how this can be integrated into market operations. At the conclusion of the education phase of this user group, the group concluded that a more detailed model for combined-cycle units might be equally applicable to other units, such as steam units with mill points. As a result, the Modeling Generation Senior Task Force (MGSTF) was created to consider expanding the model that is being used in market operation to improve the ability to model various components or operating modes of various generation resources.

There were a few recommendations from the MGSTF as mentioned below:

1	The group developed a requirement document, Stakeholder Requirements – Prioritized, for the ECC model and assigned priorities to each of the requirements. This requirement document was shared with software vendor GE for their feedback on the requirements, and PJM will use this requirement along with GE's feedback as a guide for nGEM ECC model implementation.
2	The group recommended providing the ability for the submission of an hourly segmented ramp rate curve compared to daily segmented ramp rate curve. This would allow more flexibility to generation resources to incorporate some of the characteristics of generation resources in the hourly segmented ramp rate curve. The recommendation to allow the submission of an hourly segmented ramp rate curve for all generation resources has been implemented in both Day-ahead and Real-time energy markets.
3	The group recommended providing the ability for the submission of an hourly segmented ramp rate curve compared to daily segmented ramp rate curve. This would allow more flexibility to generation resources to incorporate some of the characteristics of generation resources in the hourly segmented ramp rate curve. The recommendation to allow the submission of an hourly segmented ramp rate curve for all generation resources has been implemented in both Day-ahead and Real-time energy markets.
4	The group identified having a soak time profile modeled in the Day-ahead Market would better reflect the resource operation during the start-up of a generation resource and in turn would align its operation with the Real-time Market. This recommendation failed the vote in the group and has not been implemented.

X. Appendix

To illustrate the existing approach of selecting the cheapest schedule from all eligible schedules for a resource in the current MCE, the following examples demonstrate how some of the factors described above affect the cheapest schedule selection. For the following two simplified examples,[1] assume two units with the applicable market-based and cost-based offer schedules as follows:

Example 1

		Incremental Offer ($/MWh)			
		Price-Based	Cost-Based	EcoMax	EcoMin
Unit 1	Single Segment	$30	$30	100	0
Unit 2	Segment 1 Segment 2	40 MW@$40 60 MW@$60	40 MW@$35 60 MW@$100	100	5

In the first scenario, if the expected load is 120 MW, the MCE would clear 100 MW of Unit 1 at $30/MWh, and the remaining 20 MW from Unit 2 at $35/MWh, since the cost-based offer is cheaper than the market-based (non-PLS) offer of $40/MWh and Unit 2 failed the TPS test. This results in committing both units based on the total system production cost of $3,700 compared with $3,800, had PJM committed Unit 2 on its market-based (non-PLS) offer.

Table 1. Scenario 1

Assumption: Load = 120 MW				
	Committed on Schedule	Cleared MW	Failed TPS Test?	Production Cost
Unit 1	Price-Based	100	No	$3,000
Unit 2	Price-Based	20	Yes	$800
Total System Production Cost = $3,000 + $800 = $3,800				

	Committed on Schedule	Cleared MW	Failed TPS Test?	Production Cost
Unit 1	Price-Based	100	No	$3,000
Unit 2	Cost-Based	20	Yes	$700
Total System Production Cost = $3,000 + $700 = $3,700				

Cost-based offer for Unit 2 results in the lowest overall system production cost.

In Scenario 2 below, where the expected load is 150 MW, overall societal benefit is maximized by committing 100 MW from Unit 1 at $30/MWh and the remaining 50 MW from Unit 2 based on the market-based (non-PLS)

[1] The examples and scenarios presented are simplified examples. TPS test is constraint specific, but to simplify the example and demonstrate how offers and parameters impact the cheapest schedule selection, no transmission constraint is included in the provided example. It is also assumed that Market Seller for Unit 2 fails TPS.

schedule. This is because under Unit 2's cost-based offer, only 40 MW could be obtained at the $35/MWh price while the remaining 10 MW would be at $100/MWh. This would result in Unit 2's overall production cost being equal to $2,400. By contrast, committing Unit 2 under its market-based (non-PLS) schedule would result in Unit 2's production cost equal to $2,200. This is so because even though the first segment of Unit 2's market-based schedule is more expensive at $40/MWh (compared with the cost-based offer of $35/MWh), the second segment is much less expensive ($60/MWh) than the second segment for the cost-based schedule ($100/MWh). As a result, the MCE will commit this unit under its market-based (non-PLS) offer since it results in the overall total system production cost of $5,200 compared with $5,400 using the cost-based offer.

Table 2. Scenario 2

Assumption: *Load = 150 MW*				
	Committed on Schedule	**Cleared MW**	**Failed TPS Test?**	**Production Cost**
Unit 1	Price-Based	100	No	$3,000
Unit 2	Price-Based	50	Yes	$2,200
Total System Production Cost = $3,000 + $2,200 = $5,200				

	Committed on Schedule	**Cleared MW**	**Failed TPS Test?**	**Production Cost**
Unit 1	Price-Based	100	No	$3,000
Unit 2	Cost-Based	50	Yes	$2,400
Total System Production Cost = $3,000 + $2,400 = $5,400				

Price-based offer for Unit 2 results in the lowest overall system production cost.

