Shortfall Allocation Methodology

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I. INTRODUCTION

Several issues have come up in applying the shortfall allocation provisions of the NYISO tariff to actual day-ahead market and auction outcomes. The most important issue is that the current formulation of Equations N-5b and N-15b do not operated as intended for lines returned to service and would provide no benefit to the transmission owner that returns a line to service.

Second, Equations N-5a, N-5b, N-15a and N-15b are not currently formulated to correctly account for the impact of deratings and upratings attributable or not attributable to maintenance conditions. Third, several features of SCUC can cause the current formulation of Equation N-5a to lead to unintended consequences by under or over-compensating or charging transmission owners for outages. Finally, there are a variety of differences in the sign convention used in the current tariff and the sign convention in SCUC and the auction OPF that could potentially give rise to confusion if not clarified.

The potential problems are described below, first for the application of shortfall allocation to the day-ahead market and then to the TCC auctions. After describing the potential problems, the proposed solutions are described.

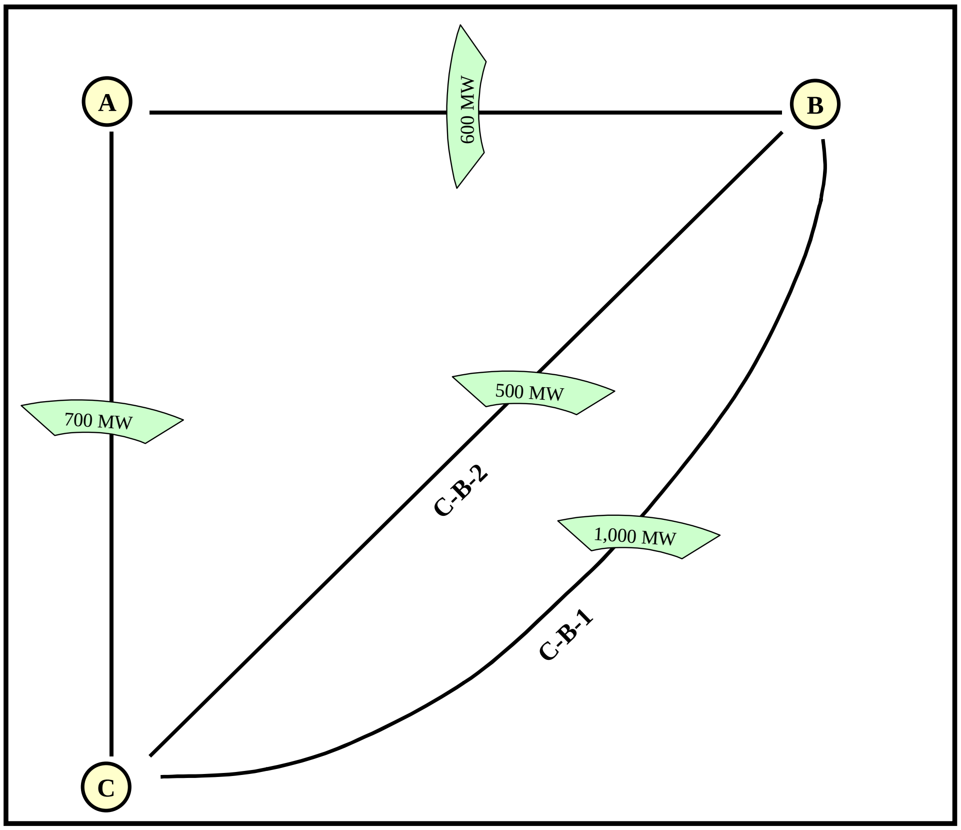
II. ALLOCATION OF DAY-AHEAD SHORTFALL COSTS

A. Conceptual Framework for Day-Ahead Shortfall Allocation Methodology

In the case of an outage that produces revenue inadequacy in the day-ahead market, the power flows on constraints binding in the day-ahead market associated with the outstanding TCCs and grandfathered rights on the day-ahead market grid would exceed the limit used in the auction. Thus, the outstanding TCCs would not be simultaneously feasible on the day-ahead market grid, giving rise to a congestion rent shortfall. The contribution to day-ahead market congestion shortfall from a particular outage would be the amount of the infeasibility times the day-ahead market shadow price of the overloaded constraint. Under the shortfall allocation methodology the day-ahead market congestion shortfall attributable to each outage is to be assigned to the transmission owner responsible for that outage.

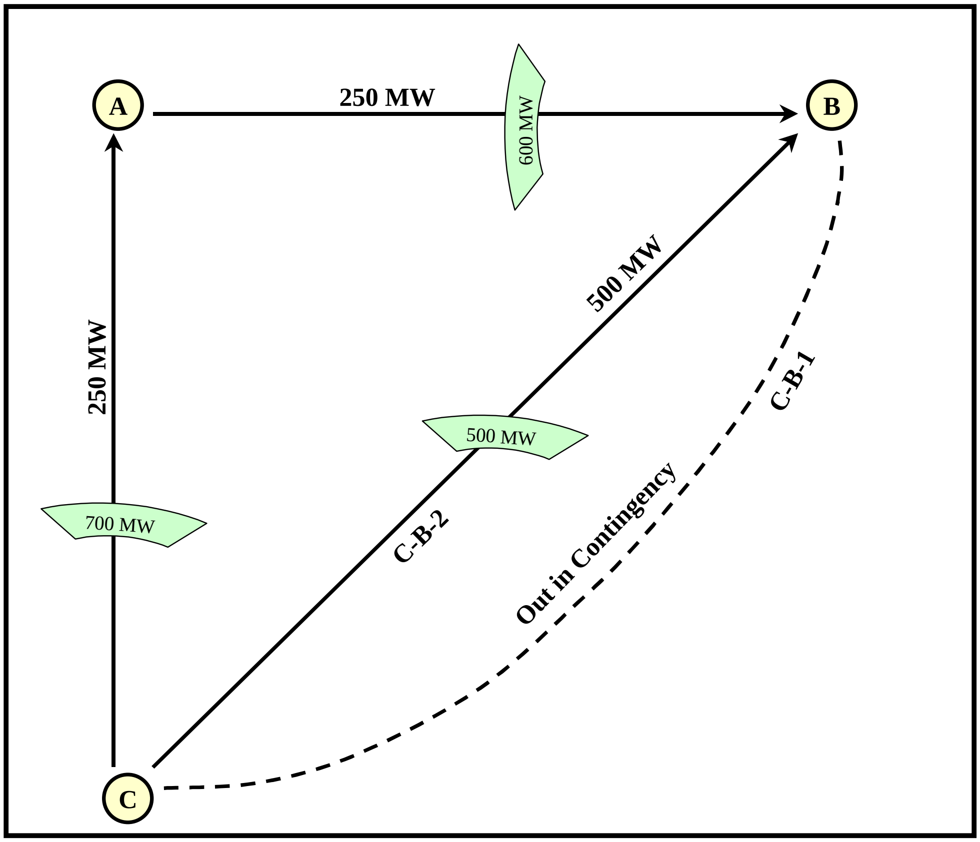
The application of this general methodology can be illustrated using the simple grid portrayed in Figure 1, with limits on A-B of 600 MW, on C-A of 700 MW, on C-B-2 of 500 MW and on C-B-1 of 1,000 MW.

Figure 1
Grid Configuration



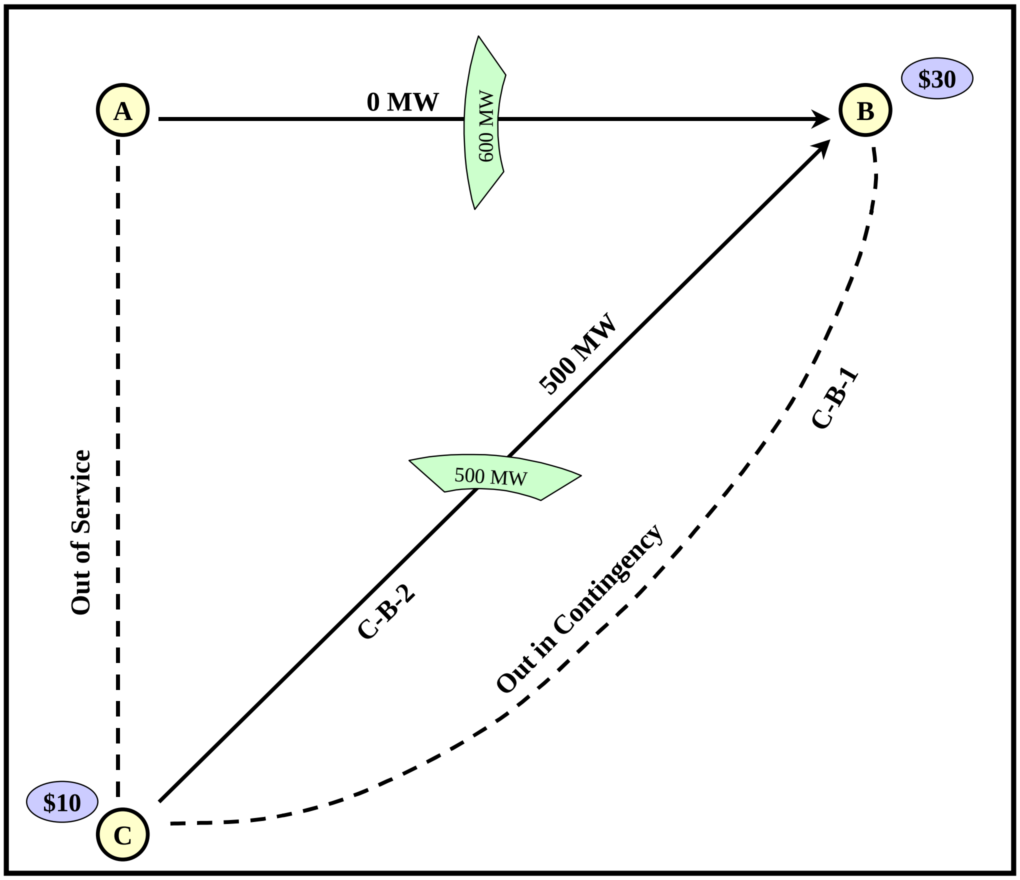
In the TCC auction, 750 MW of TCC could be awarded from C to B as illustrated in Figure 2, as the outage of C-B-1 would be the worst contingency.

Figure 2
TCC Auction Contingency



Suppose, however, that line C-A were unavailable in the day-ahead market due to transmission maintenance. It can be seen in Figure 3 that the transfer capability from C-B would be only 500 and the constraint on C-B-2 would be binding.

Figure 3
Day-Ahead Market Outage of C-A



If one calculated the flows associated with the outstanding TCCs applied to the day-ahead market grid configuration in Figure 3, the auction flows on C-B-2 would be 750, exceeding the auction limit by 250 MW. Thus the outage costs would be 250 MW times the shadow price of the constraint, as this is the amount that would be payable to TCC holders but not supported by day-ahead market congestion rent collections.

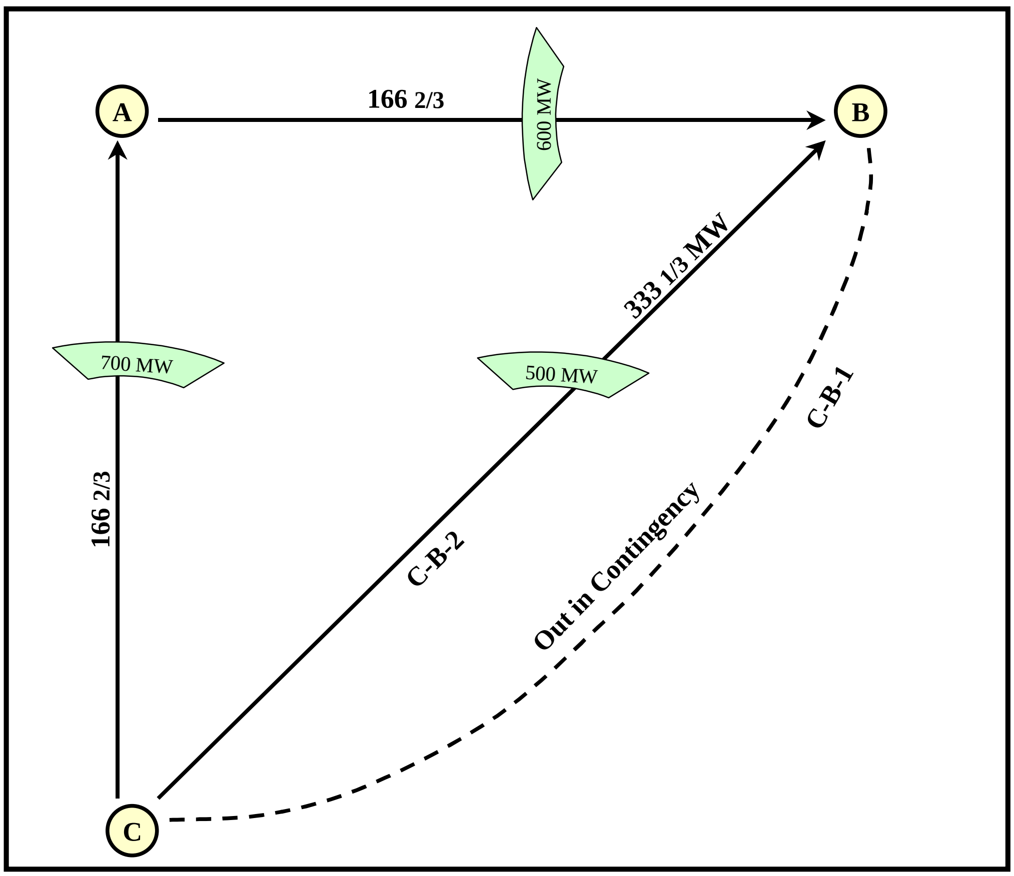
If the prices at B and C were $30 and $10 as shown in Figure 3, the payments to the holders of the 750 C-B TCCs would be $1,500 ($20/TCC * 750TCC). The congestion rent collections would be only $1,000, however, so there would be a $500 congestion rent shortfall in the day-ahead market.[1] The shadow price of the C-B-2 constraint in the day-ahead market would be $20/MWh (since the shift factor on the C-B line of generation injected at C to meet load at B would be 1 in this grid configuration, the shadow price would equal the price difference). Thus,

[1] The congestion rent collections would be 500 MWh * $30/MWh – 500 MWh * $10/MWh = $1,500 - $500 = $,1000.

the outage costs allocated to the transmission owner would be 250 * $20 = $500, which would exactly make up the day-ahead market congestion rent shortfall.

Now consider the converse case in which the line C-A is modeled as out for maintenance in the TCC auction as in Figure 3 and thus only 500 C-B TCCs are awarded. On days in which the C-A line is back in service, the system would be as shown in Figure 2 and the constraint on C-B-2 would be binding in the C-B-1 contingency. The TCC flows on line C-B-2, given the day-ahead market configuration, would be only 333 1/3 as shown in Figure 4, so the ISO settlements would collect congestion rents on 166 2/3 MW of flow on C-B-2 in the day-ahead market that would not be required to support payments to TCC holders. This would be the congestion shortfall benefit of returning the C-A line to service.

Figure 4
TCC Flows on the Day-Ahead Market Grid



If the prices at B and C are again assumed to be $30 and $10, the payments to the holders of the 500 C-B TCCs would be only $1,000. If 750 MW were injected at C in the day-ahead market and 750 MW withdrawn at B, the ISO would collect $1,500 on congestion rents in the day-ahead market, yielding a $500 day-ahead market congestion rent surplus. For the grid configuration in Figure 2 the shadow price of the C-B-2 constraint would be $30 (the shift factor for flows on C-B-2 of power injected at C and withdrawn at B would be 2/3). The transmission owner would therefore be paid $500 (166 2/3 * $30) for returning the line to service. This payment would exactly exhaust the congestion rent surplus.

B. Problems With Current Tariff Language

The methodology that is currently described in the tariff for Short-fall allocation in the day-ahead market will not assign these costs as intended either for outages or returns to service. First, the method for determining the impact of transmission outages (Equation N-5a) has two main components. First, the power flows attributable to the outstanding TCCs and grandfathered rights are to be calculated based on SCUC shift factors for the relevant day and hour applied to the net injections and withdrawals associated with the TCCs and grandfathered rights. Second, the powerflows associated with the injections and withdrawals scheduled in the day-ahead market were to be calculated based on the same SCUC shift factors. The difference between the actual SCUC flows and the calculated TCC flows were to be attributed to the relevant outages.

