California ISO
Your Link to Power

Issue Paper

Pricing Logic Under Flexible Modeling of Constrained Output Generating (COG) Units

February 1, 2008

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Prepared for Discussion at MSC/Stakeholder Meeting on February 8, 2008

1 Introduction

Constrained Output Generation (COG) units are those that are inflexible or "lumpy" in that they must operate at their full maximum output levels when they run. In addition, COG units generally have minimum run times such that, once they are started, they cannot be shut down until a pre-specified number of intervals has passed. According to the MRTU Tariff[1], a COG unit may elect to be modeled as a strictly "lumpy" resource (*i.e.*, Pmin = Pmax), or as a resource with a minimum load (Pmin) slightly lower than its maximum capacity (Pmax). For the purpose of this paper, the terms "COG" and "COG unit" will apply only to those units that elect to be modeled as truly "lumpy."

COG units are typically gas turbine units. There are approximately xx COG units with a total generating capacity of xxx MW in the CAISO master file which represents x% of average peak hour load during the summer of 2007[2]. [Note that these data will be included upon confirmation by CAISO Market Operations. In addition to number of units and aggregate MW capacity, we hope to provide information on the approximate locations of the COG units to help frame the issue.] While these units tend to be expensive to operate, they are often able to ramp up quickly and thus can fill an important gap in meeting peak demand, and can also quickly relieve shortages due to forced outages. Because of these properties, COG units when they are needed often tend to be the marginal units in the economic dispatch, and therefore from an economic perspective should be able to set Locational Marginal Prices (LMP) under these circumstances. At the same time, under MRTU as is typical of optimal economic dispatch algorithms, only flexible resources can set prices. To remedy this problem, the principle has been adopted in the MRTU market design that COG units be able to set the LMPs. [October 28, 2003 FERC Order, [1]]

To accomplish the objective of enabling COG units to set LMPs, the CAISO will model COG units as flexible resources under MRTU upon the start-up of the MRTU markets (*i.e.*, "Release 1").[3] This is expected to result in greater consistency between market energy prices and the operating needs of the CAISO system, and thus will provide good incentives for increased participation in the CAISO markets by the COG units as well as sending more accurate price signals to all market participants. Modeling these constrained units as flexible does present problems, however. Namely, there can be

- temporal distortions in Day Ahead (DA) and Real Time (RT) prices resulting largely from the fact that the COG units have minimum run times,
- spatial distortions in RT prices resulting from different constraints being imposed in the scheduling and pricing runs,

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1 MRTU Tariff, Sections 27.7.1.2-3.

2 This percentage is based on average Hour Ending 16 load for the CAISO control area for June through September 2007, which is 37,055 MW.

3 In fact, COG units are modeled as flexible resources in the IFM in both the scheduling and pricing runs, but in Real Time (RT), they are modeled as flexible only in the pricing run. The RT scheduling run respects actual operating constraints (that is, lumpiness) in order to ensure a feasible RT dispatch.

- the possibility that COG units would escape Local Market Power Mitigation (LMPM), and
- inconsistencies between the DA and RT outcomes because of the different treatment of COG units in these two markets.

As already mentioned, there is a small number of COG units, and they represent only x% of units and an aggregate generating capacity of xxx MW. This was the main reason why the concerns stated above regarding COG resources were considered not to be significant enough to preclude the flexible modeling approach to allow COGs to set prices, nor urgent enough to require remedies in MRTU Release 1. None-the-less, the days and times during which those COG units are needed will likely be those in which the grid experiences the most trying conditions. For this reason, it is important to evaluate the potential impact of the temporal and spatial distortions that may result from modeling these units as flexible, and to evaluate the need for potential design changes to remedy or minimize these effects.

2 Process and Timetable

The purpose of the present issue paper is to initiate a discussion process with stakeholders to determine the best approach for resolving the issues described above. As such this paper does not offer CAISO recommendations for how to resolve the issues. Rather, it aims to provide the background and description of the issues, to identify key criteria and objectives to be considered in evaluating potential solutions, and to describe some candidate solutions to be considered.

