350 Massachusetts Ave., Ste. 300
Cambridge, MA 02139
T: 617.761.0117
F: 617.621.8018
mcadwalader@lecg.com

MEMORANDUM

DATE:	November 21, 2007
TO:	Production Cost Guarantee Technical Study Group
FROM:	Mike Cadwalader
RE:	Comparing Methods for Calculating Production Cost Guarantee Payments That Focus on Day-Ahead Constrained Schedules

THE REASON FOR FOCUSING ON DAY-AHEAD CONSTRAINED SCHEDULES

The primary factor complicating the selection of a mechanism for calculating Production Cost Guarantees (PCGs) is the potential for the day-ahead constrained schedule (DACS) that a generator receives to differ from the day-ahead unconstrained schedule (DAUS) that it receives.[1]

Fundamentally, there are two different approaches for dealing with cases when a generator's DACS and its DAUS differ. We can start with the revenues that a generator receives in the day-ahead market, which reflect its DAUS, and the revenues it receives in the real-time market, which reflect the difference between its DAUS and its real-time constrained schedule (RTCS); calculate the costs that it incurs in the day-ahead timeframe that correspond to its DAUS, and the costs that it incurs (or saves) in the real-time timeframe as a result of being dispatched to a real-time constrained schedule (RTCS) that differs from its DAUS; and compare these revenues against the costs thus calculated to determine eligibility for a PCG. Since the day-ahead costs calculated under this approach are based on a generator's DAUS, I say that it "focuses on the DAUS."

Alternatively, we can start with the costs that a generator would incur in the day-ahead timeframe if it takes actions that are consistent with the real-time operational expectations that are communicated to it at that time—i.e,, if it incurs day-ahead costs consistent with its DACS, since the DACS is expected to be a good predictor of the RTCS—plus any incremental costs incurred (or saved) in real time as a result of moving up or down from its DACS to its actual RTCS; calculate the revenues it receives in association with being scheduled to produce those amounts of energy; and compare those revenues against those costs to determine eligibility for a PCG. Since the day-ahead costs calculated under this approach are based on a generator's DACS, I say that this approach "focuses on the DACS."

[1] The discussion to follow is couched in terms of generation, but it could also apply to dispatchable loads, imports and exports.

DAUS-Focused Methods for Calculating PCG Payments

Initially, let us follow the first of these approaches. Under the two-settlement system envisioned for DAM Option 3, a generator would receive:

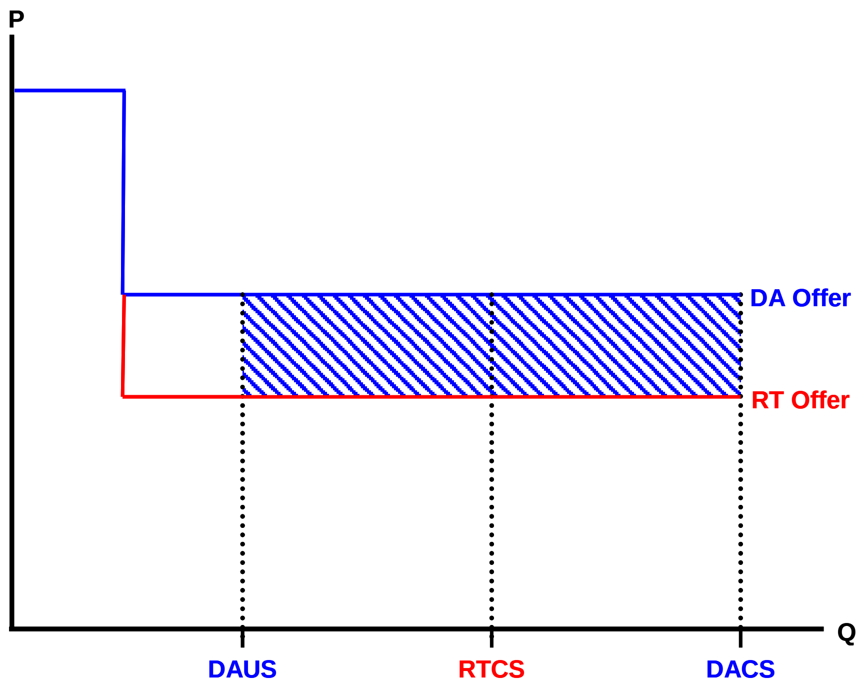
- Day-ahead revenues equal to its DAUS times the day-ahead price.
- Real-time revenues equal to its RTCS minus its DAUS times the real-time price.
- CMSC payments, when its real-time unconstrained schedule (RTUS) differs from its RTCS.

For comparison to the day-ahead revenues this generator realizes, we can calculate the costs it would incur, as offered in the day-ahead market, to be able to generate its DAUS. For comparison to the real-time revenues it realizes, we can calculate the costs it would incur, as offered in the real-time market, to increase (or decrease) its output from its DAUS to its RTCS. A generator would then be due a PCG if the sum of these costs exceeded the sum of the revenues it realizes. Methods 1b and 2, which are two of the methods we examined at our previous meetings, adopted this approach. (Method 1b was a unified calculation, while Method 2 calculated separate day-ahead and real-time PCG payments.)

However, the DAUS-focused approach has several shortcomings due to the fact that it never takes the DACS into account, and therefore may not consider costs that the generator incurs as a result of taking actions following the announcement of day-ahead schedules that are consistent with an expectation that it will be dispatched to operate at its DACS in real time.

For example, suppose that a gas-fired generator receives a DACS that exceeds its DAUS. It nominates sufficient gas to cover its DACS, and submits a reduced real-time bid for all of the energy it can generate using that gas, reflecting the fact that it will incur a financial penalty if it does not burn all of that gas, so only part of the costs incurred to purchase that gas day-ahead can be recouped. In that case, the difference between the day-ahead and real-time offers for this generator when operating at or below its DACS represent costs that it has incurred in the expectation that it will be dispatched to operate at its DACS in real time.

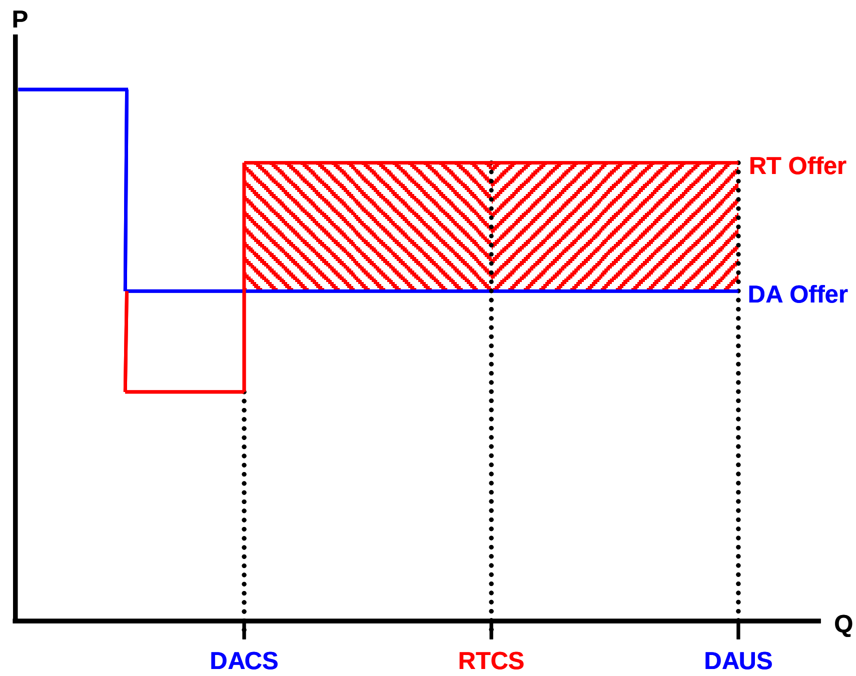
But if this generator receives an RTCS that is equal to or above its DAUS, Methods 1b and 2 for calculating PCG would only consider its real-time offer for capacity above its DAUS when calculating whether it is owed a PCG. The difference between the day-ahead and real-time offers for the difference between the DAUS and the DACS, which is represented by the shaded region in the figure below, would be ignored, even though these represent costs that the generator has actually incurred. Of course, this would discourage the generator from incurring these costs, but this is not an efficient outcome: If the DACS is the best available forecast of the RTCS, generators should expect to operate at the DACS and should enter into commitments, such as gas nominations, that are consistent with that expectation.



Problems with this approach also can arise when a generator receives a DACS that is less than its DAUS. Suppose that such a generator only nominates enough gas to cover its DACS, and submits an increased real-time bid to generate energy in excess of the amount it can generate using that gas, reflecting the fact that it will have to purchase intraday gas to operate at a level above its DACS, and it expects the cost of intraday gas to exceed the price of gas purchased a day ahead. In that case, the difference between the day-ahead and real-time offers for this generator when operating above its DACS represent costs that it has not incurred, and which it will only incur if it is dispatched to operate above its DACS in real time.

But if this generator receives an RTCS that is less than or equal to its DAUS, Methods 1b and 2 for calculating PCG would subtract its real-time offer for capacity between its RTCS and its DAUS from its day-ahead offer for that capacity when calculating the costs it incurred. In other words, this approach ignores the difference between this generator's real-time offer and its day-ahead offer, although it must incur these costs as a result of being scheduled to operate above its DACS (while having purchased only enough gas in the day-ahead gas market to cover its DACS). These unrecognized costs are represented by the region with downward-sloping shading in the figure below.

In addition, this approach imputes savings to this generator equal to the difference between its day-ahead and real-time offers resulting from having been dispatched to operate at a level below its DAUS. These "savings" are represented by the region with upward-sloping shading in the figure below. But the generator did not actually save this amount. It never purchased the gas needed to operate above its RTCS, in either the day-ahead or intraday gas markets, so it did not save any money as a result of being directed not to burn gas that it had already purchased. Consequently, this method for calculating the PCG imputes savings to this generator that it did not actually realize, because it only purchased enough gas to cover its DACS. This may encourage the generator to buy enough gas in the day-ahead gas market to cover its DAUS, but this is also not an efficient outcome, because once again, if the DACS is the best available forecast of the RTCS, generators should expect to operate at the DACS and should enter into commitments, such as gas nominations, that are consistent with that expectation.