[N-5a] $DCR = SP * [F_{DAM} - F_{TCC \& GFR}]$

where:

SP = Constraint shadow price in day-ahead market

F_{DAM} = Flows on constraint in day-ahead market

$F_{TCC \& GFR}$ = TCC flows on constraint calculated for day-ahead market grid configuration.[2]

There are three main problems in applying this methodology to outage costs. The first problem is that the calculated SCUC flows for the day-ahead market may be less than the limit in the TCC auction for a variety of reasons that are unrelated to transmission outages. First, the iteration in the power flow solution in SCUC may leave lines less than fully loaded in the final iteration. Since this amount can vary from line to line and from hour to hour, this cannot be accounted for with a simple adjustment. Second, the application of the SCUC shift factors to the net generation injections and net withdrawals from the transmission system in the day-ahead market does not account for the congestion impact of transmission system losses and no shift factors are produced to allow us to account for them. The inability to account for these losses would tend to cause the calculated SCUC flows to be less than the limit enforced in SCUC even when the constraint is binding. Third, line limits may at times be reduced in SCUC below the

2 It should be noted that because of the sign conventions regarding the direction of flows, as well as the presence of constraints on minimum flows, SP, F_{DAM} and $F_{TCC \& GFR}$ can all be either positive or negative. A secondary problem that is also corrected is that the sign convention in the current tariff assumes that $SP * F_{DAM} > 0$, whereas under actual SCUC sign conventions $SP * F_{DAM} < 0$. To avoid future confusion, the sign convention in N-5a will be made consistent with SCUC.

level used in the TCC auction for reasons unrelated to transmission outages but giving rise to day-ahead market congestion rent shortfalls.[3]

A second problem in applying this methodology is that the TCC flows calculated for the day-ahead market grid using SCUC shift factors will be less than the transmission limits actually enforced in the auction OPF because the SCUC shift factors are applied only to the net injections and withdrawals associated with the TCCs but not to the transmission system losses in the OPF, which also produce flows over the binding constraints. A third problem is that some of the constraints binding in SCUC are maintenance contingencies which are not enforced in the TCC auction because the contingency only arises in the post outage grid configuration. It is therefore not meaningful to calculate the TCC flows on such a constraint for the auction grid configuration.

There are also problems with the methodology described for calculating the benefits of returns to service (Equation N-5b). Unlike the equation for outage impacts, Equation N-5b does not depend on TCC and grandfathered rights flows but calculates the difference between the calculated flows on the constraint in the day-ahead market and the limit enforced in the TCC auction.

$$DCR = SP * (F_{DAM} - F_{RL})$$

where:

F_{RL} = Constraint rating limit in prior reconfiguration auction.

This approach has three problems. First, as pointed out above, the calculated flows in the day-ahead market can differ from the limit enforced in the day-ahead market for reasons unrelated to transmission outages, such as incomplete iteration in the SCUC powerflow solution and loss flows in the SCUC powerflow solution. In both cases the calculated day-ahead market flow would be lower than the limit in the TCC auction even if there were no change in the limit, thus understating the benefits of any uprating in the day-ahead market. The second problem is that this methodology only measures the benefits of line upratings between the auction and the day-ahead market. It would not attribute any benefits to the return to service in the day-ahead market of lines that were out in the auction, because the calculated flows in the day-ahead market would always be less than or equal to the limit in the auction, except in the special case in which the limit was derated for some reason in the auction.

C. Revised Implementation Methodology

Correctly accounting for the congestion short-fall impacts of both outages and returns to service requires taking account both of changes in limits that are attributable to outages or maintenance conditions and accounting for changes in grid configuration. A key element of the revised short-fall allocation methodology is that it explicitly accounts for both sources of changes in transfer capability.

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3 The calculated SCUC flows would also be less than the limit because of the transmission margin, but this would not be a problem as it would be simple to account for. Similar issues relating to zonal load weights and block versus ideal schedules would also be straightforward to address.

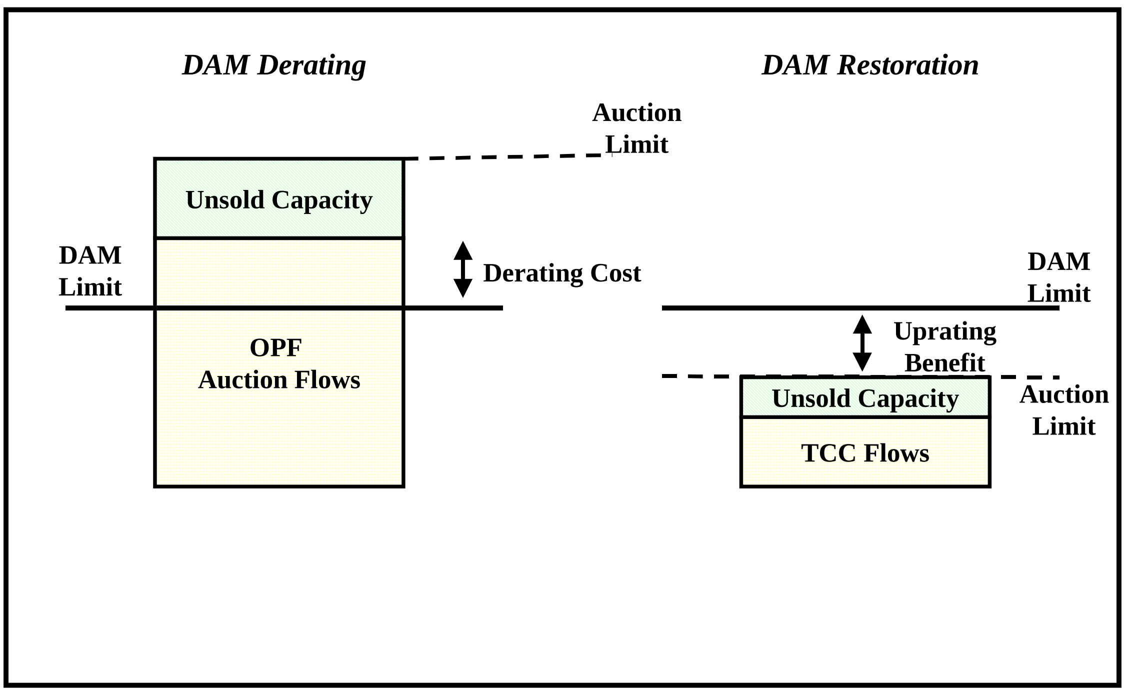
While changes in limits between the auction and the day-ahead market attributable to outages or maintenance conditions can be tracked and accounted for, calculating the exact impact of changes in grid configuration on TCC feasibility and revenue adequacy would require rerunning the auction OPF to calculate the TCC flows for the grid configuration in each hour of the day-ahead market.

It is not practical, however, for implementation purposes to calculate the exact powerflow for the outstanding TCCs based on the day-ahead market grid configuration because this would entail solving 8,760 OPFs per year. The second key element of the revised approach is to closely approximate the amount of changes in transfer capability attributable to changes in grid configuration by calculating the constraint flows produced by the outstanding TCCs and grandfathered rights using the generation and load shift factors that are calculated in SCUC for each binding constraint.

The third element of the revised methodology is to account for unsold transmission capacity explicitly, rather than indirectly, to ensure that it is accounted for correctly in cases in which there are combinations of outages, returns to service, deratings and upratings that affect transfer capability.

The first step in implementing the revised approach will be to account for the impact of upratings and deratings of transmission lines between the TCC auction and the day-ahead market. There will be a manual process by which SCUC operators will record any limit deratings in the day-ahead market that are specifically attributable to transmission maintenance, as well as any upratings that are specifically attributable to the end of transmission maintenance activities. The day-ahead market congestion rent short-fall impact of deratings would be calculated as the product of the shadow price of the constraint times the difference between the limit in the TCC auction and the limit in the day-ahead market, with an allowance for unsold capacity. Thus, as shown in Figure 5 if there were no unsold capacity in the TCC auction, the impact of the derating would be the difference between the limit in the day-ahead market and the limit in the TCC auction. If there were unsold capacity in the auction, the calculation would account for unsold capacity by multiplying the constraint shadow price by the difference between the flows on the constraint in the auction OPF solution and the day-ahead market limit, effectively subtracting the unsold capacity from the difference between the auction limit and the day-ahead market limit.

Figure 5
Ratings Changes



This methodology corresponds to the intent of the methodology originally filed in the tariff but by directly comparing the limits and identifying limit changes due to transmission maintenance, rather than relying on a very indirect comparison of calculated flows, it avoids the likelihood that the original methodology would calculate outage costs even when there was no derating between the TCC auction and the day-ahead market.[4]

[4] Under the original methodology, unscheduled capacity on the constraint in the day-ahead market attributable to incomplete iteration in SCUC would be treated as outage costs and potentially allocated to a transmission

In the case of upratings in the day-ahead market, the benefit of the uprating will be calculated as the product of the constraint shadow price and the difference between the limit in the TCC auction and the day-ahead market as also shown in Figure 5. The revised methodology also corresponds to the intent of the original methodology in the case of upratings, but the original methodology would have consistently understated the benefits of day-ahead market upratings because the methodology would have understated the actual day-ahead market limit, but not the TCC auction limit, by the amount of loss flows on the constraint in the day-ahead market and any impact of incomplete iteration in the day-ahead market.

As noted above, there is a potential for a constraint to be impacted both by changes in the grid configuration and changes in limits during a particular hour. This possibility introduces the need to ensure that unsold capacity is correctly accounted for in the case of offsetting impacts, and accounted for only once in the case of reinforcing impacts. For the purpose of clarity of exposition, the discussion in this section discusses each case individually. The method of accounting for the combined effects is discussed below.

The second step in implementing the revised approach will be to account for the day-ahead market congestion shortfall impacts of changes in grid configuration that are attributable to maintenance outages or returns to service. Under the proposed implementation methodology, the powerflows on the constraints binding in the day-ahead market associated with the outstanding TCCs and grandfathered rights will be calculated both for the grid configuration used in the auction and for the grid configuration used in the day-ahead market for that hour. If the constraint was binding in the TCC auction (and thus there was no unsold capacity on this constraint in the auction) the difference between these flows will measure the impact of the outage or return to service on transfer capability and the impact on congestion shortfalls in the day-ahead market. The flows will be calculated using SCUC shift factors calculated for the appropriate grid configuration applied to the TCC and grandfathered rights injections and withdrawals. This methodology is portrayed in Figure 6 for the case of a transmission outage in the day-ahead market. The TCC power flows calculated for the auction grid using SCUC shift factors will be less than the auction limit because the flows calculated from SCUC shift factors applied to the TCC and Grandfathered rights will not account for loss flows. Similarly, a comparison of the TCC flows calculated for the day-ahead market grid configuration using SCUC shift factors to the constraint limit would understate the actual overload because the calculated flows would not account for the loss flows.

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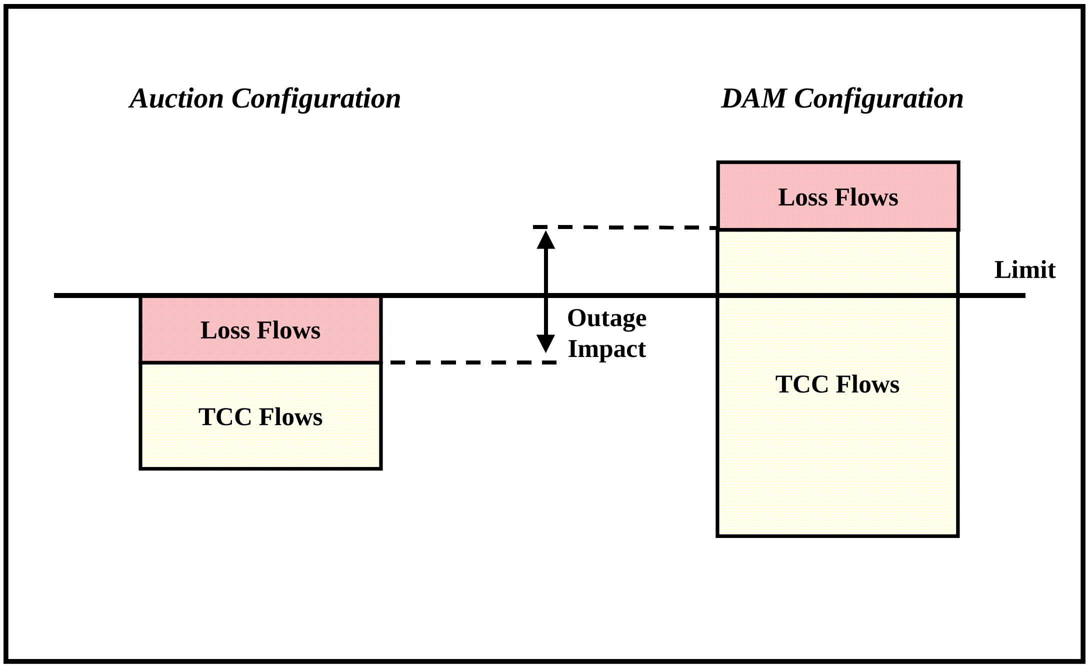
owner. Similarly, higher loss flows on a constraint in the day-ahead market solution than in the TCC auction solution would be treated as outage costs. Finally, the original methodology would have treated day-ahead market deratings that were unrelated to maintenance as giving rise to outage costs.

Since the TCC flows on the day-ahead market grid have a loss component that cannot be calculated from SCUC shift factors, rather than calculating the outage impact by comparing the calculated TCC flows on the day-ahead market grid to the constraint limit in the auction, the outage impact will be measured by the difference in the TCC flows calculated for both the auction grid and the day-ahead market grid using SCUC shift factors as illustrated in Figure 6.

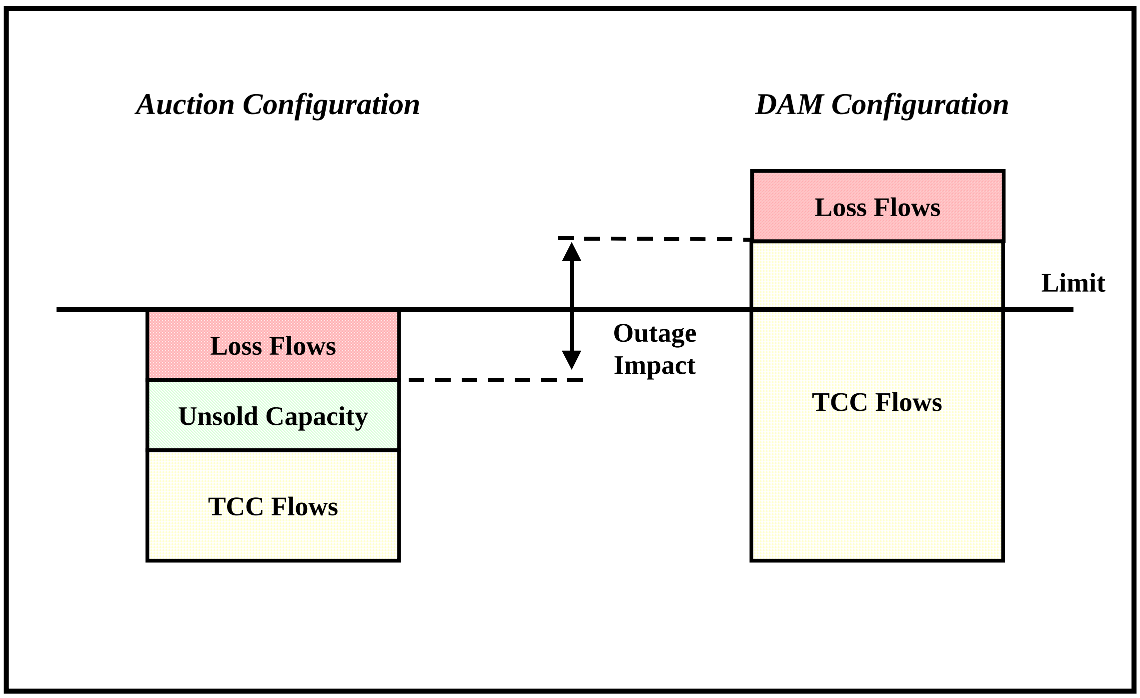
Figure 6
TCC Flow Method
Outage Case



Implicit in this methodology is the assumption that the loss flows are approximately the same between the two cases so that the difference in the TCC flows between the two cases will closely approximate the amount by which the actual TCC flows on the day-ahead market grid exceed the limit used in the auction. Since the TCC loads will be the same between the two cases, the losses will be very similar. The losses will not be exactly the same, however, because the line loadings will in fact be different between the auction and the day-ahead market as a result of the outage.

The example portrayed in Figure 6 is simplified by assuming that the constraint that is binding in the day-ahead market was also binding in the auction solution and thus that there was no unsold capacity on the constraint in the TCC auction. This is not necessarily the case and the implementation methodology also needs to account for the case in which the constraint that is binding in the day-ahead market was not fully sold in the auction. The outage cost allocation will be applied in this more general case by calculating the outage impact as the difference between the TCC flows on the day-ahead market grid configuration and the sum of the unsold capacity and TCC flows for the auction configuration as portrayed in Figure 7.