Ultimately the CAISO intends to identify appropriate changes to its MRTU market rules to address the COG issues described here, to submit the proposed changes to the CAISO Board of Governors and to file them at FERC. Any changes to the MRTU market rules that are developed as a result of this process will be included in the Market Release 1A package to be launched no later than one year after the start of MRTU.

The table below summarizes the key steps in the stakeholder process on COG resources, starting with the release of this issue paper and ending with submission of the CAISO management proposal to the Board. The CAISO invites stakeholder input on any and all topics discussed in this issue paper.

February 1	Post Issue Paper
February 8	MSC/Stakeholder meeting
February 15	Stakeholder comments due *
February 20	Post CAISO Straw Proposal
February 27	Stakeholder conference call
March 5	Stakeholder comments due *
March 12	Post Draft Final CAISO Proposal
March 14 (tentative)	MSC Opinion finalized and posted
March 26-27, 2008	Presentation to CAISO Board of Governors

* Please e-mail comments to Gillian Biedler at gbiedler@caiso.com

3 Description of the Issues

Temporal Issue
In its 2005 report "*Comments on the California ISO MRTU LMP Market Design*," [2] the consulting firm LECG identified the pricing logic for non-COG units to be problematic in light of the flexible modeling of COG units. In a situation in which a COG unit is required to meet system conditions, and is setting the LMP, it is important to keep in mind that the unit is also operating for some minimum period of time. Over the course of that minimum run time, circumstances may change such that the COG unit is no longer the marginal unit. Because it is constrained on, however, it may continue to set the LMP. In this case, unconstrained units that would otherwise be dispatched as part of the least cost solution may be displaced by the more expensive COG units. Thus, the high LMP set by the COG could persist over more intervals than is appropriate. An example of how this temporal problem would occur is included in Appendix A.

The temporal problem is, in essence, the result of "Dispatch from Telemetry" adopted in MRTU as opposed to "dispatch from the last dispatch operating target" adopted in the current market structure. The reason for moving away from the latter methodology under MRTU is that it is technically infeasible for the inflexible resource to follow. The solution that the New York Independent System Operator (NYISO) has employed to mitigate this problem in their market is to include another pass of the optimization routine in RT that will mimic the dispatch from the last dispatch operating target. [3] The NYISO optimization uses the difference between the telemetry dispatch and the counterfactual operating target dispatch to determine whether each COG unit is necessary in order to meet system conditions, and allows the COG unit to set the price if it is necessary, but not otherwise. More detail on how the NYISO had dealt with the temporal pricing distortions due to modeling COG units as flexible is described in Appendix B.

Spatial Issue
There are also potential spatial effects as well as the above-discussed temporal effects of the current market design's modeling of COG units as flexible. While the temporal problem can lead to high LMPs persisting for more operating intervals than is appropriate, the spatial problem can lead to inconsistent LMPs determined by the pricing run and MW quantities determined by the scheduling run for the non-COG generating units. Spatial price distortions can arise because the scheduling run in the RT treats COG units as strictly constrained, whereas the pricing run treats them as flexible in order that the COG units be able to set RT prices. Thus, the scheduling run determines which units are needed to meet system conditions based on the actual feasible performance of the constrained units, while the pricing run assigns LMPs as though the constrained units are flexible. A numeric example of how the spatial distortion in prices plays out as a result is included in Appendix C.

Since the COG unit is treated as flexible in the DA scheduling, assuming no change in system conditions, in RT an infra-marginal flexible resource would have to be dispatched down to accommodate the full capacity of the COG unit. So, while allowing the COG unit to set the price alleviates the need for an uplift payment to the COG, it would result in uplift payments to the flexible unit that is constrained down or off.

Local Market Power Issue
Local Market Power Mitigation passes occur in the pre-IFM scheduling run in the DA market, and in the HASP/Real-Time scheduling run in the RT market. During these passes, COG units are modeled as inflexible, meaning that their technical and inter-temporal constraints are in place. Because COG units are treated as "lumpy" in the scheduling runs of these market applications, there is no room for incremental movement of the units between Pass 1 (Competitive Constraints) and Pass 2 (All Constraints) of the LMPM

routine. Thus, they escape market power mitigation in both the DA and RT markets under the Market Release 1 design. Changes to remedy this situation are already proposed for Market Release 2.

