Proposed Guarantees and Exports Design

Material Presented to Technical Support Group for Enhanced Day-Ahead Commitment Process

August 8, 2008

"Note: This version 0.1 of the Proposed Guarantees and Exports Design Document is for viewing only. Stakeholder feedback on this proposal is being managed by web portal collaboration. For more background see:
http://www.ieso.ca/imoweb/news/newsItem.asp?newsItemID=4197.
Members of the Review team can be found at:
http://www.ieso.ca/imoweb/pubs/consult/se21/SE21_DAD_ReviewTeam.pdf.
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DA-PCG, DA-IOG, Exports

Summary

Beyond development of the common elements, the IESO was tasked with completing and presenting designs of both day-ahead guarantees for generators and intertie transactions and exports exclusion. These designs would support the benefit analysis of Option 2 expressed in their Day-Ahead Market Evolution Preliminary Assessment. The IESO has met with a technical support group (TSG) to present and discuss guarantee and export designs. The following is a summary of the work discussed with the TSG to date.

Limitations of the Settlement Equations

While the settlement equations in our examples have appropriate outcomes, the IESO would like to continue testing using a wide variety of potential values for DACS, RTCS, RTUS and RTP. Testing may demonstrate the need to modify aspects of the equations.

The methodology proposed here also does not provide for real-time PCG payments. If three-part bidding is used in the real-time market, real-time PCG payments would be necessary. The equations for calculating PCG payments at times when a generator's RTCS exceeds its DACS, which use the bifurcated approach (day-ahead and real-time PCG payments are calculated separately) , would have to be modified accordingly.

The equations here also do not account for start-up costs or ancillary services payments. They assume that there is a single schedule for each day and that the resource for which PCG and CMSC payments are being calculated is a generator. Finally, they assume that these generators follow their dispatch instructions precisely. Further modifications to this basic proposal will be necessary, as it will need to address circumstances when each of these assumptions does not hold.

Elements of DA-PCG Payments

Under the proposed method for calculating the DA-PCG payments made to eligible dispatchable generator would consist of three elements:

1. Any shortfall in payment on the delivered real-time dispatch of the day-ahead constrained advisory schedule will be based upon the real-time revenue received for that amount of energy in comparison with the costs as represented in the generator's day-ahead offer,

2. For the portion of day-ahead constrained advisory schedule that is not implemented in the real-time dispatch schedule, the DA-PCG will guarantee the unrecoverable cost of arranging the additional delivery (where real-time offer is less than day-ahead offer) or account for the over-recovery of those costs by subtracting any gain (where real-time offer is greater than day-ahead offer),
3. Any income from real-time CMSC included in a generator's day-ahead constrained advisory delivered in real-time will be used to reduce the DA-PCG payment.

Equations for Calculating DA-PCG Payments

Between day-ahead and real-time, there are six possible outcomes. Each will result in a different calculation of the DA-PCG and is based on the amount of a generator's capacity that may be included in the enhanced day-ahead commitment process, the real-time dispatch schedule (constrained schedule), and the market schedule (real-time unconstrained schedule) for a given 5 minutes dispatch interval:

1. RTCS ≥ RTUS ≥ DACS
2. RTUS ≥ RTCS ≥ DACS
3. RTCS ≥ DACS ≥ RTUS
4. DACS ≥ RTCS ≥ RTUS
5. RTUS ≥ DACS ≥ RTCS
6. DACS ≥ RTUS ≥ RTCS

Where:

RTCS = real-time constrained schedule (real-time dispatch schedule)

RTUS = real-time unconstrained schedule (real–time market schedule)

DACS = day-ahead constrained schedule (day-ahead advisory schedule)

The following describes how the DA-PCG would be calculated using a simplified formulas. For simplicity, the settlement equations do not reflect actual quantity of energy injected. Examples for each of the six possible outcomes follow the equation discussion.

1. RTCS ≥ RTUS ≥ DACS

The day-ahead PCG payment for this generator simply consists of the first element of the day-ahead PCG calculation, which is the generator's day-ahead offer to produce its DACS minus the real-time revenue it receives for that amount of energy. The second element does not apply in this case since its RTCS exceeds its DACS, and while this generator is eligible for CMSC payments for capacity because it is constrained on in real time, none of its constrained-on capacity is part of its DACS, so the third element also does not apply, and none of its CMSC payment is considered when calculating its day-ahead PCG payment. Therefore, this generator's day-ahead PCG payment is equal to:

	1. RTCS ≥ RTUS ≥ DACS
Energy Revenue	$RTP \cdot RTCS$
Constrained-Off Payments	0
Constrained-On Payments	$\int_{RTUS}^{RTCS} RTO - RTP \cdot (RTCS - RTUS).$
PCG Payments	$\max\left(0, \int_{0}^{DACS} DAO - RTP \cdot DACS\right)$
Total Revenue	$\max\left(\int_{0}^{DACS} DAO, RTP \cdot DACS\right) + RTP \cdot (RTUS - DACS) + \int_{RTUS}^{RTCS} RTO$
As-Offered Cost	$\int_{0}^{DACS} DAO + \int_{DACS}^{RTCS} RTO$
Total Margin	$\max\left(0, RTP \cdot DACS - \int_{0}^{DACS} DAO\right) + RTP \cdot (RTUS - DACS) - \int_{DACS}^{RTUS} RTO$

where:

DACS = day-ahead constrained schedule (day-ahead advisory schedule)

DAO = day-ahead offer for generator

RTP = real-time price

RTUS = real-time unconstrained schedule (real–time market schedule)

RTCS = real-time constrained schedule (real-time dispatch schedule)

RTO = real-time offer for generator

2. RTUS ≥ RTCS ≥ DACS

The day-ahead PCG payment for this generator again simply consists of the first element of the day-ahead PCG calculation, which is the generator's day-ahead offer to produce its DACS minus the real-time revenue it receives for that amount of energy. The second element does not apply in this case since its RTCS once again exceeds its DACS, and while this generator is eligible for CMSC payments for capacity because it is constrained off in real time, once again none of its constrained-off capacity is part of its DACS, so the third element also does not apply, and none of its CMSC payment is considered when calculating its day-ahead PCG payment. Therefore, just as in Ordering 1, this generator's day-ahead PCG payment is equal to:

	2. RTUS ≥ RTCS ≥ DACS
Energy Revenue	$RTP \cdot RTCS$
Constrained-Off Payments	$RTP \cdot (RTUS - RTCS) - \int_{RTCS}^{RTUS} RTO$
Constrained-On Payments	0
PCG Payments	$\max\left(0, \int_{0}^{DACS} DAO - RTP \cdot DACS\right)$
Total Revenue	$\max\left(\int_{0}^{DACS} DAO, RTP \cdot DACS\right) + RTP \cdot (RTUS - DACS) - \int_{RTCS}^{RTUS} RTO$
As-Offered Cost	$\int_{0}^{DACS} DAO + \int_{DACS}^{RTCS} RTO$
Total Margin	$\max\left(0, RTP \cdot DACS - \int_{0}^{DACS} DAO\right) + RTP \cdot (RTUS - DACS) - \int_{DACS}^{RTUS} RTO$

where variables are as defined above.

3. RTCS ≥ DACS ≥ RTUS

The day-ahead PCG payment for this generator simply consists of the first element of the day-ahead PCG calculation, which is the generator's day-ahead offer to produce its DACS minus the real-time revenue it receives for that amount of energy, less the third element, which consists of the CMSC payments it receives for constrained-on capacity that is included in its DACS. This generator also receives CMSC payments for constrained-on capacity that is not included in its DACS, but those payments are not considered when calculating its day-ahead PCG payment. The second element still does not apply since this generator's RTCS once again exceeds its DACS.

Under the procedures that are currently used to calculate CMSC payments, the CMSC payments and the DA-PCG payment this generator receives for the portion of its constrained-on capacity that is included in its DACS are:

	3. RTCS ≥ DACS ≥ RTUS
Energy Revenue	$RTP \cdot RTCS$
Constrained-Off Payments	0
Constrained-On Payments	$\max\left[0, \min\left(\int_{RTUS}^{DACS} DAO, \int_{RTUS}^{DACS} RTO\right) - RTP \cdot (DACS - RTUS)\right] + \int_{DACS}^{RTCS} RTO - RTP \cdot (RTCS - DACS).$
PCG Payments	$\max\left(0, \int_{0}^{DACS} DAO - RTP \cdot RTUS - \int_{RTUS}^{DACS} RTO\right)$
Total Revenue	$\max\left(\int_{0}^{DACS} DAO, RTP \cdot DACS\right) + \int_{DACS}^{RTCS} RTO$
As-Offered Cost	$\int_{0}^{DACS} DAO + \int_{DACS}^{RTCS} RTO$
Total Margin	$\max\left(0, RTP \cdot DACS - \int_{0}^{DACS} DAO\right)$

where variables are as defined above.

4. DACS ≥ RTCS ≥ RTUS

The day-ahead PCG payment for this generator in this case also includes all three elements of the day-ahead PCG calculation. It consists of the generator's day-ahead offer to produce its RTCS minus the real-time revenue it receives for that amount of energy, plus the difference between its day-ahead and real-time offers for the remaining capacity in its DACS, minus the CMSC payments it receives for all of its constrained-on capacity (since all of its constrained-on capacity is in its DACS).

Under the procedures that are currently used to calculate CMSC payments, the CMSC payments and the DA-PCG this generator receives are:

	4. DACS ≥ RTCS ≥ RTUS
Energy Revenue	$RTP \cdot RTCS$
Constrained-Off Payments	0
Constrained-On Payments	$\max\left[0, \min\left(\int_{RTUS}^{RTCS} DAO, \int_{RTUS}^{RTCS} RTO\right) - RTP \cdot (RTCS - RTUS)\right]$
PCG Payments	$\max\left(0, \int_{0}^{DACS} DAO - \int_{RTUS}^{DACS} RTO - RTP \cdot RTUS\right)$
Total Revenue	$\max\left(\int_{0}^{DACS} DAO - \int_{RTCS}^{DACS} RTO, RTP \cdot RTCS\right)$
As-Offered Cost	$\int_{0}^{DACS} DAO - \int_{RTCS}^{DACS} RTO$
Total Margin	$\max\left(0, RTP \cdot RTCS - \left(\int_{0}^{DACS} DAO - \int_{RTCS}^{DACS} RTO\right)\right)$

where variables are as defined above.

5. RTUS ≥ DACS ≥ RTCS

The day-ahead PCG payment for this generator in this case is the first to include all three elements of the day-ahead PCG calculation. It consists of the generator's day-ahead offer to produce its RTCS minus the real-time revenue it receives for that amount of energy, plus the difference between its day-ahead and real-time offers for the remaining capacity in its DACS, minus the CMSC payments it receives for constrained-off capacity that is included in its DACS. This generator also receives CMSC payments for constrained-off capacity that is not included in its DACS, but those payments are not considered when calculating its day-ahead PCG payment.

Under the procedures that are currently used to calculate CMSC payments, the CMSC payments this generator receives for its constrained-on capacity that is included in its DACS are:

	5. RTUS ≥ DACS ≥ RTCS and 6. DACS ≥ RTUS ≥ RTCS
Energy Revenue	$RTP \cdot RTCS$
Constrained-Off Payments	$RTP \cdot (RTUS - RTCS) - \int_{RTCS}^{RTUS} RTO$
Constrained-On Payments	0
PCG Payments	$\max\left(0, \int_{0}^{DACS} DAO + \int_{DACS}^{RTUS} RTO - RTP \cdot RTUS\right)$
Total Revenue	$\max\left(\int_{0}^{DACS} DAO - \int_{RTCS}^{DACS} RTO, RTP \cdot RTUS - \int_{RTCS}^{RTUS} RTO\right)$
As-Offered Cost	$\int_{0}^{DACS} DAO - \int_{RTCS}^{DACS} RTO$
Total Margin	$\max\left(0, RTP \cdot RTUS - \int_{0}^{DACS} DAO - \int_{DACS}^{RTUS} RTO\right)$

where all variables are as defined above

6. DACS ≥ RTUS ≥ RTCS

The day-ahead PCG payment for this generator in this case is very similar to the calculation of the payment in Ordering 5. It also includes all three elements of the day-ahead PCG calculation, and therefore consists of the generator's day-ahead offer to produce its RTCS minus the real-time revenue it receives for that amount of energy, plus the difference between its day-ahead and real-time offers for the remaining capacity in its DACS, minus the CMSC payments it receives for all of its constrained-off capacity (since all of its constrained-off capacity is in its DACS).