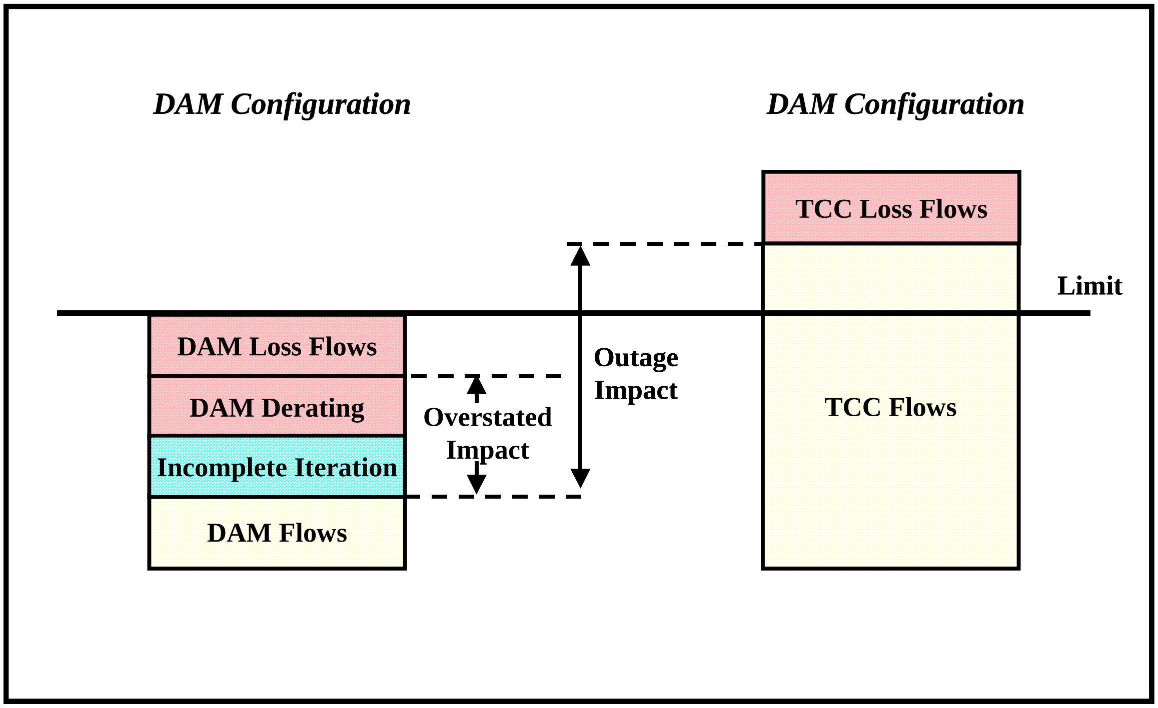
Figure 7
Alternative TCC Flow Method
Outage Case



The unsold capacity would be calculated for implementation purposes as the difference between the TCC flows in the auction solution calculated with the auction OPF and the limit for each constraint. These TCC flows in the auction solution need to be calculated using the auction OPF in any case for the purpose of assigning the congestion shortfall among outages.

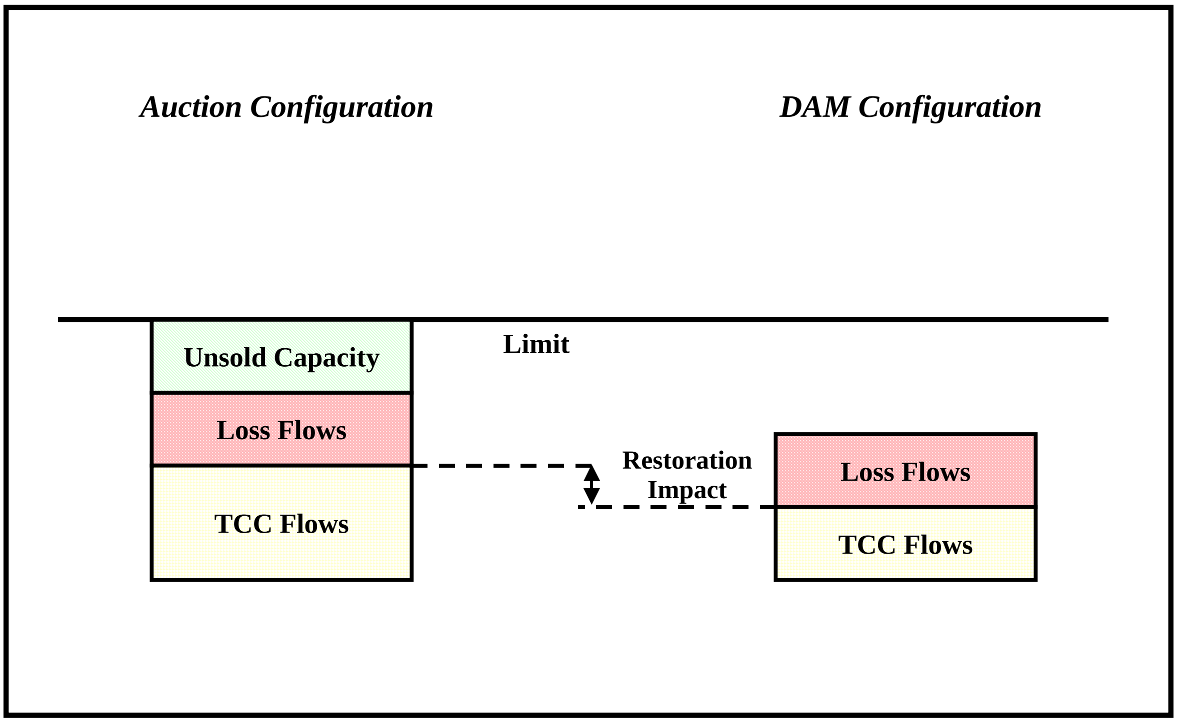
The revised approach corresponds to the intent of the original implementation methodology but avoids assigning spurious outage costs to transmission owners in the instances in which there is incomplete SCUC iteration or there are deratings in the day-ahead market that are unrelated to transmission maintenance as illustrated in Figure 8.

Figure 8
Original Methodology
Outage Case



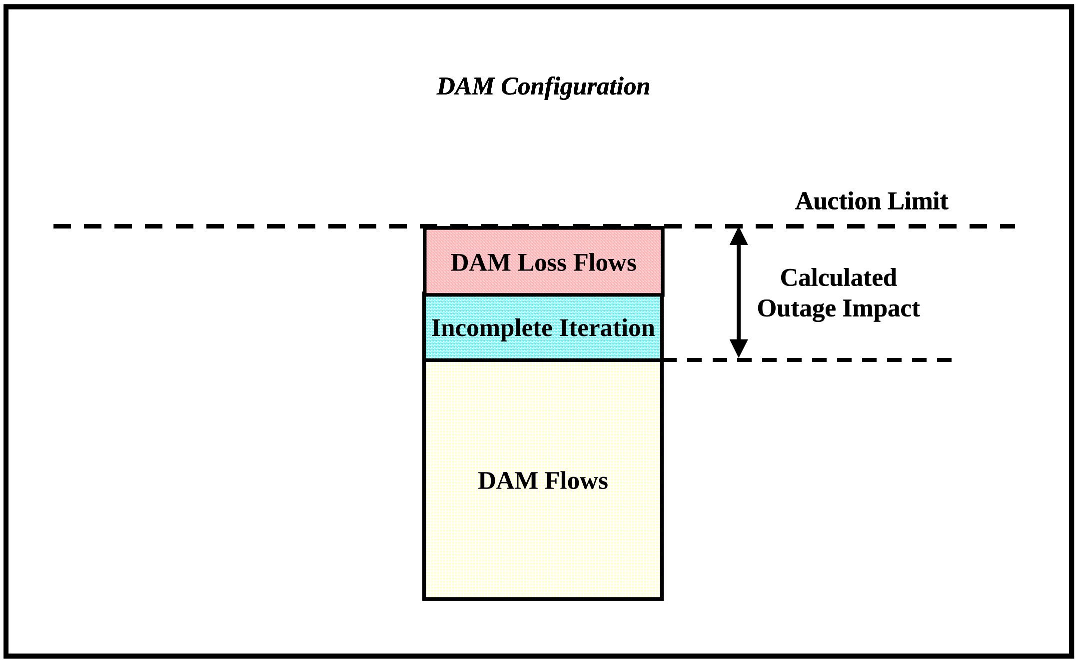
Essentially the same methodology would be applied to calculate the impact of returning transmission to service. The benefit from the return to service would be the product of the shadow price in the day-ahead market of each binding constraint times difference between the TCC flows calculated for the auction grid configuration using SCUC shift factors and the TCC flows calculated for the day-ahead market grid configuration using SCUC shift factors. In this case, the calculated TCC flows for the day-ahead market grid would be lower than the calculated TCC flows for the auction grid as shown in Figure 9 and the difference between these flows would be attributed to the return of lines to service.

Figure 9
TCC Flow Method
Restoration Case



This allocation methodology reflects the intent of the original filing but yields a completely different result than the methodology in the original filing. As illustrated in Figure 10, for benefits arising from returning lines to service rather than changes in rating limits, the calculated flows in the day-ahead market would always be less than the auction limit and thus yield a zero calculated benefit, regardless of the magnitude of the actual benefits from returning a line to service in the day-ahead market. This critical deficiency of the original tariff methodology is avoided under the revised approach.

Figure 10
Original Methodology
Restoration Case



Overall, this revised methodology for calculating the impact of transmission outages and returns to service on congestion rent shortfalls in the day-ahead market has three main components. First, the power flows on the transmission constraints binding in the day-ahead market attributable to the outstanding TCCs and grandfathered rights are to be calculated based on SCUC shift factors for the relevant day and hour applied to the net injections and withdrawals associated with the TCCs and grandfathered rights. The benefit from returning the line to service is not affected by whether grandfathered rights are scheduled or not. This calculation would need to be made each day for each hour based on that hour's SCUC shift factors for the constraints that were binding in that hour.

The second component of the calculation would be the powerflows produced by the outstanding TCCs and grandfathered rights calculated based on shift factors for the grid configuration in the TCC reconfiguration auction for the current month. These flows would be calculated using shift factors calculated in a special SCUC case that would be solved once a month for the grid configuration used in the reconfiguration auction for the current month.

Any month-to-month changes in grid configuration that are reflected in the TCC auction model will need to be incorporated in the SCUC case that is run to determine the shift factors used to calculate the TCC flows on the auction grid. Since the current SCUC implementation only calculates shift factors for constraints that are binding in the auction solution, in order to ensure that this SCUC case would produce shift factors for all relevant contingencies, the limits on all of the constraints known to bind in the day-ahead market would need to be reduced to very low levels for this special SCUC case.

This basic methodology for calculating outage impacts will need to account for PAR schedules. Although the methodology compares TCC flows between two cases that differ only in grid configuration, these changes in grid configuration could result in changes in PAR shift factors, as well as in generation shift factors. These changes in PAR shift factors and the resulting changes in PAR flows could also contribute to congestion shortfalls or surpluses. The impact of changes in grid configuration on PAR flows will be accounted for using PAR shift factors calculated in SCUC for the day-ahead market grid configuration and the auction grid configuration, and auction PAR schedules.

The third element of this methodology is the calculation of the unsold capacity in the TCC auction. This is difference between the constraint limit in the auction and the TCC flows in the auction solution. The constraint limits will be extracted from the auction OPF and the TCC flows in the auction solution will be calculated for the purpose of assigning outage costs to specific outages.

Once these impacts are calculated they would be allocated to individual transmission owners as provided for in the original tariff filing. This methodology is described in section 2.4.2.1 and needs to be carried out regardless of how the impact is calculated. There are also extensive rules in the tariff for assigning outage costs to transmission owners in the event of multiple outages.

The methodology description above has described the application of the proposed methodology to both outages/restorations and deratings/upratings.

An additional factor that needs to be accounted for in the tariff is the possibility that a derating or uprating could occur in the same hour in which there was a change in grid configuration. In this circumstance it is necessary to ensure that unsold capacity is accounted for once and only once in the calculation of outage impacts and is not included in such a way as to give rise to spurious return to service benefits. This is accounted for in the revised tariff language by calculating the combined effects of outages, returns to service, deratings and upratings without regard to unsold capacity and then including unsold capacity to reduce the shortfall charge applicable to outings and deratings.

Thus:

[N-5a] $DCR = SP * (+ F_{DAM} - F_{TCC\ Auction} + \text{Uprate Derate} * Z + \text{Unsold Capacity} * Z)$[5]

where:

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5 Note that this equation reflects the current (unintuitive) SCUC sign convention such that $SP * F_{DAM} < 0$.

SP = Constraint shadow price

F_{DAM} = TCC flows on constraint calculated for day-ahead market grid configuration

$F_{TCC\ Auction}$ = TCC flows on constraint calculated for TCC auction grid configuration

Uprate Derate = day-ahead market rating limit – Auction rating limit due to maintenance-related uprates or derates[6]

Unsold Capacity = 0 if $SP * (F_{DAM} - F_{TCC\ Auction} + \text{Uprate Derate} * Z > 0$,

or the lesser of unsold capacity in last reconfiguration auction or

$|F_{DAM} - F_{TCC\ Auction} + \text{Uprate Derate} * Z|$ if

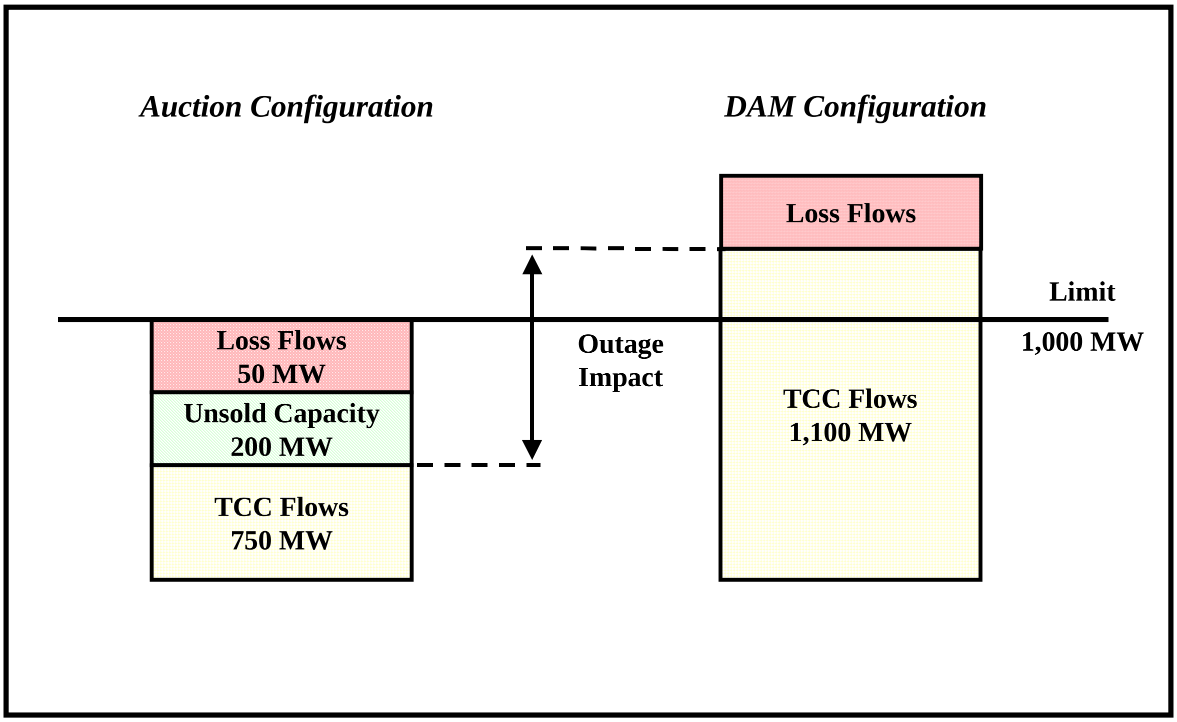
$SP * (F_{DAM} - F_{TCC\ Auction} + \text{Uprate Derate} * Z) < 0$

Z = 1, if $SP > 0$; $Z = -1$ if $SP < 0$

[6] Thus, Uprate Derate equals zero for grid configuration changes or deratings that are not maintenance related.

This approach does not change the calculation of impacts for upratings and restorations of service as portrayed in Figures 5 and 9 above (as SP * (F_{DAM} – $F_{TCC\ Auction}$ + Uprate Derate * Z) < 0 and Unsold = 0), but does affect the calculation of outage and derating impacts. Figure 11 portrays the calculation of the outage impact for combinations of outages and upratings or deratings. The outage impact is the difference between the calculated TCC flow for the auction configuration and day-ahead market configuration using SCUC shift factors. If there were no deratings or upratings, this methodology would yield the same result as that portrayed in Figure 7 with the subtraction of the unsold capacity from the outage impact.

Figure 11
Combination Outage Case



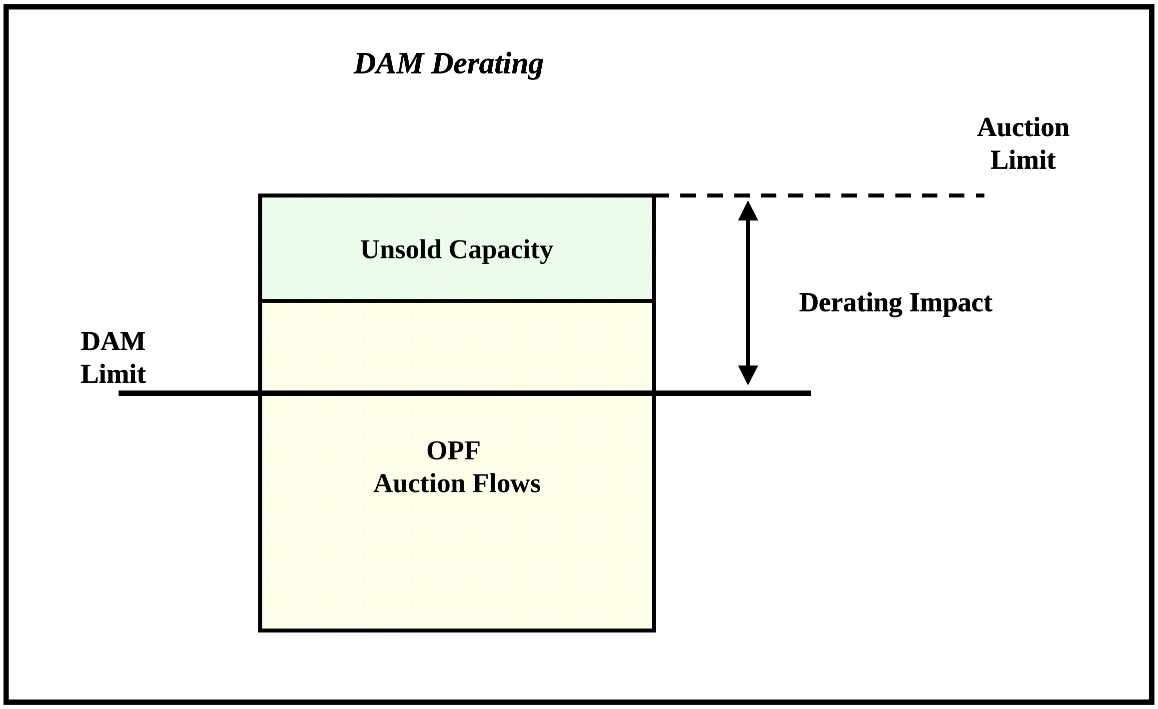
To illustrate the application of Equation 5a in this circumstance, suppose TCC flows on the auction grid were 750 MW, OPF flows on the auction grid were 800, TCC flows on the day-ahead market grid were 1,100 MW, the auction limit was 1,000 MW and the constraint shadow price was -$5/MW.[7] The unsold capacity would then be 200, (1,000 – 800), while F_{DAM} – $F_{TCC\ Auction}$ would be (1,100 – 750) = 350 and Z = -1. Thus, the DCR for the outage only would be:

-$5 (350 – 200) = -$750.