Day Ahead versus Real Time Issue
In addition to the Temporal, Spatial and Local Market Power issues described above, differences can occur between schedules resulting from the RT and DA markets due to disparities between the modeling of COG units in the scheduling runs of these two markets. In the DA, the current MRTU design enforces the correct alignment of LMPs and schedules in order to allow the use of CRRs to hedge against congestion charges. In the RT market, however, the true operating constraints of the COG units are honored in the scheduling run in order to ensure a feasible dispatch. There are several troublesome consequences of different DA and RT schedules and prices that may result from a structural (*i.e.* market model) feature rather than simply from a change in system or market conditions. First, some clarity and consistency of price signals across these two markets could be lost. Divergence between DA and RT prices can occur, though fortunately almost certainly in unpredictable ways. Although the number of COG units is small, the percentage of maximum generation capacity is small, and the frequency with which COG units are called on may be low, the circumstances in which they are called will almost certainly be those in which the market faces high prices. Thus, the cost to the market of the price differences whether through inaccurate or inconsistent price signals, counter-intuitive CRR settlement, or price divergence, may warrant some additional understanding of this potential issue.

4 Key Criteria for Evaluating Potential Solutions

This section provides some key evaluation criteria the CAISO believes are important, and invites stakeholders to identify other criteria that should be considered in assessing potential solutions.

- Any policy that is developed should balance the objective of correcting the temporal and spatial pricing inconsistencies noted above with providing constrained units the needed incentives to participate fully in the CAISO markets and sending all market participants price signals that reflect the cost of utilizing COG units to meet the operating needs of the system.

- Any policy that is developed should balance the need for uplift to COG units (when treated as “lumpy” and ineligible to set price) with the uplift payments due to flexible resources that are dispatched down in RT to make room for COG units scheduled as flexible in the IFM.

- Policy and design options should be evaluated for implementation feasibility and costs for both the CAISO Stakeholder and for the CAISO. This evaluation should be done keeping in mind the magnitude of the potential issue, *i.e.*, in light of the fact that there is a relatively small number of COG units in the control area.

5 Candidate Design Options

Temporal Issue
The NYISO solution to the temporal pricing distortions was to include an additional pass of the optimization for each interval in their Real Time market. In the NYISO, the addition of the “hybrid” pass to the scheduling and pricing passes enables a comparison of situations with and without the availability of

flexible COG units. Based on the information from the counter-factual hybrid run, if the COG is deemed necessary to meet system conditions, then it is able to set the LMP. If it is not needed, and is only on due to a minimum runtime constraint or to the binding ramping constraints of otherwise available non-COG units, then the third pass includes their minimum output in the solution, but does not enable them to set the market clearing price. It is unlikely that the current MRTU design can accommodate this solution since adding another pass to the RT optimization would present significant challenges.

It may be feasible, however, to achieve some of the benefits of the three-pass system the NYISO employs with the two-pass optimization under MRTU. Such a solution would entail having the first pass be the scheduling run that treats COG units as inflexible. This is consistent with current MRTU design, and with the NYISO design. Under MRTU, the second pass would be the pricing run in which COG units would be treated as flexible. If the COG is needed, it can set price as prescribed by FERC. If it is not needed, then the marginal non-COG unit will set the price; the price set by the marginal unit, however, will be based on the counterfactual case in which the COG unit is off, and thus the marginal unit's output is higher. In short, the marginal unit will correctly set the price when the COG unit isn't needed, but the price will perhaps be set higher up the unit's bid curve than the point at which the unit will actually operate.[4] The NYISO solution avoids this outcome by using the quantity information from the scheduling run and the prices from the hybrid run. (See Appendix B for more detail.)

Spatial Issue
As to the potential spatial price distortions, it is again worth noting that these will quite likely be small and unpredictable. None-the-less, in the case that a design change is deemed worthwhile, it is expected that a minor modification to the existing MRTU two-pass (*i.e.*, scheduling run and pricing run) set-up can be made as described above. This modification would provide most of the benefits of the NYISO approach with far less implementation difficulty.