Under the procedures that are currently used to calculate CMSC payments, the CMSC payments this generator receives for constrained-off capacity that is included in its DACS are:

	5. RTUS ≥ DACS ≥ RTCS and 6. DACS ≥ RTUS ≥ RTCS
Energy Revenue	$RTP \cdot RTCS$
Constrained-Off Payments	$RTP \cdot (RTUS - RTCS) - \int_{RTCS}^{RTUS} RTO$
Constrained-On Payments	0
PCG Payments	$\max\left(0, \int_{0}^{DACS} DAO + \int_{DACS}^{RTUS} RTO - RTP \cdot RTUS\right)$
Total Revenue	$\max\left(\int_{0}^{DACS} DAO - \int_{RTCS}^{DACS} RTO, RTP \cdot RTUS - \int_{RTCS}^{RTUS} RTO\right)$
As-Offered Cost	$\int_{0}^{DACS} DAO - \int_{RTCS}^{DACS} RTO$
Total Margin	$\max\left(0, RTP \cdot RTUS - \int_{0}^{DACS} DAO - \int_{DACS}^{RTUS} RTO\right)$

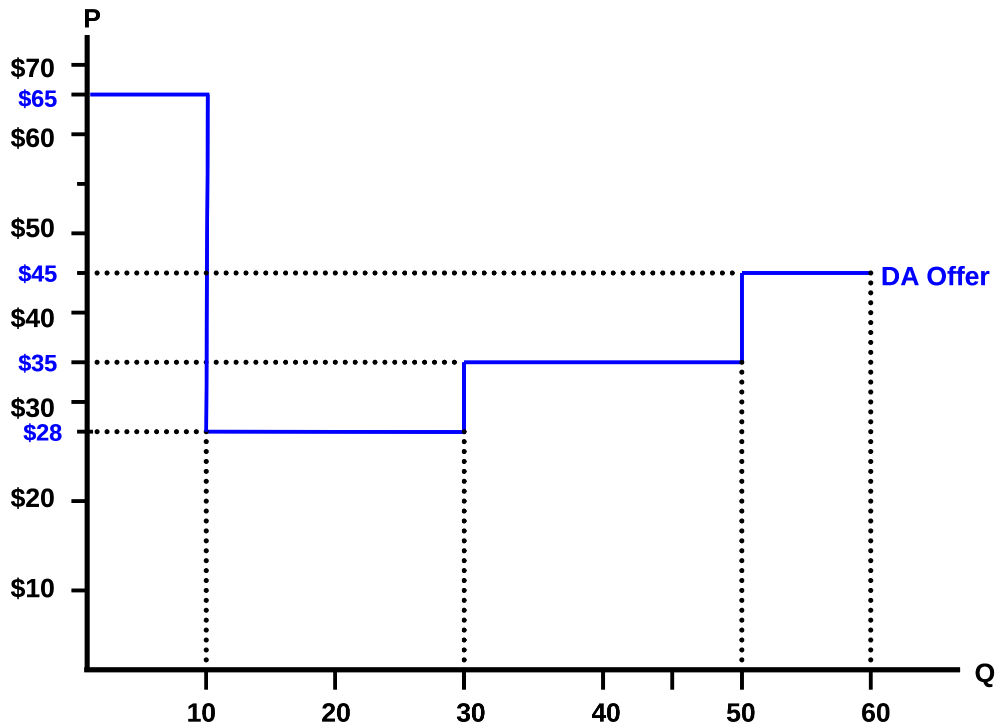
where all variables are as defined above

Examples for Each of the Six Possible Outcomes

For each of these six outcomes, the following will discuss the procedure to be used to calculate CMSC and PCG payments, with an illustrative example based on a 60 MW generator with a 10 MW minimum generation level. In the day-ahead commitment procedure, this generator offers to provide:

- 10 MW for $650/hour (the minimum generation offer).
- An additional 20 MW in addition to the minimum generation block for $28/MWh.
- An additional 20 MW in addition to the preceding two blocks for $35/MWh.
- An additional 10 MW in addition to the preceding two blocks for $45/MWh.

The resulting day-ahead offer curve is shown below.[1]



The generator is then assumed to submit a real-time offer curve that is:

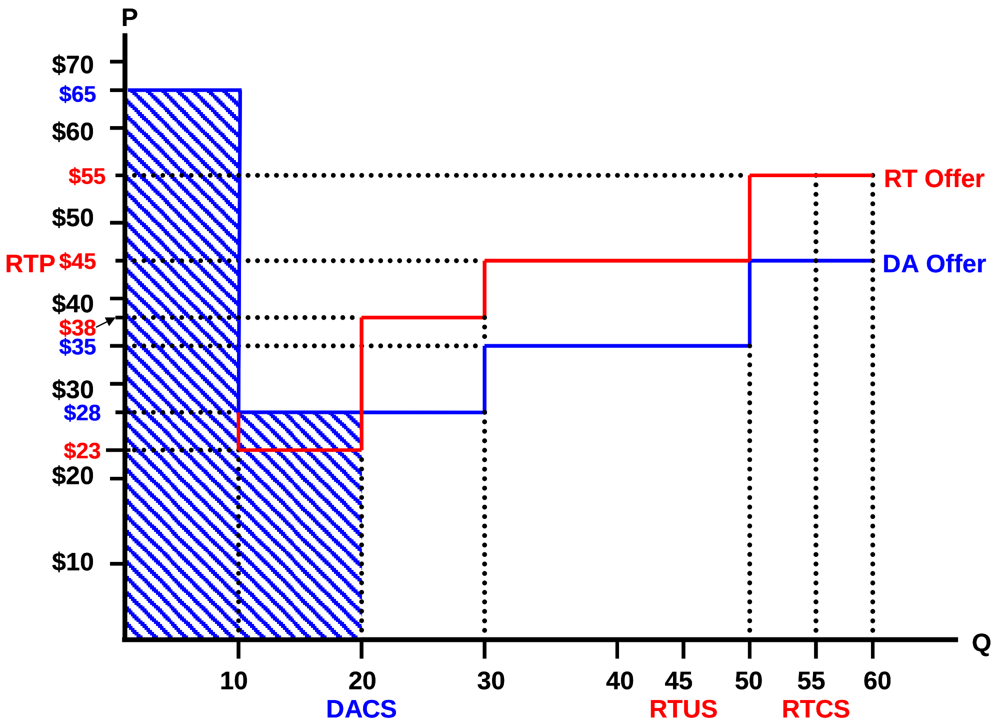
- $5/MWh below the day-ahead offer curve for all capacity included in the DACS (other than the minimum generation block).
- $10/MWh above the day-ahead offer curve for all capacity not included in the DACS.

[1] Start-up offers will be ignored for the purposes of these examples.

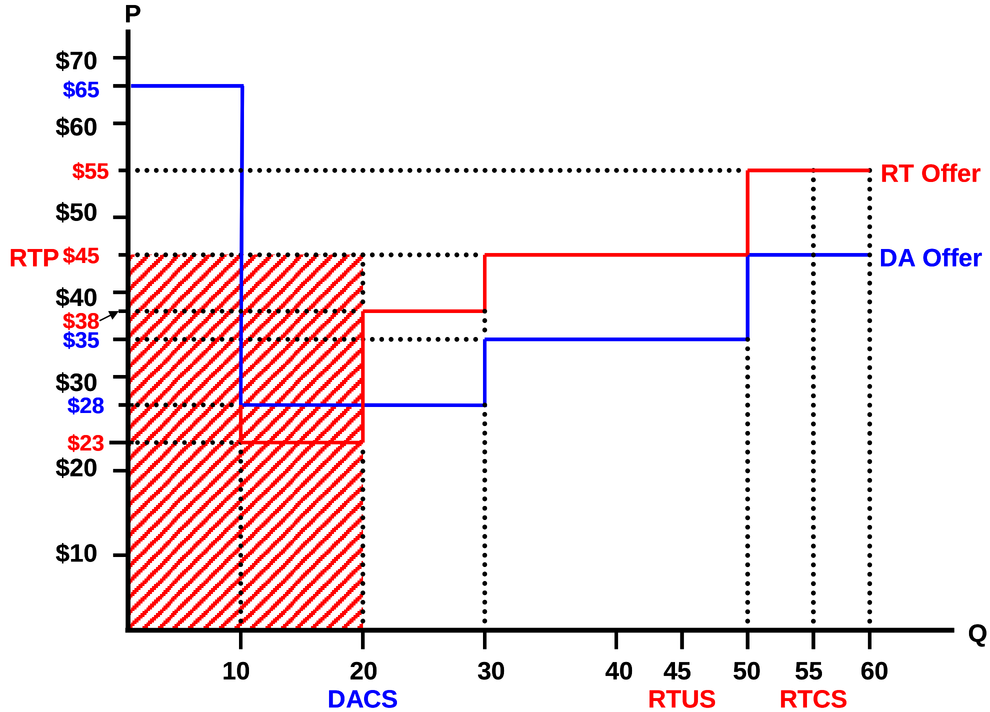
1. **RTCS ≥ RTUS ≥ DACS**

Assume that 20 MW of the capacity of the generator to be used in these examples is included in the DACS, but that 55 MW are included in the RTCS. Also assume that the RTP is $45/MWh, and this generator's RTUS is 45 MW.

In that case, the generator's day-ahead offer to produce its DACS would be $930/hour, which is equal to the area of the blue-shaded region in the figure below.

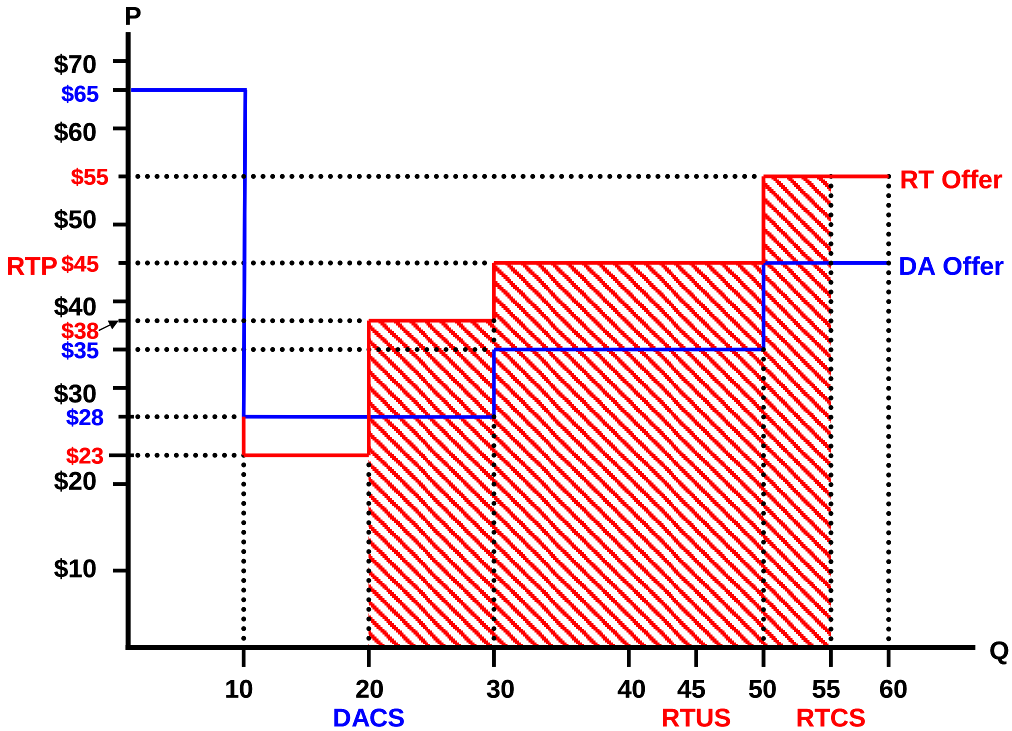


It receives $900/hour in revenue for this amount of energy, given the $45/MWh RTP, as shown below.