Example 2

This example shows how different operating parameters affect the cheapest schedule selection.

Assume that the expected load for hours ending 1–17 and 20–24 is 90 MW, while the expected load for hours ending 18–19 is 120 MW. Further assume that Unit 2 has a Minimum Run Time of 24 hours based on its market-based (non-PLS) schedule and two-hour Minimum Run Time based on its cost-based schedule.

		Incremental Offer ($/MWh)			
		Price-Based	Cost-Based	EcoMax	EcoMin
Unit 1	Single Segment	$30	$30	100	0
Unit 2	Single Segment	$60	$70	100	5

*Note: Minimum Run Time of 24 hours on price-based schedule and two hours on cost-based schedule

Assumption:	HE 1 – HE17 | HE 20 – HE 24 *Load = 90 MW*	HE 18 – HE 19 *Load = 120 MW*

Under this scenario, Unit 2's market-based (non-PLS) schedule would not result in the lowest overall system production cost because that schedule contains a Minimum Run Time of 24 hours. As a result, even though Unit 2 would otherwise not be needed from hours ending 1–17 and 20–24, PJM would have to dispatch that unit at its economic minimum of 5 MW for those hours to obtain the 20 MW needed for hours ending 18–19. **Table 3** below shows the total system production cost if PJM were to commit Unit 2 on its market-based (non-PLS) schedule:

Table 3. Price-Based Schedule

	Committed on Schedule	Cleared MW		Failed TPS Test?	Production Cost
		HE 1 – HE 17 | HE 20 – HE 24	HE 18 – HE 19		
Unit 1	Price-Based	85	100	No	$62,100
Unit 2	Price-Based	5	20	Yes	$9,000

Total System Production Cost: $62,100 + $9,000 = $71,100

In comparison, under the same set of assumptions, the total system production cost is less using Unit 2's cost-based schedule because the Minimum Run Time is for two hours even though the market-based (non-PLS) offer price is lower. Because Unit 2 would not be committed from hours ending 1–17 and 20–24, 20 MW of Unit 2 would be committed for two hours ending 18–19 at $70/MWh.

Table 4. Cost-Based Schedule

	Committed on Schedule	Cleared MW: HE 1 – HE 17 | HE 20 – HE 24	Cleared MW: HE 18 – HE 19	Failed TPS Test?	Production Cost
Unit 1	Price-Based	90	100	No	$65,400
Unit 2	Cost-Based	0	20	Yes	$2,800

Total System Production Cost: $65,400 + $2,800 = $68,200

Accordingly, by committing Unit 2 on its cost-based schedule, the total system production cost is $68,200 compared with its market-based (non-PLS) offer, which would have resulted in a total system production cost of $71,100. In other words, under the existing Tariff provisions and the existing implementation, the MCE already would dispatch Unit 2 to maximize social welfare even though the market-based (non-PLS) offer price may be cheaper because the overall system production cost is minimized with the cost-based offer.

To further illustrate the existing approach of selecting the cheapest schedule in the MCE that results in the lowest total system production cost, take the following example that modifies only the market-based (non-PLS) offer from $60/MWh to $40/MWh for Unit 2.

		Incremental Offer ($/MWh): Price-Based	Incremental Offer ($/MWh): Cost-Based	EcoMax (MW)	EcoMin (MW)
Unit 1	Single Segment	$30	$30	100	0
Unit 2*	Single Segment	$40	$70	100	5

*Note: Minimum Run Time of 24 hours on price-based schedule and two hours on cost-based schedule

Assumption:	HE 1 – HE17 | HE 20 – HE 24 *Load = 90 MW*	HE 18 – HE 19 *Load = 120 MW*

Under this modified example, with all other assumptions being the same, Unit 2's market-based (non-PLS) schedule would result in the lowest overall system production cost even though that schedule contains a Minimum Run Time of 24 hours. This is because when Unit 2's market-based offer is reduced to $40/MWh, it would be committed for 5 MW at $40/MWh from HE 1 – HE 17 and HE 20 – HE 24 (at a cost of $4,400), and 20 MW at $40/MWh for HE 18 – HE 19 (at a cost of $1,600). This results in an overall production cost for committing Unit 2 equal to $6,000.

Table 5. Price-Based Schedule

	Committed on Schedule	Cleared MW: HE 1 – HE 17 | HE 20 – HE 24	Cleared MW: HE 18 – HE 19	Failed TPS Test?	Production Cost
Unit 1	Price-Based	85	100	No	$62,100
Unit 2	Price-Based	5	20	Yes	$6,000

Total System Production Cost: $62,100 +$6,000 = $68,100

By contrast, if the MCE committed Unit 2 on its cost-based schedule, while it would only be committed from HE 18 – HE 19, it would cost $2,800 to commit this resource because the incremental offer under the cost-based schedule is $70/MWh. This results in a total system production cost of $68,200. Thus, in this example, the total system production cost resulting from committing Unit 2 on its market-based (non-PLS) schedule ($68,100) would be cheaper than if Unit 2 were committed on its cost-based offer ($68,200). Clearly, committing Unit 2 under the cost-based offer under this scenario would result in consumers paying a higher cost to meet the same level of reliability.