7 Note that the sign convention by which SP * F_{DAM} < 0 for binding constraints is not intuitive but is consistent with the actual sign convention in SCUC output data.

Similarly, Figure 12 portrays the impact of deratings in the day-ahead market for combinations of outages, returns to service and deratings. The outage impact is the difference between the day-ahead market limit and the auction limit, if the derating in the day-ahead market is attributable to an outage or maintenance condition. Once again, if there are no line outages or returns to service, this methodology leads to the same result as that portrayed in Figure 5 with the subtraction of the unsold capacity from the derating impact.[8]

Figure 12
Ratings Changes in Combination



To illustrate the application of 5a to a combination of outages and deratings, let us suppose that the line limit was reduced from 1,000 MW in the auction to 900 MW in the day-ahead market. Thus, uprate/derate * Z = (900 – 1,000) * -1 = 100.

The outage impact calculated using Equation 5a would be:

-\$5 (350 – 200 +100) = -\$5(250) = -\$1,250

8 It should be kept in mind that the impact of maintenance-related ratings charges and grid configuration charges is calculated separately because of data issues. The TCC flows calculated for the day-ahead market grid configuration based on SCUC do not include loss flows and a comparison of TCC flows to the limit in the day-ahead market needs to account for ratings charges that are not due to maintenance conditions. These data issues lead to a slightly different formulation than that applied to auction outages below.

D. Implementation Issues

There are several implementation issues related to the application of the general approach to shortfall allocation. While it would be desirable to complete the SCUC run during the month to calculate SCUC shift factors for the normal SCUC constraints so that these shift factors could be used for the determination of the outage cost allocation on an ongoing basis during the month, the set of binding constraints in the day-ahead market will not be known until the end of the month. In the event that there are unanticipated outages leading to unusual constraints in the day-ahead market during the month, it might be necessary to run an additional SCUC case at the end of the month to calculate shift factors for these constraints for the TCC auction grid configuration.[9]

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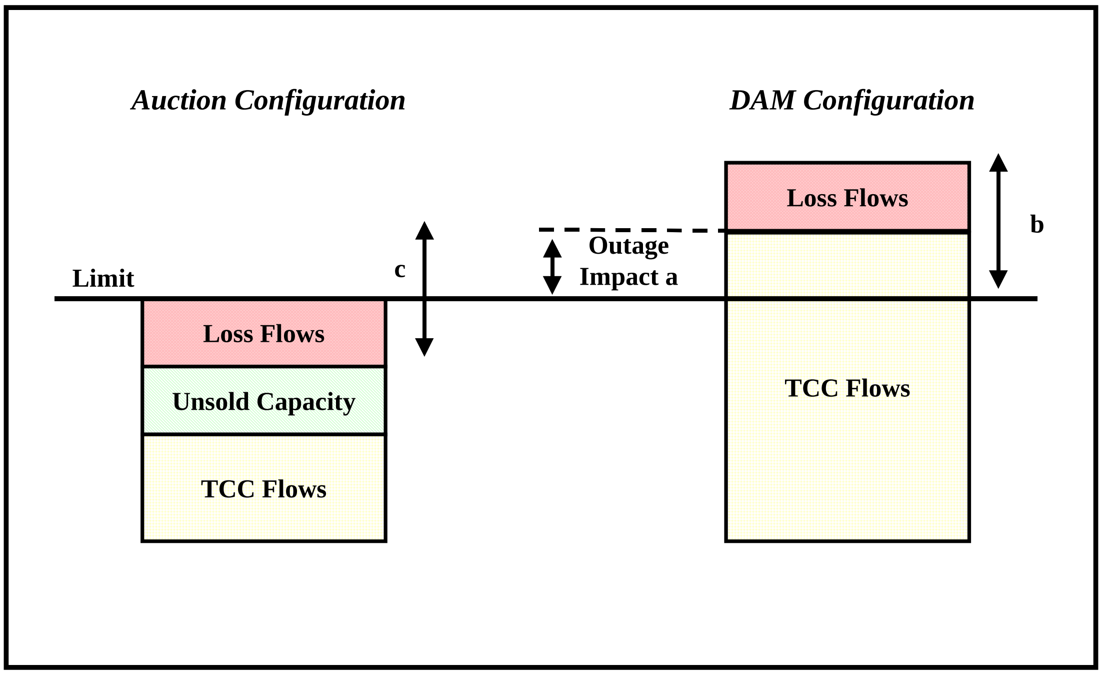
9 As discussed below, it may also be necessary to run an additional SCUC case to calculate shift factors relating to maintenance contingencies that were binding during the month to the extent that these cannot be fully anticipated.

There are also four cases involving changes in the grid configuration between the auction and the day-ahead market that will require the application of special rules. First, it will at times be difficult or impossible to use this approach to generate shift factors for constraints that can only bind when certain lines are out of service. If these other lines are modeled as in service in the auction, it will not be possible using the current SCUC to calculate shift factors for the contingency and limiting element of constraints that only bind when the lines are out of service. In these circumstances, or if auction shift factors are not available for any other reason, it is proposed that the outage costs would be calculated based on a comparison of the TCC flows calculated for the day-ahead market grid configuration to the limit used in the relevant TCC auction as portrayed by the impact a in Figure 13.

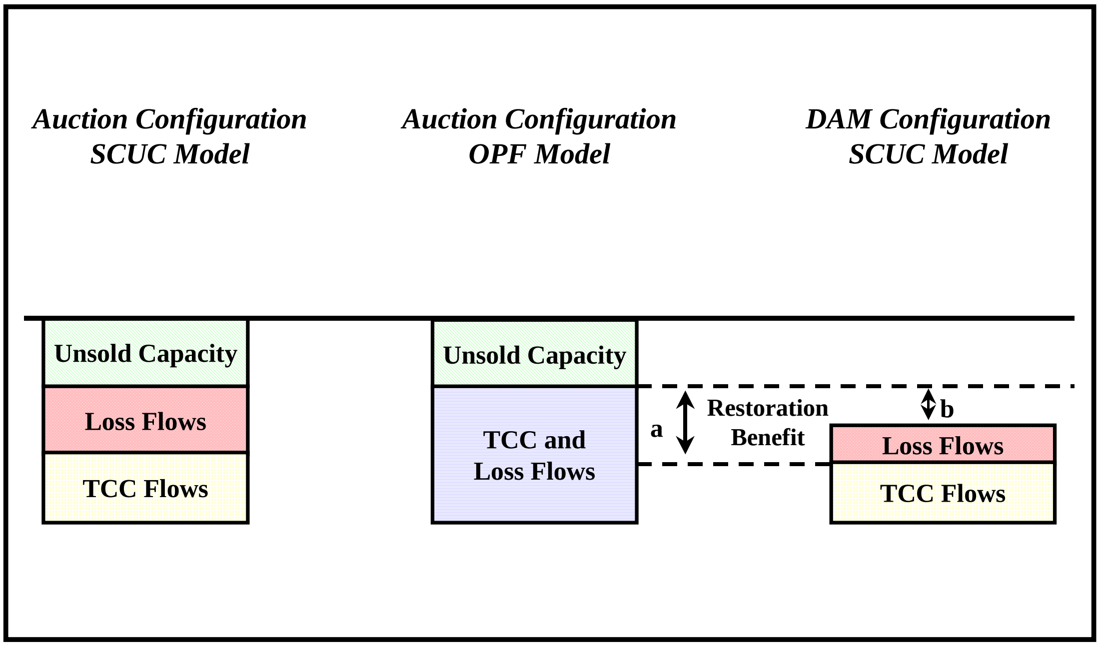
Figure 13
Missing Auction Shift Factors
Outage Case



This approach would understate outage costs by the amount of the loss flows that are not accounted for in the comparison portrayed in Figure 13 (a versus b or c). Nevertheless, this alternative assures that it will always be possible to calculate outage impacts, even when the appropriate shift factors are not available to calculate impacts.

This circumstance in which the shift factors required to calculate TCC flows for the auction configuration are not available for a particular constraint could also impact the ability to measure the impact of returning a line to service. In this situation, the benefit of the return to service would be measured as the difference between the flows on the constraint in the auction OPF solution and the flows calculated for the constraint using SCUC shift factors for the day-ahead market grid configuration as portrayed in Figure 14 (impact a). This calculation will overstate the benefits of the return to service (the difference between impact a and b) by the amount of the loss flows. This methodology will only be utilized when shift factors for the auction grid are not available from the special SCUC run.

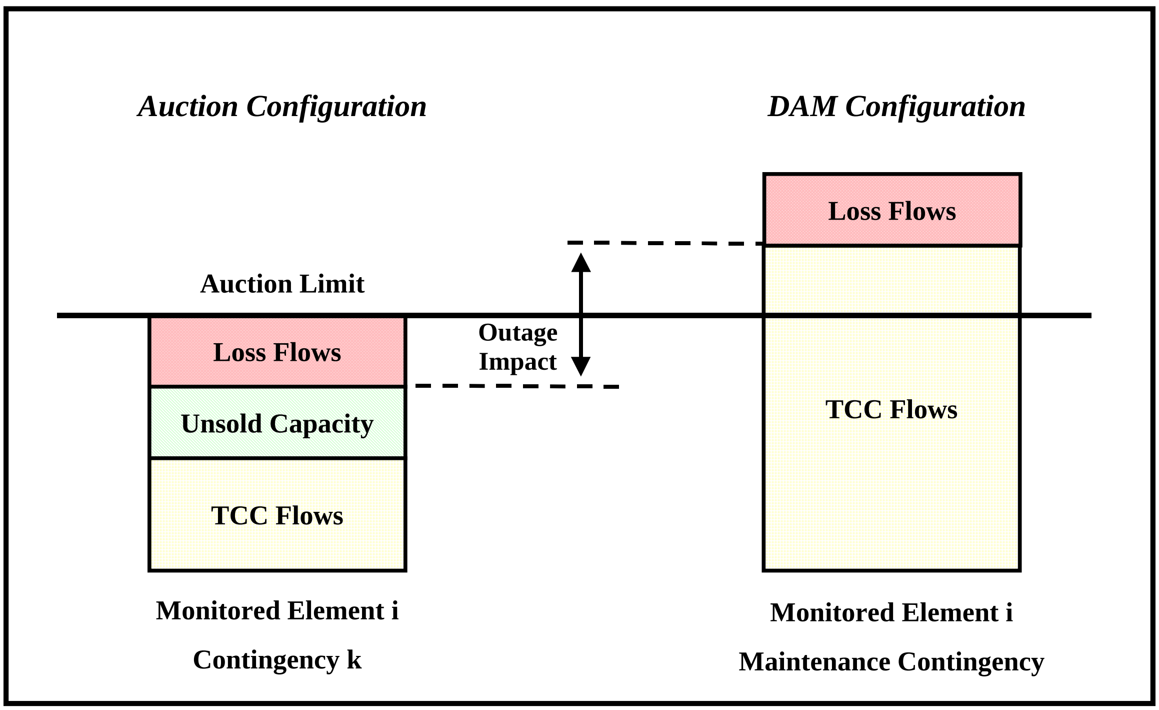
Figure 14
Missing Auction Shift Factors
Restoration Case



The need for this rule will eventually be eliminated by modifying SCUC so that it will calculate shift factors for designated constraints without regard to whether they are binding. This special rule enables the NYISO to implement shortfall allocation before such changes are made in SCUC.

Second, the methodology needs to account for outage costs associated with maintenance contingencies that are binding in the day-ahead market but are not enforced in the auction (because the contingency cannot bind except when the outage is taken). This would be done by calculating the amount of flows produced by the TCCs and grandfathered rights on the monitored element of the maintenance contingency for the day-ahead market grid and the TCC flows on that same monitored element plus the unsold capacity on that element in the next most binding contingency for the auction grid, as illustrated in Figure 15. The difference between the TCC flows on the limiting element in the maintenance case for the day-ahead market grid configuration and in the next most binding contingency on the auction grid would then be multiplied by the constraint shadow price and assigned to the responsible transmission owner.

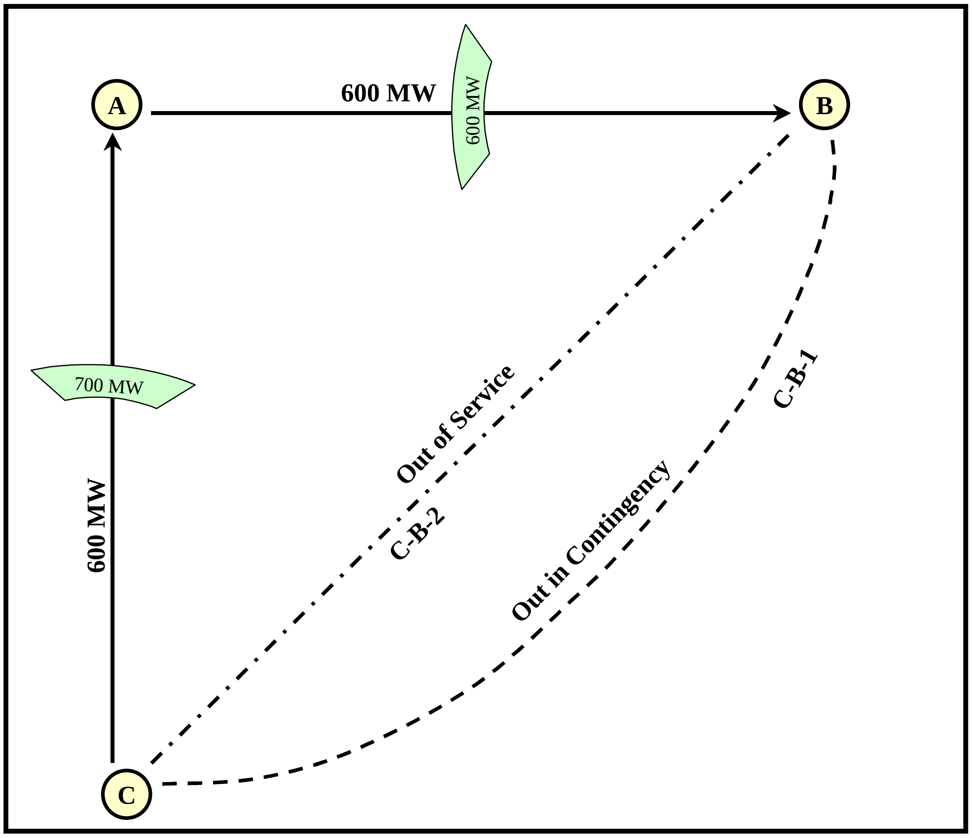
Figure 15
Maintenance Contingencies
Outage Case



The third situation is that SCUC will not calculate shift factors for the auction grid configuration for monitored elements that are out of service in the auction as there would be no flows on these elements in the auction solution. Using zero flows in the auction solution to calculate the value of returns to service, however, would misstate the actual impact of returning the line to service as the difference between the TCC flows in the auction solution (0) and the TCC flows on the day-ahead market grid configuration would be negative, implying a reduction in transfer capability and a charge rather than a credit.

This potential problem can be illustrated using the example above. If line C-B-2 were out of service in the auction, the worst contingency in the auction would be the outage of the C-B 1 line and 600 TCCs could be awarded from C- B as illustrated in Figure 16.