DACS-Focused Methods for Calculating PCG Payments

Under the alternative approach described above, we start with the costs that generators would incur if they take actions that are consistent with their operational expectations, and match revenues to those costs. If a generator incurs costs that are consistent with its operational expectations as communicated by the IESO, it would:

- Incur costs, as offered in the day-ahead market, to be able to generate its DACS.
- Incur costs, as offered in the real-time market, to increase (or decrease) its output from its DACS to its RTCS.

For comparison to the day-ahead costs this generator incurs to generate its DACS, we can calculate the amount that it is paid to produce its DACS, some of which will be realized in the real-time market if the DACS exceeds the DAUS. For comparison to the real-time costs this generator real-time incurs to move from its DACS to its RTCS, we can calculate the amount that it is paid (or pays) as a result of moving from its DACS to its RTCS, some of which will be realized in the day-ahead market if the DACS is less than the DAUS. In addition, the generator may receive a CMSC payment. Methods 1a and 3, the other two methods we examined at our previous meetings, adopted this approach.

During the last meeting of the PCG Technical Study Group (TSG), there was agreement to explore these DACS-focused methods further. Detailed calculation procedures used by Methods 1a and 3 are as follows:

Method 1a

Under Method 1a, the generator receives a PCG payment to the extent that the total revenue it earns over the course of a day is less than its total as-offered cost.

Its total revenue consists of:

- Revenue earned from sale in the DAM of an amount of energy equal to its DAUS.
- Revenue earned from the sale in the real-time market of an amount of energy equal to its RTCS minus its DAUS (or the cost of purchasing that amount of energy in the real-time market, if its RTCS is less than its DAUS).
- CMSC payments.

Its total as-offered cost consists of the sum of:

- Its day-ahead as-offered cost to produce its DACS.
- Its real-time as-offered cost to produce the difference between its RTCS and its DACS, if its RTCS exceeds its DACS, or the savings resulting from being dispatched to its RTCS, instead of its DACS, as measured by its real-time offers, if its RTCS is less than its DACS.

Method 3

Under Method 3, a generator receives a PCG payment to the extent that the sum of the DACS PCG payment for which it is eligible and the supplemental PCG payment for which it eligible exceeds the CMSC payments it receives. In turn, a generator will be eligible for a DACS PCG payment to the extent that its DACS revenue for a given day is less than its DACS as-offered cost, and it will be eligible for a supplemental PCG payment to the extent that its supplemental revenue for a given day is less than its supplemental as-offered cost.

Its DACS revenue consists of:

- Revenue earned from the sale in the DAM of an amount of energy equal to the lesser of its DAUS or its DACS.

- Revenue earned from the sale in the real-time market of an amount of energy equal to its DACS minus its DAUS (or zero, if its DAUS exceeds its DACS).

Its DACS as-offered cost is its day-ahead as-offered cost to produce its DACS.

Its supplemental revenue consists of:

- Revenue earned from the sale in the DAM of an amount of energy equal to its DAUS minus its DACS (or zero, if its DACS exceeds its DAUS).

- Revenue earned from the sale in the real-time market of an amount of energy equal to its RTCS minus the greater of its DACS and its DAUS (or the cost of purchasing that amount of energy in the real-time market, if its RTCS is less than the greater of its DACS and its DAUS).

Its supplemental as-offered cost is its real-time as-offered cost to produce the difference between the RTCS and the DACS, if its RTCS exceeds its DACS, or the savings resulting from being dispatched to its RTCS, instead of its DACS, as measured by its real-time offers, if RTCS is less than its DACS.

The allocation of revenue between DACS revenue and supplemental revenue may be easier to understand if presented graphically. Appendix A contains such an illustration.

SCENARIOS TO BE EVALUATED AND ASSUMPTIONS FOR EXAMPLE

The RTUS does not directly enter into the equations used to calculate the PCG using either Method 1a or Method 3.[2] There are six ways of ordering the three schedules that directly enter into the PCG calculation using these two methods, so we will examine these methods for one scenario corresponding to each possible ordering. Specifically:

- In Scenario 1, RTCS > DAUS > DACS.

- In Scenario 2, RTCS > DACS > DAUS.

- In Scenario 3, DAUS > RTCS > DACS.

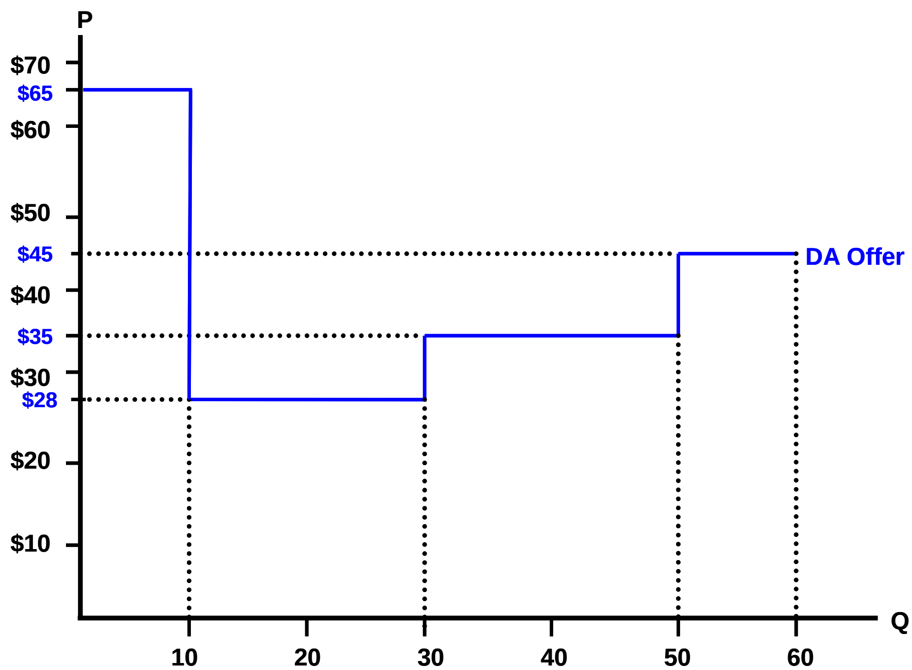
- In Scenario 4, DAUS > DACS > RTCS.

- In Scenario 5, DACS > DAUS > RTCS.

[2] The RTUS it plays an indirect role, since it is used in the calculation of the CMSC payment

- In Scenario 6, DACS > RTCS > DAUS.

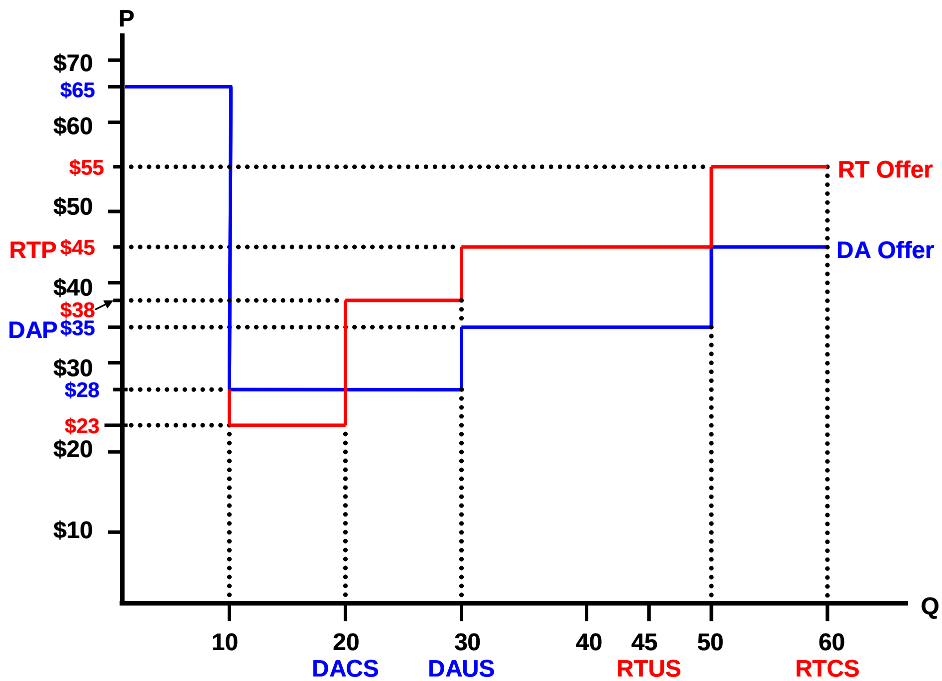
The generator that will be used in the example is similar to the generator that has been used in previous examples. As is illustrated below, its day-ahead offer consists of a minimum generation offer of $650/hour and a minimum generation level of 10 MW, corresponding to a minimum generation cost of $65/MWh; a $28/MWh offer to operate at up to 20 MW above its minimum generation level; a $35/MWh offer for its next 20 MW of capacity, and a $45/MWh offer for its last 10 MW of capacity. I will assume that these offers reflect its actual day-ahead costs.



In the real-time market, I will assume that the generator has nominated enough gas to permit it to operate at its DACS, and no more. I will assume that the generator submits a real-time offer that is $5/MWh below its day-ahead offer for all capacity between its minimum generation level and its DACS, reflecting the financial penalty it expects to incur if it does burn nominated gas, and a real-time offer that is $10/MWh above its day-ahead offer for all capacity above its DACS, reflecting its expectation that intraday gas will be more expensive than gas purchased a day ahead.