Local Market Power Issue
Changes to address the issue of COG units escaping LMPM are slated for Market Release 2.

Day Ahead versus Real Time Issue
DA prices will reflect the flexible modeling of COG units in the scheduling and pricing runs, and the RT prices will – even under the two-tiered settlement process described in Appendix D – reflect the inflexible modeling of COG units. Although this does describe a systematic difference between the DA and RT optimization, it does not imply that there will be any observable or systematic difference in the outcomes of those two markets. Given this, and the fact that the number and maximum generating capacity of the COG units is so small, no design changes are proposed in light of this issue.

6 Conclusion

The flexible modeling of COG units has the advantage of enabling them to set the LMP when they are needed to meet system conditions. This will help to provide those units with incentives to participate more fully in the CAISO markets. There are some complex ramifications of this change, however, on prices. Specifically, because of COG minimum run times and non-COG ramping constraints, COG units may set prices for more intervals than is appropriate. In addition, it is necessary that the RT schedule be feasible and so COG units are modeled as constrained (*i.e.* inflexible) in the RT scheduling run. In order to let COG

[4] The extent to which this disconnect can be addressed in post processing is being investigated.

units set prices, though, they are modeled as flexible in the RT pricing run. This can lead to inconsistencies between RT dispatch levels and RT prices. Third, the current LMPM design, which take place in the scheduling runs of the DA and RT markets (in which, recall, COG units are treated as inflexible), will not mitigate COG units as they are not able to move incrementally between the two LMPM passes. Finally, there can be differences, albeit unsystematic, between DA and RT market outcomes that result from the different treatment in the pricing run of COG units in these two markets.

The NYISO has faced the first of the issues summarized above, and has in place a three-pass optimization in their RT markets that enables COG units to set LMPs for those intervals in which it is marginal according to the counter-factual flexible assumptions, but not otherwise. The spatial inconsistencies in prices that may result from this design are not addressed.

The temporal issue can be mitigated in large part as described in the previous section, and this would less onerous from an implementation standpoint than the addition of another pass within the RT optimization. The spatial issue is potentially solvable using creative settlement adjustments as described in Appendix D. Changes to enable the LMPM routine to flag COG units are slated for Market Release 2. Potential inconsistencies between the DA and RT market outcomes as a result of different modeling assumption in those markets are expected to be very small and un-systematic, and so no design change is proposed for this issue.

7 References

[1] FERC Docket #: ER02-1656-004 issued 28 October 2003, "Further Order on the California Comprehensive Market Redesign Proposal"

[2] Law & Economics Consulting Group (LECG), February 23, 2005, "Comments on the California ISO MRTU LMP Market Design" Section V. Real –Time Dispatch, B. COG Pricing (pp 60-62)

[3] Information about the COG pricing issues experienced in the NYISO, as well as NYISO solutions and examples of these were provided by Robert deMello, Senior Staff Consultant, Siemens Power Transmission & Distribution, Inc., Power Technologies International

8 Appendix A – Temporal Issue: an example

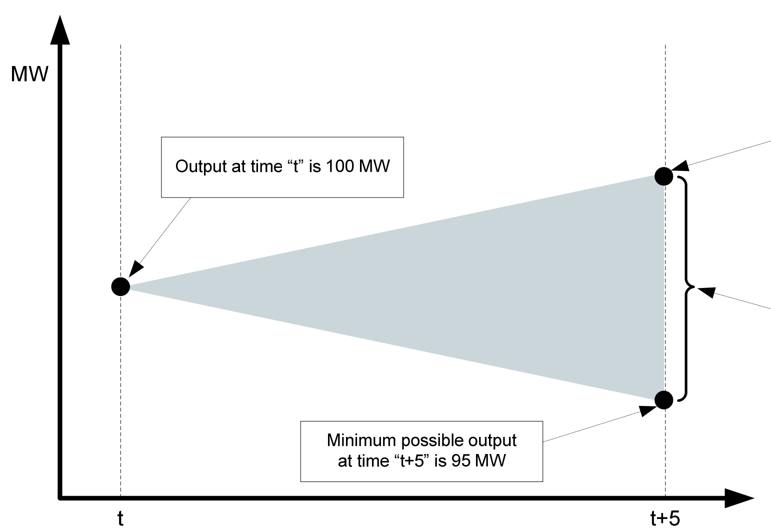
The following description of the inter-temporal issue that can enable COG units to set LMPs for longer than they are marginal is provided with thanks to Robert deMello, Senior Staff Consultant, Siemens Power Transmission & Distribution, Inc., Power Technologies International [3]