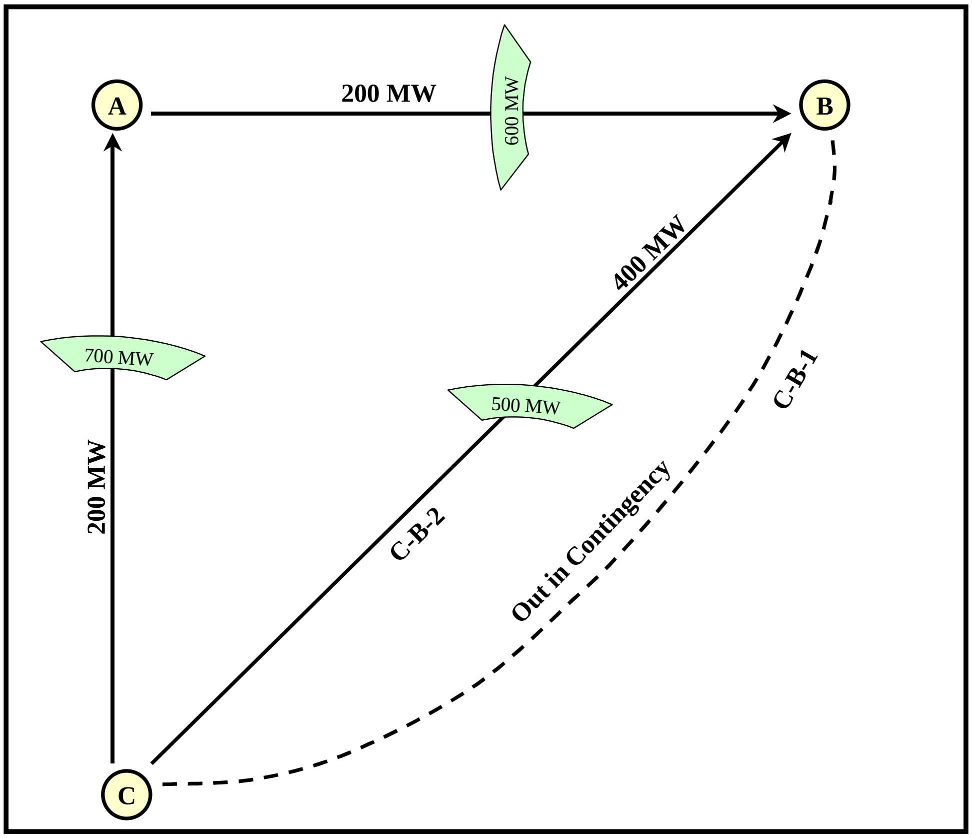
Figure 16
TCC Flows Constrained Element Out In Auction



If the C-B-2 line were back in service in the day-ahead market, the grid might be dispatched as portrayed in Figure 2 above, with the 500 MW limit on C-B-2 binding in the contingency in which C-B-1 is the outage element.

Since the constraint on C-B-2 is binding in the day-ahead market, the proposed outage cost methodology would calculate the benefits of returning the line to service by comparing the TCC flows on C-B-2 in the auction to the TCC flows on C-B-2 with the day-ahead market grid configuration. The flows in the auction solution are zero, however, as shown in Figure 16 because the line was modeled as out-of-service in the auction. The TCC flows on C-B-2 with the day-ahead market grid configuration would be 400, as shown in Figure 17.

Figure 17
TCC Flows on day-ahead market Grid



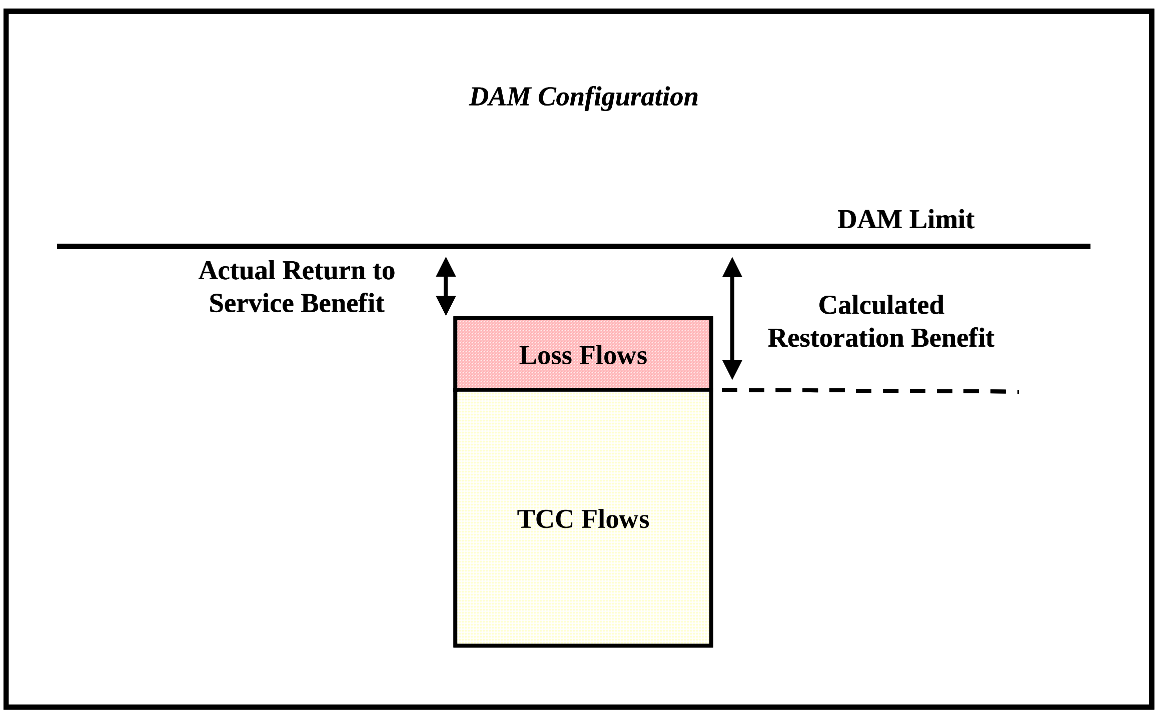
If zero were used for the TCC flows on C-B-1 for the auction grid and the standard methodology were applied to calculate the benefits of returning the line to service there would be not benefit since the return to service would increase, rather than reduce, the flows on the constrained element (flows would be 400 MW on the day-ahead market grid configuration vs zero on the auction grid for an increase of 400 MW, rather than a decrease). In reality, however the return to service would increase transfer capability by 150 MW and give rise to a $3,000 increase in congestion rent collections.

Instead, it is proposed that for the circumstance in which the monitored element that is binding in the day-ahead market is out of service in the auction, the TCC flows on the element in the day-ahead market grid configuration would be compared to the limit on the line in the day-ahead market. In the simple example above, this would result in comparing the 500 MW limit on C-B-2 in the day-ahead market to the 400 MW of TCC flows on the C-B-2 in the binding contingency for the day-ahead market grid configuration.

Thus, if the prices at B and C are again assumed to be $30 and $10, the payments to the holders of the 600 C-B TCCs would be only $1,200. If 750 MW were injected at C in the day-ahead market and 750 MW withdrawn at B, the ISO would collect $1,500 on congestion rents in the day-ahead market, yielding a $300 day-ahead market congestion rent surplus. For the grid configuration in Figure 2 the shadow price of the C-B-2 constraint would be $30 (the shift factor for flows on C-B-2 of power injected at C and withdrawn at B would be 2/3). The transmission owner would therefore be paid $300 (100 * $30) for returning the line to service. This payment would exactly exhaust the congestion rent surplus.

On the actual transmission grid this methodology will somewhat overstate the benefits of returns to service, as shown in Figure 18, as the calculated benefits of the return to service will not account for loss flows. While imperfect, this rule assures that the methodology can always be implemented. In reviewing the period January 1, 2004 to July 31, 2004 there were no instances in which it would be necessary to apply this rule as the situation covered never arose.

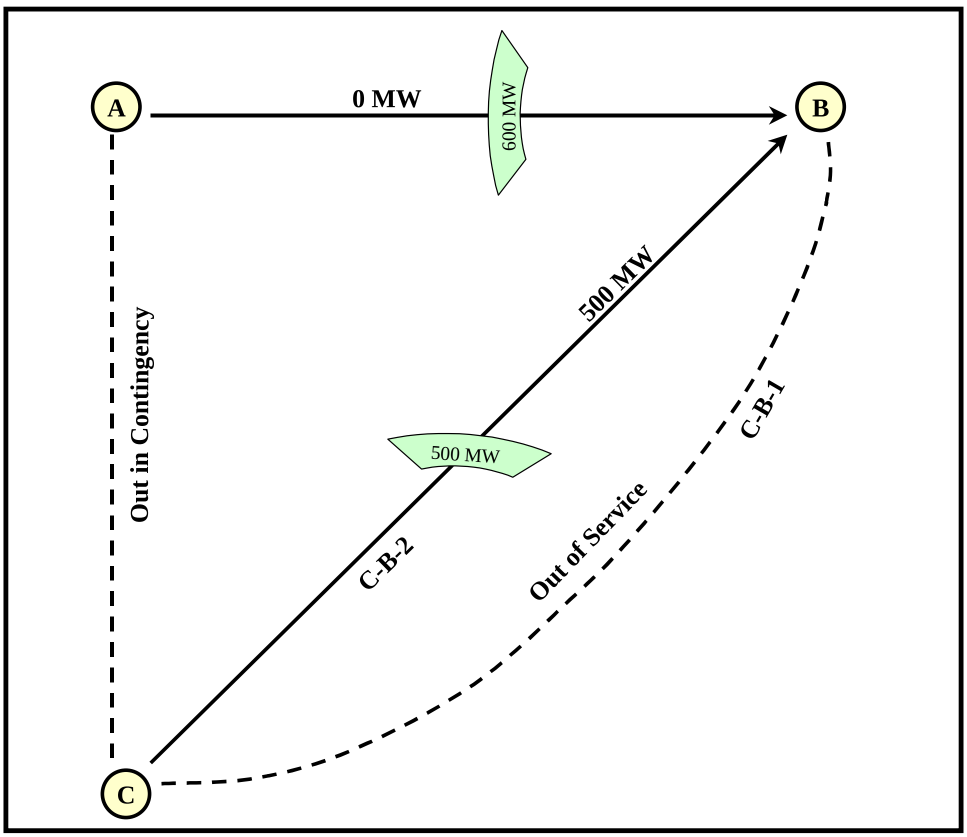
Figure 18
TCC Flows on day-ahead market Grid
Restoration Case



Since the constrained element is out of service in the auction, changes in rating between the auction model and the model for the day-ahead market have no impact on congestion rent shortfalls. The benefit of restoring the line to service would, however, be calculated using the limit in the day-ahead market as illustrated in Figure 16.

The fourth problem that is similar to the third problem is that SCUC applied to the auction grid configuration will not calculate shift factors for constraints in the day-ahead market whose contingent element was out of service in the auction. This is illustrated in Figure 19 in which C-B-1 is out of service in the auction. The outage of C-A is then a binding contingency and 500 TCCs could be awarded from C to B.

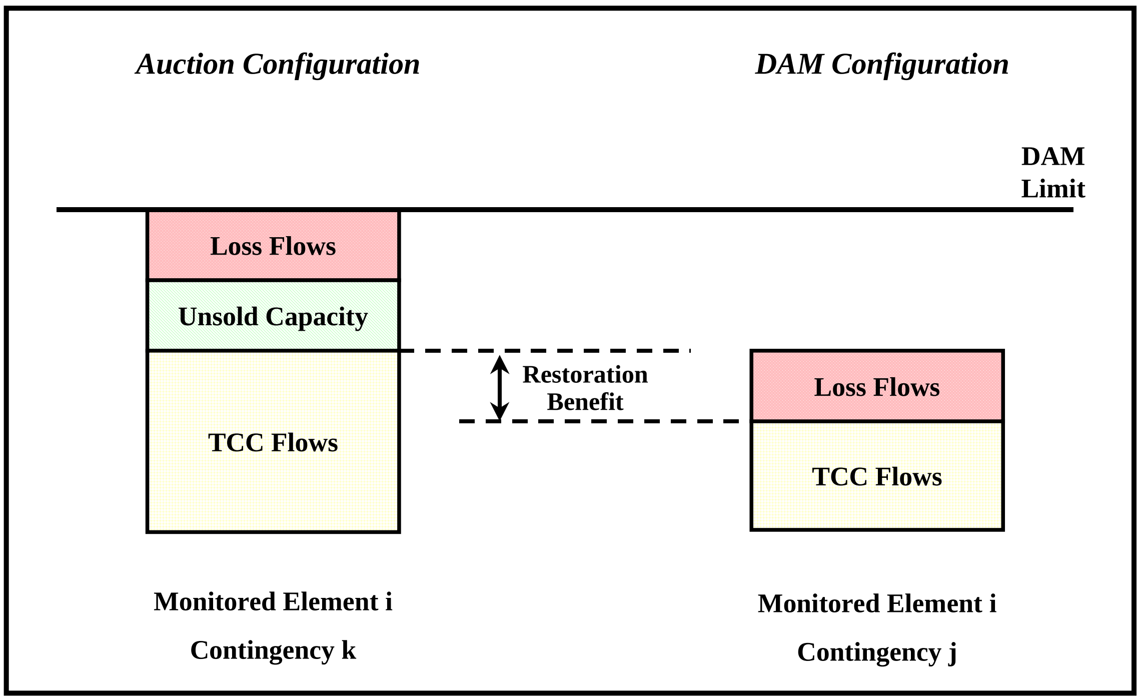
Figure 19
Contingency Element Out In Auction



If C-B-1 were back in service in the day-ahead market, the system would be dispatched as portrayed in Figure 2 with flows of 500 MW on C-B-2 in the contingency in which C-B-1 is the outage element. It is not possible to compare the flows on C-B-2 in the C-B-1 contingency between the auction grid configuration and the day-ahead market grid configuration because there was no C-B-1 contingency in the auction grid configuration.

It is proposed that this case be handled analogous to the treatment of maintenance contingencies by comparing the calculated TCC flows on the limiting element for the binding day-ahead market contingency on the day-ahead market grid to the sum of the calculated flows on the limiting element for the most limiting contingency for the auction grid configuration and the difference between the limit on this element and the flows on this element in this contingency in the auction solution, as shown in Figure 20.

Figure 20
Contingency Element Out in Auction
Restoration Case



In the example described above, there would be 500 C-B TCCs and the TCC flows on C-B-2 in the C-B-1 contingency in the day-ahead market would be 333 1/3 as shown in Figure 4. The most binding contingency in the auction for C-B-2 would be the outage of C-A or A-B as shown in Figure 19, resulting in flows of 500 on C-B-2. The benefits of returning C-B-1 to service in the day-ahead market would therefore be 166 2/3 times the shadow price of C-B-2 in the day-ahead market.

If the prices at B and C are again assumed to be $30 and $10, the payments to the holders of the 500 C-B TCCs would be only $1,000. If 750 MW were injected at C in the day-ahead market and 750 MW withdrawn at B, the ISO would collect $1,500 on congestion rents in the day-ahead market, yielding a $500 day-ahead market congestion rent surplus. Since the flows on C-B-2 in the next most binding contingency in the auction would be 500, compared to the 333 1/3 MW of TCC flows on C-B-2 in the binding contingency in the day-ahead market, the change in flows would be 166 2/3. For the grid configuration in Figure 2 the shadow price of the C-B-2 constraint would be $30 (the shift factor for flows on C-B-2 of power injected at C and withdrawn at B would be 2/3). The transmission owner would therefore be paid $500 (166 2/3 *

$30) for returning the line to service. This payment would exactly exhaust the congestion rent surplus.

Once again, there could be an additional impact arising from changes in rating between the auction model and the day-ahead market model. The benefit of upratings and deratings between the auction and the day-ahead market would be calculated separately and added to the impact attributable to the change in grid configuration.

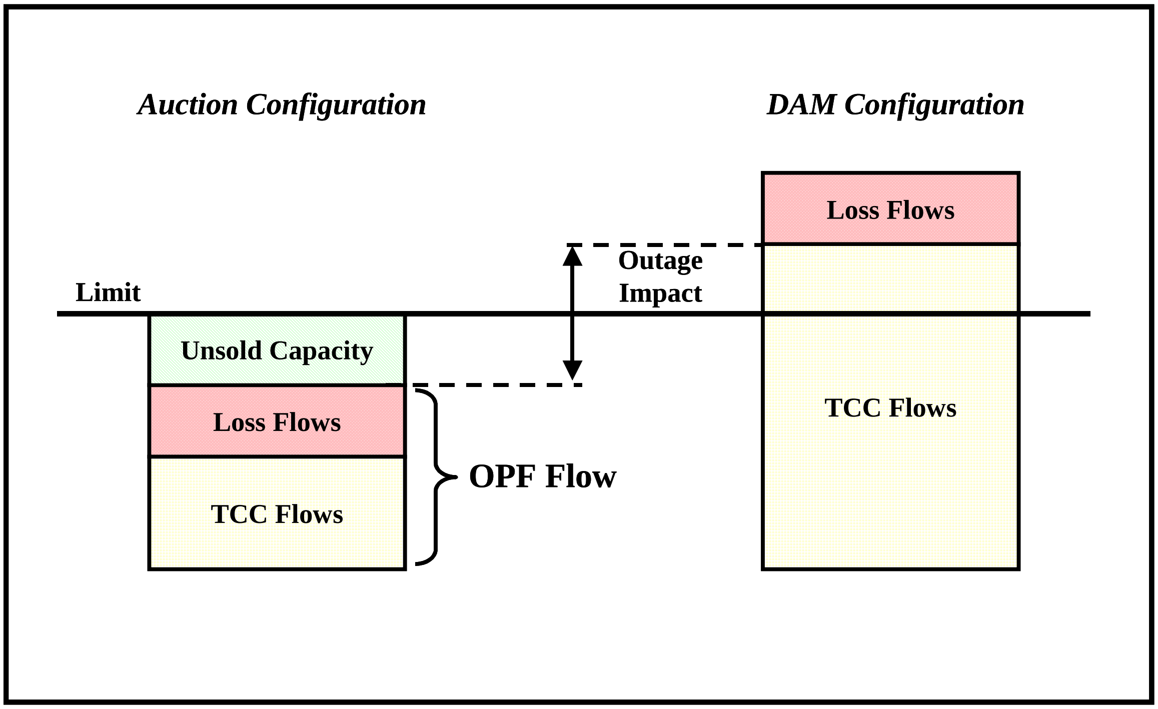
Equation 5a can be applied to these special cases for combinations of ratings changes and grid configuration changes in the same manner as described above for the base methodology as summarized in Table 21.