SCENARIO 1: RTCS > DAUS > DACS

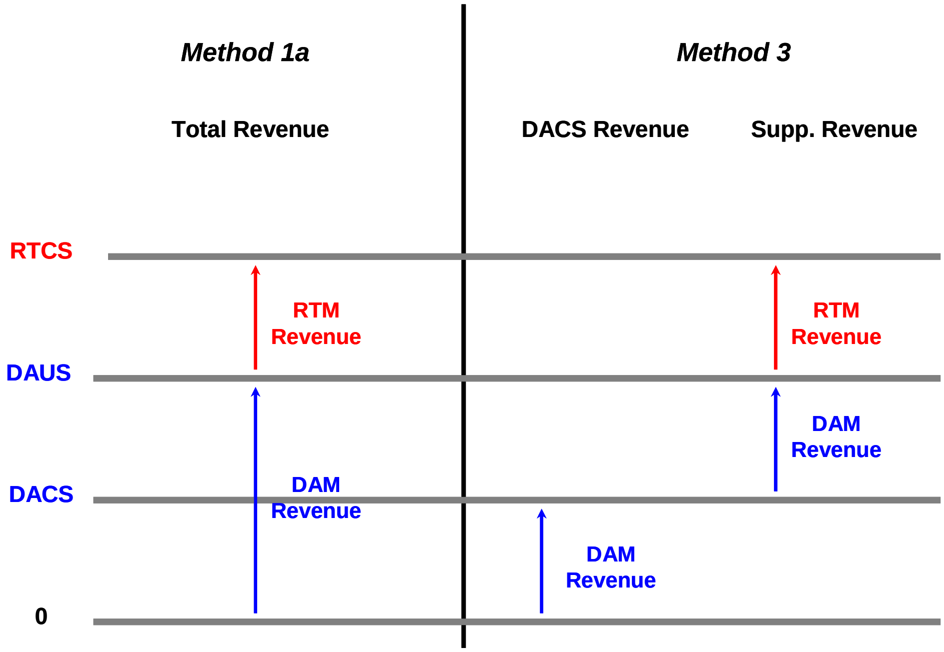
In this scenario, as illustrated in the figure below, we assume that the generator receives a DACS of 20 MWh and a DAUS of 30 MWh. The day-ahead price is $35/MWh, at the high end of the range of prices that are consistent with a 30 MWh DAUS and this generator's day-ahead offer curve. It only nominates gas to cover its 20 MWh DACS, so its real-time offer is $28/MWh – $5/MWh = $23/MWh to operate at up to 10 MW above its 10 MW minimum generation level; $28/MWh + $10/MWh = $38/MWh for its next 10 MW of capacity; $35/MWh + $10/MWh = $45/MWh for its next 20 MW of capacity, and $45/MWh + $10/MWh = $55/MWh for its last 10 MW of capacity. Then, in real time, its RTUS increases to 45 MWh and its RTCS jumps to 60 MWh; it is constrained up in real time, while it was constrained down in the DAM. The real-time price increases to $45/MWh.



This generator incurs $650 + $28/MWh x 10 MWh = $930 in day-ahead as-offered costs to produce its 20 MWh DACS, and another $38/MWh x 10 MWh + $45/MWh x 20 MWh + $55/MWh x 10 MWh = $1830 in real-time as-offered costs to increase its output to its RTCS of 60 MWh, for a total of $2760. Therefore, for the purposes of Method 1a, its total as-offered costs are $2760, and for the purposes of Method 3, its DACS as-offered costs are $930 and its supplemental as-offered costs are $1830.

The figure below illustrates how total revenue is calculated for Method 1a and how DACS revenue and supplemental revenue are calculated for Method 3 in this scenario.[3] This generator's DACS revenue is $35/MWh x 20 MWh = $700, and its supplemental revenue consists of the $35/MWh x (30 MWh – 20 MWh) = $350 in remaining day-ahead revenue, plus its $45/MWh x 30 MWh = $1350 in real-time revenue, for a total of $1700. In addition, it receives CMSC payments of ($55/MWh – $45/MWh) x (60 MWh – 50 MWh) = $100 for being constrained up in real time. Therefore, this generator's total revenue is $700 + $1700 + $100 = $2500.

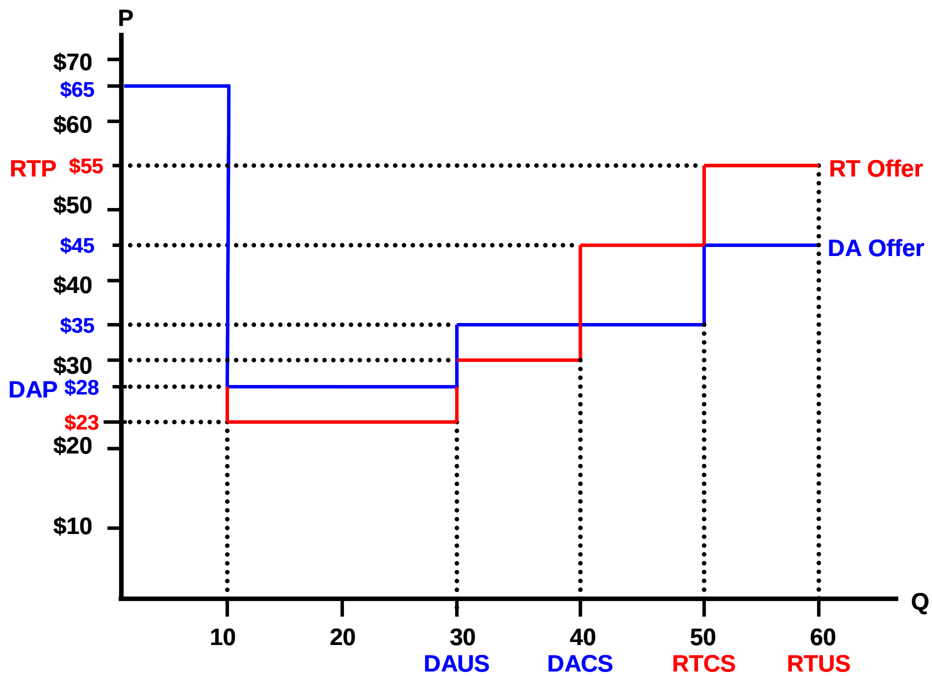
[3] These figures exclude CMSC payments.



Under Method 1a, this generator receives a PCG payment of $2760 – $2500 = $260. Under Method 3, it is eligible for a DACS PCG payment of as much as $930 – $700 = $230, and a supplemental PCG payment of as much as $1830 – $1700 = $130. However, since it receives $100 in CMSC payments, the total PCG payment it receives is reduced by $100, to $230 + $130 – $100 = $260, which is the same PCG payment that resulted from the use of Method 1a.

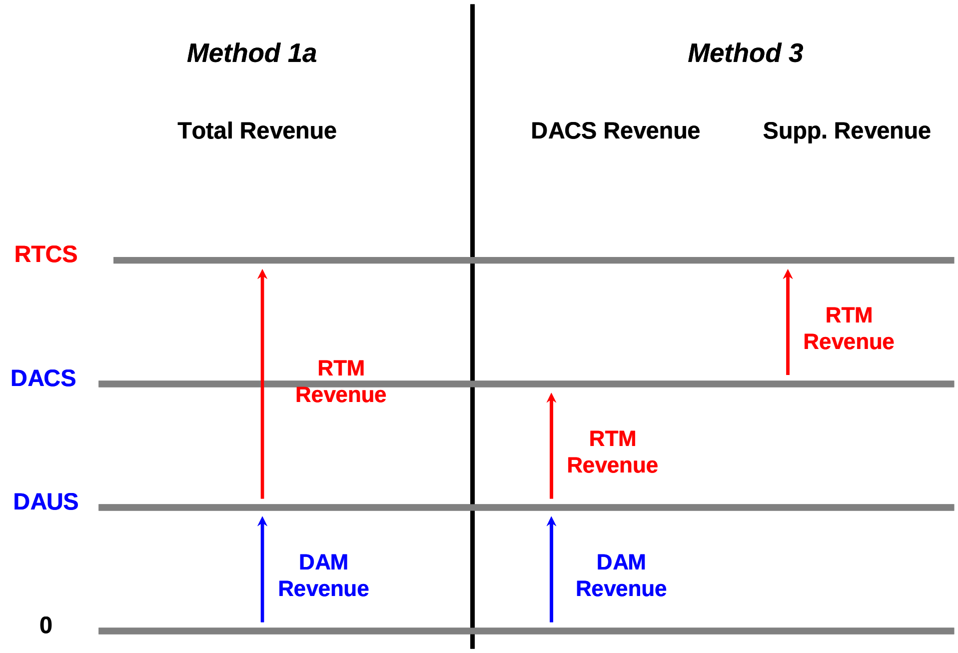
SCENARIO 2: RTCS > DACS > DAUS

In this scenario, as illustrated in the figure below, we assume that the generator's DAUS is still 30 MWh, but its DACS is now 40 MWh. The day-ahead price is $28/MWh, which is at the low end of the range of prices that is consistent with a 30 MWh DAUS and this generator's day-ahead offer curve. It nominates gas to cover its 40 MWh DACS, so its real-time offer is $28/MWh – $5/MWh = $23/MWh to operate at up to 20 MW above its 10 MW minimum generation level; $35/MWh – $5/MWh = $30/MWh for its next 10 MW of capacity; $35/MWh + $10/MWh = $45/MWh for its next 10 MW of capacity, and $45/MWh + $10/MWh = $55/MWh for its last 10 MW of capacity. Then, in real time, its RTUS increases to 60 MWh and its RTCS also increases, but only to 50 MWh; it is constrained down in real time, while it was constrained up in the DAM. The real-time price increases to $55/MWh.



This generator incurs $650 + $28/MWh x 20 MWh + $35/MWh x 10 MWh = $1560 in day-ahead as-offered costs to produce its 40 MWh DACS, and another $45/MWh x 10 MWh = $450 in real-time as-offered costs to increase its output to its RTCS of 50 MWh, for a total of $2010. Therefore, for the purposes of Method 1a, its total as-offered costs are $2010, and for the purposes of Method 3, its DACS as-offered costs are $1560 and its supplemental as-offered costs are $450.