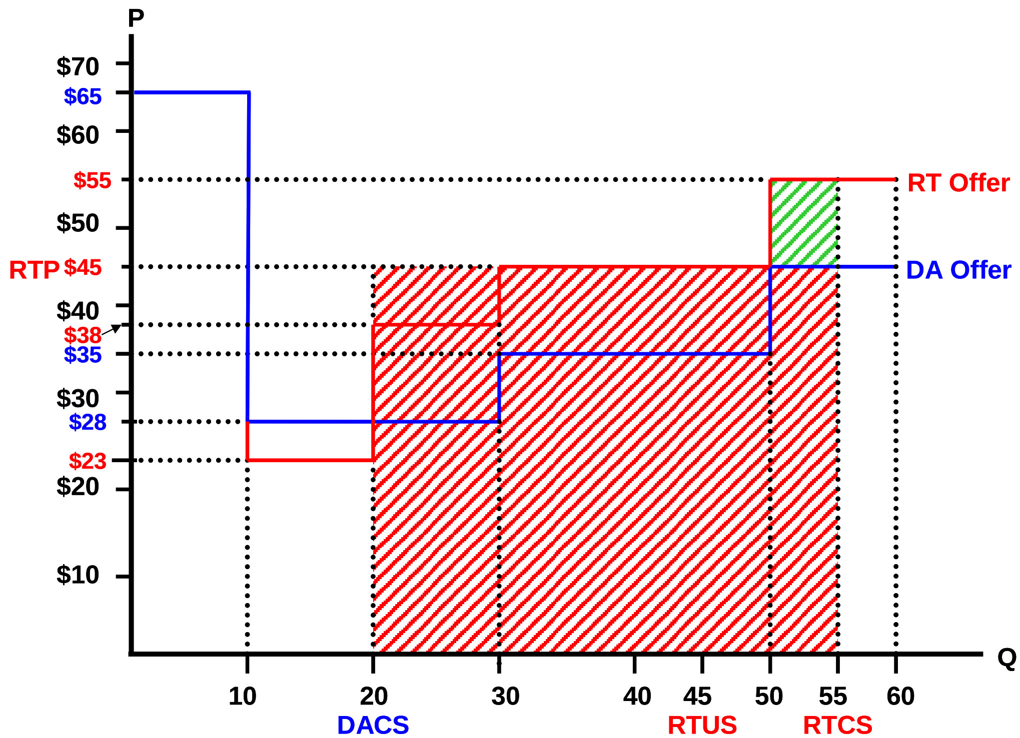


Consequently, its day-ahead as-offered cost to produce its DACS is $930 – $900 = $30/hour more than the real-time price for that amount of energy. It would receive a $30/hour day-ahead PCG payment.

Its real-time offer to increase its output from 20 MW to 55 MW is $1555/hour, which is equal to the area of the red-shaded region in the figure below.



It realizes $1575/hour in revenues from the sale of this additional energy in the real-time market, as shown by the red-shaded region below. In addition, it is constrained on to produce the last 10 MW, so it receives a CMSC payment of $50/hour, as shown by the green-shaded region below. This sums to $1625/hour, which is $70/hour more than its $1555/MWh real-time offer to increase its output from its DACS to its 55 MW RTCS. Therefore, it realizes a total margin of $70 per hour.



When a generator's RTCS exceeds its RTUS, which in turn exceeds its DACS, its CMSC and PCG payments ensure that its total margin is equal to:

- The amount by which the real-time price paid for its DACS exceeds its day-ahead offer to produce its DACS (or zero if the latter exceeds the former) plus

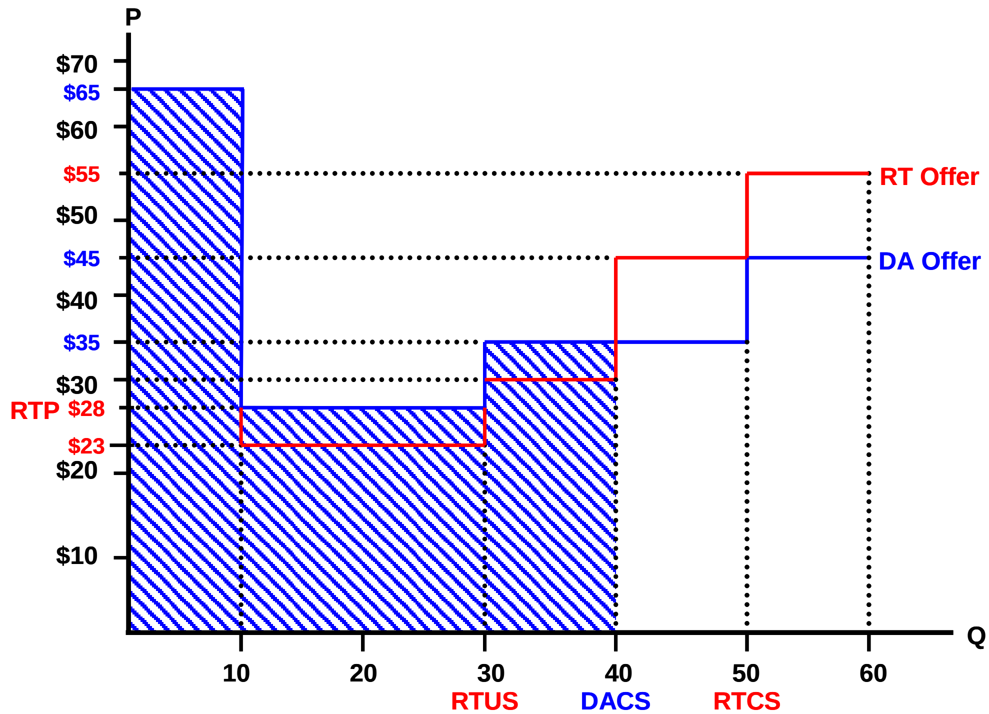
- The amount by which the real-time price paid for the difference between its RTUS and its DACS exceeds its real-time offer to produce that amount of energy.

In this example, the generator incurs a loss in its DACS, so its PCG payments make up that loss while permitting it to retain the $7/MWh in margins it realizes on the 10 MW that it sells at the $45/MWh RTP, but which were offered into the real-time market at only $38/MWh. Attempting to use those margins to offset this generator's CMSC payment would discourage this generator from being willing to increase its output from its RTUS to its RTCS.

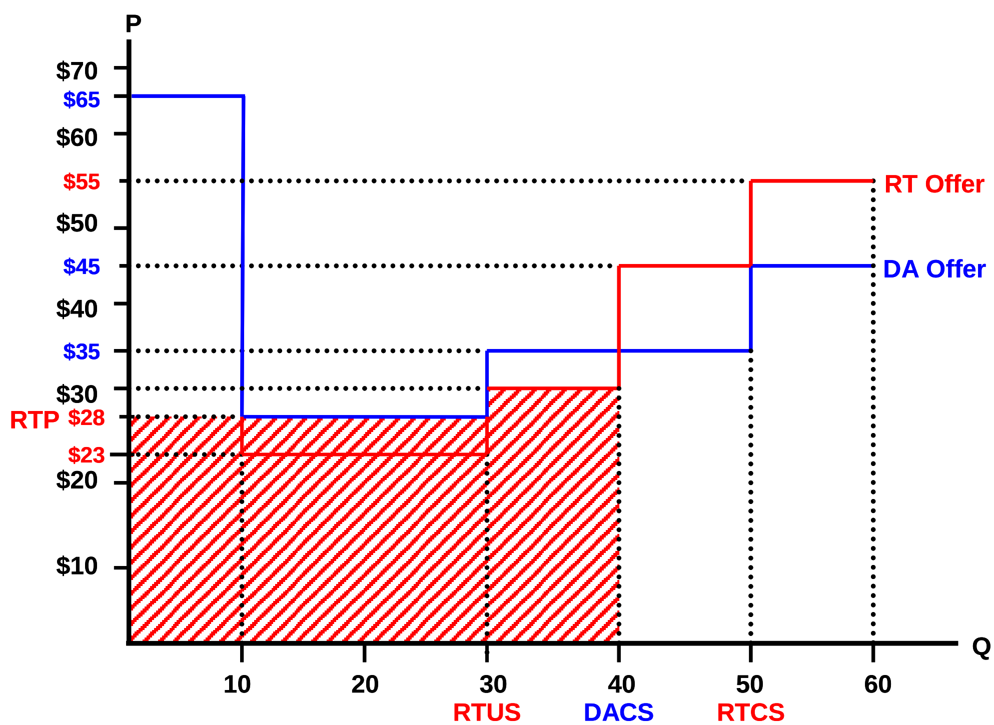
2. RTCS ≥ DACS ≥ RTUS

Assume that 40 MW of the capacity of the generator used in these examples is included in the DACS and that 50 MW are included in the RTCS. Also assume that the RTP is $28/MWh, and this generator's RTUS is 30 MW.

In that case, the generator's day-ahead offer to produce its DACS would be $1560/hour, which is equal to the area of the blue-shaded region in the figure below.

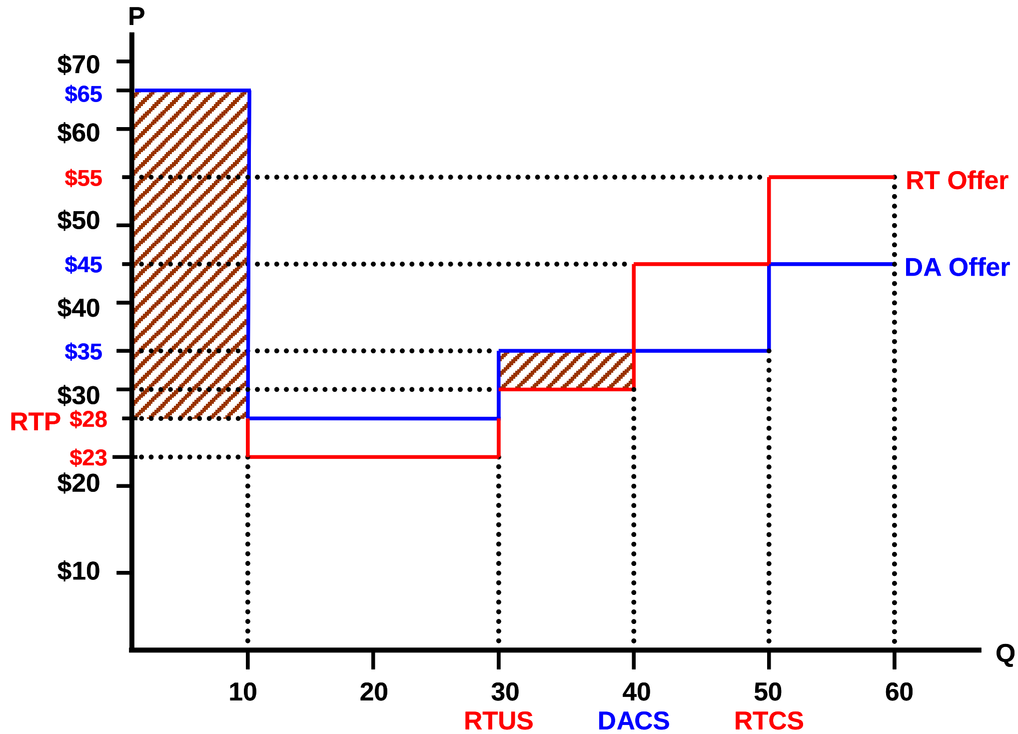


It receives $840/hour in revenue for its 30 MW RTUS,[2] and its real-time offer to produce the 10 MW difference between its 30 MW RTUS and its 40 MW DACS is $300/hour, as shown below.