LECG in their report to the CAISO describes a situation in which treating COG units as flexible could lead to a catch-22 situation in which prices are high longer than is reasonable. [2] The catch-22 occurs because, without special consideration, a flexible unit will make the COG unit appear unnecessary in a hybrid pass only if it is fast enough to replace the complete output of the COG within a single five-minute dispatch interval. The special consideration is needed for the situation in which a flexible unit can replace the entire output of the COG but needs two or more five-minute dispatch intervals to do so.

In order to fully understand the phenomenon it is necessary to understand how a flexible generator with a finite ramp rate is represented in the optimization. We will illustrate this with an example. Suppose that a 200 MW generator (called ST for Steam Turbine) is producing energy at a rate of 100 MW. Further suppose that ST can increase or decrease its energy production rate no faster than 1 MW per minute. In five minutes, the typical dispatch interval, ST could produce energy at a rate no higher than 105 MW and no lower than 95 MW. This is illustrated in the figure below. These limits are generally represented as constraints in the SCED. That is, that the generator's output at time t+5 can be no higher than 105 MW and no lower than 95 MW. (This is depicted in the figure below.)

Now suppose that load is 114 MW and that a 14 MW COG (called GT for Gas Turbine) must run. The ST schedule remains unchanged at time t+5. That is, after considering all options, the SCED decided that the best thing, or only feasible thing, to do is to have the ST output remain at 100 MW at time t+5. The optimization routine was free to schedule ST anywhere between 95 MW and 105 MW range but this is not enough to displace GT. We will determine that GT is needed and GT will set price.

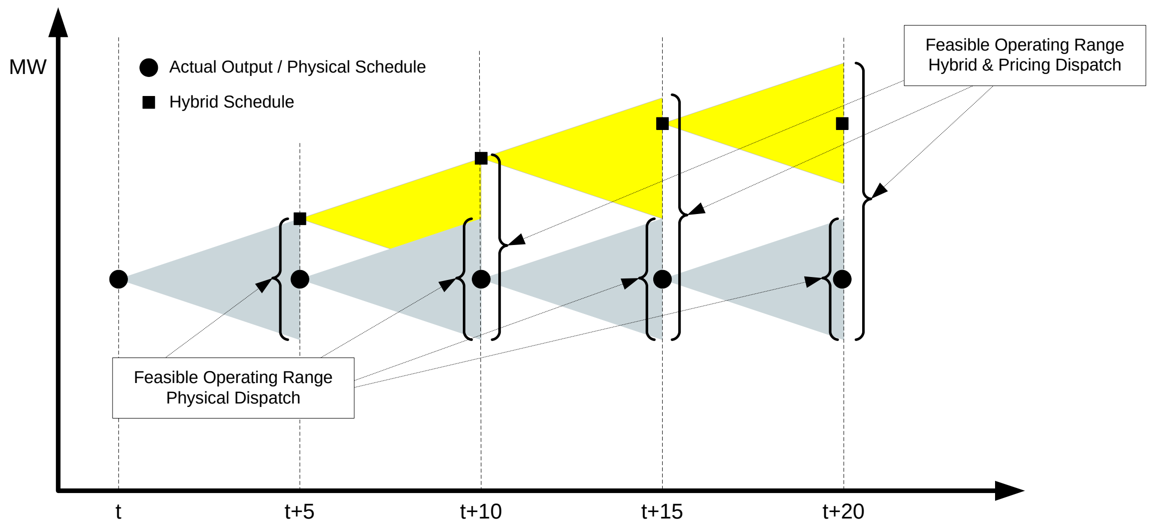
The physical schedule of ST for t+5 remained at 100, therefore the ST output at time t+10 can again be between 95 and 105 MW, and this is not enough to displace GT. In this case GT will again set the price. Let this scenario repeat and the GT will perpetually set the price.