The figure below illustrates how total revenue is calculated for Method 1a and how DACS revenue and supplemental revenue are calculated for Method 3 in this scenario. This generator's DACS revenue is its $28/MWh x 30 MWh = $840 in day-ahead revenues, plus another $55/MWh x (40 MWh – 30 MWh) = $550 in real-time revenues, for a total of $1390. Its supplemental revenue consists of its $55/MWh x (50 MWh – 40 MWh) = $550 in remaining real-time revenue. It does not receive CMSC payments, even though it is constrained down in real time, because its real-time offer for the constrained-down capacity is equal to the real-time price. Therefore, this generator's total revenue is $1390 + $550 = $1940.

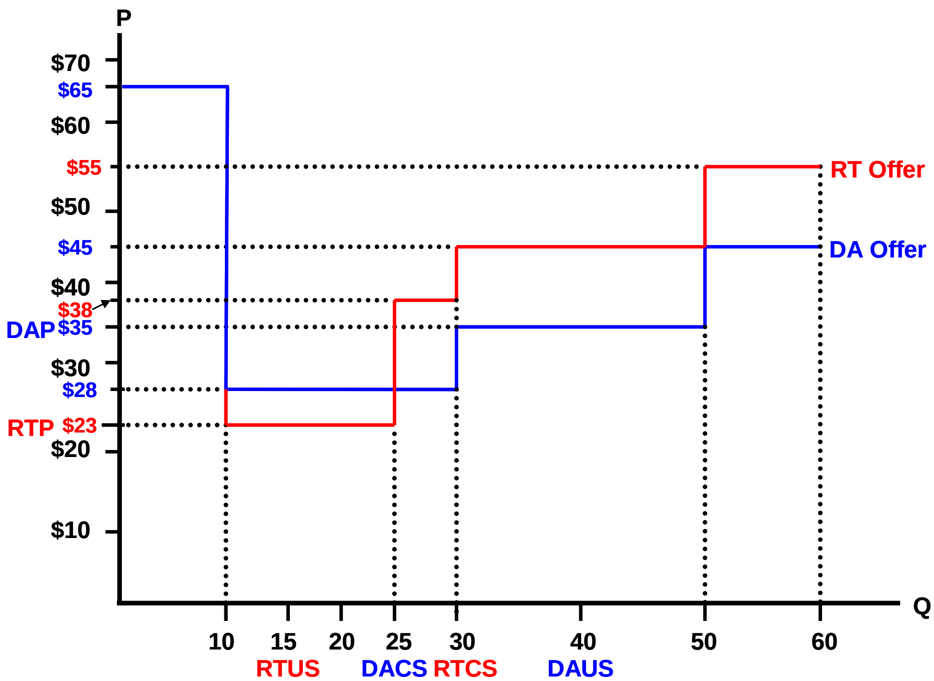


Under Method 1a, this generator receives a PCG payment of $2010 – $1940 = $70. Under Method 3, it receives a DACS PCG payment of $1560 – $1390 = $170. It is not eligible for a supplemental PCG payment, since its supplemental revenues exceed its supplemental as-offered costs, nor is its DACS PCG payment reduced to account for its CMSC payments, since it did not receive any CMSC payments. Therefore, this generator is $100 better off under Method 3 than under Method 1a; it earns an operating profit of $100 under Method 3, while Method 1a left it with an operating profit of zero.

This scenario can be used to illustrate the point that I made in my October 5 memo to the TSG regarding bifurcated methods for calculating PCG payments. While it may appear that Method 1a will lead to lower PCG payments than Method 3, that conclusion is implicitly based on the assumption that the choice of a PCG calculation method will not affect the real-time offers that a generator makes. *But it will.* In this scenario, this generator realizes $100 in margins in excess of its as-offered real-time costs as a result of being dispatched above its DACS in the real-time market; Method 1a requires it to accept a reduced PCG payment to offset those real-time margins. This gives the generator an incentive to submit offers that overstate its actual costs, in order to make its margins appear smaller than they actually are, thereby reducing the impact of those real-time margins on the PCG payments it receives. Unfortunately, because it gives generators an incentive to submit offers that do not accurately reflect their costs, this approach would impair the IESO's ability to dispatch the system efficiently in real time. In contrast, Method 3 does not give generators an incentive to submit real-time offers that do not correctly represent actual real-time costs, because the margin that a generator earns in the real-time market does not affect the DACS PCG payment for which it may be eligible. It only affects the supplemental PCG payments for which it may be eligible.[4]

SCENARIO 3: DAUS > RTCS > DACS

In this scenario, as illustrated in the figure below, we assume that the generator's DACS is 25 MWh, while its DAUS is now 40 MWh. The day-ahead price is $35/MWh, as it must be given this generator's DAUS and its day-ahead offer curve. The generator only nominates gas to cover its 25 MWh DACS, so its real-time offer is $28/MWh – $5/MWh = $23/MWh to operate at up to 15 MW above its 10 MW minimum generation level; $28/MWh + $10/MWh = $38/MWh for its next 5 MW of capacity; $35/MWh + $10/MWh = $45/MWh for its next 20 MW of capacity, and $45/MWh + $10/MWh = $55/MWh for its last 10 MW of capacity. Then, in real time, its RTUS decreases to 15 MWh but its RTCS increases to 30 MWh; it is constrained up in real time, while it was constrained down in the DAM. The real-time price falls to $23/MWh.

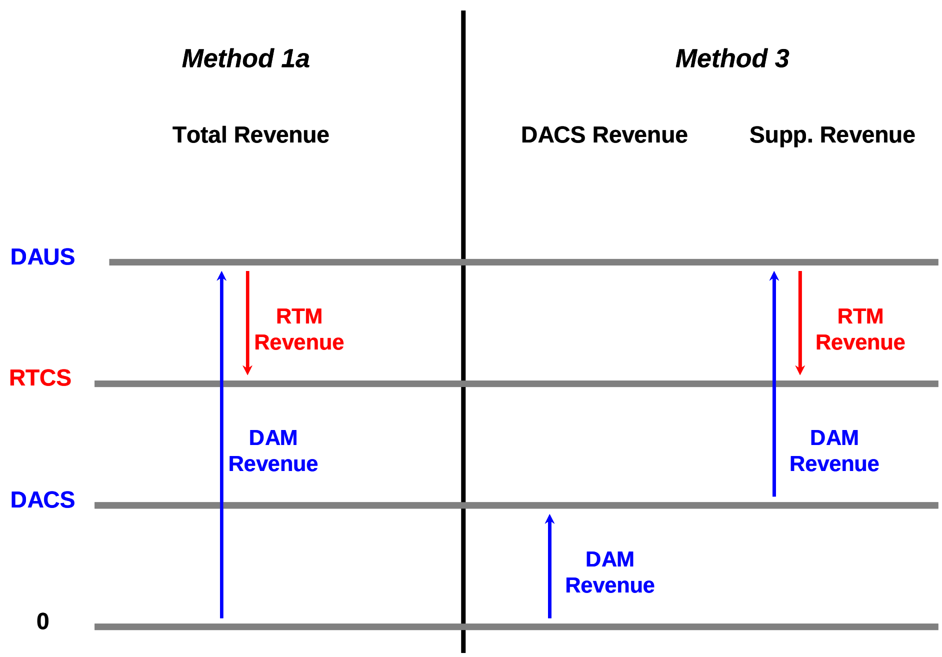


[4] It is important to note that any system of PCG payments will provide incentives for generators that expect to receive PCG payments to modify their offers, because those offers are used to determine their PCG payments. However, unified methods for calculating PCGs, such as Method 1a, exacerbate those incentives. If a generator expects to earn operating profits in the real-time market, it would not have an incentive to modify its offers in the real-time market if a bifurcated method of PCG calculation is used, but it may have such an incentive if a unified method is used.

PCG Calculation Using Methods 1a and 3

This generator incurs $650 + $28/MWh x 15 MWh = $1070 in day-ahead as-offered costs to produce its 25 MWh DACS, and another $38/MWh x 5 MWh = $190 in real-time as-offered costs to increase its output to its RTCS of 30 MWh, for a total of $1260. Therefore, for the purposes of Method 1a, its total as-offered costs are $1260, and for the purposes of Method 3, its DACS as-offered costs are $1070 and its supplemental as-offered costs are $190.

The figure below illustrates how total revenue is calculated for Method 1a and how DACS revenue and supplemental revenue are calculated for Method 3 in this scenario. This generator's DACS revenue is $35/MWh x 25 MWh = $875 in day-ahead revenues. Its supplemental revenue consists of $35/MWh x (40 MWh – 25 MWh) = $525 in remaining day-ahead revenues, minus $23/MWh x (40 MWh – 30 MWh) = $230 in real-time purchases, for a total of $295. In addition, it receives CMSC payments of ($38/MWh – $23/MWh) x (30 MWh – 25 MWh) = $75 for being constrained up in real time. Therefore, this generator's total revenue is $875 + $295 + $75 = $1245.



Under Method 1a, this generator receives a PCG payment of $1260 – $1245 = $15. Under Method 3, it is eligible for a DACS PCG payment of as much as $1070 – $875 = $195. It is not eligible for a supplemental PCG payment, since its supplemental revenue exceeds its supplemental as-offered costs. However, since it receives $75 in CMSC payments, the DACS PCG payment it receives is reduced by $75, to $195 – $75 = $120, which is still considerably more than it receives under Method 1a. It earns an operating profit of $105 under Method 3, while Method 1a left it with an operating profit of zero.