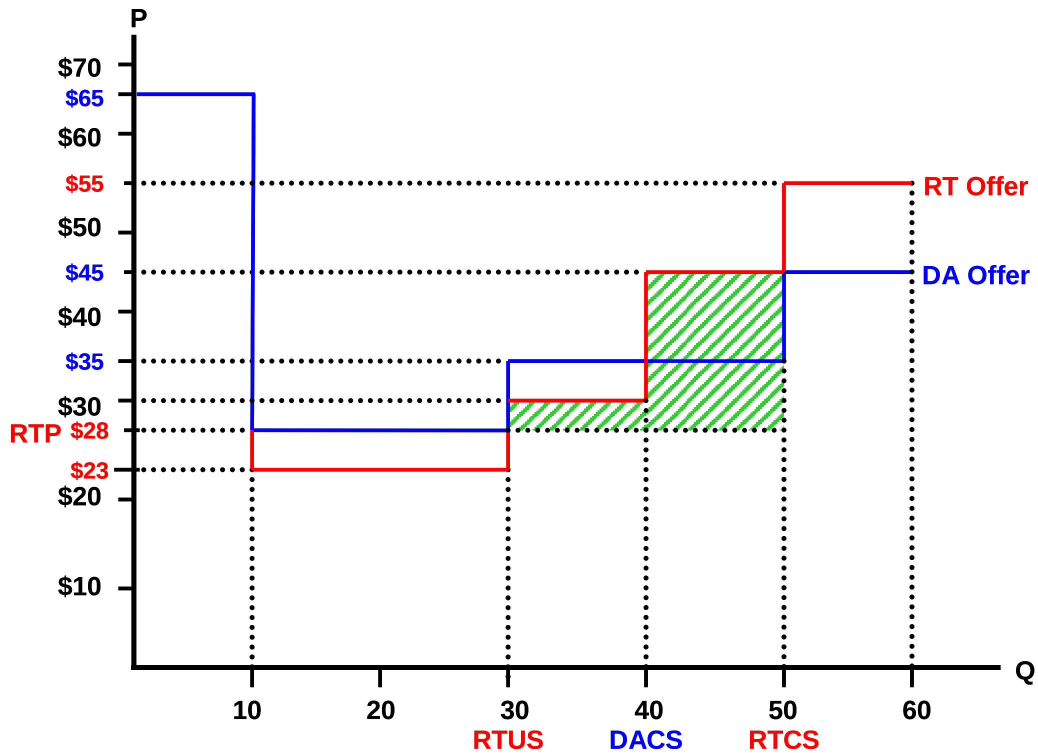


[2] While it receives the $28/MWh RTP for its full 50 MW RTCS, only the portion of that revenue received for its RTUS is relevant for the calculation of this generator's day-ahead PCG payment.

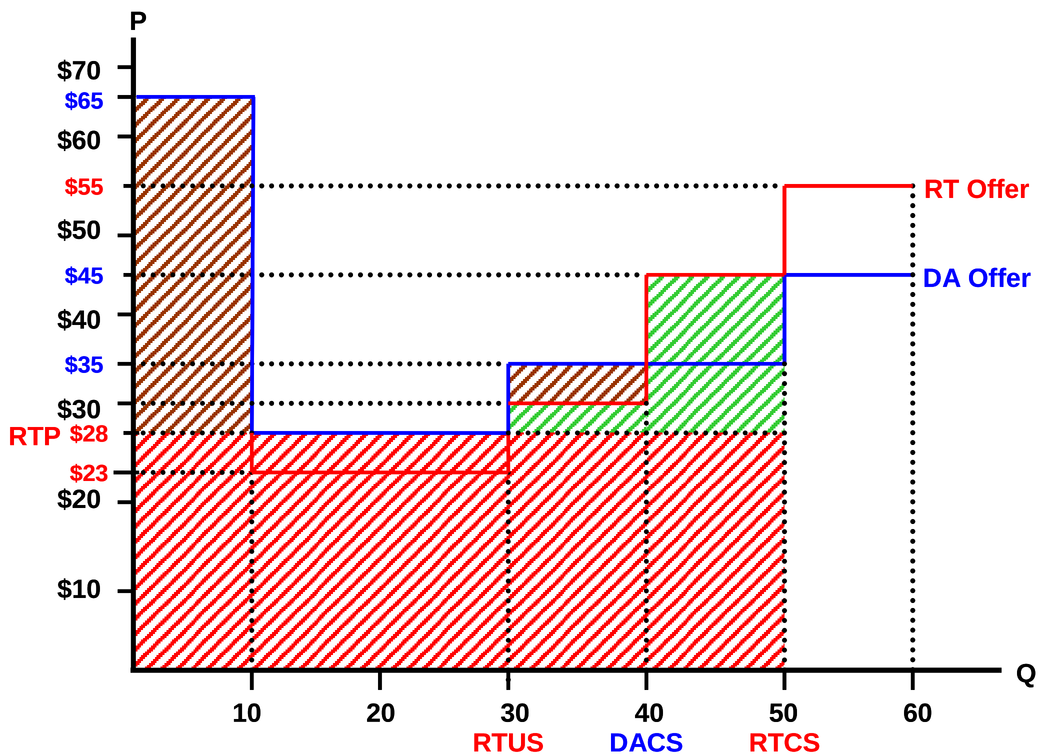
Consequently, it would receive a day-ahead PCG payment of $1560 – $840 –$300 = $420/hour, shaded in brown in the figure below.



In addition, since its real-time offer for the difference between its 30 MW RTUS and its 40 MW DACS is less than its day-ahead offer for that capacity, but greater than the real-time price, it would receive a $20/hour CMSC payment as a result of constraining those 10 MW of capacity on, and another $170/hour for constraining the generator to operate at its 50 MW RTCS instead of its 40 MW DACS. This yields a total CMSC payment of $190/hour, shaded in green in the figure below.



Between its real-time energy revenue of $1400/hour, its PCG payment of $420/hour, and its CMSC payment of $190/hour, this generator realizes $2010/hour in revenues, which matches the sum of its day-ahead offer to produce its 40 MW DACS and its real-time offer to increase output from its DACS to its 50 MW RTCS. Therefore, it recovers its as-offered cost, but it does not realize a margin.

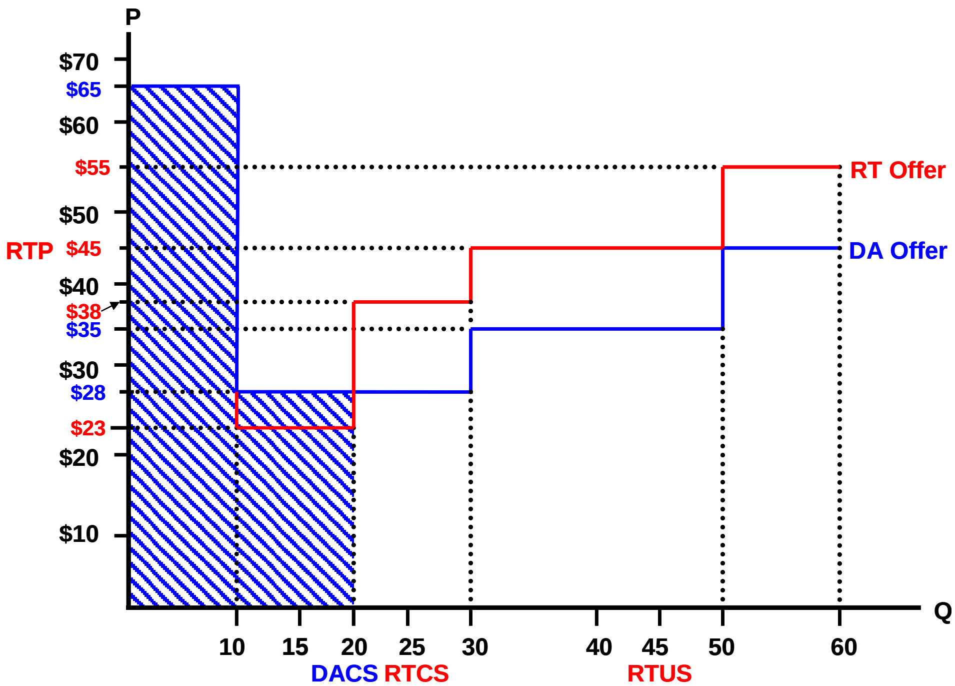


When a generator's RTCS exceeds its DACS, which in turn exceeds its RTUS, its CMSC and PCG payments ensure that its total margin is equal to the amount by which the real-time price paid for its DACS exceeds its day-ahead offer to produce its DACS (or zero if the latter exceeds the former). In this example, the RTP was less than this generator's day-ahead offer, so the PCG and CMSC payments ensure that it breaks even, both on the energy included in the DACS and on the additional energy produced when increasing output to the 50 MW RTCS.

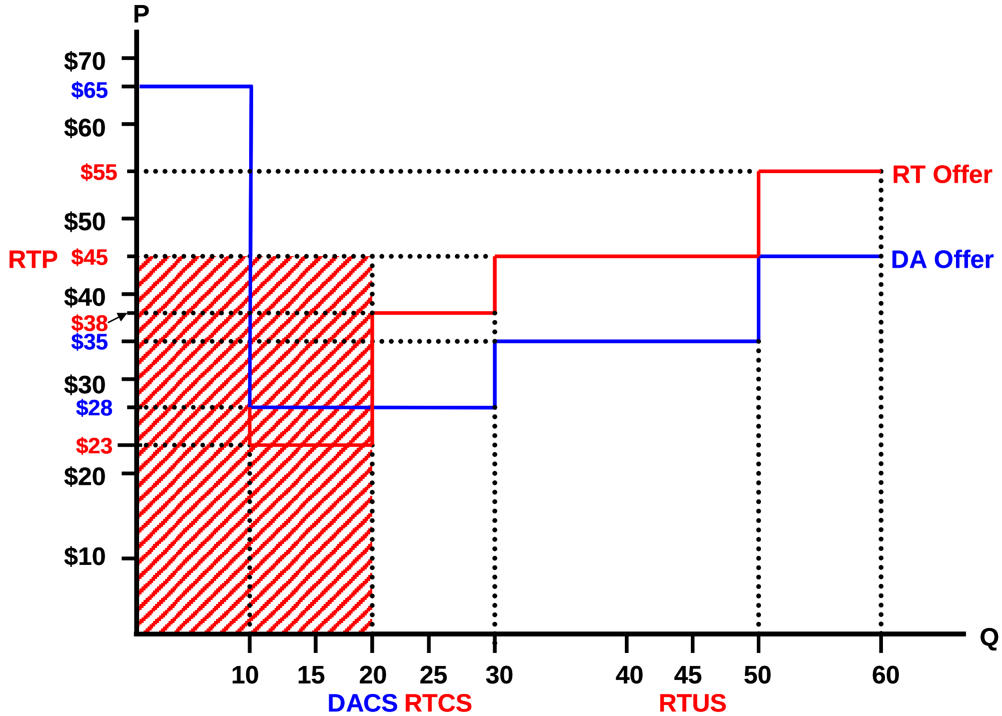
3. RTUS ≥ RTCS ≥ DACS

Assume that 20 MW of the capacity of the generator used in these examples is included in the DACS and that 25 MW are included in the RTCS. Also assume that the RTP is $45/MWh, and this generator's RTUS is 40 MW.

In that case, the generator's day-ahead offer to produce its DACS would be $930/hour, which is equal to the area of the blue-shaded region in the figure below.

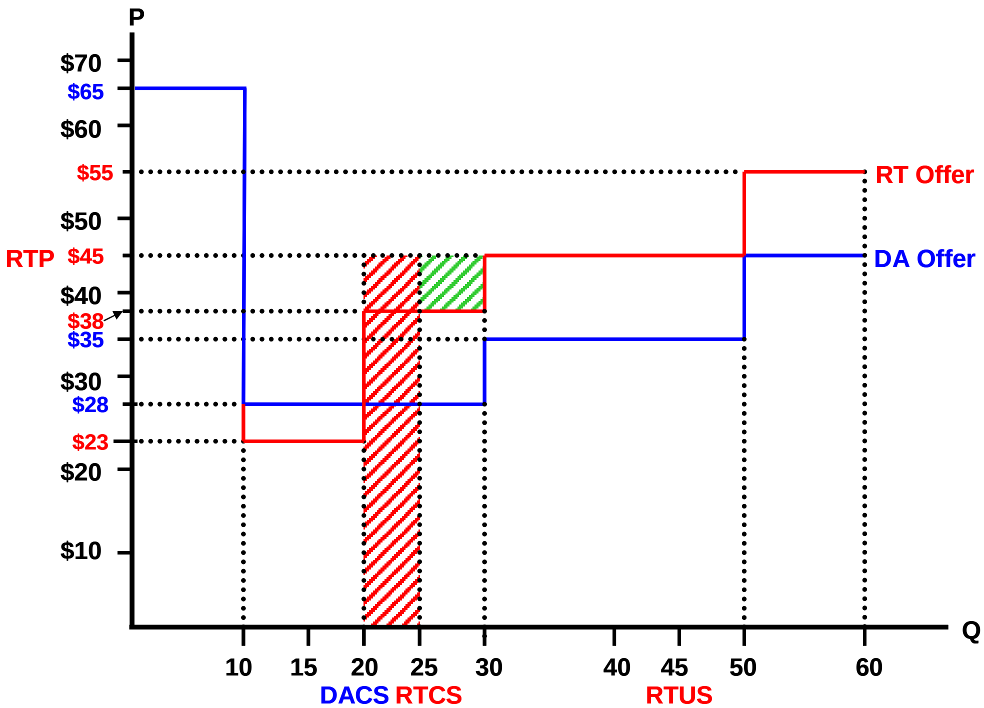


It receives $900/hour in revenue for this amount of energy, given the $45/MWh RTP, as shown below.