In an ideal situation, if GT were flexible, ST could displace the output of GT in three dispatch intervals. The more expensive GT should set price for the first two dispatch intervals and ST should set price thereafter.

In order to accomplish this, the NYISO uses the schedule from the previous hybrid pass of the RT optimization as an initial operating state for flexible generators in the hybrid and pricing runs. [More information about the NYISO solution is provided in Appendix B of this Issue Paper.] If the previous hybrid run had scheduled ST at 105 MW at t+5 its valid operating range at time t+10 would be anywhere between 110 MW and 100 MW. Its physical operating range is would still be 95-105 MW. The current hybrid run and pricing run would be allowed to set the valid operating range of ST anywhere between 95 MW and 110 MW at t+10.

As is illustrated in the figure below, utilizing the counter-factual information from the hybrid run gives the flexible unit the ability to displace the COG unit in terms of setting price while the physical operating range still dictates the actual dispatch of the flexible unit.



ST Feasible Operating Ranges

9 Appendix B – NYISO COG Pricing Logic Details

The following information on the adaptations made by the NYISO to accommodate the flexible modeling of COG units is provided with thanks to Robert deMello, Senior Staff Consultant, Siemens Power Transmission & Distribution, Inc., Power Technologies International [3]

The NYISO has two real-time processes. The first is a short term Security Constrained Unit Commitment (SCUC) called the Real-Time Commitment (RTC). RTC is used to commit or de-commit quick start generators. RTC is a complete co-optimization of energy, reserves, and regulation. RTC runs every 15 minutes and has an optimization horizon of 2.5 hours. While RTC produces prices, they are only advisory.

The second real-time process is a Security Constrained Economic Dispatch (SCED) called the Real Time Dispatch (RTD). RTD produces prices and schedules every five minutes. RTD is also a complete co-optimization of energy, reserves, and regulation. RTD has an optimization horizon of approximately one hour but only the prices and schedules of the first interval are binding. It is in RTD that special consideration is given to COG units — sometimes a COG unit is represented as flexible and permitted to set price; sometimes the COG is represented as inflexible and cannot set price. No special treatment is given to other (non-COG) generators. If a non-COG generator is pinned at its minimum generation level, it will not set price.

The philosophy behind the hybrid pricing is that a COG unit should be allowed to set price if it is needed, even if only transiently. That is, the COG should be allowed to set price if it is needed (i) because there would be a capacity shortage without it, or (ii) because other generators cannot respond quickly enough to satisfy load within the next five minutes. The initial implementation of hybrid pricing used four SCED simulations. RTD uses three SCED simulations to determine prices and schedules, including determining whether a COG can set price. These three are (i) the physical SCED, (ii) the hybrid SCED, and (iii) the pricing SCED. Each is a full co-optimization of energy reserves and regulation.

Physical SCED

The physical SCED is used to determine schedules and these schedules are sent as base points to the generators. Prices produced by the physical SCED are not used. The physical SCED represents generators as follows:

- COG units that are on-line are represented as inflexible.
- COG units that are off-line but able to start on short notice are represented as flexible and able to be scheduled anywhere from zero to full output.
- Other generators are represented as they are offered. Self scheduled generators are considered fixed and dispatchable generators are considered flexible between their normal limits. Ramp limits are honored.
- Imports, exports and wheels through are represented as fixed.