However, there is reason to believe that neither of these outcomes is the correct outcome. To see why, suppose for the moment that both the DACS and the RTCS for this generator were zero, but that its DAUS is positive. (This may not actually be possible, because generators with constrained schedules of zero may not be permitted to receive nonzero unconstrained schedules.) In that case, the generator would not run, nor would it be scheduled to run in the DAM, so it should not incur any costs. It would sell energy in an amount equal to its DAUS in the DAM, and it would buy that energy back in the real-time market. It would realize a gain if the real-time price is less than the day-ahead price, and it should realize a loss if the reverse occurs. But, under both Methods 1a and 3, it would not realize a loss if the real-time price is greater than the day-ahead price, because the PCG would make up any loss. Under Method 1a, its total revenue would be negative, which is less than its total as-offered cost of zero, so the PCG would offset its losses. Under Method 3, its DACS revenue would be zero, so its supplemental revenue would be negative, which is less than its supplemental as-offered cost of zero, so the supplemental PCG would offset its losses.

PCG Calculation Using Methods 1a' and 3'

This illustrates the need to modify these methods to guard against such outcomes. In general, to the extent that a generator's DAUS exceeds both its DACS and its RTCS, losses (and gains) on the difference between day-ahead and real-time prices should be excluded from the PCG calculation. This gives rise to the following modifications of the preceding PCG calculation methods, which I will call Methods 1a' and 3':

Method 1a'

Under Method 1a', the generator still receives a PCG payment to the extent that the total revenue it earns over the course of a day is less than its total as-offered cost. Its total as-offered cost is the same as defined above for Method 1a. But its total revenue is modified so that it now consists of:

- Revenue earned from sale in the DAM of an amount of energy equal to the lesser of (1) its DAUS, or (2) the greater of its DACS and its RTCS.
- Revenue earned from the sale in the real-time market of an amount of energy equal to its RTCS minus the lesser of (1) its DAUS, or (2) the greater of its DACS and its RTCS (or the cost of purchasing that amount of energy in the real-time market, if its RTCS is less than the lesser of (1) its DAUS, or (2) the greater of its DACS and its RTCS).
- CMSC payments.

Method 3'

Under Method 3', a generator still receives a PCG payment to the extent that the sum of the DACS PCG payment for which it is eligible and the supplemental PCG payment for which it eligible exceeds the CMSC payments it receives. The procedures for calculating the DACS PCG payment for which it is eligible remain the same as defined above for Method 3, but the procedures for calculating the supplemental PCG payment for which it is eligible change due to a modification in the formula for calculating its supplemental revenue, which now consists of:

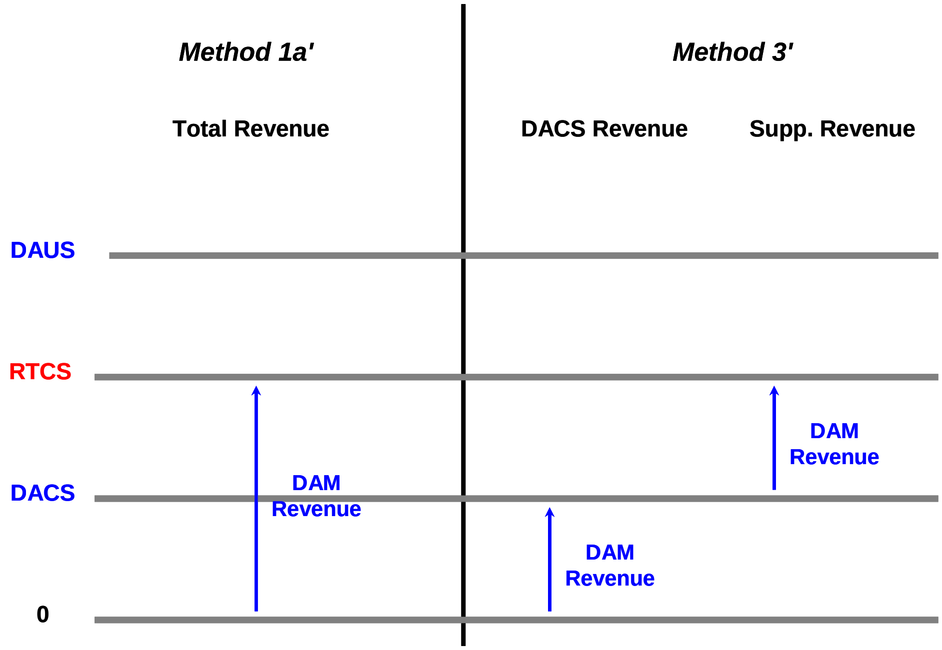
- Revenue earned from the sale in the DAM of the lesser of its DAUS and its RTCS minus its DACS (or zero, if its DACS exceeds the lesser of its DAUS and its RTCS).
- Revenue earned from the sale in the real-time market of an amount of energy equal to its RTCS minus the greater of (1) its DACS and (2) the lesser of its DAUS and its RTCS (or the cost of purchasing that amount of energy in the real-time market, if its RTCS is less than the greater of (1) its DACS and (2) the lesser of its DAUS and its RTCS).

Appendix B contains an illustration of the revenue allocation procedures used by Method 3'.

These modifications will only produce different results than Methods 1a and 3 when the generator's DAUS exceeds both its DACS and its RTCS, which correspond to Scenarios 3 and 4. They produce the same results as Methods 1a and 3, respectively, when applied to Scenarios 1 and 2 above, or to Scenarios 5 and 6 to follow.

Calculation

The figure below illustrates how total revenue is calculated for Method 1a' and how DACS revenue and supplemental revenue are calculated for Method 3' in this scenario. This generator's DACS revenue remains \$35/MWh x 25 MWh = \$875. Its supplemental revenue for Method 3' consists of \$35/MWh x (30 MWh – 25 MWh) = \$175 in day-ahead revenues. In addition, it still receives CMSC payments of \$75 for being constrained up in real time. Therefore, this generator's total revenue for Method 1a' is \$875 + \$175 + \$75 = \$1125.

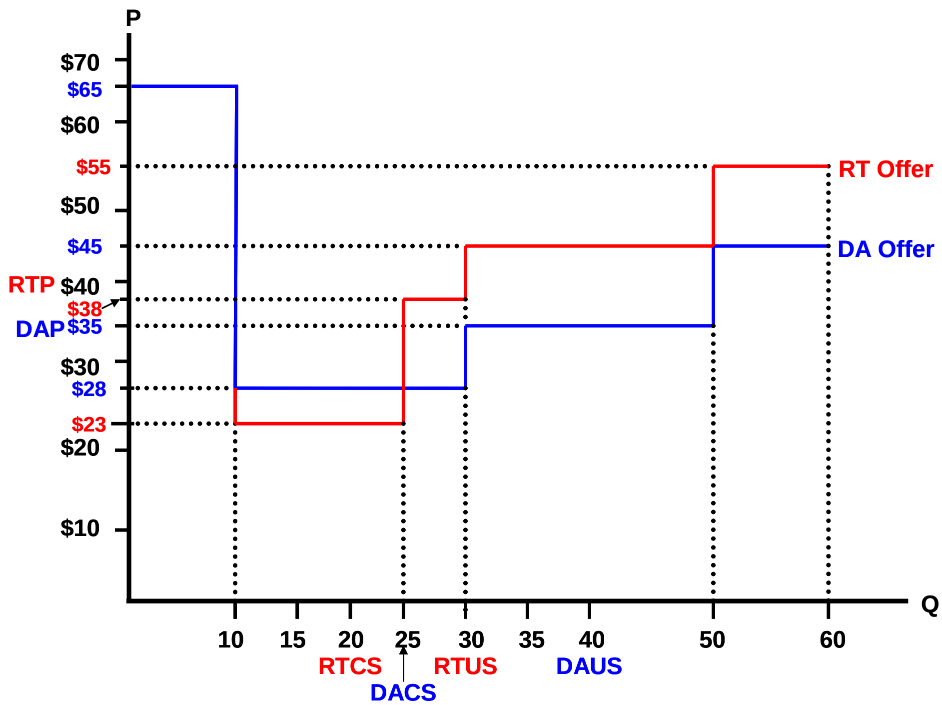


Under Method 1a', this generator receives a PCG payment of $1260 – $1125 = $135. Under Method 3', it remains eligible for a DACS PCG payment of as much as $1070 – $875 = $195; in addition, it is now eligible for a supplemental PCG payment of $190 – $175 = $15, since its supplemental revenue for Method 3' is less than its supplemental as-offered costs. However, since it receives $75 in CMSC payments, the PCG payments it receives are reduced by $75, to $195 + $15 – $75 = $135, the same amount that it receives under Method 1a'.

Either of these methods pays the generator $120 more than it would have received under Method 1a; in other words, both Methods 1a' and 3' leave the generator with an operating profit of $120, since Method 1a calculates the PCG that is necessary to bring the operating profit up to zero. This outcome is not surprising. The difference between this generator's DAUS and its RTCS is 10 MW. It sold those 10 MWh at a day-ahead price of $35/MWh, and covered that position by buying 10 MWh in the real-time market at a price of $23/MWh, thereby realizing a profit of 10 MWh x ($35/MWh – $23/MWh) = $120. These $120 in operating profits were excluded when total revenues were redefined for Method 1a' and supplemental revenues were redefined for Method 3'; consequently, the operating profit that the generator should realize under either of these methods should be at least $120.