Consequently, its day-ahead as-offered cost to produce its DACS is $930 – $900 = $30/hour more than the real-time price for that amount of energy. It would receive a $30/hour day-ahead PCG payment.

In addition, this generator earns $225/hour as a result of increasing its output from its 20 MW DACS to its 25 MW RTCS, as shown by the red-shaded region in the figure below, plus a $35/hour CMSC payment that results from having been constrained off, which is shaded in green in that figure. These payments sum to $260/hour. This generator's real-time offer to increase its output from 20 MW to 25 MW is $190/hour, so this generator realizes a total of $70/hour in total margins.



When a generator's RTCS is less than its RTUS but is greater than its DACS, its CMSC and PCG payments ensure that its total margin is equal to:

- The amount by which the real-time price paid for its DACS exceeds its day-ahead offer to produce its DACS (or zero if the latter exceeds the former) plus

- The amount by which the real-time price paid for the difference between its RTUS and its DACS exceeds its real-time offer to produce that amount of energy.

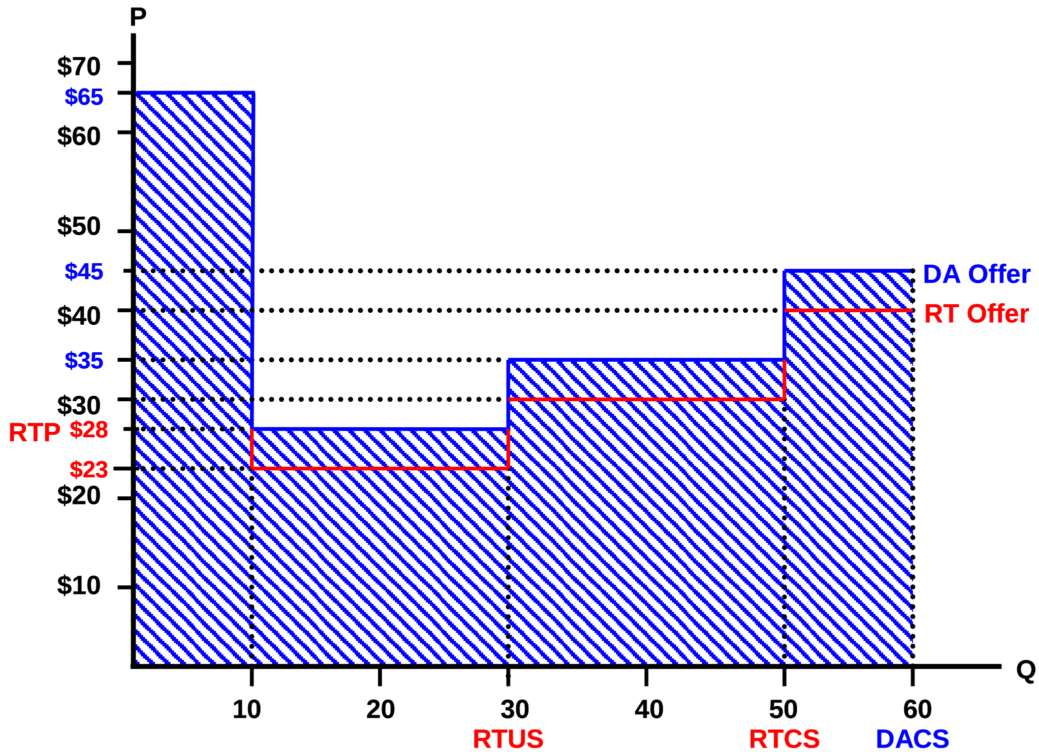
In this example, the generator incurs a loss in its DACS, so its PCG payments make up that loss while permitting it to retain the $7/MWh in margins it realizes on the 10 MW that it sells at the $45/MWh RTP, but which were offered into the real-time market at only $38/MWh.

The $70/hour total margin is the same amount that the generator used in the example for Ordering 1 realized. In that case, the DACS was also 20 MW, the RTUS was also 45 MW, and the RTP was also $45/MWh, but the RTCS was 55 MW instead of 25 MW. In each case, the total margins that the generator realized reflected the $7/MWh difference between the RTP and the RTO for the 21st through 30th megawatts of the generator's capacity, even though the generator actually produced all of that energy in Ordering 1 (when its RTCS was 55 MW), while it only produced part of that energy here. This illustrates that this system of side payments ensures that the generator is properly compensated for being constrained on or off, as the generator realizes the same margins when it is constrained off, in this example, as it earned when it was constrained on previously.

4. DACS ≥ RTCS ≥ RTUS

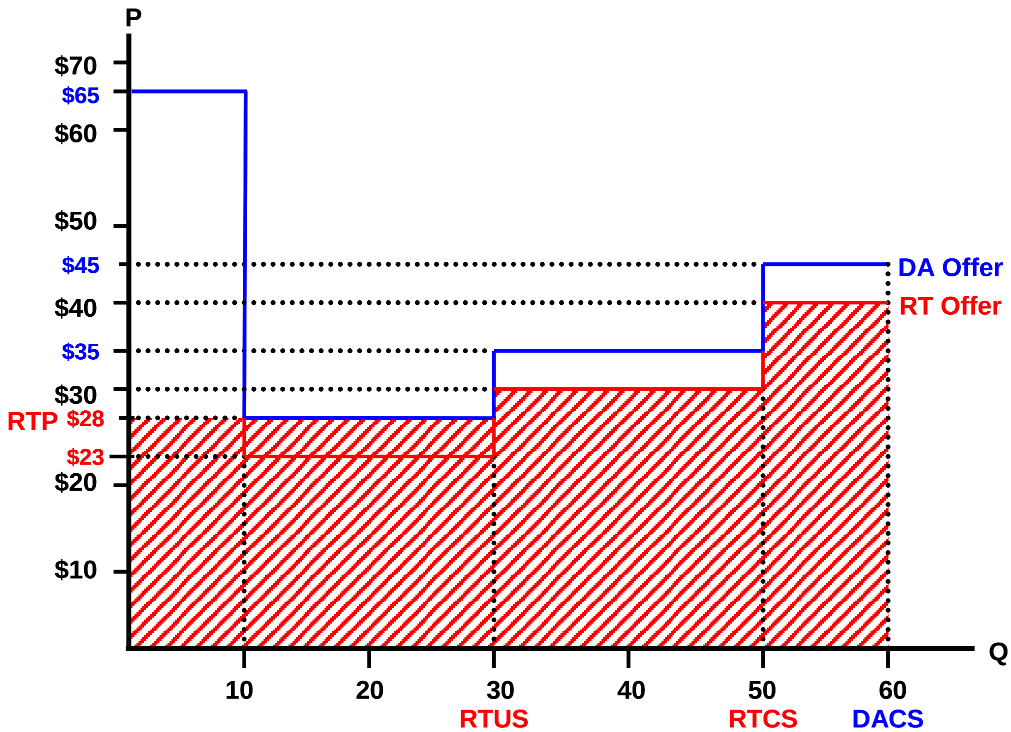
Assume that all 60 MW of the capacity of the generator used in these examples is included in the DACS, but only 50 MW are included in the RTCS. Also assume that the RTP is $28/MWh, and this generator's RTUS is 30 MW.

In that case, the generator's day-ahead offer to produce its DACS would be $2360/hour, which is equal to the area of the blue-shaded region in the figure below.

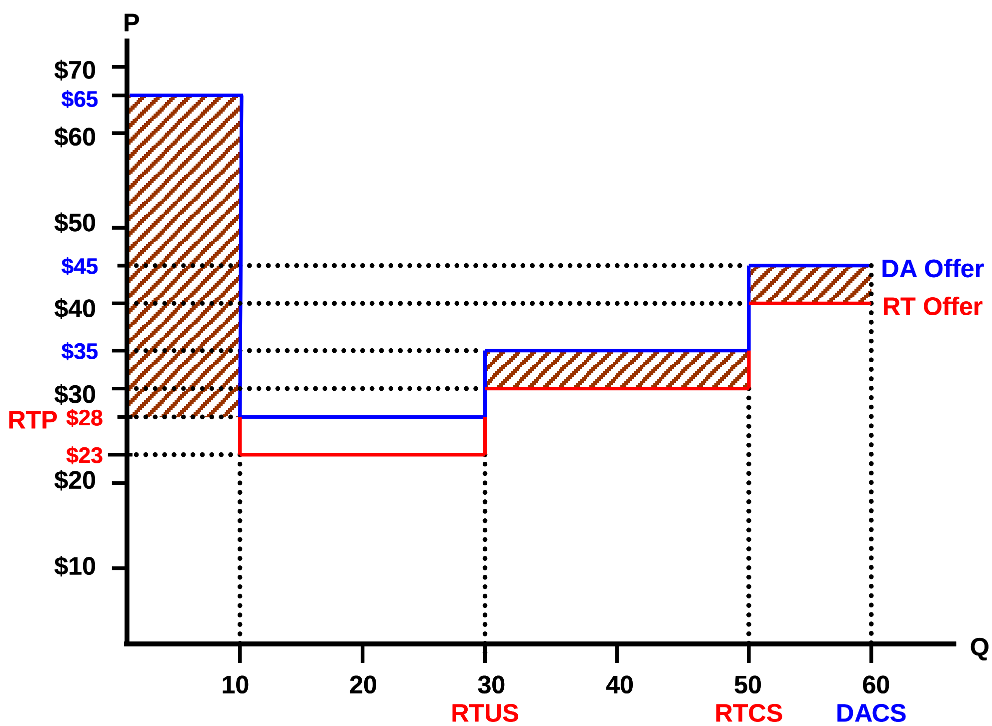


It receives $28/MWh x 30 MW = $840/hour in revenue for its 30 MW RTUS,[3] and its real-time offer to produce the 30 MW difference between its 30 MW RTUS and its 60 MW DACS is $1000/hour, both of which are graphed below.

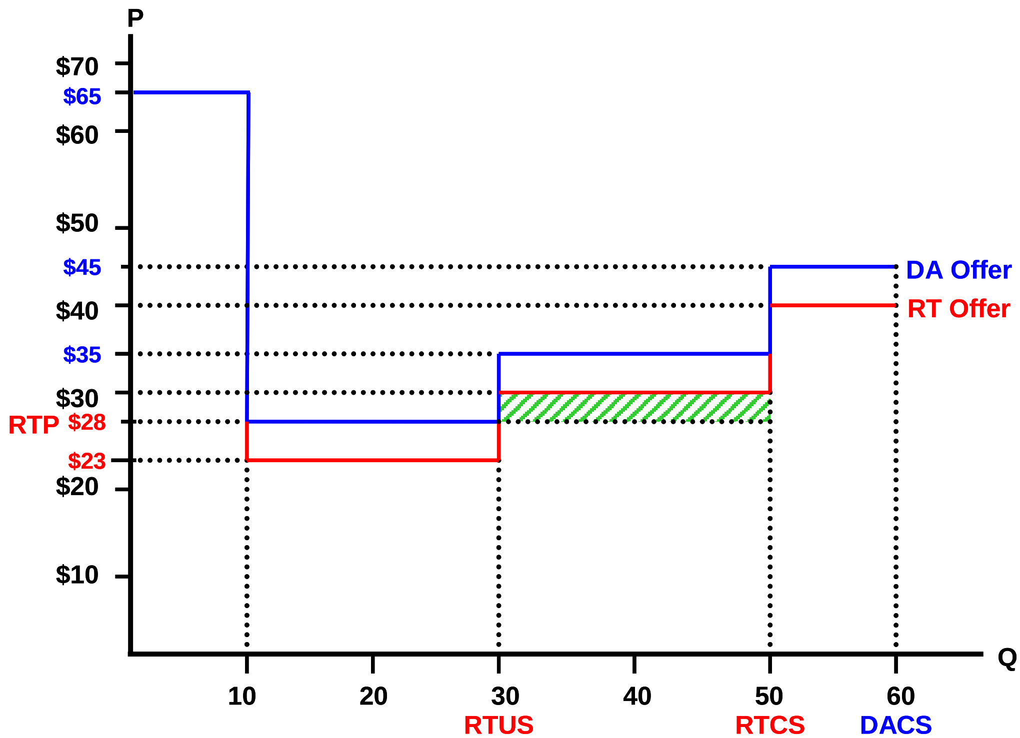
[3] While it receives the $28/MWh RTP for its full 50 MW RTCS, only the portion of that revenue received for its RTUS is relevant for the calculation of this generator's PCG payment.