Hybrid SCED

The hybrid SCED is a "what if" or counter-factual simulation that is used to determine whether individual COG units are really needed and should be allowed to set price. The schedules produced by the hybrid SCED are used internally to decide which COG units can set price in the pricing SCED. Neither prices nor schedules of the hybrid SCED are published nor are they binding. The hybrid SCED represents generators as follows:

- COG units that are on-line are represented as flexible from zero to full output.
- COG units that are off-line but able to start on short notice are represented as flexible and able to be scheduled anywhere from zero to full output.
- Other generators are represented as they are offered. Self-scheduled generators are considered fixed and dispatchable generators are considered flexible between their normal limits. Ramp limits are honored but a special calculation is used to determine the attainable operating range of these generators. The method used to determine the attainable operating range is discussed later in this memo.
- Imports, exports and wheels through are represented as fixed.

The schedule produced by the hybrid pass for each on-line COG determines whether it is really needed. If zero, the COG is not needed. That is, if the COG were turned off a combination of cheaper off-line COG units and dispatchable generators could make up the difference. If the schedule is greater than zero, the COG is needed.

Pricing SCED

The pricing SCED is used to determine prices. The pricing SCED represents generators as follows:

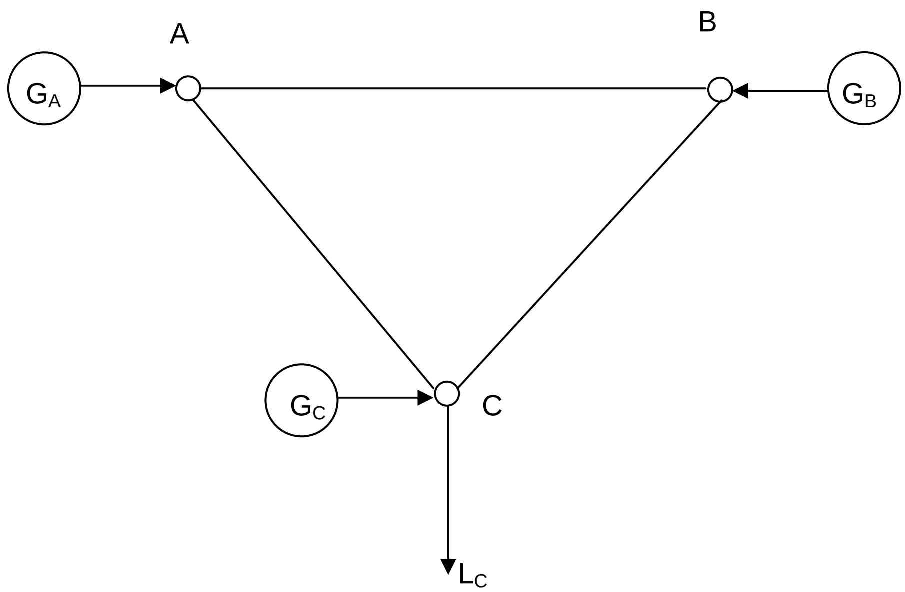
- COG units that are on-line are represented either as fixed or as flexible (from zero to full output) depending on the results of the hybrid SCED. All of these COG units have a non-zero schedule in the physical SCED. If the COG unit's schedule in the hybrid SCED is:
    - Zero, then the COG is considered unnecessary, it is represented as inflexible, and not allowed to set price.
    - Greater than zero, then some or all of the COG is needed and the COG is represented as flexible (from zero to full output) and allowed to set price.
- COG units that are off-line but able to start on short notice are represented as flexible from zero to full output.
- Other generators are represented as they are offered. Self-scheduled generators are considered fixed and dispatchable generators are considered flexible between their normal limits. Ramp limits are honored but a special calculation is used to determine the attainable operating range of these generators for the next dispatch interval. [This was illustrated in Appendix A of this Issue Paper.]
- Imports, exports and wheels through are represented as fixed.

10 Appendix C – Spatial Issue: an example

The following proposal and example is provided with thanks to Edward Lo, Lead Engineering Specialist, CAISO Market & Product Development.

The FERC, in its October 28, 2003 Order [1], order mandates that, in instances in which the output of a COG unit is needed, the cost of the COG unit should be allowed to set LMP. Within the framework of the current CAISO MRTU Tariff, this will require that the pricing run of the RT market model COG units as flexible. Prior to the RT pricing run, schedules will be determined by the RT scheduling run in which COGs will be treated as inflexible in order to ensure a feasible RT dispatch. The MW quantities determined in the RT scheduling run will be settled at the prices resulting from the RT pricing run. This settlement approach could potentially lead to inconsistencies between schedules and prices for some non-COG resources as demonstrated in the example below.