SCENARIO 4: DAUS > DACS > RTCS

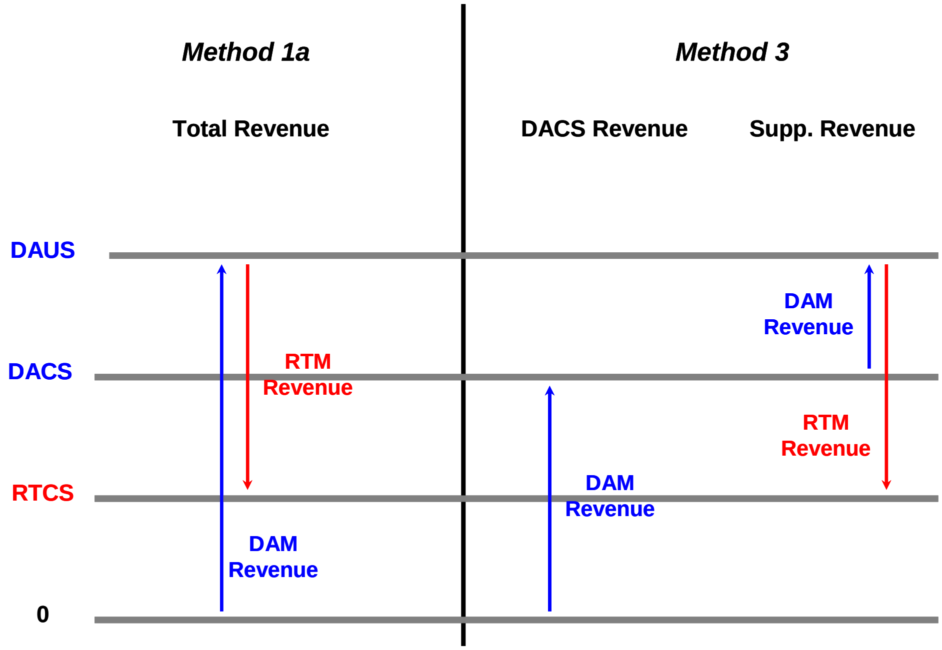
In this scenario, as illustrated in the figure below, we assume that the generator's DACS remains at 25 MWh, its DAUS remains 40 MWh, and the day-ahead price remains $35/MWh, each as in Scenario 3. The generator only nominates gas to cover its 25 MWh DACS, as in Scenario 3, so its real-time offer is also the same as in Scenario 3: $28/MWh – $5/MWh = $23/MWh to operate at up to 15 MW above its 10 MW minimum generation level; $28/MWh + $10/MWh = $38/MWh for its next 5 MW of capacity; $35/MWh + $10/MWh = $45/MWh for its next 20 MW of capacity, and $45/MWh + $10/MWh = $55/MWh for its last 10 MW of capacity. In real time, its RTCS decreases to 20 MWh and its RTUS decreases to 30 MWh; it is constrained down both in real time and in the DAM. The real-time price increases, to $40/MWh.



PCG Calculation Using Methods 1a and 3

This generator incurs $650 + $28/MWh x 15 MWh = $1070 in day-ahead as-offered costs to produce its 25 MWh DACS, minus $23/MWh x 5 MWh = $115 in real-time as-offered costs to decrease its output to its RTCS of 20 MWh, for a total of $955. Therefore, for the purposes of Method 1a, its total as-offered costs are $955, and for the purposes of Method 3, its DACS as-offered costs are $1070 and its supplemental as-offered costs are –$115.

The figure below illustrates how total revenue is calculated for Method 1a and how DACS revenue and supplemental revenue are calculated for Method 3 in this scenario. This generator's DACS revenue consists of $35/MWh x 25 MWh = $875 in day-ahead revenues. Its supplemental revenue for Method 3 consists of $35/MWh x (40 MWh – 25 MWh) = $525 in remaining day-ahead revenues, minus $40/MWh x (40 MWh – 20 MWh) = $800 in real-time purchases, for a total of –$275. In addition, it receives CMSC payments of ($40/MWh – $23/MWh) x (25 MWh – 20 MWh) + ($40/MWh – $38/MWh) x (30 MWh – 25 MWh) = $95 for being constrained down in real time. Therefore, this generator's total revenue for Method 1a is $875 – $275 + $95 = $695.

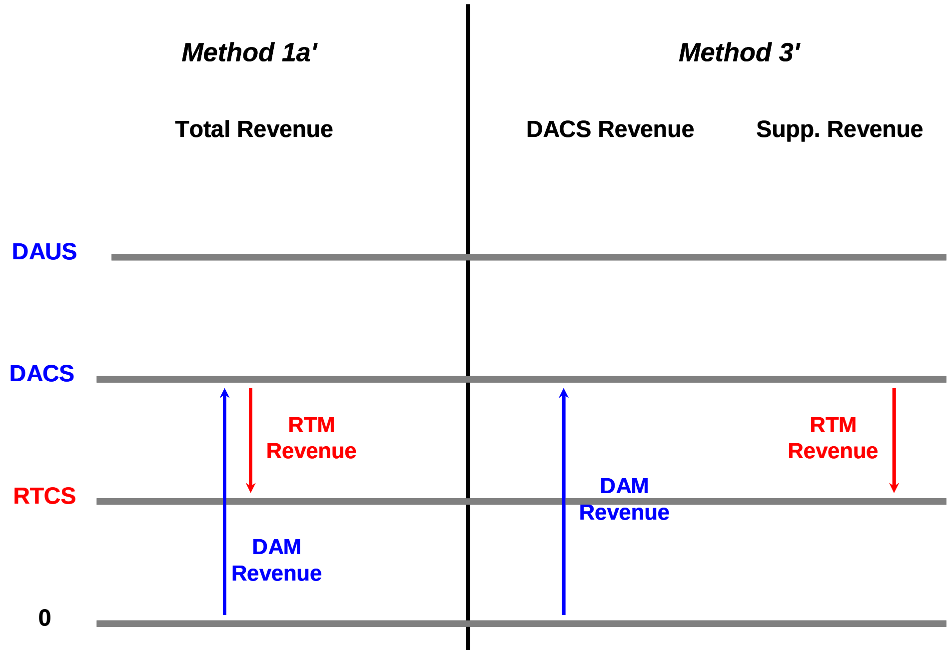


Under Method 1a, this generator receives a PCG payment of $955 – $695 = $260. Under Method 3, it is eligible for a DACS PCG payment of as much as $1070 – $875 = $195, and it is eligible for a supplemental PCG payment of as much as –$115 – (–$275) = $160. However, since it receives $95 in CMSC payments, the DACS PCG payment it receives is reduced by $95, to $195 + $160 – $95 = $260, the same amount that it receives under Method 1a. As a result, it earns an operating profit of zero under either Method 1a or Method 3.

PCG Calculation Using Methods 1a' and 3'

This generator's DAUS, which is 40 MWh, exceeds both its DACS (25 MWh) and its RTCS (20 MWh) in this scenario, just as in Scenario 3. Methods 1a' and 3' exclude gains or losses realized on the difference between day-ahead and real-time prices for the day-ahead position that a generator takes in excess of the greater of its DACS and its RTCS. In this case, since the real-time price exceeds the day-ahead price by $5/MWh, the generator realized a loss of $5/MWh x (40 MWh –25 MWh) = $75 on this position, so this $75 loss is excluded from the revenues used to determine the PCG it is due.

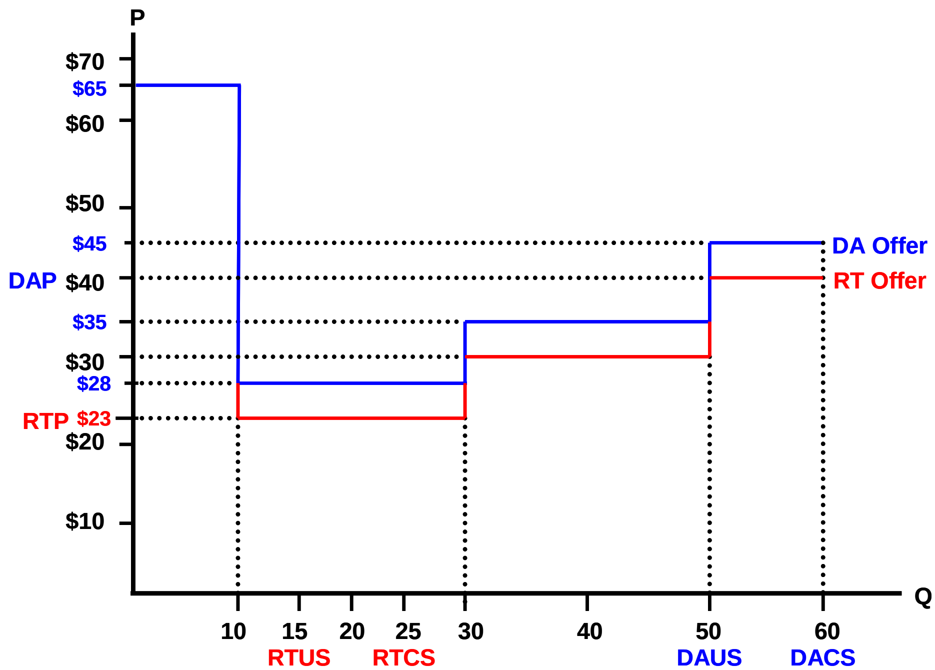
The figure below illustrates how total revenue is calculated for Method 1a' and how DACS revenue and supplemental revenue are calculated for Method 3' in this scenario. This generator's DACS revenue remains $35/MWh x 25 MWh = $875. Its supplemental revenue for Method 3' consists of $40/MWh x (20 MWh – 25 MWh) = –$200, reflecting the cost of buying out the difference between its DACS and its RTCS in the real-time market. In addition, it still receives CMSC payments of $95 for being constrained down in real time. Therefore, this generator's total revenue for Method 1a' is $875 – $200 + $95 = $770.



Under Method 1a', this generator receives a PCG payment of $955 – $770 = $185. Under Method 3', it remains eligible for a DACS PCG payment of as much as $1070 – $875 = $195, and it is eligible for a supplemental PCG payment of as much as –$115 – (–$200) = $85. However, since it receives $95 in CMSC payments, the DACS PCG payment it receives is reduced by $95, to $195 + $85 – $95 = $185, the same amount that it receives under Method 1a. These PCG payments are $75 less than the PCG payments this generator would have received in this scenario if Methods 1a or 3 had been used; therefore, the generator realizes an operating loss of $75, as was expected, since this was the loss it realized on the amount by which its financial position in the day-ahead market exceeded the greater of its DACS and its RTCS, and Methods 1a' and 3' do not compensate for such losses.