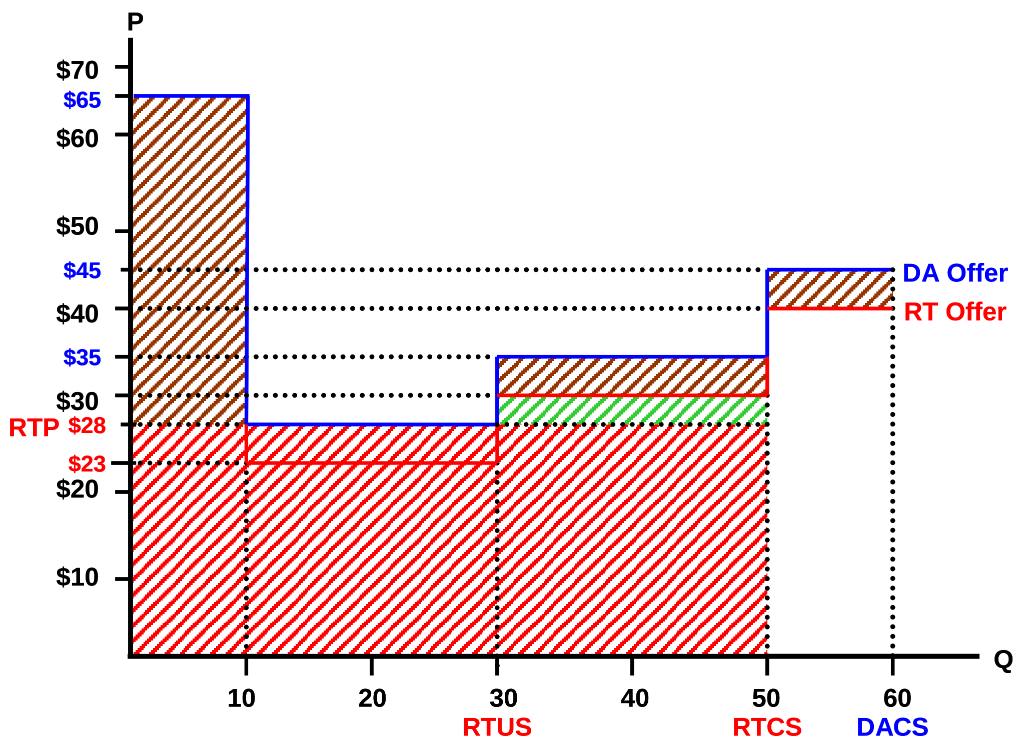
Consequently, it would receive a day-ahead PCG payment of $2360 – $840 – $1000 = $520/hour, shaded in brown in the figure below.



In addition, since its real-time offer for the difference between its RTUS and its RTCS is less than its day-ahead offer for that capacity, but greater than the real-time price, it would receive a $40/hour CMSC payment as a result of constraining that capacity on, shaded in green in the figure below.



Between its real-time energy revenue of $28/MWh x 50 MW = $1400/hour, its PCG payment of $520/hour, and its CMSC payment of $40/hour, this generator realizes $1960/hour in revenues, which matches the sum of its day-ahead offer to produce its 60 MW DACS less its real-time offer to decrease output from its DACS to its 50 MW RTCS. Therefore, it recovers its as-offered cost, but it does not realize a margin.

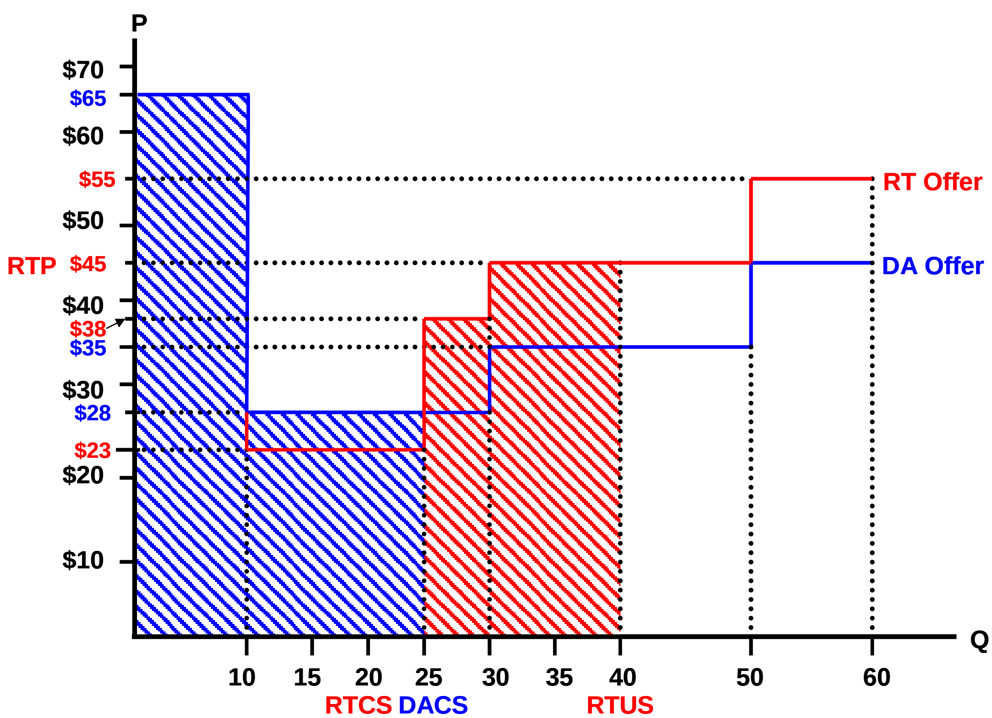


As the table in the appendix shows, when a generator's RTCS is less than its DACS but is greater than its RTUS, its CMSC and PCG payments ensure that its total margin is equal to the amount by which the real-time price paid for its RTCS exceeds its day-ahead offer to produce its DACS less its real-time offer to reduce its output from its DACS to its RTCS, or zero if this would produce a negative total margin. In this case, the RTP was less than this generator's day-ahead offer to produce its DACS net of its real-time offer to reduce output to its RTCS, so the PCG and CMSC payments ensure that it breaks even.

5. RTUS ≥ DACS ≥ RTCS

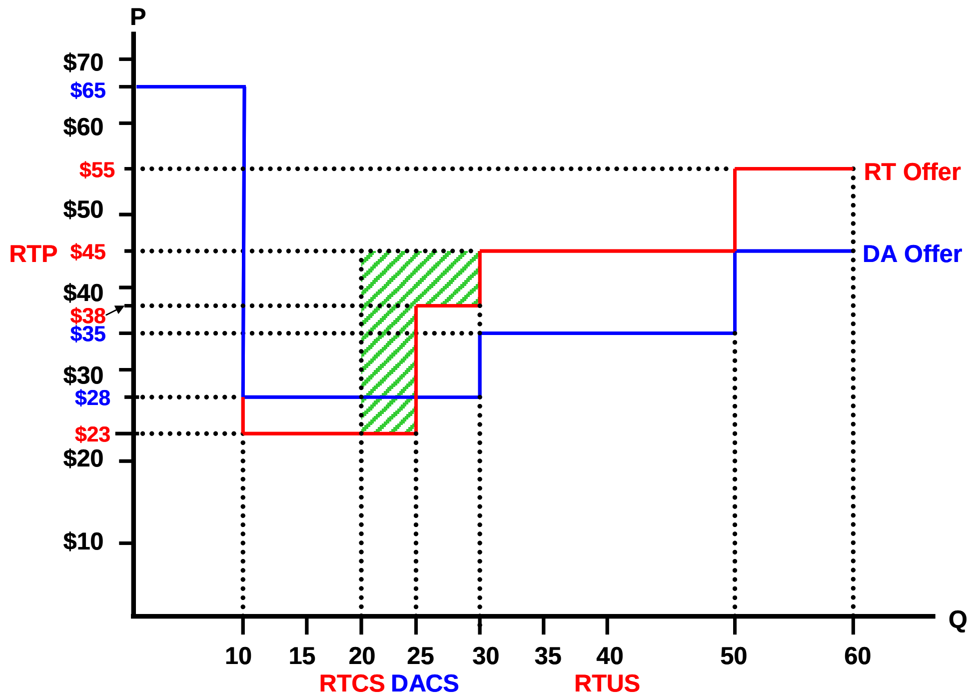
Assume that 25 MW of the capacity of the generator used in these examples is included in the DACS, and 20 MW are included in the RTCS. Also assume that the RTP is $45/MWh, and this generator's RTUS is 40 MW.

In that case, the generator's day-ahead offer to produce its DACS would be $1070/hour, which is equal to the area of the blue-shaded region in the figure below, and its real-time offer to produce the 15 MW difference between its 25 MW DACS and its 40 MW RTUS is another $640/hour, which is equal to the area of the red-shaded region in that figure. These offers sum to $1070 + $640 = $1710/hour.

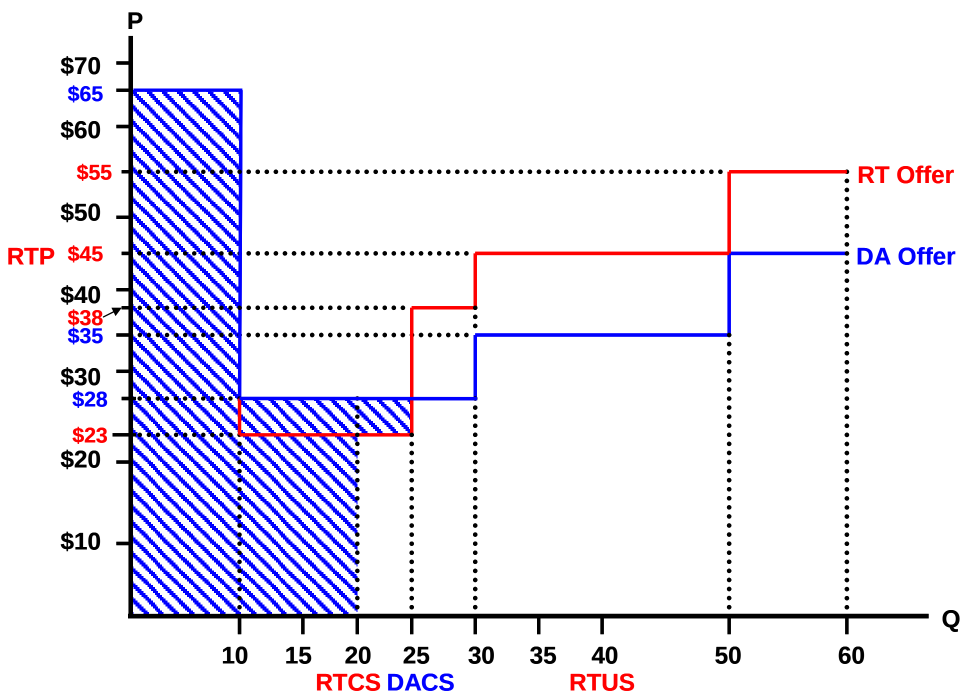


To calculate the PCG payment, subtract the product of the $45/MWh RTP and the 40 MW RTUS, which is $1800/hour, from the sum of these costs. Since the result is negative, this generator does not receive a PCG payment.