Consider a 3-bus power system in a triangular connection as shown in the following diagram. We denote the 3 buses as A, B and C. Generators G_A, G_B, G_C are connected to buses A, B and C respectively. Generator G_C is a COG unit. Only bus C has load, L_C. All three lines are identical in reactance and they are assumed to be lossless. Only line AC is subject to a MW transmission constraint of 240MW limit.



The bids of different resources are:

G_A: [0,280]MW@$20,

[280,400]MW@$30,

Zero minimum load cost

G_B: [0,200]MW@$50,

[200,400]MW@$60,

Zero minimum load cost

G_C: Minimum and Maximum Generation at 80MW

Minimum load cost = $7200

L_C: Fixed at 500MW

<u>Scheduling Run</u>:

Results from scheduling run (in which G_C is modeled <u>with</u> its constraints) are as follow:

G_A = 300MW	G_B = 120MW	G_C = 80MW	L_C = 500MW
LMP_A = $30	LMP_B = $50	LMP_C = $70	
Flow A to B = 60MW	Flow A to C = 240MW (binding)		Flow B to C = 180MW

Shadow price of the transmission constraint of line AC = $60

Note that in the scheduling run results above,

- G_A sets LMP of bus A at $30,
- G_B sets LMP of bus B at $50, and
- The LMP of bus C is $70 determined jointly by the marginal costs of other generators and the transmission network.

<u>Pricing Run – The case in which COG units are modeled as flexible</u>:

Again, under the current MRTU Tariff, COG units would need to be modeled as flexible in the pricing run in order to adhere to the FERC order that COGs be able to set LMPs. In order to impose this flexibility on the constrianed unit, the dispatchable range of the COG is modeled from 0 up to the minimum generation level (80MW) and the bid price is the minimum load cost divided the minimum generation level which equals $90/MWh for G_C in this example.

The results of the pricing run with the COG unit modeled as flexible are as follow:

G_A = 260MW	G_B = 200MW	G_C = 40MW	L_C = 500MW
LMP_A = $20	LMP_B = $55	LMP_C = $90	
Flow A to B = 20MW	Flow A to C = 240MW (binding)		Flow B to C = 220MW

Shadow price of the transmission constraint of line AC = $105

Note that the MW levels determined in pricing run are different from the scheduling run.

- The MW level of G_A is reduced from 300 to 260MW on a lower price segment ($20/MWh). It therefore sets the LMP of bus A at $20.

- The MW level of the COG unit G_C is 40MW. It sets the LMP of bus C at $90. Note that this does not respect the actual operating constraint of the COG unit, namely that Pmin = Pmax = 80MW.
- The MW level of G_B is increased from 120 MW to 200MW on the same price segment ($50/MWh) but moves to the segment break point. The LMP of bus B is $55, determined jointly by the marginal costs of other generators and the transmission network.

Using this set of prices to settle the MW quantities determined in the scheduling run, settlements between ISO and market participants are as follow:

$L_C \rightarrow$ ISO : $90*500 = $45,000

$G_A \leftarrow$ ISO : $20*300 = $6,000

$G_B \leftarrow$ ISO : $55*120 = $6,600

$G_C \leftarrow$ ISO : $90*80 = $7,200

Using this set of LMP determined by the pricing run with flexible COG to settle the MW quantity determined by the scheduling run, the revenue of COG is able to cover its minimum load cost. However, the example demonstrates that there is problem for G_A because it was scheduled at 300MW with a bid price of $30/MWh at that level but is settled with $20 LMP. The bid cost of G_A is the integral of the calculated bid curve of the generator from 0 to 300MW. This yields a value of $6,200. Thus, G_A has a shortfall of $200. Therefore, instead of bid cost recovery for the COG G_C, G_A will need bid cost recovery to cover its cost because the price for settling its energy is artificially suppressed because of the COG unit was modeled as flexible.