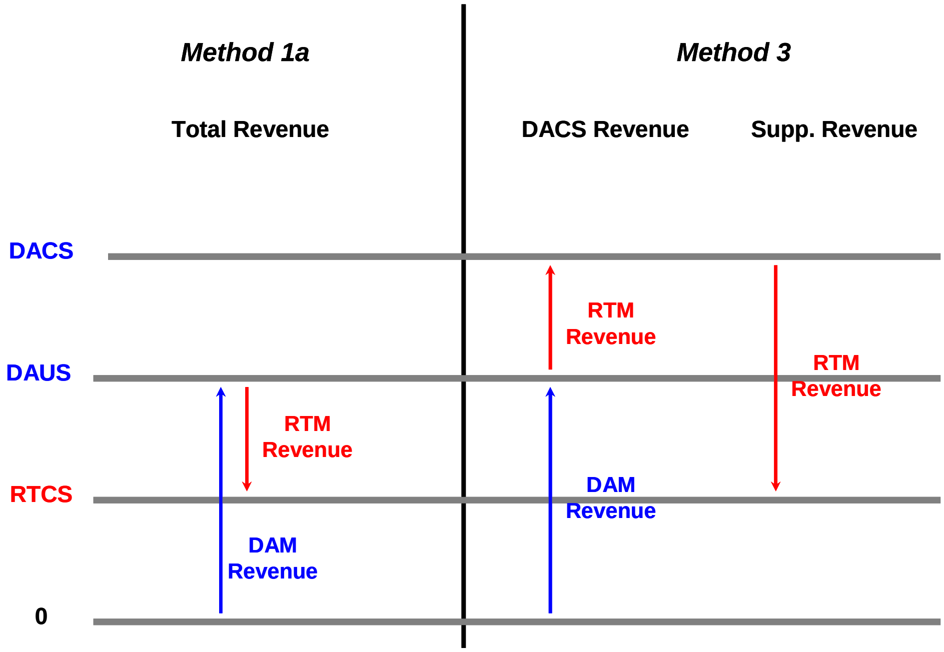
SCENARIO 5: DACS > DAUS > RTCS

In this scenario, as illustrated in the figure below, we assume that the generator's DACS is 60 MWh, its DAUS is 50 MWh, and the day-ahead price is $40/MWh, at the midpoint of the range of prices that is consistent with a 50 MWh DAUS and this generator's day-ahead offer curve. The generator nominates gas to cover its entire 60 MWh DACS, so its real-time offer is $28/MWh – $5/MWh = $23/MWh to operate at up to 20 MW above its 10 MW minimum generation level; $35/MWh – $5/MWh = $30/MWh for its next 20 MW of capacity, and $45/MWh – $5/MWh = $40/MWh for its last 10 MW of capacity. In real time, its RTCS decreases to 25 MWh and its RTUS decreases to 15 MWh; it is constrained up in both real time and the DAM. The real-time price falls to $23/MWh.



This generator incurs \$650 + \$28/MWh x 20 MWh + \$35/MWh x 20 MWh + \$45/MWh x 10 MWh = \$2360 in day-ahead as-offered costs to produce its 60 MWh DACS, minus \$23/MWh x 5 MWh + \$30/MWh x 20 MWh + \$40/MWh x 10 MWh = \$1115 in real-time as-offered costs to decrease its output to its RTCS of 25 MWh, for a total of \$1245. Therefore, for the purposes of Method 1a, its total as-offered costs are \$1245, and for the purposes of Method 3, its DACS as-offered costs are \$2360 and its supplemental as-offered costs are –\$1115.

The figure below illustrates how total revenue is calculated for Method 1a (and Method 1a', since they are equivalent in this scenario, as well as Scenario 6) in this scenario, as well as how DACS revenue and supplemental revenue are calculated for this scenario for Methods 3 and 3' (which are also equivalent in this scenario and in Scenario 6). This generator's DACS revenue consists of \$40/MWh x 50 MWh = \$2000 in day-ahead revenues, plus the remainder of its DACS valued at real-time prices, or \$23/MWh x (60 MWh – 50 MWh) = \$230, for a total of \$2230. Its supplemental revenue is \$23/MWh x (25 MWh – 60 MWh) = –\$805, reflecting the difference between its DACS and its RTCS valued at real-time prices. It does not receive CMSC payments, even though it is constrained up in real time, because its real-time offer for the capacity that is constrained up is equal to the real-time price. Therefore, this generator's total revenue for Method 1a is \$2230 – \$805 = \$1425.

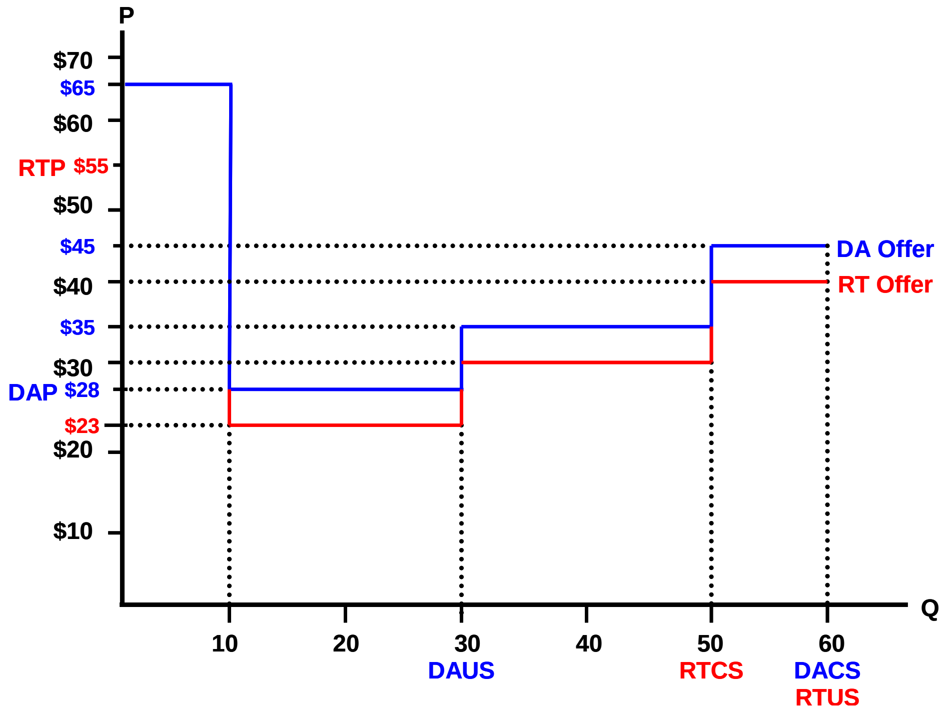


Under Method 1a, this generator does not receive a PCG payment, since its total revenue of $1425 exceeds its total as-offered costs of $1245. Instead, it realizes an operating profit of $180. Under Method 3, however, this generator receives a $130 PCG payment, because its DACS as-offered cost exceeds its DACS revenue by $2360 – $2230 = $130. (It is not eligible for a supplemental PCG payment since its supplemental revenues exceed its supplemental as-offered costs, but its DACS PCG payment does not need to be reduced to reflect any CMSC payments, since it does not receive any.) Therefore, under Method 3, this generator realizes an operating profit of $180 + $130 = $310.

At its 50 MWh DAUS, this generator receives $40/MWh x 50 MWh = $2000 in day-ahead revenues, which exceeds the $650 + $28/MWh x 20 MWh + $35/MWh x 20 MWh = $1910 in day-ahead as-offered costs that it incurs by $90. The payment of a PCG to this generator results from the fact that a payment of the $23/MWh real-time price is imputed to it for the 10 MWh difference between its DAUS and its DACS, which is considerably less than its $45/MWh day-ahead offer to generate that energy. The resulting $220 “loss” on these last 10 MWh converts the $90 day-ahead operating profit that this generator appeared to have earned on its DAUS into a $130 day-ahead operating loss, leading to a $130 DACS PCG payment.

SCENARIO 6: DACS > RTCS > DAUS

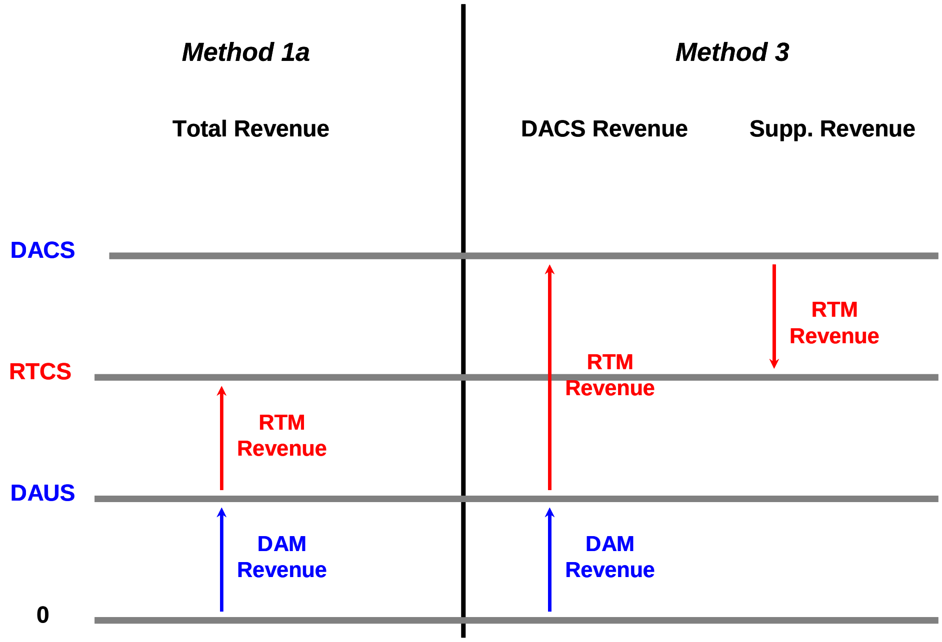
In this scenario, as illustrated in the figure below, we continue to assume that the generator’s DACS is 60 MWh, but its DAUS decreases to 30 MWh, and the day-ahead price falls to $28/MWh, the lowest price that is consistent with a 30 MWh DAUS and this generator’s day-ahead offer curve. The generator once again nominates gas to cover its entire 60 MWh DACS, so its real-time offer curve is the same as in Scenario 5: \$28/MWh – \$5/MWh = \$23/MWh to operate at up to 20 MW above its 10 MW minimum generation level; \$35/MWh – \$5/MWh = \$30/MWh for its next 20 MW of capacity, and \$45/MWh – \$5/MWh = \$40/MWh for its last 10 MW of capacity. In real time, its RTCS decreases to 50 MWh while its RTUS increases to 60 MWh; it is constrained down in real time after having been constrained up in the DAM. The real-time price increases to \$55/MWh.