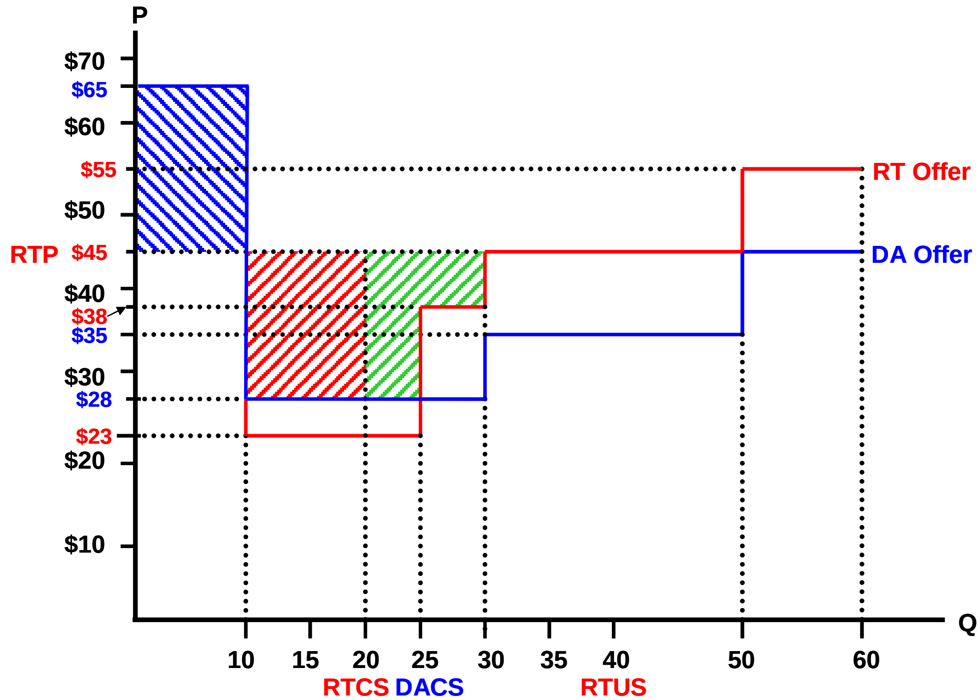
However, it does receive a CMSC payment, since it is constrained off in the real-time dispatch. This payment, which is equal to the amount by which the RTP exceeds the real-time offer for the capacity between the RTUS and the RTCS, is $145/hour in this example, and is shaded in green in the figure below.



Between its real-time energy revenue of $900/hour and its CMSC payment of $145/hour, this generator realizes $1045/hour in revenues. Its day-ahead offer to produce its 25 MW DACS less its real-time offer to decrease output from its DACS to its 20 MW RTCS is $955/hour, as shown below.



Therefore, the generator realizes a margin of $1045 – $955 = $90/hour. As the figure below illustrates, while this generator loses $200 on the output corresponding to its 10 MW minimum generation level, it realizes $170/hour in margins on energy that it produces above minimum generation, and another $120/hour in margins on capacity that is constrained off (after deducting the difference between day-ahead and real-time offers for capacity that is included in the DACS but not the RTCS); those margins of $290/hour exceed the $200/hour in losses, resulting in a net of $90/hour.

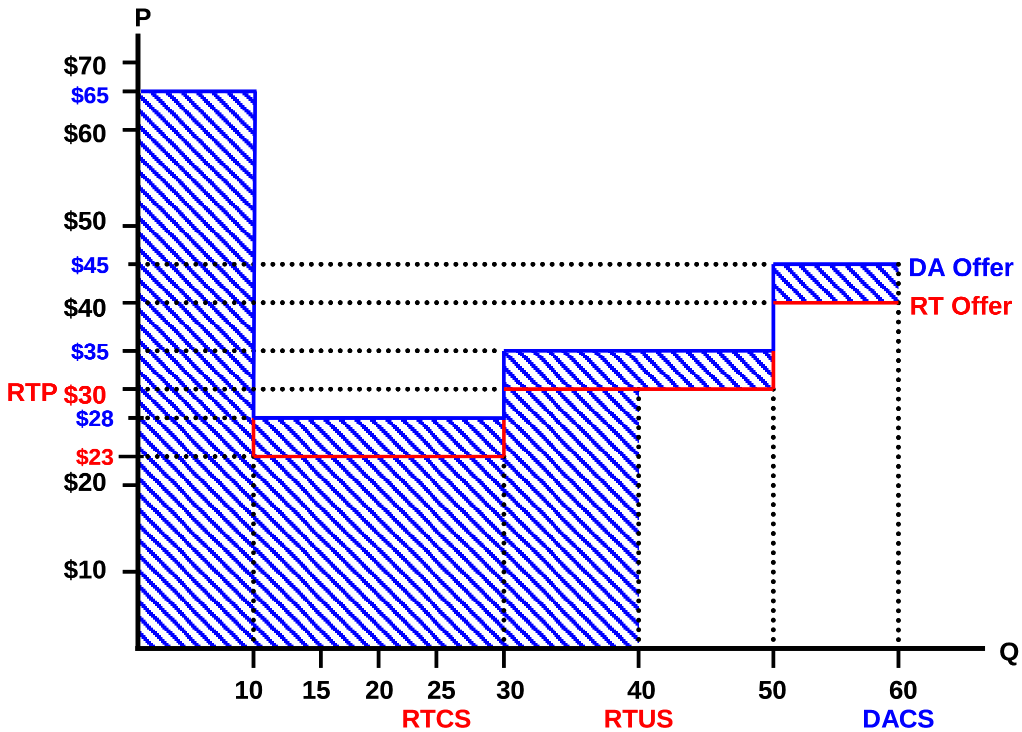


When a generator's RTCS is less than its DACS, which in turn is less than its RTUS, its CMSC and PCG payments ensure that its total margin is equal to the amount by which the real-time price paid for its RTUS exceeds the sum of its day-ahead offer to produce its DACS and its real-time offer to increase its output from its DACS to its RTUS, or zero if this would produce a negative total margin. In this case, the RTP for that amount of energy was $1800/hour, which exceeded the sum of the generator's day-ahead offer to produce its DACS and its real-time offer to increase its output from its DACS to its RTUS (which, as calculated above, was $1710/hour) by $90/hour, so it realizes a total margin of $90/hour.

6. DACS ≥ RTUS ≥ RTCS

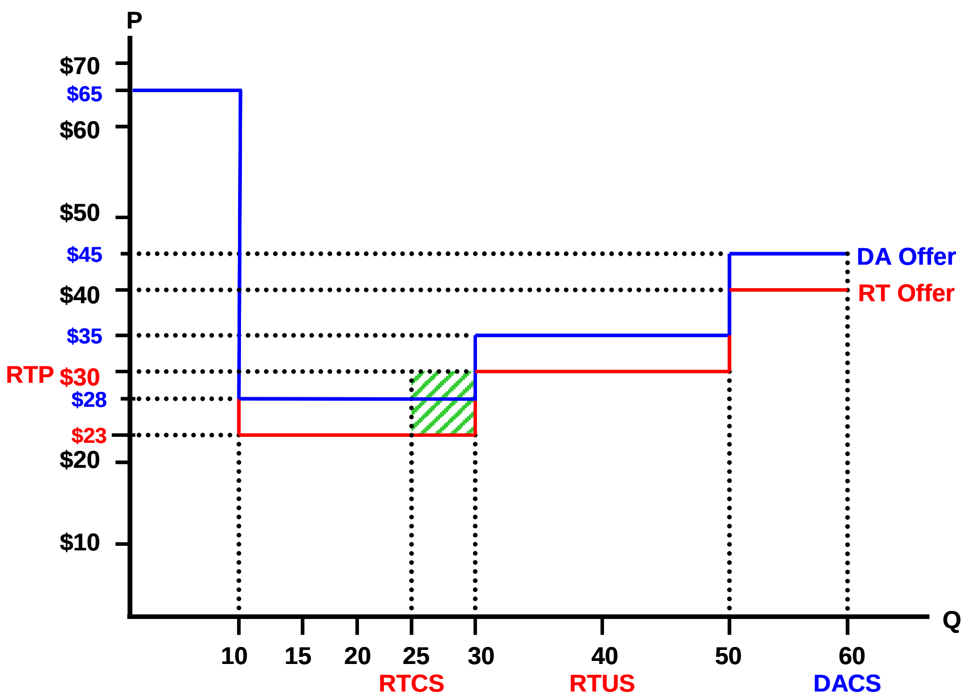
Assume that all 60 MW of the capacity of the generator used in these examples is included in the DACS, but only 25 MW are included in the RTCS. Also assume that the RTP is $45/MWh, and this generator's RTUS is 40 MW.

In that case, the generator's day-ahead offer to produce its DACS, less its real-time offer to produce the 35 MW difference between its 40 MW RTUS and its 60 MW DACS, is $1660/hour, which is equal to the area of the blue-shaded region in the figure below.

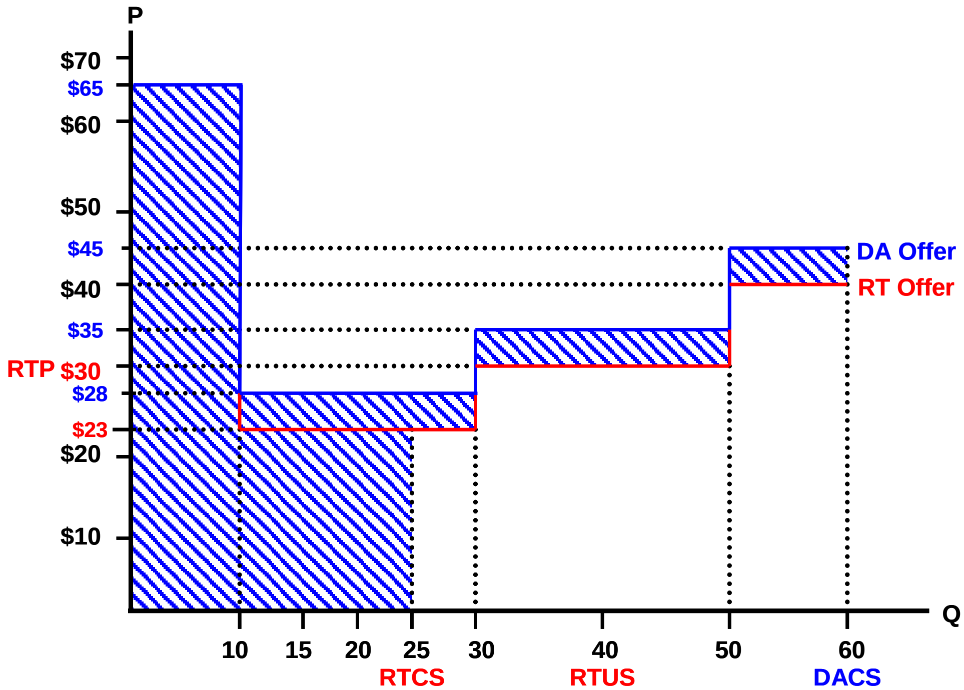


To calculate the PCG payment, subtract the product of the $30/MWh RTP and the 40 MW RTUS, which is $1200/hour, from the sum of these costs. Since the result is positive, this generator receives a PCG payment of $1660 – $1200 = $460/hour.

It also receives a CMSC payment, since it is constrained off in the real-time dispatch. This payment, which is equal to the amount by which the RTP exceeds the real-time offer for the capacity between the RTUS and the RTCS, is $35/hour in this example, and is shaded in green in the figure below.



Between its real-time energy revenue of $750/hour, its PCG payment of $460/hour, and its CMSC payment of $35/hour, this generator realizes $1245/hour in revenues. Its day-ahead offer to produce its 60 MW DACS less its real-time offer to decrease output from its DACS to its 25 MW RTCS is also $1245/hour, as shown below.



When a generator's RTCS is less than its RTUS, which in turn is less than its DACS, its CMSC and PCG payments ensure that its total margin is equal to the amount by which the real-time price paid for its RTUS exceeds its day-ahead offer to produce its DACS less its real-time offer to decrease its output from its DACS to its RTUS, or zero if this would produce a negative total margin. In this case, the RTP for that amount of energy was $1200/hour, which was less than the generator's day-ahead offer to produce its DACS net of its real-time offer to decrease its output from its DACS to its RTUS (which, as calculated above, was $1660/hour), so it breaks even.