Table 21
Summary of Cases

Case	Outage		Return
	Singe	Combination	
1	Figure 11	Figure 22	Figure 12
2	Figure 13	Figure 23	N/
3	N/A	N/A	Figure 16
4	N/A	N/A	Figure 18

Figure 22 portrays the calculation of the impact of outages for which auction shift factors are not available (case 1) in combination with upratings or deratings in the day-ahead market attributable to outages or maintenance conditions. In this case the impact will be calculated as the difference between the TCC flow in the auction solution (from the OPF) and the TCC flows calculated for the day-ahead market grid using the SCUC shift factors. This methodology would yield the same result as that portrayed in Figure 13 once unsold capacity is subtracted from the calculated outage impact.

Figure 22
Missing Auction Shift Factors
in Combination Outage Case

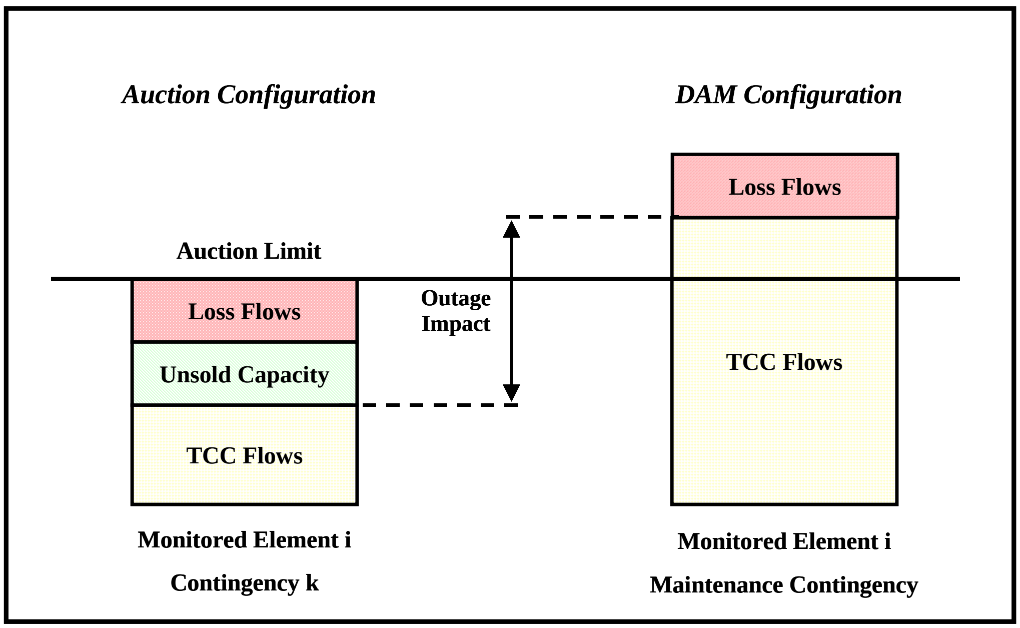


This case can also be illustrated for the example used for the base case by supposing that SCUC shift factors are not available for the constraint in the auction grid configuration. The $F_{DAM} – F_{TCC\ Auction}$ would then be calculated using the OPF flows for the auction grid rather than flows calculated from SCUC shift factors. $F_{DAM} – F_{TCC\ Auction}$ would be 300 (1,100 – 800) rather than 350, because the OPF flows would include some loss flows that are not included in the TCC flows calculated using SCUC shift factors.

The overall impact of the combination of the outage and derating would therefore be $1,000 = (-$5(300 – 200 + 100).

Finally, Figure 23 portrays the calculation of the outage impact for maintenance contingencies which were not enforced in the TCC auction (case 2) in combination with upratings or deratings in the day-ahead market attributable to outages or maintenance conditions. The impact of the outage is calculated as the difference between the TCC flows on the auction grid and the TCC flows on the day-ahead market grid calculated using SCUC shift factors in the relevant contingencies. Once again, this methodology yields the same result as the methodology portrayed in Figure 15 when unsold capacity is subtracted from the calculated total outage impact.

Figure 23
Maintenance Contingencies
Combination Outage Case



E. Allocation of Day-Ahead Shortfall Among Transmission Owners

Equations N-6 to N-11 assign outage costs and restoration benefits to transmission owners when there is more than one transmission owner whose outages and restorations impact the congestion shortfall. The current tariff language operates as intended for lines that are taken out of service and returned to service. The current tariff language is not written to allocate costs to the transmission owner whose maintenance conditions lead to deratings and upratings.

It is proposed to address this omission by allocating DCR between uprates/derates and reconfiguration outages based on the ratio

$$\frac{UprateDerate * z}{\left(F_{DAM} - F_{TCCAuction}\right) + UprateDerate * Z}$$

Thus:

for deratings and upratings:

N-6 $$CSCa,t,h = DCRa,h * \frac{UprateDerate * Z}{F_{DAM} - F_{TCC} + UprateDerate * Z}$$

for outages and restorations:

$$CSCa,t,h = DCRa,h * \frac{\left(F_{DAM} - F_{TCC}\right)}{F_{DAM} - F_{TCC} + UprateDerate * Z} \frac{\sum_{l \in Da,q,h \, and \, q = t} Vagl}{\sum_{\substack{for\,all\,\ell \in Dq,a,\ell \\ for\,all\,q \in T}} Vaq,l}$$

Equations [N-6] to [N-11] would then be applied to the portion of DCR that is allocated to configuration changes.

For the example above,

$$\frac{UprateDerate * Z}{F_{DAM} - F_{TCC} + UprateDerate * Z} = \frac{+100}{1{,}100 - 750 + 100} = \frac{2}{9}$$

$$\frac{\left(F_{DAM} - F_{TCC}\right)}{F_{DAM} - F_{TCC} + UprateDerate * Z} = \frac{350}{450} = \frac{7}{9}$$

In addition, the current tariff language assumes that the sign convention in the SCUC flow data is such that all shadow prices are positive, which is not the case. Minor changes are made to align the tariff language with actual SCUC sign conventions.

It is also desirable to clarify the application of Equations N-6 to N-11 in the circumstance in which a positive or negative DCR arises in part from NYISO determined changes in grid configuration. It is intended in this circumstance that V and X would be calculated separately for these changes in grid configuration but any costs or benefits assigned to the outage would be included in the net congestion rents for that hour.

Finally, certain transmission line outages, such as 1) the outage of a free-flowing transmission line or a PAR included in the definition of an interface into an area where the powerflow is controlled mostly by PARs or 2) the outage of a free-flowing transmission line inside or near an area where the powerflow is controlled mostly by PARs, could render the auction PAR schedules infeasible and require PAR schedule adjustments in the DAM to account for the transmission facility outage. In performing the calculations to determine the impact of the transmission line outage on the auction network in the circumstance in which the auction

PAR schedules would be infeasible as a result of the outage, the powerflow analysis performed to determine this impact will make appropriate adjustments to auction PAR schedules.

III. ALLOCATION OF AUCTION SHORTFALL COSTS

A. Problems with Current Tariff Methodology

1. Reconfiguration Auction

If limit is binding in the six-month auction and/or SP * (F_{Actual} - $F_{Base\ Case}$) < 0, then N-15a is used to calculate outage and restoration costs and benefits.

N-15a

$ACR = SP * (F_{Actual} - F_{Base\ Case}) * \%$

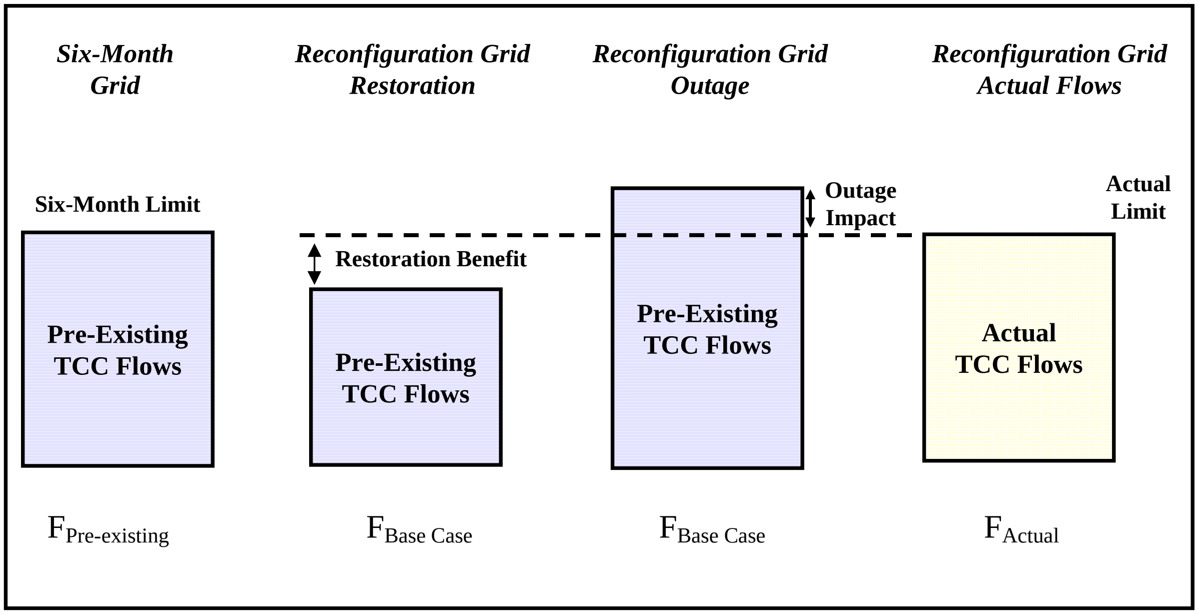
F_{Actual} = Actual TCC OPF flows in reconfiguration auction

$F_{Base\ Case}$ = OPF flows of pre-existing TCCs on reconfiguration auction grid.[10]

[10] As in the day-ahead market, SP, F_{Actual} and $F_{Base\ Case}$ can all be either positive or negative, depending on the direction of flow and whether the constraint is a minimum or maximum.

Figure 24 shows that if a transmission constraint is fully sold in the six month auction (i.e., the limit is binding) and there is no change in the limit between the six-month auction and the reconfiguration auction, then the impact of transmission line outages and returns to service will be reflected in the difference between the pre-existing TCC flows on the reconfiguration auction grid and the limit in the reconfiguration auction, the "restoration benefit" or "outage impact."[11]

Figure 24
Reconfiguration Auction

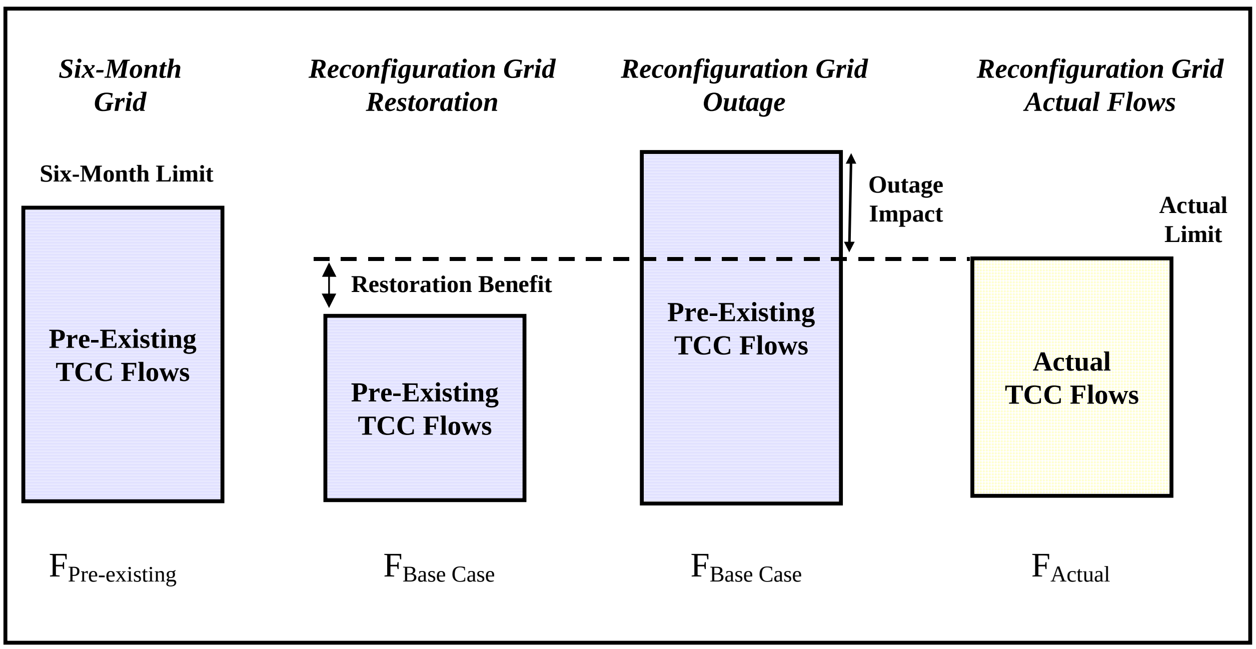


11 Note that if F_{Actual} is less than the limit, the constraint is not binding in the reconfiguration auction, the shadow price of the constraint will be zero and there will be no outage costs or restoration benefits associated with this constraint.

With this methodology, the value of $F_{Base\ Case}$ will reflect the impact of both changes in grid configuration and rating changes. Higher rating limits in the six-month auction than in the reconfiguration auction will raise the pre-existing TCC flows if the limit is binding in the six-month auction, leading to a greater outage impact or smaller restoration benefit if the limit is reduced to reflect a maintenance condition in the reconfiguration auction.

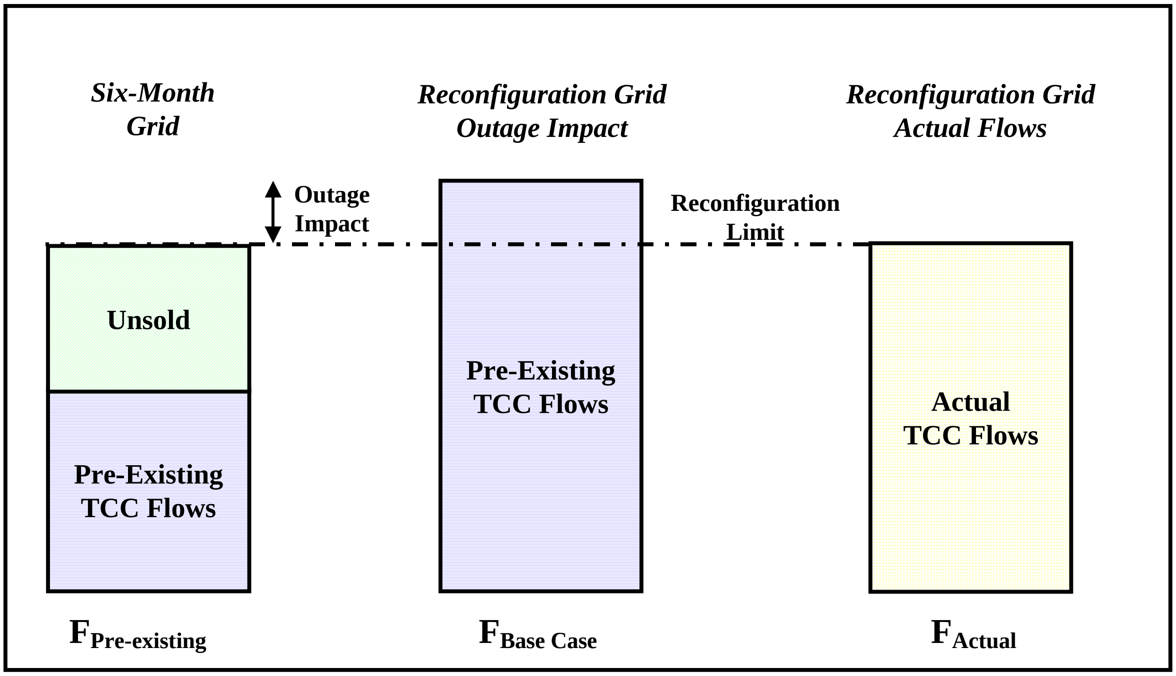
Figure 25 shows that if the transmission constraint is fully sold in the six month auction (i.e., the limit is binding), this methodology will also work if there is a maintenance-related change in the limit between the six-month auction and the reconfiguration auction. Once again, the impact of transmission line outages and returns to service will be reflected in the difference between the pre-existing TCC flows on the reconfiguration auction grid and the limit in the reconfiguration auction.

Figure 25
Reconfiguration Auction



The current tariff methodology also produces the intended outcome in the circumstance in which a transmission constraint is not fully sold in the six-month auction (i.e., the limit is not binding) and there is an outage that causes the pre-existing flows on the reconfiguration auction grid to exceed the limit in the reconfiguration auction as portrayed in Figure 26.