This generator once again incurs \$650 + \$28/MWh x 20 MWh + \$35/MWh x 20 MWh + \$45/MWh x 10 MWh = \$2360 in day-ahead as-offered costs to produce its 60 MWh DACS, minus \$40/MWh x 10 MWh = \$400 in real-time as-offered costs to decrease its output to its RTCS of 50 MWh, for a total of \$1960. Therefore, for the purposes of Method 1a, its total as-offered costs are \$1960, and for the purposes of Method 3, its DACS as-offered costs are \$2360 and its supplemental as-offered costs are –\$400.

The figure below illustrates how total revenue is calculated for Method 1a (and Method 1a', since they are equivalent in this scenario) in this scenario, as well as how DACS revenue and supplemental revenue are calculated for this scenario for Methods 3 and 3' (which are also equivalent in this scenario). This generator's DACS revenue consists of \$28/MWh x 30 MWh = \$840 in day-ahead revenues, plus the remainder of its DACS valued at real-time prices, or \$55/MWh x (60 MWh – 30 MWh) = \$1650, for a total of \$2490. Its supplemental revenue is \$55/MWh x (50 MWh – 60 MWh) = –\$550, reflecting the difference between its DACS and its RTCS valued at real-time prices. It also receives CMSC payments of (\$55/MWh – \$40/MWh) x (60 MWh – 50 MWh) =

$150 for being constrained down in real time. Therefore, this generator's total revenue for Method 1a is $2490 – $550 + $150 = $2090.



This generator does not receive a PCG payment under either Method 1a or Method 3. Under Method 1a, its total revenue of $2090 exceeds its total as-offered costs of $1960, so it realizes an operating profit of $130. Under Method 3, its DACS revenue of $2490 also exceeds its DACS as-offered cost of $2360, so it is not eligible for a DACS PCG payment. Its supplemental as-offered cost of –$400 is $150 higher than its supplemental revenue of –$550, so it is eligible for a supplemental PCG payment of $150, but the CMSC payment must be deducted from any PCG payments under Method 3. The CMSC payment is also $150, leaving the generator with a PCG payment of zero.

Summary of Results

The table below summarizes the PCG payments and operating revenues that this generator would receive under Methods 1a, 1a', 3, and 3' in each of the six scenarios examined in this memo.

As the table shows, Method 1a only makes PCG payments to the generator if it is realizing an operating loss, and in those circumstances, it only makes the minimum payment necessary to prevent an operating loss. However, like any unified method for calculating PCGs, it will give an incentive to generators that would be due PCG payments at the close of the DAM to modify their real-time offers to disguise any margins that they may earn in the real-time market, which may reduce the efficiency of the IESO's real-time dispatch. In addition, it may provide insufficient or excessive payments in cases when the generator's DAUS exceeds both its DACS and its RTCS.

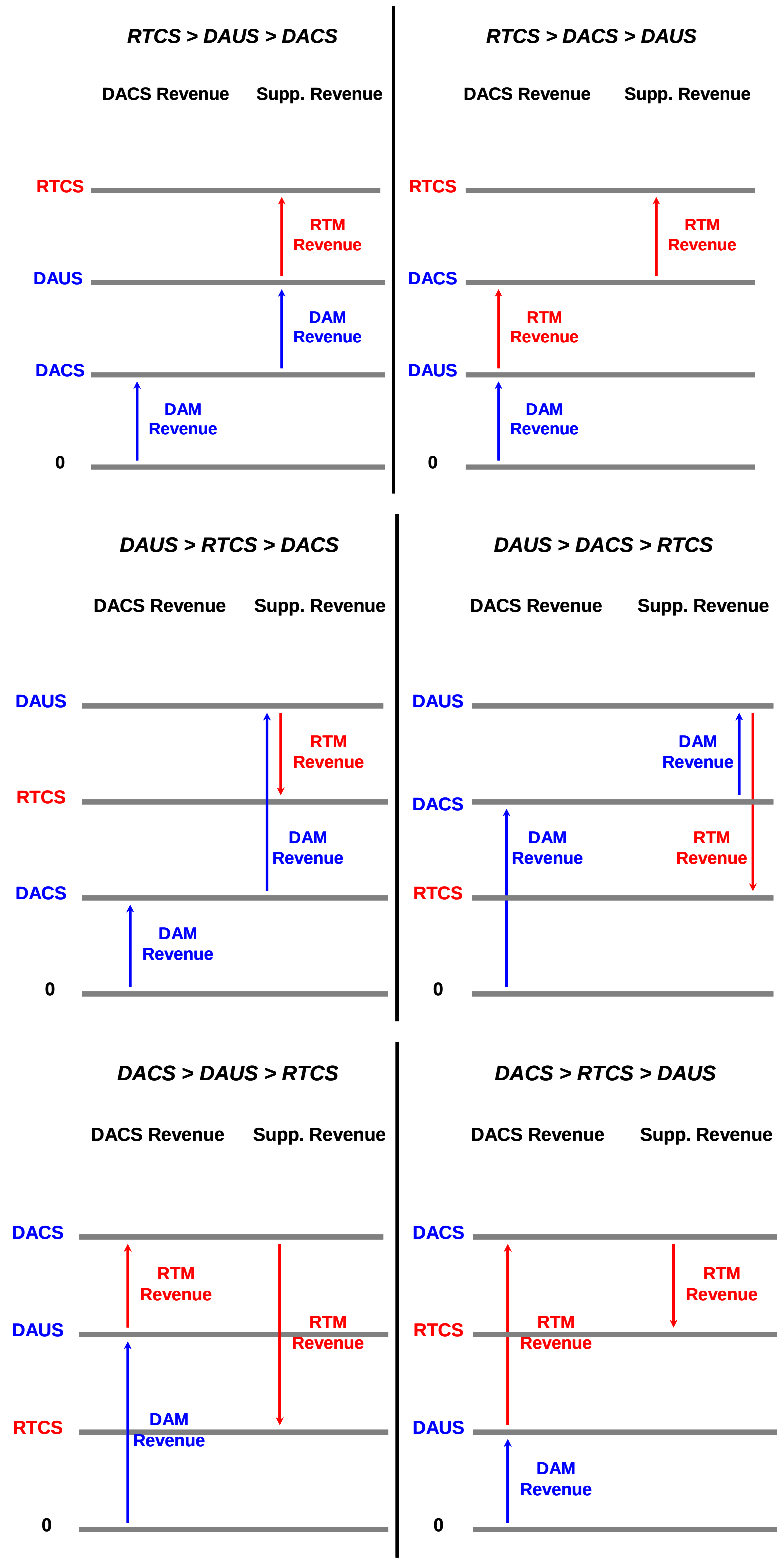
	Scenario					
	1	2	3	4	5	6
Assumptions						
DACS (MWh)	20	40	25	25	60	60
DAUS (MWh)	30	30	40	40	50	30
RTCS (MWh)	60	50	30	20	25	50
RTUS (MWh)	45	60	15	30	15	60
DAP ($/MWh)	35	28	35	35	40	28
RTP ($/MWh)	45	55	23	40	23	55
Method 1a						
PCG Payments ($)	260	70	15	260	-	-
Operating Profit ($)	-	-	-	-	180	130
Method 1a'						
PCG Payments ($)	260	70	135	185	-	-
Operating Profit ($)	-	-	120	(75)	180	130
Method 3						
PCG Payments ($)	260	170	120	260	130	-
Operating Profit ($)	-	100	105	-	310	130
Method 3'						
PCG Payments ($)	260	170	135	185	130	-
Operating Profit ($)	-	100	120	(75)	310	130

Method 1a' only makes PCG payments to the generator to the extent that its operating profit (or loss) is less than the operating profit (or loss) that would result from selling the amount by which its DAUS exceeds the greater of its DACS and its RTCS in the day-ahead market and buying that amount of energy back in the real-time market. Because it is also a unified method for calculating PCGs, using it has the same drawbacks for efficient real-time dispatch as does Method 1a.

Method 3 makes PCG payments to generators which, in some cases, may be greater than are needed to eliminate operating losses. This can occur because the generator is making operating profits in the real-time market. It can also occur in cases such as Scenario 5, when the DACS exceeds both the DAUS and the RTCS, and relatively low real-time revenues are imputed to that portion of the generator's output, although this does not always happen in such circumstances (as Scenario 6 showed). Because the DACS PCG for which a generator may be eligible is calculated using only day-ahead offers, it does not provide additional incentives for generators to modify their real-time offers in order to preserve their PCG payment, like Methods 1a or 1a'. Like Method 1a, it may provide insufficient or excessive payments in cases when the generator's DAUS exceeds both its DACS and its RTCS.

Method 3' makes PCG payments to generators which, in some cases, may be greater than are needed to make operating profits equal to the operating profit (or loss) that would result from selling the amount by which each generator's DAUS exceeds the greater of its DACS and its RTCS in the day-ahead market and buying that amount of energy back in the real-time market, for the same reasons as given above for Method 3. However, also like Method 3, it does not provide additional incentives for generators to modify their real-time offers in order to preserve their PCG payment, as Methods 1a and 1a' do.

Appendix A: Revenue Allocation Rules for Method 3



APPENDIX B: REVENUE ALLOCATION RULES FOR METHOD 3'