Day-Ahead Intertie Offer Guarantee

The design of the enhanced day-ahead commitment process DA-IOG is consistent with the principles behind that of the DA-PCG and for the most part the current design of the Day-Ahead Intertie Offer Guarantee Settlement Credit (Charge Type 1130) of the DACP.

1. Any shortfall in payment on the real-time import flow of the day-ahead constrained advisory schedule will be based upon the real-time revenue received for that amount of energy in comparison with the costs as represented in the importer's day-ahead offer,
2. For the portion of day-ahead constrained advisory that is not implemented in the real-time dispatch schedule, the DA- IOG will guarantee the cost incurred of arranging the import (where real-time pre-dispatch offer is less than day-ahead offer) or subtract any gain by the reduction in day ahead advisory (where real-time pre-dispatch offer is greater than day-ahead offer),
3. Any income from real-time CMSC included in an importer's day-ahead constrained advisory delivered in real-time will be used to reduce the DA-IOG payment.

Current DACP DA-IOG payment formulas recorded in the IESO Charge Types and Equations (IMP_LST_0001) document will need to be changed reflect the addition of covering the costs to arrange the imports between day-ahead and real-time but for the most part the calculation will remain unchanged. Appendix A illustrates different day-ahead to real-time situations that were studied to test the robustness of the DA-IOG.

Mathematically, the DA-IOG calculations are the same as those for the DA-PCG. For imports there are no start-up costs to consider only incremental energy offers. For any given import committed by the enhanced DACP, the DA-IOG evaluated for each MW committed of that import can fall into one of four scenarios:

1. Portion of import that flows in real-time:
   DACS = 1MW, RTUS = 1MW, RTCS = 1MW

2. Portion of import that is constrained on in real-time:
   DACS = 1MW, RTUS = 0MW, RTCS = 1MW

3. Portion of import that is constrained off in real-time:
   DACS = 1MW, RTUS = 1MW, RTCS = 0MW

4. Portion of import that does not flow:
   DACS = 1MW, RTUS = 0MW, RTCS = 0MW

Now calculations of each of these scenarios are explained below. In the DA-IOG calculations, RTP = real-time price, RTO = real-time offer, RTCS = real-time constrained schedule, RTUS = real-time unconstrained schedule, DAO = day-ahead offer, and DACS = day-ahead constrained schedule.

Scenario 1: Portion of Import That Flows In Real-time

In this scenario, the MW that is committed day-ahead flows in real-time. Both the RTCS and RTUS equal to 1 MW. The importer is paid RTP for this 1 MW, but the RTP might be less than the DAO. Thus, the DA-IOG is the DAO minus RTP. This ensures that the importer recovers its day-ahead offer for that 1 MW. The DA-IOG calculation for this scenario is no different than how they are calculated today:

$$\text{DA-IOG}^1 = \text{DAO} - \text{RTP}$$

or more generally expressed as:

$$\text{DA-IOG}^1 = \max(0, \text{DAO} - \text{RTP})$$

Scenario 2: Portion of Import that is Constrained On In Real-time

In this case, the MW is committed day-ahead and is constrained on in real-time. The RTUS = 0 and the RTCS = 1MW. The importer is paid RTP for the 1MW and a CMSC payment equal to its RTO minus RTP. However, it is possible that the sum of the energy payment and the CMSC could be insufficient to cover the importer's day-ahead offer for this 1MW. If this was the case, the importer would also be paid a DA-IOG of DAO minus the sum of the RTP and CMSC. By doing the math, the DA-IOG is equal to DAO-RTO. Again, the DA-IOG calculations are no different than how they are calculated today. Any CMSC paid for the committed import is netted from the calculation of the DA-IOG.

$$\text{DA-IOG}^2 = \text{DAO} - \text{RTP} - \text{CMSC}$$
$$\text{DA-IOG}^2 = \text{DAO} - \text{RTP} - (\text{RTO} - \text{RTP})$$
$$\text{DA-IOG}^2 = \text{DAO} - \text{RTO}$$

or more generally expressed as:

$$\text{DA-IOG}^2 = \max(0, \text{DAO} - \text{RTO})$$

Scenario 3: Portion of Import that is Constrained Off In Real-time

In this third scenario, the MW import that is committed day-ahead and is constrained off in real-time. Its RTUS = 1MW and RTCS = 0. The importer is paid a CMSC payment equal to RTP minus its RTO. Even with a CMSC payment, this may not be sufficient to cover the importers as-offered costs in preparing the day-ahead offer. This day-ahead as-offered cost could be evaluated as DAO minus RTO. If DAO minus RTO is positive, it represents the cost premium the importer places to make day-ahead arrangements for that 1 MW of import. Thus, the DA-IOG in this case is DAO minus RTO minus CMSC. The equations for the DA-IOG are:

$$\text{DA-IOG}^3 = \text{DAO} - \text{RTO} - \text{CMSC}$$
$$\text{DA-IOG}^3 = \text{DAO} - \text{RTO} - (\text{RTP} - \text{RTO})$$
$$\text{DA-IOG}^3 = \text{DAO} - \text{RTP}$$

or more generally expressed as:

$$\text{DA-IOG}^3 = \max(0, \text{DAO} - \text{RTP})$$

Under the current DACP, the importer would only receive the CMSC payment and no DA-IOG. Thus, today any cost the importer incurs to arrange the day-ahead transaction exceeding the CMSC payment is not paid.

Scenario 4: Portion of Import That Does Not Flow in Real-Time

For this last scenario, the MW import that is committed day-ahead doesn't flow in real-time. Its RTUS = 0 and RTCS = 0. The importer is paid neither energy nor CMSC. However, the importer should be paid at least its as-offered cost for preparing the day-ahead offer that got committed. As indicated in scenario 3, this day-ahead as-offered cost would be evaluated as DAO minus RTO. If RTO is greater than DAO, this is an indication that the importer would realize a sufficient gain from not flowing and DA-IOG is then recovered back. Thus, DA-IOG for this scenario is just that:

$$\text{DA-IOG}^4 = \text{DAO} - \text{RTO}$$

For this scenario, under the current DACP, DA-IOG would not apply. So today, any cost the importer incurs to arrange the day-ahead transaction is not paid or any gain an importer realizes not to flow a day-ahead transaction in real-time is recovered back.

The table below summarizes the four scenarios described above. In addition, a generalized calculation of the total margin for the transaction is shown in the last row.

Table 1: DA-IOG for Imports Committed Day-Ahead

Real-time Outcome	Import Flows RTUS = 1MW RTCS = 1MW	Import is Constrained On RTUS = 0MW RTCS = 1MW	Import is Constrained Off RTUS = 1MW RTCS = 0MW	Import does not Flow RTUS = 0MW RTCS = 0MW
1) Energy Revenue	RTP	RTP	0	0
2) CMSC	0	RTO – RTP	RTP – RTO	0
3) DA-IOG	max(0, DAO – RTP)	max(0, DAO – RTO)	max(0, DAO – RTP)	DAO – RTO
4) Total Revenue	max(RTP, DAO)	max(RTO, DAO)	max(RTP, DAO) – RTO	DAO – RTO
5) As-Offered Cost	DAO	DAO	DAO – RTO	DAO – RTO
6) Total Margin	max(RTP – DAO, 0)	max(RTO – DAO, 0)	max(RTP – DAO, 0)	0

Note: Total Revenue = Energy Revenue + CMSC + DA-IOG
Total Margin = Total Revenue – As-Offered Cost

Table 2 below shows the calculations for real-time IOG. As a comparison, one should notice that an import committed day-ahead has a better opportunity for gaining margins over an import only in real-time.

Table 2: Real-time IOG Only

Real-time Outcome	Import Flows RTUS = 1MW RTCS = 1MW	Import is Constrained On RTUS = 0MW RTCS = 1MW	Import is Constrained Off RTUS = 1MW RTCS = 0MW	Import does not Flow RTUS = 0MW RTCS = 0MW
1) Energy Revenue	RTP	RTP	0	0
2) CMSC	0	RTO – RTP	RTP – RTO	0
3) IOG	max(0, RTO – RTP)	0	0	0
4) Total Revenue	max(RTP, RTO)	RTO	RTP – RTO	0
5) As-Offered Cost	RTO	RTO	0	0
6) Total Margin	max(RTP – RTO, 0)	0	RTP – RTO	0

Inclusion of Exports in an Enhanced Day-ahead Commitment Process

Recap: Why are exports not included in the current DACP?
The current DACP was put into operation to address reliability concerns. During the design phase of DACP, the IESO and the working group made the decision not to consider export transactions for the commitment of day-ahead internal generation and imports. Quoting from the working group memo published on November 22, 2005, the reasons for this decision were:

> "The IESO and the working group were unable to identify a means of including exports, either as forecasted bulk volumes or individual transactions, that did not either:
>
> - Require significant administrative measures to ensure exports included and/or committed day-ahead did not result in over committing supply with the cost of the corresponding reliability guarantees borne by Ontario customers; or
> - Require a complex market mechanism to allow committed exports to buy out of their day-ahead position when real-time conditions warranted. Such a market mechanism is a typical feature of a day-ahead market."

Why consider exports in the enhanced day-ahead commitment process of option 1or 2?

The enhanced day-ahead commitment process includes commitment of resources based on optimization of multi-part offers over 24-hours of the next day. As discussed in the background section of this paper, the goodness of the results from this optimization relies on having the most complete information. The most complete information would include bids for day-ahead exports.

There would be a net benefit to the Ontario market if the cost of meeting real-time export load using resources committed by the enhanced day-ahead commitment process is less than that of using resources committed by the current DACP (all the while the total cost of meeting Ontario load is also not increased). However, the inclusion of exports in an enhanced day-ahead commitment process should not provide any incentives to over schedule exports day-ahead and cause over-commitment nor facilitate opportunities for gaming.

Proposal to Include Exports in the Enhanced Day-Ahead Commitment Process
There is no guarantee design equivalent to the DA-IOG to commit exports in the enhanced day-ahead commitment process that mitigates the same concerns expressed in the 2005 working group memo. The only way to include export bids in the enhanced day-ahead commitment process is to have an accompanying day-ahead export failure charge (DA-EFC). The assessment of when the DA-EFC applies is based on a price test that indicates whether the failed export could have resulted in Ontario consumers bearing its commitment costs.

This price test is a mirror to that of the current day-ahead import failure charge. The DA-EFC applies if:

- an export committed day-ahead is not scheduled in pre-dispatch, and
- the pre-dispatch shadow price at the intertie is less than or equal to the day-ahead bid.

To further describe how exports can be bid into the enhanced day-ahead commitment process and the general form of the DA-EFC price test, consider the following example and scenarios

- Day-ahead export bid is $100 for 100MW.
- Based on the day-ahead shadow (constrained) price (which would be less than or equal to $100), the exporter receives a day-ahead advisory schedule of 100MW.

Scenario 1: Keeping the real-time bid equal to the day-ahead bid

- The exporter keeps the real-time bid at $100.
- Pre-dispatch shadow price is $100, the export flows in real-time.
- There is no DA-EFC.

Scenario 2: Increasing the real-time bid

- The exporter has an outside contract to deliver in real-time and raises its real-time bid is $120 to get great assurance of flowing in real-time.
- In pre-dispatch shadow price is $125, the export is not economic and doesn't get scheduled for real-time.
- Since the pre-dispatch shadow price is greater than the day-ahead bid, the DA-EFC does not apply.

Scenario 3: Reducing the real-time bid, but the export flows

- Real-time export bid is $90.
- Pre-dispatch shadow price is $90, the export is still economic despite its bid is lower than its day-ahead bid. It is scheduled for real-time.
- There is no DA-EFC.

Scenario 4: Reducing the real-time bid, but the export fails

- Real-time export bid is $90.
- Pre-dispatch shadow price is $95, the export is not economic. It is not scheduled for real-time.
- Since the export fails and the pre-dispatch shadow price at the intertie is less than the day-ahead bid the exporter faces the DA-EFC. The export could have potentially caused an over-commitment in the day-ahead.

Details of the DA-EFC are to be determined with Market Assessment and Compliance. Any exception scenarios of the DA-EFC also need to be explored. Additional rules for day-ahead wheeling, failure code tagging and interaction with other IOG calculations are also required.