Figure 26
Reconfiguration Auction



A potential problem with the formulation of Equation N-15a in the current tariff is that it does not account for the possibility of a non-maintenance related limit reduction in a monthly reconfiguration auction. This circumstance will probably arise very infrequently but will be accounted for in the proposed tariff changes.

A more material problem with the current tariff methodology arises in the circumstance in which the ACR computed using N-15a > 0 but the constraint was not binding in the six month auction, i.e., there was unsold capacity on the constraint in the six-month auction.

In this circumstance in which there are restoration benefits, SP * (F_{Actual} - $F_{Base\ Case}$ > 0), but the limit was not binding in the six-month auction, N-15b is to be used to calculate the restoration benefits. Equation N-15b is intended to compensate transmission owners for the additional revenues collected in a reconfiguration auction as a result of restoring to service facilities that were modeled as derated or out of service in the six-month auction but to distinguish these benefits from the revenues attributable to selling transmission capacity that was available but not sold in the six-month auction.[12]

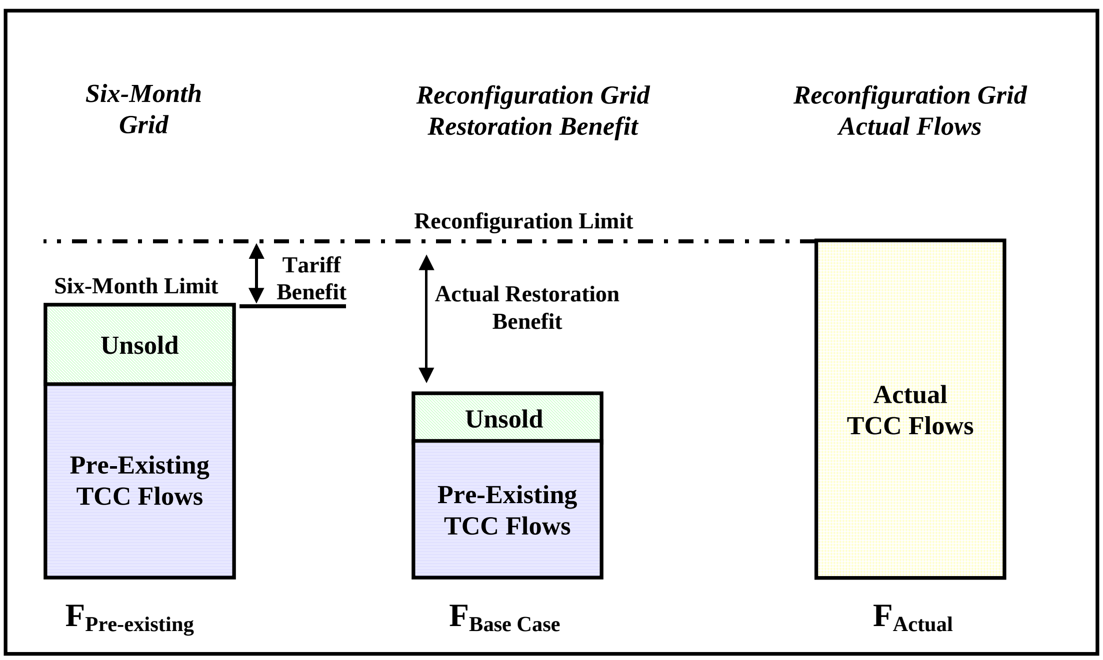
[*N-15b*] ACR = SP * (F_{actual} - F_{RL}) * %

F_{RL} = Rating limit in six-month auction

F_{actual} = OPF flows on constraint in reconfiguration auction.

If SP ≠ 0 (i.e., the constraint is binding), Factual = the rating limit in the reconfiguration auction and ACR will be equal to the change in the limit between the six-month auction and the reconfiguration auction. Thus under N-15B, ACR will always equal zero for changes in grid configuration (returns to service), as shown in Figure 27.

Figure 27
Reconfiguration Auction



[12] The revenues attributable to selling TCCs on capacity that was available but not sold in the six-month auction would be distributed among the transmission owners like other auction revenues.

This outcome does not reflect the intent of the short-fall allocation filing and is analogous to the problem with N-5b. Unless the tariff is corrected, there would be no direct benefit to a transmission owner for returning to service in the monthly reconfiguration auction a line that had been represented as out in the six-month auction.

2. Six-Month Auction

Conceptually, the current tariff applies the same methodology to outages in the six-month auction as discussed above for the reconfiguration auction, but there are some differences in implementation. The key difference between the methodology applied to outages in the reconfiguration auction and the six-month auction is that the equivalent of pre-existing TCCs are defined for the six-month auction using a simulated auction. The simulated auction defines a set of simulated pre-existing TCCs for the six-month auction by applying the bids and offers from the actual six-month auction to an all lines in grid configuration to define the set of TCCs that would have been awarded in the six-month auction had there been no line outages. The reason for this difference in methodology between the six-month auction and the reconfiguration auction is that absent outages the entire transmission grid is made available for sale in the six-month auction, so if the limit was binding in the six-month auction the pre-existing TCCs for the period covered by a reconfiguration auction would reflect all of the available transfer capability. This is not the case in the six-month auction, because a substantial proportion of the transfer capability of the grid is sold on a six-month basis, so at the time of a six-month auction there will be no pre-existing TCCs for a substantial proportion of the transfer capability of the grid for the period covered by the six-month auction.

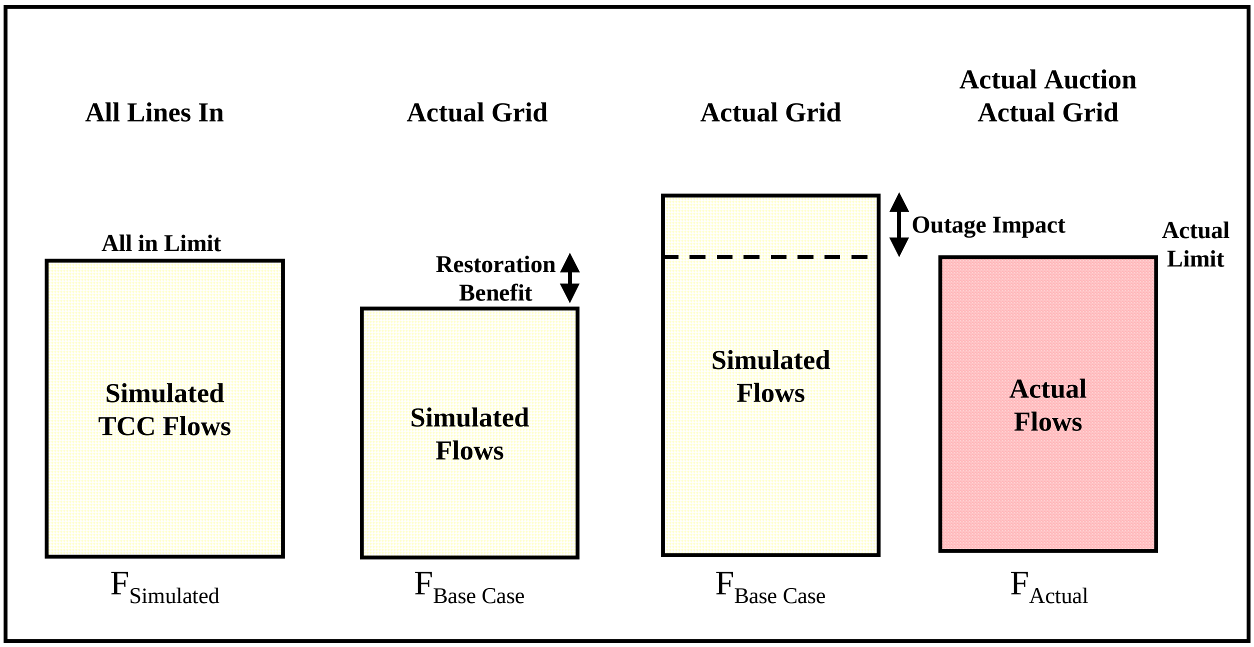
If the limit is binding in the simulated auction and/or SP * $(F_{Actual} - F_{Base\ Case}) < 0$, then outage costs and/or restoration benefits for the six-month auction will be calculated using N-15a as portrayed in Figure 28.

[N-15a] $ACR = SP * (F_{Actual} - F_{Base\ Case}) * \%$

F_{Actual} = Actual TCC OPF flows in six-month auction

$F_{Base\ Case}$ = OPF flows of simulated TCCs on six-month auction grid.

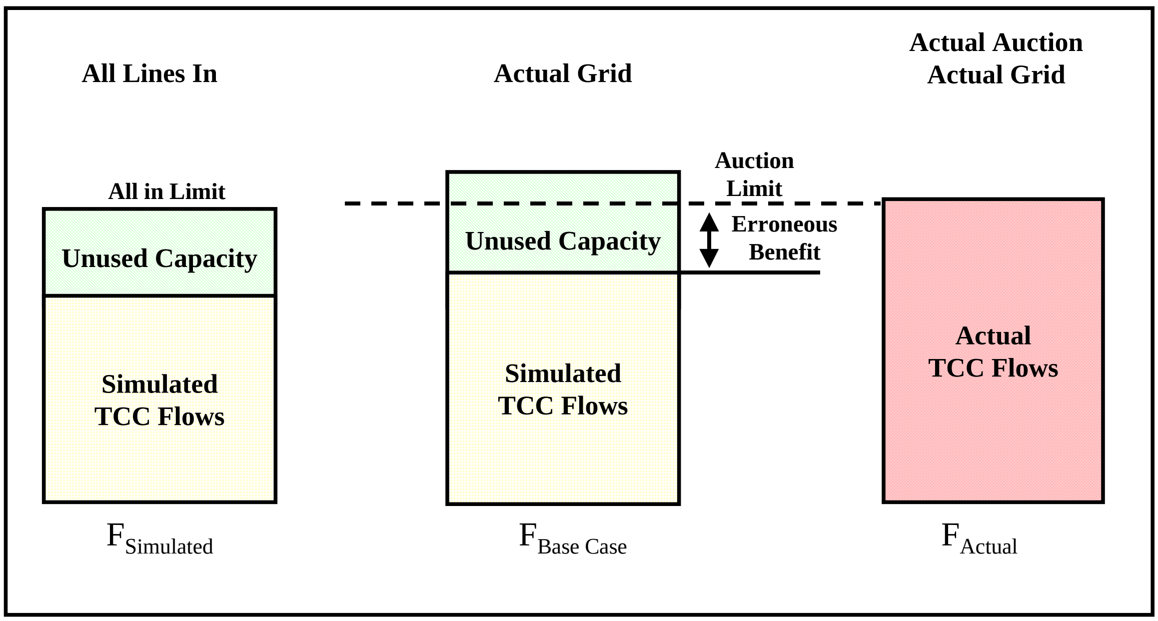
Figure 28
Six-Month Auction
Current Tariff



As explained for the reconfiguration auction, the value of $F_{Base\ Case}$ will reflect the impact of both changes in grid configuration and rating changes. Equation N-15a will therefore generally operate as intended and correctly identify outage costs and restoration benefits but, as in the case of the reconfiguration auction, Equation N-15a does not account for the possibility of a non-maintenance related limit reduction in a six-month auction.

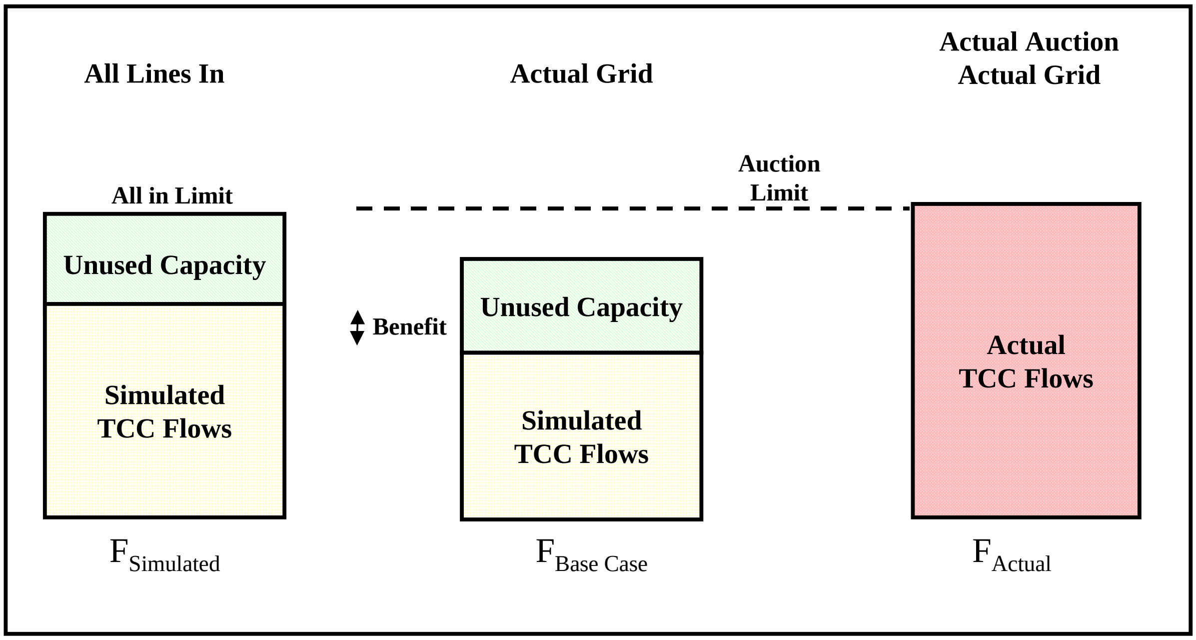
It is important in understanding the application of N-15a and N-15b to the six-month auction to recognize that while the limit will be binding in the actual six-month auction for all constraints with positive shadow prices in the six month auction, it is possible for there to be unsold capacity on transmission constraints in the simulated auction, even if there is no unsold capacity on that constraint in the actual auction as portrayed in Figure 29 below. This possibility arises because the simulated auction can have a different solution than the actual auction, with a different set of TCCs awarded and different binding constraints. While the overall set of TCCs awarded in the simulated auction will be the same or higher valued than the set awarded in the actual auction if there are outages or deratings in the actual auction, this outcome could entail lower TCC flows on some lines and higher flows on others. If N-15a were applied to a constraint that is not binding in the simulated auction, it could result in the calculation of a restoration benefit reflecting such unsold capacity in the simulated auction, rather than reflecting a real benefit of a change in grid configuration resulting from a return to service (labeled “erroneous benefit” in Figure 24). Equation N-15b addresses this possibility by limiting the restoration benefit to the difference between the actual limit and the all lines in limit, which must be less than or equal to zero because the actual auction limit would be less than or equal to the all lines in limit.

Figure 29
Six-Month Auction



The potential limitation of the formulation of N-15b in the current tariff is that the restoration benefit is always zero or negative. This outcome will generally be appropriate as there are no returns to service in the six-month auction. This outcome, however, does not reflect the intent in the relatively rare circumstance in which an outage increases transfer capability by reducing flows on a constraint that is binding in the six-month auction, as portrayed in Figure 30.

Figure 30
Six-Month Auction



B. Revised Implementation Methodology

1. Reconfiguration Auction

Since N-15a generally operates as intended, only a minor change is necessary in the application of N-15a to account for the possibility of ratings changes between the six-month and reconfiguration auction that are unrelated to maintenance activities. Thus:

[N-15a] ACR = $SP * (F_{Actual} – F_{Base\ Case} + RC * Z) * \%$

where:

F_{Actual} = Actual TCC OPF flows in reconfiguration auction

$F_{Base\ Case}$ = OPF flows of preexisting TCCs on reconfiguration auction grid

RC = Ratings change unrelated to transmission maintenance (six-month rating – reconfiguration rating)

$Z \quad = \quad 1$ if $SP > 0$; -1 if $SP < 0$.

The principal proposed tariff change is to revise N-15b so that it accounts for the impacts of both changes in limits and changes in grid configuration, in the circumstance in which $SP * (F_{Actual} – F_{Base\ Case}) > 0$. The proposed methodology is very similar to that applied in the revised version of N-5a. If the limit is not binding in the six-month auction (i.e., unsold ≠ 0) and $SP * (F_{Actual} - F_{Base\ Case}) > 0$, then:

[N-15b] $ACR = SP * (F_{Actual} - F_{Base\ Case} - Unsold * Z + RC *Z) * \%$

$Unsold = R_L - |F_{Pre\text{-}existing}|$

R_L = Rating limit in six-month auction

F_{Actual} = Actual TCC OPF flows in reconfiguration auction

$F_{Base\ Case}$ = OPF flows of preexisting TCCs on reconfiguration auction grid

$F_{Pre\text{-}existing}$ = OPF flows of pre-existing TCCs on six-month auction grid

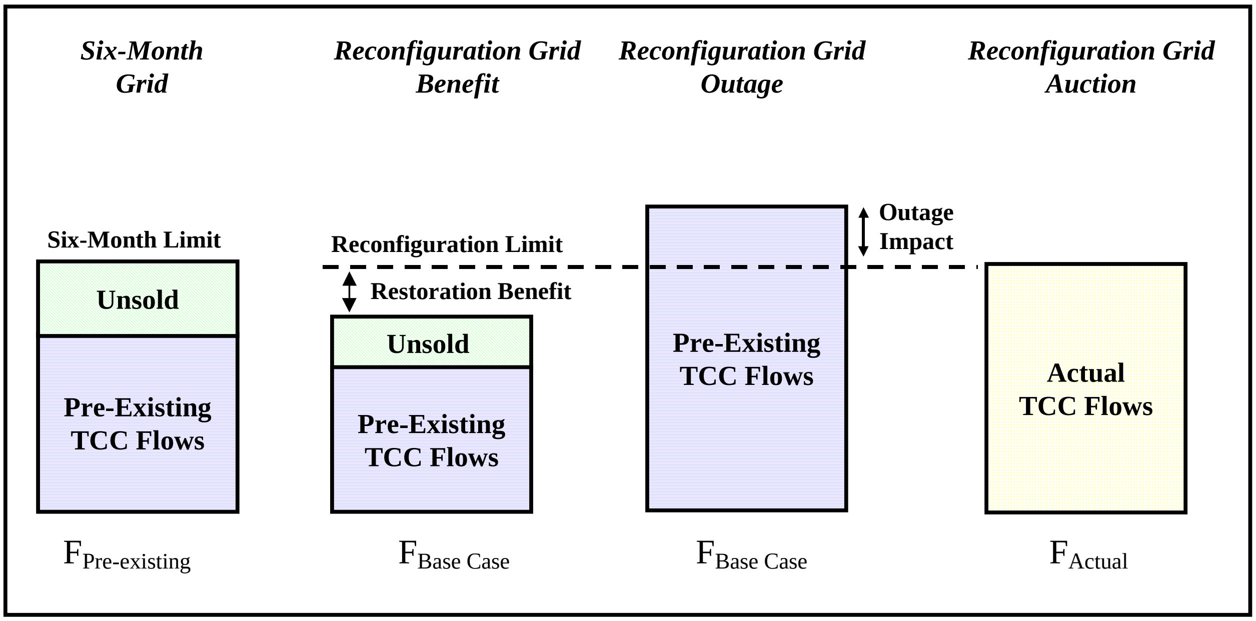
RC = Ratings change unrelated to transmission maintenance (six-month rating – reconfiguration rating)

$Z \quad = \quad 1$ if $SP > 0$; -1 if $SP < 0$.

This formulation provides the intended result for all combinations of outages, restorations and changes in ratings limit between the six-month and reconfiguration auction.

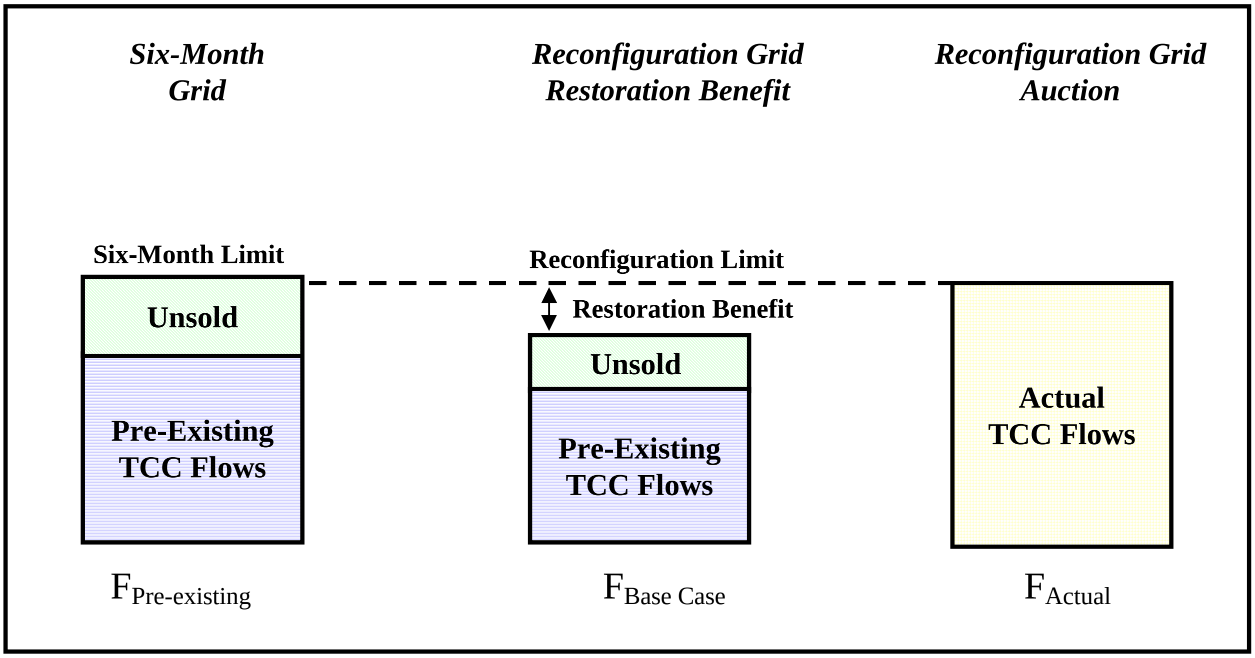
Consider first the case portrayed in Figure 31 in which there is no change in rating limit between the six month auction and the reconfiguration auction. The restoration benefit is the difference between the limit in the reconfiguration auction (F_{Actual}) and the sum of pre-existing TCC flows on the reconfiguration auction grid and the capacity on the constraint that was not sold in the six-month auction. Since N-15b only applies when the constraint was not binding in the six-month auction, the unsold capacity adjustment will always be non-zero when N-15b is applied. The effect of the unsold capacity adjustment is to reduce the restoration benefit to the actual benefit from restorations as shown in Figure 31. The sign of unsold capacity depends on the direction of flow. It will be the same sign as $F_{Base\ Case}$.

Figure 31
Reconfiguration



This revised formulation also works if there is a derating in the reconfiguration auction attributable to a maintenance condition, as illustrated in Figure 32. A maintenance related derating between the six month auction and the reconfiguration auction reduces the benefits of the line restoration because F_{Actual} will be reduced. Deratings in the reconfiguration or six-month auctions attributable to causes other than maintenance conditions are accounted for in RC which increases the restoration benefit if F_{Actual} is reduced by non-maintenance deratings.[13]

Figure 32
Reconfiguration Auction



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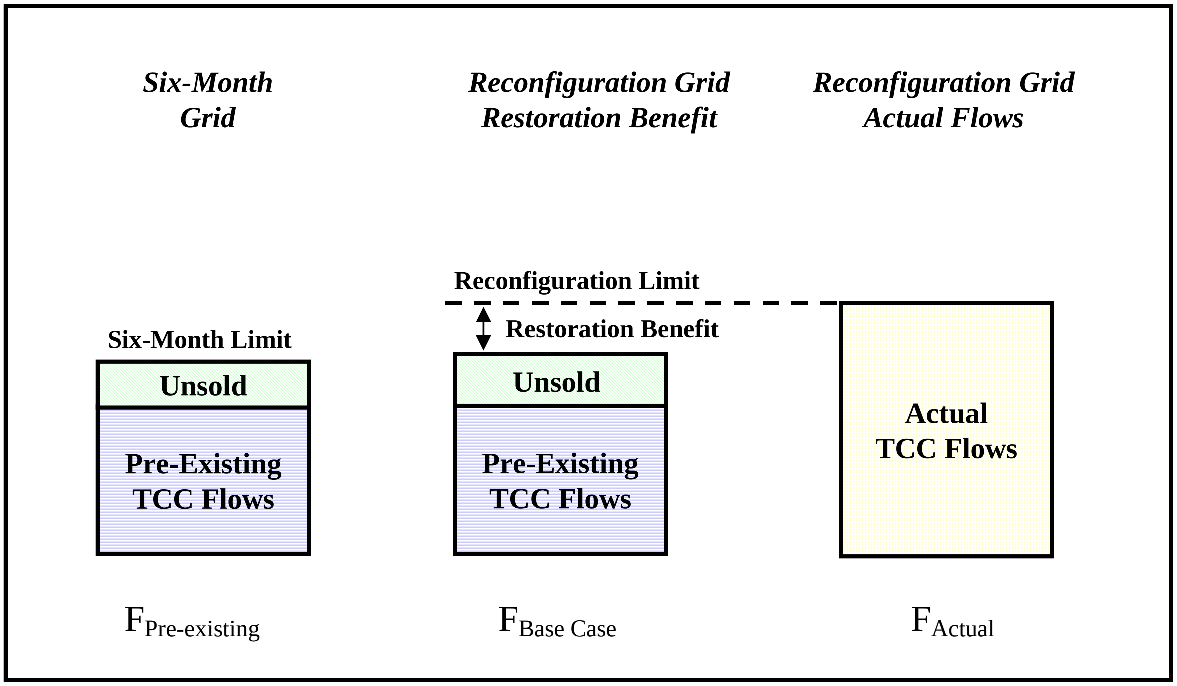
13 The impact of non-maintenance line outages and restorations (as opposed to changes in rating limits) are accounted for in Equations N-16 to N-19.

This revised formulation also works if there is an uprating in the reconfiguration auction attributable to elimination of a maintenance conditions. Figure 33 illustrates how an increase in line rating between the six month auction and the reconfiguration auction attributable to elimination of a maintenance condition would increase the restoration benefit.

Figure 33
Reconfiguration Auction



2. Six-Month Auction

Similar changes would be made in the current tariff as applied to the six-month auction, although these changes are less likely to have practical impact. First, the application of N-15a to the six-month auction would also be modified to account for the possibility of deratings in the six-month auction that are unrelated to maintenance activities. Thus,

[N-15a] $ACR = SP * (F_{Actual} – F_{Base\ Case} + RC * Z) * \%$

where:

F_{Actual} = Actual TCC OPF flows in six-month auction

$F_{Base\ Case}$ = OPF flows of simulated TCCs on six-month auction grid

RC = Deratings in six-month auction below all lines in limit that are unrelated to maintenance activities (all lines in – six-month rating)

Z = 1 if SP > 0; -1 if SP < 0

Second, the same approach would in principle be applied to N-15B for the six month auction as in the reconfiguration auction, although it is relatively unlikely that an outage in the six-month auction would lead to a benefit. If the limit is not binding in the simulated auction and SP * (F_{Actual} - $F_{Base\ Case}$) > 0, then:

N-15b $ACR = SP * (F_{Actual} - F_{Base\ Case} - Unused * Z + RC * Z) * \%$

Unused = $R_L - |F_{Simulated}|$

R_L = Rating limit in “all lines in” simulated auction

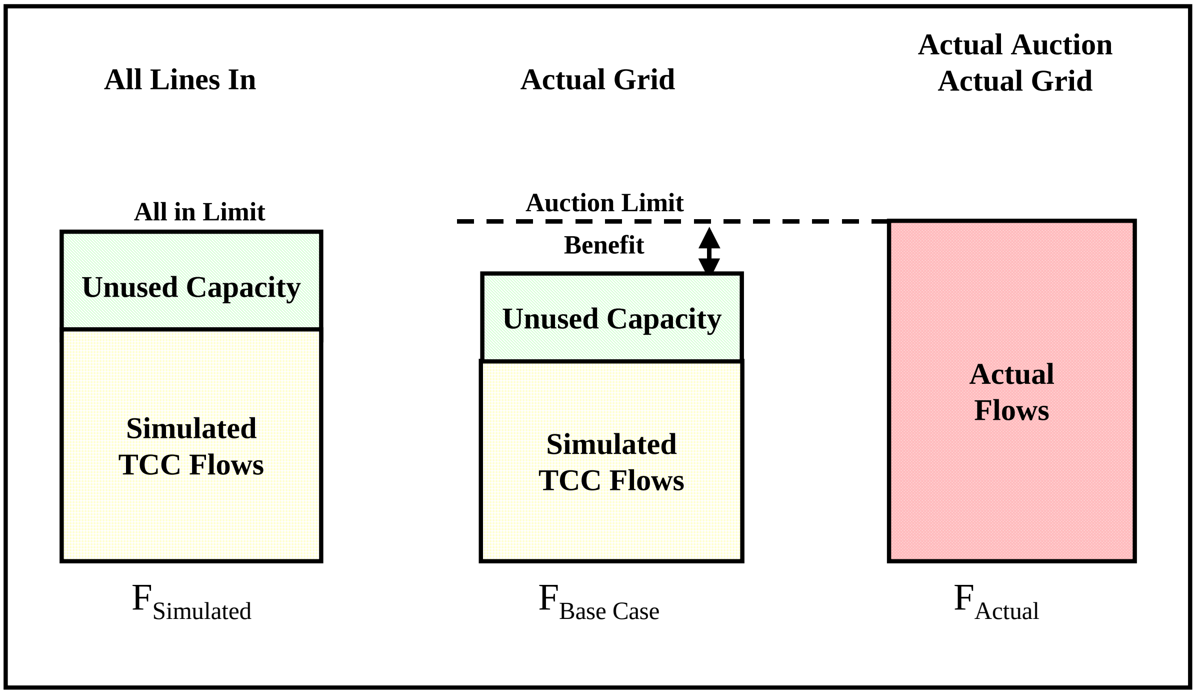
$F_{Simulated}$ = OPF flows in “all lines in” simulated auction

RC = Ratings change unrelated to transmission maintenance (all lines in – six-month rating)

Z = 1 if SP > 0; -1 if SP< 0.

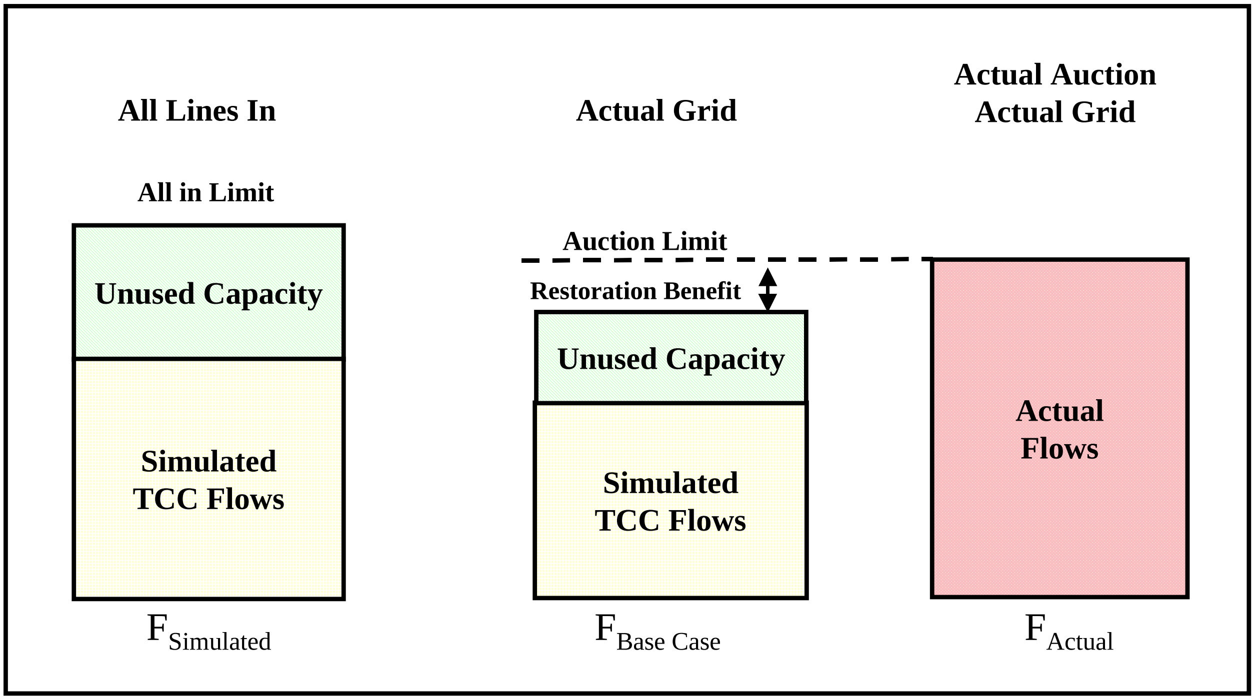
This formulation provides the intended result if the ratings limit is the same in the "all lines in" and six-month auctions, as illustrated in Figure 34.

Figure 34
Six-Month Auction



The revised formulation will also work if there is a derating in the six-month auction attributable to a maintenance condition, as illustrated in Figure 35, with the restoration benefit reduced by the derating. If there is a derating in the six-month auction for reasons unrelated to maintenance conditions, the ACR calculation needs to be adjusted in the same month as described for the reconfiguration auction.

Figure 35
Six-Month Auction



C. Allocation of Auction Shortfall Among Transmission Owners

Equations N-16 to N-21 assign auction outage costs and restoration benefits to transmission owners when there is more than one transmission owner whose outages and restorations impact auction revenues. Two changes are proposed in the current tariff methodology.

First, the definition of V and X in Equations N-16 to N-21 would be expanded to include maintenance-related upratings and deratings, rather than just outages and returns to service. As explained for outages in the day-ahead market, there are two alternative ways of implementing this. One way would be to include deratings and upratings in N-16 to N-21. An alternative approach would be to allocate ACR between maintenance deratings ad outages and then apply N-16 through N-21 to the portion of ACR assigned to outages.

Second, it is also desirable to clarify the application of Equations N-16 to N-21 in the circumstance in which a positive or negative ACR arises in part from NYISO determined changes in grid configuration that are not the result of a maintenance outage. It is intended in this circumstance that V and X would be calculated separately for these changes in grid configuration but any costs or benefits assigned to the outage would be included in the net auction revenues for that hour.